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November 2, 2021

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

Re: Eversource Gas Company of Massachusetts d/b/a Eversource Energy, D.P.U. 21-118
2021/2022 – 2025/2026 Forecast and Supply Plan

Dear Mr. Marini:

On behalf of Eversource Gas Company of Massachusetts d/b/a Eversource Energy (the "Company"), enclosed is the Company's Long-Range Forecast and System Gas Supply Resource Plan (the "F&SP"), submitted pursuant to G.L. c. 164, § 69I, for the forecast period of November 1, 2021 through October 31, 2026.

In this filing, the Company presents its forecasting methodology and resource-planning process, along with a strategic resource plan based on the current forecast of customer requirements and market conditions. Approval of the Company's FS&P is warranted because the plan is in compliance with the demand forecasting and integrated resource planning standards and methods set by the Department of Public Utilities.

Accompanying this letter is a Notice of Appearance relating to this docket. Should you have any questions regarding the information provided with this filing, please do not hesitate to contact me directly.

Thank you for your attention to this filing.

Very truly yours,

Steven Frias

Steven Frias

Encl.
cc: George Yiankos, Director, Gas Division
Sarah Smegal, DPU Hearing Officer
Nathan Forster, Assistant Attorney General
Matthew Saunders, Assistant Attorney General

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Eversource Gas Company of Massachusetts d/b/a Eversource Energy	))))	D.P.U. 21-118

APPEARANCE OF COUNSEL

In the above-referenced proceeding, I hereby appear for and on behalf of Eversource Gas Company of Massachusetts d/b/a Eversource Energy.

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Dated: November 2, 2021

EVERSOURCE GAS OF MASSACHUSETTS

2021
LONG RANGE FORECAST AND
SUPPLY PLAN
2021/2022 – 2025/2026

Submitted to:

Massachusetts Department of Public Utilities

November 2, 2021

I. INTRODUCTION

The purpose of this report by Eversource Gas of Massachusetts ("EGMA" or the "Company")[1] is to present the long-range forecast and supply plan (the "F&SP" or the "Plan") for the period November 1, 2021 through October 31, 2026. The F&SP details EGMA's resource-planning process and presents the Company's resource requirements based on a forecast of customer demand and prevailing market conditions. EGMA submits this F&SP for review and approval by the Department of Public Utilities (the "Department") pursuant to G.L. c. 164, § 69I. The Department's approval of the Company's F&SP is warranted because the F&SP sets forth a resource plan to meet expected customer requirements using the Department's established forecasting planning processes, standards and methods.

The Company's FS&P meets the Department's established standards for approval under G.L. c. 164, § 69I. The F&SP provides a complete description of the planning processes employed by the Company, which will enable the Department to adequately review the Plan and to come to a full understanding of the methods used and the results reached by applying those methods to current circumstances. The Plan demonstrates that EGMA's planning standards are appropriate and that the resource strategies described herein are in the best interest of customers and result in a reliable, long-range, least cost supply to meet the Company's forecasted firm demand. Lastly, the Plan demonstrates that the Company's resource portfolio is sufficient to meet design day, design winter and design year requirements, as well as demand that could be expected during a cold snap.[2]

A. Overview of EGMA Services and Resources

EGMA provides local distribution service to over 320,000 customers residing in three separate operating divisions, located in areas of Massachusetts surrounding the major cities of Brockton, Springfield and Lawrence. The majority of EGMA's customer base is comprised of

[1] In October 2020, EGMA became the successor in interest to Columbia Gas of Massachusetts as part of a settlement approved by the Department. Joint Petition of Eversource Energy, Eversource Gas Company of Massachusetts, NiSource Inc. and Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of Purchase and Sale of Assets Pursuant to General Laws Chapter 164, §§ 94 and 96, D.P.U. 20-59 (2020).

[2] The required Energy Facilities Siting Board ("EFSB") tables are set forth in Appendix 1.

residential customers. The remainder of EGMA's customers are traditional small and medium-size commercial and industrial ("C&I") customers, as well as some larger industrial customers. The forecast aggregate design day demand for sales customers ("Planning Load") on EGMA's system for the upcoming winter is approximately 517 MDth, including the expected demand-side resource offsets. Normal annual requirements are expected to be about 57.2 MMDth in the initial year of the Plan.

All of EGMA's customers have the option of purchasing supply from a competitive supplier and receiving transportation-only service from EGMA, pursuant to the Company's unbundled tariff options. EGMA has numerous customers being served by seven suppliers. The terms and conditions applicable to transportation-only service specify EGMA's obligation to assign capacity to portions of the transportation customer loads in each division. EGMA's resource planning process appropriately reflects its obligation to assign capacity and maintain reliability in conjunction with its unbundled service offerings.

EGMA's current resource portfolio is comprised of long and short-haul transportation capacity, storage capacity and associated transportation capacity, city-gate and off-system peaking supplies and on-system peak-shaving facilities. All of EGMA's upstream long- and short-haul transportation capacity and underground storage and city-gate peaking supplies are ultimately delivered to the Company's divisions located off of the Tennessee Gas Pipeline Company ("Tennessee" or "TGP") and Algonquin Gas Transmission, LLC ("Algonquin" or "AGT") pipelines. EGMA's on-system peaking facilities include on-system liquid propane gas ("LPG") and liquefied natural gas ("LNG") facilities located within each of its divisions as well as off-system peaking services that provide deliveries to the Brockton, Springfield and Lawrence Divisions. The combination of base load, winter and peaking resources provides a diverse, reliable and cost-effective means of serving EGMA's overall firm customer and associated demand profile.

B. STANDARD OF REVIEW

The Department assesses each LDC's long-range planning standards, demand forecasting methods and resultant design and normal sendout forecasts in order to determine if they are reviewable, appropriate, and reliable. A forecast method is reviewable, if it "contains enough information to allow a full understanding of the forecast methodology"; appropriate, if it is "technically suitable to the size and nature of the particular gas company;" and reliable, if it "provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is most likely to occur." Bay State Gas Company, D.P.U. 08-79, at 2 (2010). The Department also reviews an LDC's long-range demand forecasts to ensure that it has accurately projected gas sendout requirements of the utility's market area. Lastly, the Department reviews an LDC's supply planning process and the resulting resource portfolio with an emphasis on adequacy and cost. The Department's review of an LDC's supply plan investigates whether the portfolio is adequate to meet forecast firm requirements under design year, design day and cold-snap conditions for the base case. In instances where the portfolio is not adequate to meet the base case of forecast requirements, the LDC must demonstrate that it has an adequate Action Plan to address any deficiency.

C. ORGANIZATION OF THE FORECAST AND SUPPLY PLAN

This Plan is organized into six sections, including this Section I (Introduction). Section II provides a summary of the current resource planning environment, the Company's resource planning objectives and goals, and the resource planning process prior to examining each of the Plan's elements in more detail. Also, Section II summarizes the Company's resource planning tools.

Section III presents EGMA's Demand Forecast, including: (a) an overview of the methodology that EGMA followed to prepare the F&SP demand forecast; (b) a description of the forecast models that were developed for this F&SP and a summary of the model results; (c) projected customer demand offsets due to energy efficiency ("EE") or demand-side resources; (d) a summary of the derivation of the resource requirements, or "planning load" that EGMA used to assess the adequacy of its resources, including the derivation of several scenarios to reflect weather-related extremes and optimistic and pessimistic economic scenarios; and (e) a description for the derivation of the weather-related extremes, or "planning standards" used to derive estimates of future design day, cold snap and normal and design winter requirements, which are all used in the Company's portfolio optimization model.

Section IV describes the Company's current resource planning process, including special considerations given to today's planning environment and supply-side resource strategies based on current customer requirements and market conditions. Section V summarizes EGMA's Action Plan. Lastly, Section VI states EGMA's conclusion regarding its resource plan. The required Energy Facilities Siting Board ("EFSB") tables, plus supporting detail for the demand forecast and the resource assessment, are provided in the appendices to this report. EGMA's Plan incorporates flexibility and reflects expected future conditions. It is a dynamic living document in the sense that it continues to be refined as needed in order to reasonably respond to the changing requirements of EGMA's customers and market conditions. Supply requirements are planned for and procured within a dynamic environment involving a marketplace influenced by various economic conditions. Therefore, the Company's decisions will be based on current assessments of the best information known at the time that are subject to change. All assessments, however, will be based upon the methodology set forth in this Plan.

II. OVERVIEW OF RESOURCE PLANNING PROCESS

EGMA's resource planning process begins with the establishment of appropriate goals and objectives. The primary goal of EGMA's planning process is to acquire and manage resources in a manner that achieves a least-cost resource portfolio for its customers. A least-cost portfolio appropriately balances resource cost with EGMA's other planning objectives, which are to maintain the security and reliability of supply, provide contract flexibility and pursue the acquisition of viable resources. Pursuit of a least-cost portfolio allows EGMA to provide its customers with reliable service at the lowest possible cost, consistent with the planning criteria required by G.L. c. 164, § 69I and Department precedent. In addition, EGMA's resource planning process incorporates the current status of market restructuring in natural gas markets.

A. CURRENT RESOURCE PLANNING ENVIRONMENT

Market and regulatory restructuring of wholesale and retail natural gas markets over the last few decades have increased the complexity associated with acquiring and managing a least-cost resource portfolio. Virtually every aspect of LDC portfolio management has been transformed by regulatory and market changes. In the broadest of terms, the very markets that LDCs such as EGMA participate in, the types of products and services that are bought and sold, and the manner in which these transactions are completed are vastly different today than they were 40, 30 or even 20 years ago. Market transformation has brought about many new opportunities and risks for all market participants, including LDCs, which must continue to reliably meet the supply requirements of their customers.

Natural gas markets continue on a course of broad restructuring that began with the initial deregulation of most wellhead supply prices starting in 1978 through an act of Congress. Through a series of physical infrastructure, financial market, regulatory and technological advances, the manner in which gas supplies are traded and delivered to end-use customers has changed entirely. Whereas in the past, an LDC or end user might have only been able to procure gas from one or two entities, today there are many more available choices. The result is a dynamic and more competitive marketplace that is capable of delivering greater value to customers, but also increases the complexity of resource planning.

Wholesale natural gas commodity markets are no longer price-regulated and the delivery of supplies to LDC city-gate stations is unbundled from supply and storage services. Large volumes of gas are traded at many different pooling points along the interstate pipeline transmission system at transparent prices. LDCs, and even many end users, purchase supplies directly from marketing entities offering flexible contract terms. Additionally, natural gas contracts are among the most actively traded futures and options in financial markets. Even pipeline and storage capacity services are actively traded under more flexible terms in the primary and secondary release markets.

The U.S. natural gas industry has experienced significant change over the past fifteen years, including the discovery and production of natural gas from prolific shale gas deposits. The increasing domestic production of natural gas has resulted in numerous changes to not only the broader U.S. natural gas market, but also to the New England region. Specifically, in the New England region, the increase in domestic natural gas supplies has generally resulted in lower annual natural gas prices and an increase in the demand for natural gas.

These changes in natural gas markets have brought greater competition and customer choice along with increased market instability and uncertainty, substantially complicating the factors involved and manner in which an LDC forecasts customer demand and designs its resource portfolio. As the Department recognized in its investigation into the appropriate capacity assignment methodology, unlike electricity markets, for example, gas markets do not have centralized bodies such as independent system operators that can effectively take responsibility for regional reliability. With the introduction of competition from marketers, the LDC remains responsible for ensuring the supply reliability for its firm sales and non-capacity exempt firm transportation customers (i.e., “Planning Load”), a responsibility that can be more challenging with the reliance of marketers to deliver supply to their capacity exempt customers. As the Department has found in its decision for a mandatory capacity assignment construct, the responsibility of ensuring supply reliability for the then-existing firm customer base is an appropriate role that EGMA and other LDCs must fulfill until upstream gas markets are sufficiently robust to be relied upon for the provision of reliable, low-cost gas deliveries.

Today's marketplace is witnessing another fundamental change that is reinforcing the need for LDC's to manage the responsibility to supply their customers under design conditions. As the New England region grapples with how to counter the drastic impacts of climate change, a new reality has impacted how to access new sources of supply to reliably serve existing and new customers. The public has become increasingly more vocal in its opposition to any new gas infrastructure to be added in New England that would help alleviate bottlenecks that would allow access to new supplies sourced out of the Marcellus region. As a result, there is not enough infrastructure in place in New England to adequately serve the demand of both LDC load and the gas-fired generators servicing New England's electric load. Electric generators are now the largest single consumers of natural gas in New England, yet the vast majority of these consumers do not have enough pipeline capacity to supply their needs during the winter months. This has led to regional pipelines that consistently operate at maximum capacity, winter prices in Massachusetts that are forecasted to be far higher than other parts of the country and a dramatic reduction in the flexibility historically experienced on the pipelines that serve New England. Currently access to incremental supplies to serve LDC growth is limited to imported LNG from either the Everett or Canaport or other LNG facilities that can provide supplies from the backend of the pipeline system that does not require pipeline expansions to serve incremental growth. Relying on imported LNG to serve incremental growth exposes LDC's to cost that are set by volatile global LNG markets during winter months.

The new reality of new regulations and our collective work to address the effects of rising CO2 levels that is impacting climate change is that the LDC's role in planning process is even more vital to ensure the reliability of service its customers during the transition to more environmentally friendly economy. To help reduce the need for new gas supplies, EGMA's customers continue with their strong energy conservation and efficiency efforts. The Company offers a comprehensive set of energy efficiency ("EE") programs for residential, low-income, and commercial and industrial ("C&I") markets. These programs are developed as part of the statewide EE effort pursuant to an Act Relative to Green Communities, Chapter 169 of the Acts of 2008, which was designed to promote enhanced energy efficiency throughout the Commonwealth through "the acquisition of all available energy efficiency demand reduction resources that are cost effective or less expensive than supply." G.L. c. 25, § 21(b)(1). Stable energy prices and Company-sponsored EE measures wherever cost effective have helped to increase customer-driven conservation.

The Company also continues to explore alternative supply options as part of number of initiatives:

1. Future of Gas Proceeding (D.P.U. 20-80)

Eversource is actively engaged in the D.P.U. 20-80 proceeding, which is an investigation into and proceeding on the future of the natural gas systems in Massachusetts opened by the Department on October 29, 2020. This investigation and proceeding directs the Massachusetts gas distribution companies to investigate how they will meet the state emissions reduction mandates by 2050 while also maintaining safe, reliable and affordable service for customers. Eversource and the other gas distribution companies conducted a rigorous solicitation process to identify a consultant to perform decarbonization modeling and analysis utilizing both the Commonwealth's analysis from the draft 2030 CECP and the 2050 Roadmap. Additionally, the consultant is evaluating alternative pathways to decarbonize that may involve, but is not limited to, combinations of electrification, biogas (renewable natural gas and hydrogen), networked geothermal, and deep energy efficiency measures.

This technical analysis will ultimately inform a new or revised regulatory framework to be proposed by Eversource and the other natural gas distribution companies in March 2022. In addition to the technical analysis, Eversource is also coordinating with the other natural gas distribution companies to conduct a robust stakeholder engagement process enabled by a third-party facilitator. This process is intended to involve all stakeholders across the Commonwealth and invites them to share perspectives and feedback on decarbonizing the natural gas systems. Eversource and the other natural gas distribution companies have committed to take all feedback, incorporate what they can into the decarbonization analyses, or, if the feedback was not incorporated, Eversource and the natural gas distribution companies will provide rationale as to why not. Eversource and its peers are approaching decarbonization seriously and in a technology agnostic way to ensure a safe, cost-effective and successful transition to meet the Commonwealth's 2050 goals.

2. Demand Response Pilot

Eversource is looking forward to rolling out its gas demand response pilot by November 1, 2021. Eversource has made commitments to use wi-fi thermostats for up to 2,000 residential and small commercial customers with up to 10 medium-to-large customers. The Company anticipate this will be modeled after the electric demand response program already underway and would take a technology agnostic approach.

3. Networked Geothermal Pilot

Eversource is currently developing a networked geothermal demonstration pilot project to test the technology at utility scale in a dense, urban, mixed use setting in its NSTAR Gas service territory. The Company intends to test three main concepts informed by this pilot:

- Can networked geothermal be a fiscally sound business line offering that the Company can provide to its customers?
- Does networked geothermal provide increased environmental benefits to the Company and its customers?
- Do the customers receive the space conditioning desired and needed?

If the pilot project is deemed successful, the Company looks forward to expanding its networked geothermal offerings to customers including within the EGMA footprint.

4. Renewable Natural Gas and Differentiated Natural Gas

As the longer-term decarbonization solutions are being analyzed and vetted, Eversource continues to look for ways to reduce emissions currently or in the near term while maintaining the expected level and cost of service to customers. EGMA recently entered into a one-year pilot with an upstream pipeline and natural gas producer to receive differentiated, or responsible, natural gas at no additional cost to customers. This pilot will begin in November 2021. The Company also continues to look for renewable natural gas ("RNG") opportunities to provide to customers while also mitigating renewable natural gas premiums and in the absence of regulatory cost recovery framework. RNG offers a low or no carbon solution for customers while also utilizing the existing natural gas infrastructure and reducing overall emissions.

5. Other Clean Technology Opportunities

Eversource continues to investigate ways to mitigate emissions and other low to no carbon solutions that utilize its existing infrastructure. In the near term, the Company is engaged on any new technologies that mitigate or reduce methane emissions, included replacement of existing distribution systems that reduce methane leaks presently. With the advent of the recently enacted climate bill Senate Bill 9, the Company is looking for synergies with solar and natural gas systems. The Company also continues to research hydrogen and look for ways to spur development. Additionally, from a hydrogen perspective, the advent of the Company's offshore wind assets may provide a clean and cost-effective partnership with the existing natural gas infrastructure in the future.

B. CURRENT AND FUTURE MARKET CONDITIONS

The most recent expansions of pipeline capacity sponsored by the LDCs into the New England market included the Algonquin "AIM" project (342,000 MMBtu/day) which was placed into service during the winter of 2016-17 and the Algonquin "Atlantic Bridge" project (133,000 MMBtu/day) which was partially placed into service in 2017-18 and which went into full service on October 1, 2019. Both Tennessee (TGP) and Algonquin (AGT) planned to expand to serve gas fired electric generation load with their proposed Northeast Direct project (NED) and Access Northeast (ANE) project respectively, but both projects were dropped when the Massachusetts Supreme Judicial Court determined that the Department did not have the authority to approve contracts that would have allowed Electric Distribution Companies (EDCs) the ability to pass on the costs of pipeline capacity to the EDC's customers.

Several Massachusetts LDCs had contracts with TGP for NED capacity. Once the NED project was terminated, an alternative approach was developed that would deliver incremental gas supplies from Dawn, Ontario to the Portland Natural Gas Transmission System interconnection with TransCanada and subsequently to TGP New England Customers. EGMA was one such customer and the Department approved its pipeline contracts in D.P.U. 17-172 on May 31, 2018.

The order approved the TGP Zone 6 to Zone 6 contract for 96,400 Dth/day, a PNGTS expansion of 14,300 Dth/day and a peaking services contract with Repsol for deliveries at Dracut, MA. The TGP contract was initially in service in November 2018 at 50,000 Dth/day, increased to 76,000 Dth /day in Nov 2020 and reached full delivery of 96,400 Dth on November 2021.

Although production of shale gas in the Marcellus and Utica basins primarily in Pennsylvania and Ohio has continued to grow in recent years, incremental supplies can't reach the New England market because of pipeline capacity constraint. The pipeline infrastructure in the region remains constrained and reliant upon LNG imports for its marginal supply. Notably, the future of the Everett Marine LNG Terminal remains in question with the expiration of its parent company's agreement with ISO New England. Gas-fired electric generators still want to use natural gas to fuel their facilities, but their unwillingness to pay for incremental pipeline capacity means that the New England gas market will continue to suffer from high delivered gas costs during the winter season.

C. EGMA's Planning Process

This section of the Plan provides an overview of the various elements of EGMA's planning process, and how each of the elements interact. This planning process has been approved, most recently in D.P.U. 19-135, by the Department and in other past F&SP proceedings. Each element is described in detail in the following sections of the Plan.

Appendix 1 provides a simplified representation of EGMA's resource planning process. The process encompasses three major elements: (1) a forecast of requirements; (2) a resource evaluation; and (3) a resource action plan. Although EGMA has employed the same general planning framework for a number of years, the Company continues to refine its methods and to update the data relied upon in order to continually improve its planning process.

As more completely described in Sections III.A and III.B, EGMA's planning process begins with an assessment of customer requirements. EGMA employs econometric modeling techniques to generate its base case forecast of Planning Load. Forecasts are generated separately for four customer segments: residential heat, residential non-heat, C&I low load factor, and C&I high load factor, by division, based on models that independently estimate the number of customers and their associated usage per customer. The development of the forecast models relies on a number of important data sources including historical customer count, usage, and demographic and economic variables. In addition to a base case forecast, EGMA also prepares optimistic and pessimistic economic scenarios to establish a range of reasonably expected customer requirements to test the Company's portfolio under higher and lower than expected demand. The impact of projected energy efficiency savings is included in customer forecast requirements as part of the Plan.

The primary design criterion that drives EGMA's customer requirements is weather. EGMA performs statistical analyses of historical weather data to derive planning standards related to normal year, design winter, cold snap and design day conditions. Resource adequacy is always measured against design conditions derived from these planning standards.

The second aspect of EGMA's planning process is resource evaluation. EGMA's resource evaluation encompasses a number of techniques that comprise a thorough process. Resource evaluation begins with a determination of resource need. Determination of need is accomplished initially by comparing current daily and seasonal capacity resources to projected design day and design winter customer requirements, which include energy efficiency measures. Further analysis of need is undertaken by simulating EGMA's existing portfolio utilizing the SENDOUT® Optimization Model ("SENDOUT®") based on its current design winter, design year and cold snap requirements forecasts. If a need for additional resources is determined, then EGMA identifies the potential resources that are available to meet its customer requirements. These resources may include renewal or restructuring of existing resources as well as acquisition of additional pipeline, storage, city-gate-delivered or on-system resources.

Resource evaluation encompasses the assessment of both the cost and non-cost characteristics of potential available resources. Sophisticated cost analysis is performed utilizing SENDOUT®, which evaluates the cost impact of changes to EGMA's portfolio by simulating the daily dispatch of available resources under specified conditions over a defined period of time. SENDOUT® also possesses the capability to size a least-cost incremental resource or package of resources based on the total cost impact upon the existing portfolio, including fixed costs. EGMA conducts cost analyses based upon the base and high case forecasts, as well as under design conditions. Separately, EGMA evaluates the non-cost characteristics of alternative resources like supply security, contract flexibility and supplier viability. Evaluation of the non-cost characteristics is accomplished through appropriate assessment techniques and scoring.

The Company employs the Total Resource Cost ("TRC") test, as required and approved by the Department in its Order in D.P.U. 08-50-A to analyze the cost effectiveness of its gas energy efficiency programs. The TRC test measures the value of avoided gas supply and any additional direct economic benefits against the costs of a program to participating customers. The avoided gas supply costs used in these cost-effectiveness determinations are based on reports prepared for the avoided energy supply component ("AESC") study group, as part of the statewide energy efficiency process.

D. EGMA's Resource Portfolio

An important focus of EGMA's Plan is the effective management of resources in its portfolio, including the minimization of the associated current and future costs of this portfolio. During the forecast period, a number of resource decisions must be made primarily related to the potential renewal or replacement of several individual supply, transportation and storage resources that currently comprise EGMA's best-cost portfolio. Those decisions, needed to be made within the first two years of this forecast period, some of which are subject of approval through the Department's decision of this Plan, are identified and discussed later in Section IV. Several upstream pipeline capacity contracts require notice of renewal or termination one year in advance, and others require an even longer notice. The analysis of renewal or replacement of specific expiring resources, as well as the acquisition of incremental resources, must take place early in the planning process for EGMA to appropriately evaluate all alternatives.

Highlights of EGMA's current resource portfolio are as follows:

- Tennessee Transportation and Storage Capacity Contracts: These contracts provide for the delivery of Gulf Coast and/or Appalachian sourced supplies via long-haul transportation capacity, access to market-area storage capacity and short-haul transportation capacity from the United States border at Niagara and other locations where EGMA imports or receives its Canadian supplies including Iroquois and PNGTS, transported to the border by Union and TCPL. Since EGMA's Springfield and Lawrence

Divisions are served solely by the Tennessee pipeline, it is critical that EGMA retain all of its primary delivery-point capacity on Tennessee. The Tennessee capacity are legacy contracts and/or provide a competitively priced service offering and important supply diversity benefits to the portfolio.

- Algonquin Gas Transmission Transportation Capacity Contracts: Supplies transported on Algonquin include production from the U.S. Gulf Coast, Appalachian supply basins, and Canadian supply basins, and transportation of storage supplies from TETCO and EGTS[3]underground storage facilities. Algonquin is the sole supplier to the Brockton Division customers and EGMA must retain primary delivery point capacity to ensure continued service reliability. In addition, most Algonquin contracts are legacy contracts, which represent the most economic transportation option for EGMA's Brockton Division customers.

- Iroquois Gas Transmission System, L.P. ("Iroquois") Transportation Capacity Contract: EGMA has one contract on Iroquois for transportation of underground storage volumes and pipeline supplies from Dawn, Ontario onto Tennessee that provides for deliveries to all EGMA's service areas.

- National Fuel Gas Supply Corporation ("National Fuel") Transportation and Storage Capacity Contracts: EGMA has storage and transportation legacy contracts with National Fuel that provide for the delivery of underground storage supplies into Tennessee for transport to the Company's Springfield and Lawrence Divisions. These legacy contracts provide much needed balancing flexibility and supply reliability.

- Eastern Gas Transmission and Storage (EGTS) formally Dominion Transmission Inc. ("DTI") Storage Capacity Contracts: EGMA has legacy storage capacity with EGST that provides for the delivery of underground storage supplies to Texas Eastern Transmission, LP ("TETCO") for transport to the Company's Brockton Division. This contract provides much needed balancing flexibility and supply reliability for customers.

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3 Eastern Gas Transmission and Storage Company (EGST) is the current owner of the former Dominion Transmission Inc. and operates the former DTI pipeline and storage facilities.

- Union Gas Transportation Contract: The Company has two firm transportation contracts on Union, which provides access to supply and storage at the Dawn Hub for ultimate delivery to all three divisions.

- Texas Eastern ("TETCO") Transportation and Storage Capacity Contracts: EGMA has TETCO long-haul firm transportation capacity contracts that provide United States Gulf Coast and Appalachian supplies to its Brockton Division customers. EGMA also holds two market area storage contracts on the TETCO system and associated short-haul transportation capacity to the Brockton Division. Further, EGMA holds short-haul TETCO transportation capacity from EGTS storage to the Brockton Division. These legacy contracts provide much needed balancing flexibility and supply reliability.

- Enbridge Storage: The Company has two storage contracts with Enbridge Storage. The storage services are located at the Dawn Hub and provide a natural hedge against winter prices increases. The supply from these storage services can be delivered to EGMA's Brockton, Springfield and Lawrence Divisions.

- Portland Natural Gas ("PNGTS") Transportation Contracts: The Company has three firm transportation agreements with PNGTS, one of which delivers gas from an Enbridge storage contract and the other two that deliver supplies purchased at Dawn to the Company's Springfield and Lawrence Divisions.

- Repsol Energy North America Corporation ("Repsol"): The Company has two peaking supply contracts for firm seasonal deliveries of re-gasified LNG from Repsol's Canaport LNG terminal. These supplies are delivered to TGP capacity at Dracut, MA.

- Millennium Pipeline Company ("MPC"): The Company has one firm transportation agreement with MPC allowing for delivery of Marcellus basin supplies into AGT for delivery to the Company's Brockton Division.

- Transcontinental Gas Pipe Line ("Transco") Transportation Capacity Contract: EGMA has one legacy contract on Transco that transports some of the EGTS storage volumes onto Algonquin for ultimate delivery to EGMA's Brockton Division.

- Granite: The Company has one firm transportation agreement that allows for delivery to a Northern Utilities city-gate as part of an Exchange Agreement which EGMA is examining the future of. EGMA receives gas at Lawrence, Springfield and Brockton from Northern Utilities as reciprocation.

An important consideration in determining whether renewal of legacy contracts is consistent with a least-cost strategy is the cost of new capacity. During the past five to ten years, most new pipeline projects built in the region have charged marginal-cost-based rates for the associated incremental pipeline capacity. Marginal-cost-based rates are higher than current legacy capacity[4] rates on the pipelines that serve EGMA. These legacy pipeline rates and associated capacity are advantaged by lower initial construction costs and significant depreciation of their plant and rate base, of which the revenue requirement is recovered by pipelines at average cost-based rates. These lower rates result in higher load factors and higher billing determinants, which in combination help to further maintain the lower rates associated with these legacy pipeline contracts. Further, because legacy transportation capacity is fully subscribed from the reliable, low-cost basins to the south and west, the only opportunity for the Company to replace these needed resources would be (a) from higher cost resources sourced from the north and east;[5] or (b) from supplies from traditional supply areas transported by higher cost, incremental facilities.

In the context of this report, EGMA has therefore reflected the renewal and continuation of all legacy capacity resources, for which the Company has a right-of-first refusal or a rollover right that comes up for renewal during the five-year planning horizon of the Plan. Given the current market dynamics where new capacity serving New England has become more costly and harder to obtain FERC approvals and general support new infrastructure, renewing legacy contracts helps ensure that the Company maintains competitively-priced services and supply diversity benefits for its customers.

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4 Legacy capacity is defined here as firm interstate pipeline transportation and storage service provided to EGMA and other New England LDCs under FERC-approved rate schedules, which were in effect upon or soon after the unbundling of the United States' interstate pipeline system resulting from FERC Order No. 636.

5 As noted hereinabove, the Company has executed agreements for capacity from TGP/PNGTS/TCPL/Union and Repsol. While these resources are generally more costly than the Company's traditional legacy contracts, the Company has exerted much effort to ensure access to highly reliable supplies as compared to the increasing uncertainty and volatility of prices for supplies procured at New England supply points, for example, Dracut, MA.

In addition, rollover of the Company's other existing capacity with a right-of-first refusal or roll-over right has historically proven to be far more economical than procuring capacity on most of the new pipeline projects available to the Company. This valuable legacy capacity is expected to continue to be more economical in the future, and therefore, the Plan reflects these rollovers. The Company notes, however, that when making renewal, replacement, or incremental capacity decisions, it will employ the planning, supply and capacity acquisition methods approved under this Plan to further ensure that the decision-making process used is reasonable and appropriate, and that the decision is based on the best information available to EGMA at the time it is made.

EGMA's on-going evaluation of these resource strategies will be reflected in its Resource Action Plan in Section V ("Action Plan"). The Action Plan includes the results of EGMA's resource assessments and the factors that EGMA will evaluate in making its decisions to contract or de-contract for capacity in order to satisfy its obligation to meet firm customer demand and, in the process, ensure that each decision constitutes the best available alternative at the time it is made. All new supply and capacity contracts entered into by the Company for more than one year will be filed with the Department for approval, as required by law and Department precedent. The Company has identified in Table G-24, page 1, those contracts that expire within two years of this F&SP filing date.

III. FIVE-YEAR LOAD FORECAST

A. FORECAST METHODOLOGY

1. Methodology Overview

The primary objective of the demand forecast process is to determine Eversource Gas of Massachusetts' planning load forecast under normal and design weather conditions, and high and low growth scenarios. The Company uses these forecasts to assess the adequacy of its resource plans relative to the extreme weather and growth conditions.

The Company developed the Residential and C&I sales & transportation forecasts included here. The Company has prepared a base case planning load forecast, together with a number of planning load forecasts that reflect a range of weather and growth scenarios. The planning load forecast for the gas-supply planning years 2021/22 through 2025/26 (the "forecast period") is derived from forecast models that were developed for four customer segments. The weather-related scenarios that are applied to the forecast models include normal year and design year; the design year scenario includes the design winter, design day and cold snap standards. High growth and low growth scenarios were also performed.

Separate demand forecasts were developed for the Company's three divisions, Brockton, Lawrence, and Springfield. For each division, base case forecasts of quarterly demand for each customer segment were developed by applying normal weather data and data representing forecasted economic and demographic conditions to the forecast models; the economic and demographic variables in the forecast models were identified in the modeling process to be the major factors influencing natural gas demand in each of the Company's service territories. The Company's planning load forecast was determined by combining: (a) customer segment demand forecasts; (b) minus capacity exempt demand; (c) minus incremental savings expected from the Company's existing energy efficiency programs; and (d) plus adjustments for Company Use and losses. The process that was used to develop the 2021 Forecast and Supply Plan ("F&SP") demand forecast is further described in this Section III.A

This report uses the terms that are listed in Figure 1 to refer to and distinguish between different types of natural gas demand.

Figure 1: Forecast Terms

Term	Definition
Demand, Usage, Volume or Load	Generic terms that refer to the gas used by customers to meet their energy requirements.
Customer Segment Demand	Total firm sales plus total firm transportation demand (measured at the customer meter on a billing period basis) for a customer group, which is a defined group of rate classes.

Term	Definition
Throughput	Total gas sendout measured at Company gate stations and at Company LNG facilities on a calendar period basis; throughput also equals the sum of (a) sales plus total transportation gas use measured at customers' meter, (b) Company Use, and (c) losses and unaccounted for gas.
Capacity Exempt customers	Transportation customers that are not subject to the capacity assignment provisions as set forth in the Company's Distribution and Default Service Terms and Conditions, Section 13, M.D.P.U. No. 400D.
Non-Capacity Exempt customers	Transportation customers that are subject to the capacity assignment provisions as set forth in the Company's Distribution and Default Service Terms and Conditions, Section 13, M.D.P.U. No. 400D. These customers are also referred to as capacity eligible customers.
Planning Load	Total firm sales plus non-capacity exempt transportation usage measured at the gate station on a calendar period basis (i.e., includes Company Use, and losses) – excludes capacity exempt transportation load.

2. Summary of Normal Year Forecast Results

As determined in the forecast process that is described in Sections III.A and III.B, the Company's normal year planning load,[6] including the effects of expected future energy efficiency measures, is projected to increase at a 0.78% compound annual growth rate ("CAGR") from 2021/22 through 2025/26. Residential demand[7] is forecasted to increase at a 0.79% annual rate, and Commercial and Industrial ("C&I") demand[8] is forecasted to increase by 0.94% per year during the forecast period. The planning load forecast results are summarized in Figure 2 below.

[6] Includes all firm sales and firm transportation customer demand, Company Use, Lost and Unaccounted for Sales and the effects of Energy Efficiency programs; excludes all interruptible, and capacity exempt demand.

[7] Includes Residential Heating and Residential Non-Heating customer segments.

[8] Includes High Load Factor and Low Load Factor customer segments.

Figure 2: Normal Year Firm Planning Load Forecast Results Summary (Including Effects of Energy Efficiency) (MMBtu)[9,10]

EGMA Gas Total

Gas Year	Residential	C&I Sales plus Capacity Eligible Transportation	Energy Efficiency Adjustment	Company Use and Losses	Planning Load
2021/22	27,262,676	20,108,049	(511,243)	869,978	47,729,459
2022/23	27,421,004	20,167,785	(537,332)	873,599	47,925,057
2023/24	27,614,602	20,454,351	(580,521)	881,572	48,370,003
2024/25	27,873,929	20,673,597	(627,475)	889,518	48,809,570
2025/26	28,129,905	20,877,529	(674,798)	897,155	49,229,791
CAGR	0.79%	0.94%	7.19%	0.77%	0.78%

B. CUSTOMER SEGMENT FORECAST MODELS

1. Development

The customer segment demand forecast was developed by preparing separate quarterly forecast models for the following four customer segments for the Company's three operating divisions, Brockton, Lawrence, and Springfield:

- Residential Heating
- Residential Non-Heating
- C&I Low Load Factor (LLF)
- C&I High Load Factor (HLF)

Separate econometric models were developed for the number of customers and use per customer for the residential heating and non-heating and C&I LLF and HLF customer segments.

Starting in the mid-1990s, EGMA has provided unbundled transportation to some C&I customers, who purchase gas directly from third party suppliers. To estimate firm transportation

9 The values in the Energy Efficiency Adjustment columns represent the EE savings impacts on Planning Load, i.e., net of Capacity Exempt ("CE") EE savings. Total EE savings are allocated between firm Sales, Non-capacity Exempt and CE load on a pro-rata basis.

10 Throughout this F&SP and the Appendices, gas quantities are reported as dekatherms ("Dth") and MMBtu; these two terms are identical units of measure, 1,000,000 British thermal units.

demand, the Company developed forecasts for (a) combined firm sales and firm transportation customer segments; and (b) firm sales only demand for the C&I customer segments. The firm transportation forecast is calculated as the difference between the firm sales and transportation forecast and the firm sales forecast. Non-capacity-exempt, i.e., capacity eligible, transportation demand was calculated by taking the ratio of capacity eligible volumes to total transportation volumes from the first quarter 2017 through the fourth quarter of 2019, and applying that ratio to the total forecast transportation demand.

The regression analyses were conducted using the EViews software package. Regression modeling techniques were used to develop the number of customers and use per customer based on variables such as weather, natural gas prices, and other economic and demographic variables. Each model was tested for autocorrelation, heteroskedasticity, instability, multicollinearity, and outliers. Models were corrected for any violations of standard assumptions of regression analysis that were identified by these tests. The modeling development process and specific statistical techniques are discussed in Appendix 3. The results of these tests are provided in Appendix 4.

Projected customer demand for this F&SP is derived from the forecast models and forecasts of future economic conditions in the region. The total demand for each residential and C&I customer segment for each quarter in the forecast period is calculated by multiplying the forecasted number of customers by the forecasted use per customer in that forecasted quarter. The Planning Load projections for each forecasted customer segment account for the portion of transportation-only throughput that is capacity eligible. Thus, the Company's resource planning accounts for the loads served by third-party suppliers for capacity exempt and capacity eligible transportation customers. Projected customer requirements are forecasted for the base case as well as for high and low load growth scenarios to ensure that the EGMA portfolio is adequate to meet its customer requirements under a range of potential future conditions.

Forecasts of Company Use and Lost and Unaccounted for gas were developed based on recent history and added to the customer segment forecast. Projected customer requirements also were adjusted for the impact of energy efficiency measures that are projected to be installed during the forecast period.

Lastly, EGMA determined its design planning standards based on a statistical analysis of historical weather data for each division. The design planning standards establish the design day, design winter and cold snap conditions that the EGMA resource portfolio must satisfy in order to ensure system safety, integrity and reliability.

2. Variable Descriptions

The first step in the demand forecasting process is the collection of various historical and projected data required to develop the forecast models. The forecast models used to derive the Company's five-year demand forecast rely on a number of internal and external data sources. Historical values of the dependent variables in these forecast models are obtained from EGMA billing data for customer counts and delivered volumes; use per customer values were calculated using the customer and volume billing data. Independent variables for the forecast models include measures for weather, demographic conditions, and economic conditions. Historical and projected values of the economic independent variables were obtained from Moody's Analytics. The general data and variable categories that were utilized in the development of the forecast are described in the following sections.

a) Customer Segment Data

The Company analyzed monthly billing data by customer class for the Brockton, Lawrence, and Springfield divisions for historical periods ending September 2020 (2020 Q3); the starting points for the statistical analyses vary. The EGMA customer class data was aggregated into the four customer segments, as shown in Figure 3 below.

Figure 3: Customer Segment Definitions

Rate Class	Customer Segment
R-1, R-2	Residential Non-Heating
R-3, R-4	Residential Heating Sales and Transportation
G-40, G-41, G-42, G-43	Low Load Factor
G-50, G-51, G-52, G-53	High Load Factor

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

- Company billing month customer, usage, and revenue data for each rate class was collected for the historical period beginning as early as January 2005 – depending on customer segment – through September 2020
- The billing month rate class data was aggregated into Customer Segments as defined by the table above
- The billing month Customer Segment data was aggregated into billing quarters to be used as dependent variables in the customer and use per customer quarterly forecast models.

b) Weather Variable

Effective Degree Days ("EDDs") were utilized as the weather measure. Daily U.S weather bureau data was purchased for the Company's three divisions. The data were used by the Company to calculate EDDs. EDDs are Heating Degree Days ("HDDs") adjusted for average daily wind speed.

The historical daily EDD data was converted to a billing quarter basis to be used in the quarterly forecast models. The process that was used to calculate the billing quarter EDD variable from daily EDD data is described in Appendix 5.

c) Natural Gas Price Variable

Because economic theory suggests that demand is likely to be influenced by price, a natural gas price variable was developed to be included in the customer segment models. Data to construct gas price variables were obtained from Company resources; historical data were obtained from Company billing records and price forecasts were developed using the process described in Appendix 6.

d) Economic and Demographic Variables

Economic theory suggests that demand may also be affected by other economic and demographic variables. To reflect economic and demographic conditions for EGMA operating divisions, the Company obtained historical metropolitan statistical area (MSA) data from Moody's

Analytics for the period from 2005Q1 through 2020Q3 and forecasted data from 2020Q4 through 2030Q4. The MSAs in the Company's three divisions are shown in Figure 4 and the data series that were obtained from Moody's are shown in Figure 5.

Figure 4: Metropolitan Statistical Areas in EGMA Divisions

Statistical Areas
Providence-Warwick, RI-MA Boston-Cambridge-Newton, MA-NH Springfield, MA

Figure 5: Data Obtained from Moody's Analytics

Economic and Demographic Data
Employment (NAICS), Total Nonfarm Employment (NAICS), Manufacturing Average Personal Income per Household Real Per Capita Income Gross Metro Product Number of Households Housing Completions Population
Prices
Henry Hub market price of natural gas, $/MMBtu U.S. No. 2 Diesel Retail Sales by All Sellers, $/Gallon
Price Deflators
Consumer Price Index, All Urban Consumers

e) Dependent Variables

The dependent variable data for the customer and use per customer ("UPC") customer segment models were derived from Company billing records. Billing month[11] rate class customer count and billing data were aggregated into quarters and also aggregated into the four customer segments that are shown in Figure 3. The dependent variables that were used to develop the F&SP

[11] An explanation of the process of converting calendar EDDs to billing period EDDs can be found in Appendix 5.

forecast models are listed in Appendix 7; graphical summaries of the dependent variable data are provided in Appendix 8.

f) Other Variables

The following additional variables were created to be used in the development of the customer segment models:

- Trend variables were created to represent changes in the number of customers or use per customer that were a function of time.
- Binary variables (or dummy variables) were created to represent time-related events.[12]
- Interaction terms related to certain binary variables were created to represent changes in the relationships between the dependent variable and independent variables as a result of time-related events.

C. Customer Segment Model Results

1. Introduction

The following sections summarize each customer segment model and the model forecast results. As explained in Appendix 3, each model was tested for the presence of autocorrelation, heteroskedasticity, multicollinearity, stability, and outliers, and appropriate modifications were made to the models based on the test results. An ex post analysis was performed for each model and the model specification was modified if necessary. Detailed statistical results for each customer segment model are provided in Appendix 4. In addition to the model statistics and the results of the tests for autocorrelation, heteroskedasticity, multicollinearity, stability and outliers, Appendix 4 includes explanations for any dummy variables that were used in a forecast model.

2. Residential Heating Customer Segment

The Residential Heating customer segment represented 85% of total customers and 50% of total actual demand in 2020. From 2017 to 2020, the number of Residential Heating customers

[12] These binary variables equal 1 when a specific time-related event occurs, and equal 0 outside of that specific time.

increased by 1.6% per year, and weather normalized Residential Heating customer demand increased by 2.0% per year.

a) Residential Heating Customer Model Results

Economic theory suggests that the number of Residential Heating customers may be dependent on such variables as a measure of the number of people living in the service territory (e.g., households or population); measures of income or wealth; and measures that reflect the competitiveness of natural gas relative to other energy types. In addition, the number of Residential Heating customers in a quarter reflects a seasonal pattern; generally, the greatest number of Residential Heating customers take service from a typical New England gas distribution company in Quarter 1, and the fewest number of Residential Heating customers take service in Quarter 3.

The Final EGMA Residential Heating customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

*Total customer count = (a) + (b)*Economic Variable + + (c)*Quarterly Variables + (d)*Price Variable + (e)*Binary Variables + (f)*Interaction Variables*

The economic driver in the Residential Heating customer models for all three divisions is oil to natural gas conversion savings . The variable coefficients and the binary and interaction variables that are included in the Residential Heating Customer models are listed and supporting explanations for the variables are provided in Appendix 4.

Over the forecast period, the number of Residential Heating customers is projected to grow at an annual rate of 0.93%, as shown by Figure 6 below.

Figure 6: Residential Heating Customer Model Forecast[13]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	146,940	45,742	91,527	284,209
2022/23	148,706	46,200	92,184	287,089
2023/24	150,311	46,622	92,785	289,718
2024/25	151,915	47,043	93,387	292,345
2025/26	153,483	47,455	93,975	294,914
CAGR	1.10%	0.92%	0.66%	0.93%

b) Residential Heating Use per Customer Model Results

Economic theory suggests that use per customer in the Residential Heating customer segment may be dependent on such variables as weather, price, income, wealth, household size, and efforts to conserve.

The Final Residential Heating use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Use per Customer} = (a) + (b)\text{*}\textit{Effective Degree Days} + (c)\text{*}\textit{Price} + (d_i)\text{*}\textit{Binary Variables}_i + (e_i)\text{*}\textit{Interaction Variables}_i$$

Residential Gas Price and weather are the major drivers in the Residential Heating use per customer models in all three territories. The variable coefficients and the binary and interaction variables that are included in the models are listed and supporting explanations for the variables are provided in Appendix 4.

Over the forecast period, the weighted average use per customer for the Residential Heating segment is projected to decrease by 0.09% per year, as shown in Figure 7 below.

[13] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 7: Residential Heating Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[14]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	95.4	103.3	90.1	288.8
2022/23	94.9	103.2	89.9	288.0
2023/24	94.6	103.0	89.8	287.5
2024/25	94.7	103.0	89.9	287.6
2025/26	94.8	103.0	89.9	287.8
CAGR	-0.16%	-0.07%	-0.05%	-0.09%

c) Residential Heating Demand Results

The Residential Heating demand forecast was calculated by multiplying the forecasted number of Residential Heating customers for each quarter by the forecasted Residential Heating use per customer for that quarter. Over the forecast period, total Residential Heating demand is projected to increase by 0.56% per year, as shown in Figure 8A below, and the Residential Heating segment planning load is projected to increase by 0.69% per year, as shown in Figure 8B.

Figure 8A: Residential Heating Demand Forecast (MMBtu – Normal Year)[15, 16]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	14,079,982	4,744,080	8,337,260	27,161,321.7
2022/23	14,079,982	4,785,268	8,374,800	27,240,050.8
2023/24	14,154,769	4,813,167	8,410,351	27,378,286.8
2024/25	14,247,193	4,846,534	8,454,498	27,548,225.6
2025/26	14,393,081	4,884,492	8,498,478	27,776,051.3
CAGR	0.55%	0.73%	0.48%	0.56%

14 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

15 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13.

16 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 8B: Residential Heating Planning Load Forecast (MMBtu – Normal Year)[17],[18]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	14,084,434	4,746,218	8,339,476	27,170,127.9
2022/23	14,155,446	4,785,851	8,375,013	27,316,309.7
2023/24	14,251,510	4,813,986	8,411,434	27,476,930.6
2024/25	14,399,437	4,847,787	8,456,098	27,703,321.0
2025/26	14,544,029	4,885,706	8,499,404	27,929,139.5
CAGR	0.81%	0.73%	0.48%	0.69%

3. Residential Non-Heating Customer Segment

Residential Non-Heating was the smallest EGMA customer segment in terms of demand for all three divisions in 2020. The Residential Non-Heating customer segment represented 6% of total customers and 0.7% of total actual demand in 2020. From 2017 to 2020, the number of Residential Non-Heating customers decreased by 2.4% per year, and weather normalized Residential Non-Heating customer demand decreased by 2.3% per year.

a) Residential Non-Heating Customer Model Results

Economic theory suggests that the number of Residential Non-Heating customers may be dependent on such variables as a measure of the number of people living in the service territory (e.g., households or population); measures of income or wealth; a trend variable to represent the

17 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

18 The planning load results summarized in this table are net of unbilled adjustments, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

decline in the number of non-heating customers;[19] and measures that reflect the competitiveness of natural gas relative to other energy types.

The EGMA Residential Non-Heating customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Total customer count} = (a) + (b)*\textit{Trend} + (c_i)*\textit{Binary Variables}_i + (d_i)*\textit{Interaction Variables}_i$$

A quarterly trend was the significant driver in the Residential Non-Heat Customer models for all three divisions. The variable coefficients and the binary and interaction variables that are included in the Residential Non-Heating Customer models are listed and supporting explanations for the variables are provided in Appendix 4.

Over the forecast period, the number of Residential Non-Heating customers is projected to decline at an annual rate of 3.04%, as shown by Figure 9 below.

Figure 9: Residential Non-Heating Customer Model Forecast[20]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	7,007	2,276	8,579	17,863
2022/23	6,785	2,231	8,328	17,344
2023/24	6,563	2,186	8,077	16,826
2024/25	6,341	2,142	7,826	16,308
2025/26	6,118	2,098	7,574	15,790
CAGR	-3.33%	-2.02%	-3.07%	-3.04%

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19 The steady decline in the number of Residential Non-Heating customers is the result of these customers converting from oil to gas heating. Measures that captured the relative competitiveness of oil and gas prices were tested in the Residential Non-Heating models to explain the decline in non-heating customers. However, a trend variable was used because no statistically significant economic or price-based variable could be identified.

20 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

b) Residential Non-Heating Use per Customer Model Results

Economic theory suggests that use per customer in the Residential Non-Heating customer segment may be dependent on such variables as weather, price, income, wealth, household size and efforts to conserve.

The EGMA Non-Residential Heating use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Use per Customer} = (a) + (b)*\textit{Effective Degree Days} + (c_i)*\textit{Binary Variables}_i + (d_i)*\textit{Interaction Variables}_i$$

The major driver of the Residential Non-Heat Use per Customer models in all three divisions was weather and the real price of non-heating gas. The variable coefficients and the binary and interaction variables that are included in the models are listed and supporting explanations for the variables are provided in Appendix 4.

Over the forecast period, the average use per customer for the Residential Non-Heating segment is projected to decrease by 0.05% per year, as shown in Figure 10 below.

Figure 10: Residential Non-Heating Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[21]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	17.1	19.9	18.9	55.9
2022/23	16.9	19.6	18.8	55.3
2023/24	17.2	20.1	18.9	56.1
2024/25	17.2	20.2	19.0	56.3
2025/26	17.0	19.9	18.9	55.8
CAGR	-0.05%	-0.07%	-0.02%	-0.05%

[21] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

c) Residential Non-Heating Demand Results

The Residential Non-Heating demand forecast was calculated by multiplying the forecasted number of Residential Non-Heating customers for each quarter by the forecasted Residential Non-Heating use per customer for that quarter. Over the forecast period, the total demand from the Residential Non-Heating segment total demand is projected to decrease by 3.18% per year, as shown in Figure 11A, and the Residential Non-Heating segment planning load is projected to decrease by 3.17% per year as shown in Figure 11 B.

Figure 11A: Residential Non-Heating Demand Forecast (MMBtu – Normal Year)[22, 23]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	121,708	46,026	164,996	332,730
2022/23	116,340	44,243	159,231	319,815
2023/24	114,122	44,317	115,246	313,685
2024/25	110,577	43,639	150,472	304,688
2025/26	105,496	42,041	144,799	292,335
CAGR	-3.51%	-2.24%	-3.21%	-3.18%

Figure 11B: Residential Non-Heating Planning Load Forecast (MMBtu – Normal Year)[24, 25]

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22 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13.

23 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

24 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

25 The planning load results summarized in this table are net of unbilled adjustments, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	121,121	45,792	164,440	331,353.1
2022/23	116,149	44,250	158,866	319,265.5
2023/24	113,880	44,294	154,862	313,035.2
2024/25	110,145	43,501	149,980	303,626.8
2025/26	105,061	41,899	144,305	291,265.9
CAGR	-3.49%	-2.20%	-3.21%	-3.17%

4. Low Load Factor Customer Segment[26]

The Low Load Factor customer segment represented 8% of total customers and 30% of total actual demand in 2020. From 2017 to 2020, the number of Low Load Factor customers increased by 1.6% per year, and weather normalized Low Load Factor customer demand increased by 3.4% per year.

a) Low Load Factor Customer Model Results

Economic theory suggests that the number of Low Load Factor customers may be dependent on such variables as a measure of the economy in the service territory (e.g., gross metro product and/or non-manufacturing employment); and measures that reflect the competitiveness of natural gas relative to other energy types.

The EGMA Low Load Factor customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Total customer count} = (a) + (b)*\textit{Economic Variable} + (c_i)*\textit{Quarterly Variables}_i + (d)*\textit{Price Variable} + (e_i)*\textit{Binary Variables} + (f_i)*\textit{Interaction Variables}_i$$

The economic driver in the Low Load Factor customer models in all three territories is gross metro product. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the Low Load Factor Customer models are

26 Includes both low load factor default sales and low load factor transportation customers.

provided in Appendix 4. Over the forecast period, the number of Low Load Factor customers is projected to grow at an annual rate of 1.51%, as shown by Figure 12 below.

Figure 12: Low Load Factor Customer Model Forecast[27]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	15,711	3,195	8,407	27,314
2022/23	15,950	3,254	8,489	27,692
2023/24	16,215	3,323	8,583	28,120
2024/25	16,495	3,397	8,681	28,573
2025/26	16,759	3,466	8,771	28,996
CAGR	1.63%	2.06%	1.06%	1.51%

b) Low Load Factor Use per Customer Model Results

Economic theory suggests that use per customer in the Low Load Factor customer segment may be dependent on such variables as weather, price, and/or efforts to conserve.

The EGMA Low Load Factor use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\text{Use per Customer} = (a) + (b)*\text{Effective Degree Days} + (c)*\text{Price} + (d_i)*\text{Quarterly Variables}_i + (e_i)*\text{Binary Variables}_i + (f_i)*\text{Interaction Variables}_i$$

Weather and low load factor price variables are the drivers in all three divisions. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the models are provided in Appendix 4.

Over the forecast period, the weighted average use per customer for the Low Load Factor segment is projected to decrease by -0.1% per year, as shown in Figure 13 below.

27 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 13: Low Load Factor Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[28]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	535.3	779.8	642.8	1,957.8
2022/23	531.6	779.3	636.6	1,947.6
2023/24	530.3	779.1	634.3	1,943.8
2024/25	531.3	779.3	636.1	1,946.7
2025/26	532.4	779.4	638.1	1,949.9
CAGR	-0.1%	0.0%	-0.2%	-0.1%

c) Low Load Factor Demand Results

The Low Load Factor demand forecast was calculated by multiplying the forecasted number of Low Load Factor customers for each quarter by the forecasted Low Load Factor use per customer for that quarter. Total demand includes load from all sales and transportation customers, while planning load is total demand minus capacity exempt load. Over the forecast period, the total demand from the Low Load Factor segment is projected to increase by 1.43% per year, as shown in Figure 14A, and the Low Load Factor planning load is projected to increase by 1.43% per year, as shown in Figure 14B.

Figure 14A: Low Load Factor Demand Forecast (MMBtu – Normal Year)[29, 30]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	7,299,653	1,940,324	4,251,451	13,491,428
2022/23	7,363,440	1,975,554	4,260,752	13,599,746
2023/24	7,458,964	2,018,235	4,302,890	13,780,089
2024/25	7,601,327	2,065,080	4,369,540	14,035,947
2025/26	7,735,628	2,108,760	4,433,981	14,278,369
CAGR	1.46%	2.10%	1.06%	1.43%

28 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

29 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13.

30 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 14B: Low Load Factor Planning Load Forecast (MMBtu – Normal Year)[31, 32]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	7,302,046	1,941,664	4,252,161	13,495,871.4
2022/23	7,364,473	1,976,597	4,261,364	13,602,433.4
2023/24	7,462,809	2,019,622	4,304,644	13,787,074.5
2024/25	7,605,881	2,066,415	4,371,988	14,044,284.3
2025/26	7,738,037	2,109,949	4,435,039	14,283,025.2
CAGR	1.46%	2.10%	1.06%	1.43%

5. High Load Factor Customer Segment[33]

The High Load Factor customer segment represented 1.6% of total customers and 20% of total actual demand in 2020. From 2017 to 2020, the number of High Load Factor customers decreased by 2.3% per year, and weather normalized High Load Factor customer demand decreased by 2.5% per year.

a) High Load Factor Customer Model Results

Economic theory suggests that the number of High Load Factor customers may be dependent on such variables as a measure of the economy in the service territory (e.g., gross metro product and/or manufacturing employment) and measures that reflect the competitiveness of natural gas relative to other energy types.

The EGMA High Load Factor customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

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31 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

32 The planning load results summarized in this table are net of unbilled adjustments, without capacity exempt volumes, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

33 Includes both high load factor default sales and high load factor transportation customers.

$$\textit{Total customer count} = (a) + (b)^{*}\ \textit{Price Variable} + (c)^{*}\textit{Economic Variable} + (d_i)^{*}\textit{Binary Variables}_i + (e_i)^{*}\textit{Interaction Variables}$$

The economic driver in the High Load Factor customer models in all territories is natural gas prices. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the High Load Factor Customer models are provided in Appendix 4.

Over the forecast period, the number of High Load Factor customers is projected to grow at a compound annual growth rate of 0.08%, as shown by Figure 15 below.

Figure 15: High Load Factor Customer Model Forecast[34]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	2,701	727	1,736	5,164
2022/23	2,719	726	1,733	5,178
2023/24	2,801	726	1,730	5,257
2024/25	2,758	726	1,731	5,215
2025/26	2,722	727	1,732	5,181
CAGR	0.19%	-0.02%	-0.05%	0.08%

b) High Load Factor Use per Customer Model Results

Economic theory suggests that use per customer in the High Load Factor customer segment may be dependent on such variables as weather, price, and / or efforts to conserve.

The Final NSTAR Gas High Load Factor use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Use per Customer} = (a) + (b)^{*}\textit{Effective Degree Days} + (c)^{*}\textit{Price} + (d)^{*}\textit{Economic Variable} + (e_i)^{*}\textit{Quarterly Variables} + (f_i)^{*}\textit{Binary Variables}_i + (g_i)^{*}\textit{Interaction Variables}_i$$

34 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

The price variable and weather variables are the drivers of High Load Factor use per customer in all three territories. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the models are provided in Appendix 4.

Over the forecast period, the use per customer for the High Load Factor segment is projected to decline by 0.10% per year, as shown in Figure 16 below.

Figure 16: High Load Factor Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[35]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	1,620.6	1,921.2	2,818.8	6,360.6
2022/23	1,595.8	1,910.9	2,798.8	6,305.5
2023/24	1,596.5	1,911.2	2,834.8	6,342.5
2024/25	1,603.7	1,914.2	2,824.2	6,342.1
2025/26	1,611.1	1,917.3	2,806.0	6,334.4
CAGR	-0.15%	-0.05%	-0.11%	-0.10%

c) High Load Factor Demand Results

The High Load Factor demand forecast was calculated by multiplying the forecasted number of High Load Factor customers for each quarter by the forecasted High Load Factor use per customer for that quarter. Total demand includes load from all sales and transportation customers, while planning load is total demand minus capacity exempt load. Over the forecast period, the total demand from the High Load Factor segment is projected to decrease by 0.08% per year, as shown in Figure 17A below, and the High Load Factor planning load is projected to decrease by 0.47% per year, as shown in Figure 17B.

[35] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 17A: High Load Factor Demand Forecast (MMBtu – Normal Year)[36, 37]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	3,644,490	1,021,167	1,998,520	6,664,177
2022/23	3,595,590	1,013,890	1,984,138	6,593,618
2023/24	3,696,790	1,013,051	2,000,682	6,710,524
2024/25	3,669,922	1,014,940	1,995,655	6,680,517
2025/26	3,639,302	1,017,043	1,987,357	6,643,702
CAGR	-0.04%	-0.10%	-0.14%	-0.08%

Figure 17B: High Load Factor Planning Load Forecast (MMBtu – Normal Year)[38, 39]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	3,778,089	1,020,502	1,997,409	6,796,000.1
2022/23	3,630,787	1,013,215	1,985,486	6,629,487.1
2023/24	3,604,939	1,012,953	1,999,914	6,617,805.6
2024/25	3,696,687	1,015,187	1,994,386	6,706,260.1
2025/26	3,665,356	1,016,754	1,987,125	6,669,234.8
CAGR	-0.75%	-0.09%	-0.13%	-0.47%

6. Transportation Forecasts

The Company offers transportation service in accordance with the Department's directives in D.T.E. 98-32-B (1999). Transportation customer and volume forecasts for the C&I customer segments have been calculated by subtracting C&I sales customer and volume forecasts from C&I total sales and transportation customer and volume forecasts. As described in the following

36 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13.

37 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

38 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

39 The planning load results summarized in this table are net of unbilled adjustments, without capacity exempt volumes, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

sections, sales customer and use per customer models were developed for all divisions for C&I Low Load Factor and C&I High Load Factor customer segments.

7. Low Load Factor Firm Sales Customer Segment

The Low Load Factor Firm Sales customer segment represented 84% of total Low Load Factor customers and 47% of total actual Low Load Factor demand in 2020. From 2017 to 2020, the number of Low Load Factor Firm Sales customers increased by 1.2% per year, and weather normalized Low Load Factor Firm Sales customer demand increased by 2.4% per year.

a) Low Load Factor Firm Sales Customer Model Results

Economic theory suggests that the number of Low Load Factor Firm Sales customers may be dependent on such variables as a measure of the economy in the service territory (e.g., Gross Metro Product and/or non-manufacturing employment) and/or measures that reflect the competitiveness of natural gas relative to other energy types. Over time, the number of Low Load Factor customers that have switched from bundled sales service to transportation service depends on the number and type of competitive suppliers that are working to attract new customers in the Company's service territory. Therefore, consumer behavior theory suggests that the number of sales customers may be dependent on non-economic and difficult-to-measure factors that are related to Low Load Factor customers' awareness of competitive choice and understanding of the benefits and risks of unbundled transportation service from EGMA coupled with supply service from competitive suppliers.

The EGMA Low Load Factor Firm Sales customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

*Total Customer Count = (a) + (b)*Economic Variable + (c_i)*Quarterly Variables + (d)*Personal Income + (e_i)*Binary Variables$_i$ + (f_i)*Interaction Variables*

Gross Metro Product is an economic driver in all divisions. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the Low Load Factor Firm Sales Customer models are provided in Appendix 4.

Over the forecast period, the number of Low Load Factor Firm Sales customers is projected to grow at an annual rate of 1.42%, as shown by Figure 18 below.

Figure 18: Low Load Factor Firm Sales Customer Model Forecast[40]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	12,874	2,646	7,029	22,548
2022/23	13,005	2,699	7,138	22,841
2023/24	13,151	2,761	7,263	23,175
2024/25	13,305	2,829	7,394	23,527
2025/26	13,450	2,892	7,513	23,855
CAGR	1.10%	2.25%	1.68%	1.42%

b) Low Load Factor Firm Sales Use per Customer Model Results

Economic theory suggests that use per customer in the Low Load Factor Firm Sales customer segment may be dependent on such variables as weather, price, and/or efforts to conserve.

The EGMA Low Load Factor Firm Sales use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

Use per Customer $= (a) + (b)$**Effective Degree Days* $+ (c)$**Price Variable* $+ (d)$** Economic Variable* $+ (e_i)$**Quarterly Variables*$_i$ $+ (f_i)$**Binary Variables*$_i$ $+ (g_i)$**Interaction Variables*$_i$

[40] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Weather and price are the drivers of Low Load Factor Sales use per customer in all three divisions. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the models are provided in Appendix 4.

Over the forecast period, the average use per customer for the Low Load Factor Firm Sales segment is projected to remain steady with a compound annual growth rate of 0.0%, as shown in Figure 19 below.

Figure 19: Low Load Factor Firm Sales Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[41]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	332	388	333	1,053
2022/23	332	388	331	1,050
2023/24	330	388	331	1,050
2024/25	332	388	332	1,052
2025/26	332	388	332	1,053
CAGR	0.04%	0.00%	-0.04%	0.00%

c) Low Load Factor Firm Sales Demand Results

The Low Load Factor Firm Sales demand forecast was calculated by multiplying the forecasted number of Low Load Factor Firm Sales customers for each quarter by the forecasted Low Load Factor Firm Sales use per customer for that quarter. Over the forecast period, the total demand from the Low Load Factor Sales segment is projected to increase by 1.45% per year, as shown in Figure 20A below, and the Low Load Factor Sales planning load is projected to increase by 1.45% per year, as shown in Figure 20B.

41 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 20A: Low Load Factor Sales Demand Forecast (MMBtu – Normal Year)[42, 43]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	4,276,725	1,022,234	2,366,758	7,665,717
2022/23	4,314,674	1,041,770	2,388,540	7,744,984
2023/24	4,345,477	1,067,269	2,433,626	7,846,373
2024/25	4,420,167	1,094,016	2,481,540	7,995,723
2025/26	4,475,542	1,117,783	2,526,709	8,120,034
CAGR	1.14%	2.26%	1.65%	1.45%

Figure 20B: Low Load Factor Sales Planning Load Forecast (MMBtu – Normal Year)[44, 45]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	4,278,172	1,022,966	2,367,870	7,669,008.5
2022/23	4,314,179	1,042,450	2,389,599	7,746,228.9
2023/24	4,348,018	1,068,122	2,435,115	7,851,254.3
2024/25	4,422,378	1,094,765	2,483,280	8,000,422.3
2025/26	4,476,392	1,118,461	2,527,784	8,122,637.2
CAGR	1.14%	2.26%	1.65%	1.45%

8. <u>High Load Factor Firm Sales Customer Segment</u>

The High Load Factor Firm Sales customer segment represented 77% of total High Load Factor customers and 27% of total High Load Factor actual demand in 2020. From 2017 to 2020,

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42 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13.

43 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

44 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

45 The planning load results summarized in this table are net of unbilled adjustments, without capacity exempt volumes, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

the number of High Load Factor Firm Sales customers decreased by 2.3% per year, and weather normalized High Load Factor Firm Sales customer demand decreased by 0.6% per year.

a) High Load Factor Firm Sales Customer Model Results

Economic theory suggests that the number of High Load Factor Firm Sales customers may be dependent on such variables as a measure of the economy in the service territory (e.g., Gross Metro Product and/or manufacturing employment) and/or measures that reflect the competitiveness of natural gas relative to other energy types. Over time, the number of High Load Factor customers that have switched from bundled sales service to transportation service depends on the number and type of competitive suppliers that are working to attract new customers in EGMA's service territory. Therefore, consumer behavior theory suggests that the number of sales customers may be dependent on non-economic and difficult-to-measure factors that are related to High Load Factor customers' awareness of competitive choice and understanding of the benefits and risks of unbundled transportation service from EGMA coupled with supply service from competitive suppliers.

The EGMA High Load Factor Firm Sales customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Total Customer Count} = (a) + (b)*\textit{Economic Variable} + (c)*\textit{ Price Variable} + (d_i)*\textit{Binary Variables}_i + (e_i)*\textit{Interaction Variables}$$

Natural gas prices are the main drivers in all territories for High Load Factor Customer models. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the High Load Factor Firm Sales Customer models are provided in Appendix 4.

Over the forecast period, the total number of High Load Factor Firm Sales customers is projected to increase by 0.02%, as shown by Figure 21 below.

Figure 21: High Load Factor Firm Sales Customer Model Forecast[46]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	2,208	575	1,315	4,098
2022/23	2,207	574	1,310	4,091
2023/24	2,214	570	1,305	4,089
2024/25	2,225	569	1,304	4,097
2025/26	2,226	569	1,305	4,101
CAGR	0.21%	-0.25%	-0.19%	0.02%

b) High Load Factor Firm Sales Use per Customer Model Results

Economic theory suggests that use per customer in the High Load Factor Firm Sales customer segment may be dependent on such variables as weather, price, and efforts to conserve.

The EGMA High Load Factor Firm Sales use per customer models, which were developed according to the modeling process described in Appendix 3, have the following general form:

$$\textit{Use per Customer} = (a) + (b)*\textit{Effective Degree Days} + (c)*\textit{Price Variable} + (d_i)*\textit{Quarterly Variables}_i + (e_i)*\textit{Binary Variables}_i + (f_i)*\textit{Interaction Variables}$$

Weather and price are the main drivers of High Load Factor Sales use per customer in all three divisions. The variable coefficients, binary and interaction variables, and supporting explanations for the variables that are included in the models are provided in Appendix 4.

Over the forecast period, the use per customer for the High Load Factor Firm Sales segment is projected to decrease by 0.15%, as shown in Figure 22 below.

Figure 22: High Load Factor Firm Sales Use per Customer Model Forecast (MMBtu/Customer – Normal Year)[47]

Split Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	699.0	686.7	625.2	2,010.9
2022/23	689.7	679.6	624.9	1,994.2

46 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

47 Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

2023/24	685.9	682.4	627.3	1,995.6
2024/25	687.4	685.9	627.3	2,000.5
2025/26	688.9	684.1	626.1	1,999.0
CAGR	-0.36%	-0.10%	0.04%	-0.15%

c) High Load Factor Firm Sales Demand Results

The High Load Factor Firm Sales demand forecast was calculated by multiplying the forecasted number of High Load Factor Firm Sales customers for each quarter by the forecasted High Load Factor Firm Sales use per customer for that quarter. Over the forecast period, the total demand from the High Load Factor Sales segment is projected to decrease by 0.16% per year, as shown in Figure 23A below, and the High Load Factor Sales planning load is projected to decrease by 0.16% per year, as shown in Figure 23B.

Figure 23A: High Load Factor Sales Demand Forecast (MMBtu – Normal Year)[48, 49]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	1,558,603	396,125	829,695	2,784,423
2022/23	1,538,645	391,660	826,785	2,757,091
2023/24	1,534,147	390,650	826,551	2,751,348
2024/25	1,544,994	391,538	825,827	2,762,358
2025/26	1,550,232	390,992	825,222	2,766,446
CAGR	-0.13%	-0.33%	-0.14%	-0.16%

[48] All Customer Segment forecast results are before adjustments for EE savings, which will be discussed in Section III.C.13.

[49] Customer segment models were developed on a quarterly basis; the model results are presented on a split year basis that corresponds to Q4-Q3 (i.e., the twelve months from October through the following September).

Figure 23B: High Load Factor Sales Planning Load Forecast (MMBtu – Normal Year)[50,51]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	1,557,617	395,691	829,781	2,783,089
2022/23	1,536,572	391,319	826,472	2,754,363
2023/24	1,534,794	390,658	826,234	2,751,686
2024/25	1,545,942	391,506	825,680	2,763,129
2025/26	1,549,462	390,844	825,127	2,765,433
CAGR	-0.13%	-0.31%	-0.14%	-0.16%

9. Capacity-Eligible Transportation Load

The Company's Distribution and Default Service Terms and Conditions provide for the assignment of a share of all EGMA Gas resource contracts that are eligible for assignment to customers that received bundled sales service after February 1, 1999.[52] All other customers that (a) received bundled sales service at some time but converted to unbundled transportation service prior to February 1, 1999 or (b) have never received bundled sales service, are "Capacity Exempt" transportation customers. The Company must have adequate resources to meet the projected demands of bundled sales customers and non-capacity exempt customers; as directed by the

50 All Customer Segment forecast results are before adjustments for Energy Efficiency savings, which will be discussed in Section III.C.13

51 The planning load results summarized in this table are net of unbilled adjustments, without capacity exempt volumes, and on a gas year basis that corresponds to Nov-Oct (i.e., the twelve months from November through the following October).

52 EGMA customers that were taking firm transportation service prior to February 1, 1999 were "grandfathered" and were therefore exempt from the provisions of the Company's capacity assignment requirements.

Department, EGMA does not plan its resources to meet the projected demand of capacity exempt customers[53].

In terms of resource planning, one of the components of the Company's total load that must be accounted for is capacity eligible firm transportation load; capacity eligible load is that portion of the Company's firm transportation load that is subject to mandatory capacity assignment as specified in the Company's Distribution Terms and Conditions, Section 13.0.

For each of the three divisions, Brockton, Lawrence and Springfield, statistical models were used to derive (a) forecast total firm sales and transportation load and (b) forecast firm sales load. Total forecast firm transportation load was derived by subtracting forecast firm sales demand from forecast total firm sales and transportation demand. This forecast firm transportation demand consists of (a) capacity eligible firm transportation demand and (b) capacity exempt demand.

The forecast of capacity eligible transportation demand is calculated by multiplying (a) capacity eligible factors, by division and customer type, which EGMA derived based on four years of historical data, times (b) total forecast C&I transportation demand, by division and customer type. Forecast capacity exempt transportation demand is the difference between forecast transportation demand and forecast capacity eligible demand. The capacity eligible factors were calculated as the ratio of quarterly capacity eligible transportation demand divided by total transportation demand using data from 2017 Q1 through 2020 Q4.

The resulting percentages by division and customer type were used to forecast capacity eligible transportation over the forecast period. To illustrate the recent trend of conversions, historical data for the period 2016Q3 through 2020Q4 is shown in Figure 24.

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[53] In D.P.U. 14-111, the Department authorized LDCs to plan for up to 30% of their capacity exempt customers to convert from capacity exempt status to default sales/capacity eligible status for the winter of 2014-15 and in D.P.U. 15-43, the Department allowed the LDCs to plan for the conversion of up to 30% of the remaining capacity exempt customers to convert. Under Department policies, once a customer converts from capacity exempt to default sales, they become part of the Company's planning load. In D.P.U. 15-43, the Department also instructed each LDC to include in their long range Forecasts and Supply Plans a forecast of subsequent conversions from capacity exempt to default sales/capacity eligible status. The current forecast includes the loads that have returned to default sales/capacity eligible status pursuant to the Department's decisions in D.P.U. 14-111 and to D.P.U. 15-43.

Figure 24: Capacity Eligible C&I Transportation as a fraction of Total C&I Transportation Demand

Capacity Eligible Ratio				
Year	Quarter	Brockton	Lawrence	Springfield
2016	3	30%	55%	67%
2016	4	30%	48%	61%
2017	1	27%	42%	54%
2017	2	28%	42%	61%
2017	3	33%	46%	68%
2017	4	30%	43%	61%
2018	1	25%	39%	53%
2018	2	25%	39%	60%
2018	3	29%	44%	71%
2018	4	28%	42%	58%
2019	1	24%	36%	51%
2019	2	26%	33%	59%
2019	3	30%	32%	71%
2019	4	27%	30%	58%
2020	1	23%	28%	51%
2020	2	25%	32%	53%
2020	3	30%	40%	70%
2020	4	28%	36%	59%

Over the forecast period, the Capacity Eligible load is projected to increase at an annual rate of 0.88%, as shown by Figure 25 below.

Figure 25: Capacity Eligible C&I Transportation Demand (MMBtu – Normal Year)[54]

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	5,097,043	1,543,510	3,051,919	9,692,471.9
2022/23	5,118,661	1,556,042	3,030,778	9,705,481.0
2023/24	5,276,684	1,573,795	3,043,209	9,893,688.3
2024/25	5,302,917	1,595,330	3,057,414	9,955,661.8
2025/26	5,351,255	1,617,398	3,069,253	10,037,906.6
CAGR	1.22%	1.18%	0.14%	0.88%

54 Volumes are calendar period basis.

10. Company Use Forecast

Company Use gas is (a) metered gas usage for space heating at Company buildings and (b) metered gas used in the production of gas at Company LNG facilities. Consistent with its prior approved filings, EGMA determined that average company use values by quarter, using data from 2011Q1 through 2020Q4, were most representative of forecast Company Use through the Forecast Period. See Appendix 9 and Figure 26.

Figure 26: Company Use Forecast (MMBtu – Normal Year)

Gas Year	Company Use
2021/22	83,409
2022/23	83,409
2023/24	83,409
2024/25	83,409
2025/26	83,409
CAGR	0.00%

11. Forecast of Lost and Unaccounted For Gas

Lost and Unaccounted for gas ("LAUF") is the difference between (1) the gas that is added into the distribution system (a) at interconnection points between interstate pipelines and the distribution system or (b) from locally-produced gas at LNG facilities; and (2) gas that is withdrawn from the distribution system to be used by the LDC's customers.[55]

To forecast LAUF volumes, the Company calculated an LAUF Factor by dividing actual LAUF volumes as a percent of total metered usage for the period from 2018 through 2020. Over the three-year historical period, the average LAUF percentage is 1.63%, as shown in Figure 27.

[55] The major sources of lost and unaccounted for gas include meter measurement variances; billing and record keeping variances, distribution system losses (e.g. leaks, third party damage) and unmeasured usage.

Figure 27: Lost and Unaccounted for Gas Analysis

Gas Year	Company Use
2018	2.24%
2019	1.46%
2020	1.20%
3 Year Average	1.63%

During the forecast period, the losses associated with firm sendout and capacity eligible transportation is expected to increase by 0.85% per year as shown in Figure 28 below.

Figure 28: Unaccounted for Forecast Volumes (MMBtu – Normal Year)

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	415,034	127,975	243,560	786,569
2022/23	416,930	129,130	244,130	790,190
2023/24	421,942	130,412	245,810	798,163
2024/25	426,523	131,888	247,699	806,109
2025/26	430,936	133,356	249,454	813,746
CAGR	0.94%	1.04%	0.60%	0.85%

12. Forecast of Unbilled Sales

To account for unbilled volumes, the Company used net unbilled history back to 2015. For each month from January 2015 through December 2020, the Company calculated historical average net unbilled. Those monthly historical averages became the forecast for net unbilled. The annual sum of net unbilled in this history is shown below in Figure 29.

Figure 29: Historical Unbilled Sales (MMBtu)[56]

Gas Year	Sum of Net Unbilled
2015/16	(145,554)
2016/17	(452,196)
2017/18	994,886
2018/19	(1,007,630)
2019/20	(325,187)

The annual forecast of unbilled sales volumes is shown in Figure 30 below.

Figure 30: Unbilled Sales Forecast (MMBtu – Normal Year)[57]

Gas Year	Unbilled Forecast All Division
2021/22	(102,625)
2022/23	(102,625)
2023/24	(102,625)
2024/25	(102,625)
2025/26	(102,625)

The total forecast monthly unbilled sales are allocated to division and customer segment based on the ratio of volumes for each customer segment and division to total firm sales and transportation. See Appendix 10.

[56] Historical Unbilled Sales are total system unbilled sales.

[57] Forecast Unbilled Sales are planning load unbilled sales.

13. Energy Efficiency

The Company's forecast includes actual load reductions achieved from energy efficiency measures that were installed through 2019,[58] are planned to be installed through 2021 pursuant to the Company's Department-approved 2019-2021 Three-Year Energy Efficiency Plan ("Plan"),[59] and are forecast to be installed in 2022 through 2026.[60] These actual, planned, and forecast values were developed by the Company's Energy Efficiency department and reflect the most recent information, consistent with the Company's Department-approved 2019-2021 Plan and the upcoming 2022-2024 Three-Year Energy Efficiency Plan. Figure 31 below illustrates the cumulative savings in MMBtu due to energy efficiency used in this forecast.

For background and context, an Act Relative to Green Communities, Chapter 169 of the Acts of 2008 ("Green Communities Act" or "Act") was signed into law on July 2, 2008. This legislation was designed to promote enhanced energy efficiency throughout the Commonwealth and in so doing, the Green Communities Act required gas (and electric) distribution companies and municipal aggregators ("Program Administrators") to develop energy efficiency plans to "provide for the acquisition of all available energy efficiency demand reduction resources that are cost effective or less expensive than supply." G.L. c. 25, § 21(b)(1). In October 2018, Columbia Gas of Massachusetts, along with the other Program Administrators in the Commonwealth, developed and filed a comprehensive statewide energy efficiency plan for the period 2019 through 2021 that not only advanced the objectives of the Green Communities Act, but also promoted the parallel goals of decreasing GHGs and promoting job creation in the clean energy sector.

As part of the Company's Plan for 2019-2021, which was approved in Columbia Gas of Massachusetts, D.P.U. 18-110, the Company developed a comprehensive set of energy efficiency

58 See Columbia Gas of Massachusetts, D.P.U. 16-120 (2013-2015 Energy Efficiency Term Report Data Tables, submitted to the Department August 1, 2016 and revised February 21, 2017); Columbia Gas of Massachusetts, D.P.U. 19-90 (2016-2018 Term Report Data Tables, submitted to the Department August 1, 2019 and revised January 31, 2020); and Columbia Gas of Massachusetts, D.P.U. 20-50 (2019 Plan-Year Report Data Tables, submitted to the Department May 29, 2020).

59 See D.P.U. 18-110 (2019-2021 Three-Year Plan Data Tables, submitted February 19, 2019).

60 2025-2026 estimates are held constant the incremental 2024 level.

programs and correspondingly appropriate budgets and expected savings associated with these programs. The portfolio of programs target the residential, income eligible, and commercial and industrial ("C&I") markets, and serves all utility customers. The Company offers traditional weatherization programs to its income eligible and residential customers. Additionally, the Company offers programs to its multi-family customers served by either a residential or C&I meter, heating and water heating programs, as well as new construction and major renovation programs to residential and business customers. C&I customers are eligible for heating, water heating, thermostat, infrared and food service equipment rebates, as well as direct install retrofit measures.

The Company employed the Total Resource Cost ("TRC") test, as required and approved by the Department in its Order in D.P.U. 08-50-A, to analyze the cost effectiveness of the gas energy efficiency programs in its Plan for each of the three years, 2019-2021. See Columbia Gas of Massachusetts, D.P.U. 18-110 at Exh. 4 (Cost-Effectiveness Tables) and Exh. 5 (BCR Model). The TRC test measures the value of avoided gas supply and any additional direct economic benefits against the costs of a program to participating customers. The avoided gas supply costs used in these cost-effectiveness determinations are based on Appendix C of the "Avoided Energy Supply Components in New England: 2018 Report" March 30, 2018 (Revised October 24, 2018), prepared for the Avoided Energy Supply Component (AESC) Study Group, by Synapse Energy Economics, Resource Insights et al.[61] See D.P.U. 18-110 to D.P.U. 18-119, "2019-2021 Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Investment Plan" Exhibit 1, Appendix H (October 31, 2018). All programs were found to be cost-effective. See, D.P.U. 18-110 through D.P.U. 18-119 at 179 (January 29, 2019).

The Company is also exploring a series of alternative solutions to meet its customers energy demands including:

[61] Unlike previous studies, the 2015 and 2018 AESC studies were designed to be updated in synch with the three-year planning cycle of energy efficiency plans required by the GCA. A three-year cycle for the AESC study is consistent with the Department's focus on the three-year planning and performance construct envisioned by the GCA. D.P.U. 11-120-A, Phase II at 2.

(1) Gas demand response demonstration project that would have a duration of three years and is designed to test whether such a program can shave peak demand, alleviate temporary physical pipeline constraints, reduce the amount of pipeline capacity the Company needs to buy, and reduce greenhouse gas emissions by reducing overall gas usage.

(2) EGMA Is examining a geothermal network demonstration project to test the viability of this business model, assess the enabling technology, and evaluate those costs and benefits.

(3) Exploring opportunities to meet customer demand with Renewable Natural Gas ("RNG") as source of supply. RNG is gas that is recovered from a waste stream; and if refined to a pipeline-quality standard; and is introduced into a gas pipeline and ultimately delivered to customers.

(4) Exploring the opportunities to acquire Environmentally Responsible Natural Gas ("ERNG"). ERNG is evaluated and certified by a third party as meeting certain criteria and qualifications for environmentally sound production.

The Company used the methodology approved in its 2018 NSTAR Gas Company Supply Plan (D.P.U. 18-47) to reflect energy efficiency in the Planning Load forecast. These Planning Load forecasts discussed above were modeled without energy efficiency-related adjustments to the historical values; therefore, the resulting models include historical energy efficiency savings. For projected sales and/or transportation the amount of new energy efficiency that exceeds the historical trend value from 2013 to 2019 was deducted from the forecast to account for forecasted energy efficiency savings. Appendix 11 demonstrates these calculations in detail.

Figure 31: Energy Efficiency Savings Projections (Dekatherms)

Year	Residential & Low	Commercial & Industrial	Total
2012	306,439	444,889	751,328
2013	481,131	640,904	1,122,035
2014	681,673	849,045	1,530,718
2015	927,467	969,792	1,897,259
2016	1,182,713	1,095,685	2,278,399
2017	1,415,762	1,187,039	2,602,801

2018	1,698,660	1,375,902	3,074,563
2019	1,991,394	1,500,004	3,491,398
2020	2,333,719	1,847,032	4,180,751
2021	2,673,390	2,199,607	4,872,997
2022	2,931,706	2,323,610	5,255,316
2023	3,202,489	2,447,641	5,650,129
2024	3,489,805	2,571,856	6,061,661
2025	3,777,121	2,696,071	6,473,192
2026	4,064,437	2,820,286	6,884,723

14. Firm Planning Load Forecast

The normal year firm planning load forecast was calculated by summing the normal year forecasts for the four customer segments (reduced by expected savings from energy efficiency programs and capacity-exempt transportation), plus Company Use, Lost and Unaccounted for gas sales.

The total number of planning load customers is projected to increase over the forecast period by 0.76% per year, as shown in Figure 32. Gas year customers shown in Figure 32 are the average number of customers.

Figure 32: Total Company Customer Forecast Number of Customers

Gas Year	Brockton	Lawrence	Springfield	All Divisions
2021/22	172,359	51,941	110,249	334,550
2022/23	174,159	52,411	110,733	337,304
2023/24	175,889	52,857	111,175	339,921
2024/25	177,509	53,307	111,624	342,440
2025/26	179,083	53,746	112,052	344,881
CAGR	0.96%	0.86%	0.41%	0.76%

As shown in Figure 33, the total firm planning load, after adjustments for Company Use, losses and energy efficiency, is projected to increase by 0.78% per year over the forecast period.

Figure 33: Firm Planning Load Forecast (MMBtu – Normal Year)

Gas Year	Brockton	Lawrence	Springfield	All Divisions

2021/22	25,161,311	7,784,770	14,783,378	47,7299,459
2022/23	25,263,931	7,850,505	14,810,620	47,925,057
2023/24	25,547,810	7,921,448	14,900,745	48,370,003
2024/25	25,803,742	8,003,483	15,002,344	48,809,570
2025/26	26,049,123	8,084,903	15,095,765	49,229,791
CAGR	0.87%	0.95%	0.52%	0.78%

D. CUSTOMER DEMAND SCENARIOS

In addition to the base-case forecast results discussed in Sections III.B and III.C, the Company developed a high-case scenario and a low-case scenario. The high-case reflects a more optimistic set of economic drivers; the low-case forecast reflects a below-trend economic scenario from Moody's.

Over the forecast period, the total EGMA base-case annual, traditional Planning Load is projected to increase by 0.78% per year; the high-case scenario projects Planning Load will increase by 0.77% annually; the low-case scenario projects Planning Load will increase by 0.73% annually. A summary of the high-case, low-case and base-case forecast results are provided in figure 34 below:

Figure 34: Firm Planning Load Forecast (MMBtu – Normal Year)

Brockton			
Gas Year	Base	High	Low
2021/22	25,161,311	25,286,592	24,915,065
2022/23	25,263,931	25,404,594	24,949,242
2023/24	25,547,810	25,673,975	25,217,319
2024/25	25,803,742	25,929,052	25,484,013
2025/26	26,049,123	26,171,384	25,744,248
CAGR	0.87%	0.86%	0.82%

Lawrence			
Gas Year	Base	High	Low
2021/22	7,784,770	7,833,622	7,690,075
2022/23	7,850,505	7,905,488	7,728,548
2023/24	7,921,448	7,970,572	7,792,363

2024/25	8,003,483	8,051,821	7,878,639
2025/26	8,084,903	8,131,530	7,966,758
CAGR	0.95%	0.94%	0.89%

Springfield			
Gas Year	Base	High	Low
2021/22	14,783,378	14,844,278	14,663,952
2022/23	14,810,620	14,878,727	14,658,831
2023/24	14,900,745	14,961,519	14,741,441
2024/25	15,002,344	15,062,566	14,848,209
2025/26	15,095,765	15,154,344	14,949,006
CAGR	0.52%	0.52%	0.48%

EGMA Total			
Gas Year	Base	High	Low
2021/22	47,729,459	47,964,493	47,269,091
2022/23	47,925,057	48,188,810	47,336,621
2023/24	48,370,003	48,606,066	47,751,124
2024/25	48,809,570	49,043,439	48,210,860
2025/26	49,229,791	49,457,259	48,660,012
CAGR	0.78%	0.77%	0.73%

IV. DEVELOPMENT OF PLANNING STANDARDS AND PLANNING REQUIREMENTS

A. INTRODUCTION

The role of weather is critical in all aspects of the Company's supply planning process, including forecasting, resource planning and resource acquisition. Because most of the Company's sendout is temperature sensitive, temperature is a primary driver of firm sendout. The impact of temperature is reflected in the choice of a weather variable to apply consistently in all modeling and planning processes, including econometric models, normal-year, design-year, design-day and cold-snap analysis. The Company uses Effective Degree Days which take into account the effect of wind speeds, rather than conventional Heating Degree Days. This is in compliance with Department directives.

In this section, the Company describes the development of its design planning standards for normal year, design year, and design day. The normal year is defined as a weather pattern consistent with a distribution of EDDs that has the same number of EDDs for a given period above each EDD level as the historical EDD period. The period used for the normal EDD distribution calculations is the period from November 2000 through October 2020. Figure X-1 provides the normal year monthly EDD levels for each of the Company's Divisions, Brockton, Springfield, and Lawrence.

The Company used the same historical EDD database used by Columbia Gas of Massachusetts ("CMA") in its previous Forecast & Supply Plan (F&SP)[62] and added the most recent available data to the database. EGMA decided to use a Gas Year basis (November through October) instead of the Calendar Year basis used by CMA. For design planning purposes, EGMA used the entire available historical database from November 1967 through October 2020 to take advantage of the more complete data set

B. Normal Year Planning Standard

To develop the normal year planning standard, the Company developed frequency distributions for EDDs for each division for each month based on the 20-year average of the EDD data above each EDD level. The EDDs for each location for each month were then distributed over each month based on average daily EDD levels for Brockton, the Company's largest division, with the highest EDD levels paired with the days that had the highest average EDD level. This eliminated the possibility that a warm day in one division would be paired with a cold day in another and thus underestimate the overall Company's daily requirement. Although the EDD levels in each division generally differ on any given day, the EDD levels in the various divisions are closely correlated.

[62] D.P.U 19-135, filed October 30, 2019 and approved October 27, 2020.

The result of this analysis is a distribution of EDD within a month that has the 20- year average of EDDs above each EDD level, arranged in an order set by the average daily EDD level during the 20-year base period. This eliminates the need to distribute EDDs in a manner based on a particular actual month's EDDs, which may or may not actually be reasonably distributed. Figure 35 below provides the normal year EDD levels for each month by Division.

Figure 35
EGMA Normal Year EDDs
(Based on Nov 2000 - Oct 2020 Data)

	Brockton	Springfield	Lawrence
November	716	729	770
December	1,060	1,086	1,126
January	1,207	1,268	1,274
February	1,035	1,081	1,093
March	920	927	972
April	558	509	598
May	266	210	299
June	60	38	80
July	0	0	0
August	0	0	0
September	96	86	122
October	403	402	452
Winter Subtotal	4,938	5,091	5,235
Summer Subtotal	1,383	1,245	1,551
Total	6,321	6,336	6,786

C. DESIGN YEAR AND DESIGN DAY PLANNING STANDARDS

As indicated above, the Company's customer load is highly temperature sensitive, with the greatest demand during the coldest periods of the year. If appropriate planning is not adopted to address periods of extreme cold weather, the demand for gas may exceed available supply resulting in shortages, the consequences of which could be severe, ranging from large pipeline penalties to system depressurization and customer outages. To avoid the potential negative effects of shortages, the Company plans its resource portfolio to ensure that adequate resources are available during very severe weather conditions.

1. Review of Historical Frequency of Occurrences

The Company reviewed the historical weather data for each division for the 53 gas years between November 1967 and October 2020 to determine the five coldest winter periods and their respective recurrence periods, or probabilities. Using the distribution of the historical winter season EDD data, the Company calculated design winter standards for various occurrence probabilities and also noted the frequency of a potential design standard being exceeded during the 53-year historical period. This information is summarized in Figure 36 below. The analysis shows that the coldest winter in the past 53 years has a recurrence period ranging from 21 years in Springfield, to 28 years in Brockton, and to 21 years in Springfield.

Figure 36: EGMA Design Winter EDD Analysis
(Data from November 1967 through October 2020)

Brockton 151 Day Winter			
Mean	5,025	EDD	
Stand Dev	429.719	Level	Rec Per
Maximum	2014-15	5,798	27.8
2nd highest	2013-14	5,629	12.5
3rd highest	1968-69	5,627	12.4
4th highest	1967-68	5,620	12.1
5th highest	1969-70	5,601	11.1
Alternative Standards		6,024.2	100.0
		5,976.9	75.0
		5,907.1	50.0
		5,830.8	33.0
		5,812.6	30.0
		5,776.8	25.0
Proposed Standard		5,831	33.0

Springfield 151 Day Winter			
Mean	5,198	EDD	
Stand Dev	378.879	Level	Rec Per
Maximum	1968-69	5,832	21.3
2nd highest	1969-70	5,792	17.1
3rd highest	2014-15	5,710	11.4
4th highest	2013-14	5,702	10.9
5th highest	1993-94	5,681	9.9
Alternative Standards		6,078.9	100.0
		6,037.2	75.0
		5,975.6	50.0
		5,908.4	33.0
		5,892.3	30.0
		5,860.8	25.0
Proposed Standard		5,908.0	32.9

Lawrence 151 Day Winter			
Mean	5,257	EDD	
Stand Dev	446.564	Level	Rec Per
Maximum	2014-15	6,096	33.2
2nd highest	2013-14	5,951	16.7
3rd highest	2002-03	5,919	14.5
4th highest	1968-69	5,879	12.2
5th highest	1967-68	5,872	11.9
Alternative Standards		6,295.6	100.0
		6,246.5	75.0
		6,173.9	50.0
		6,094.7	33.0
		6,075.7	30.0
		6,038.5	25.0
Proposed Standard		6,095.0	33.1

The Company also conducted a similar statistical analysis of 24-day cold snaps for each of the EGMA divisions, based on the highest 24-day EDD level experienced during each winter season. The 24-day cold snap is an important component of a design winter. The Company used the actual pattern of EDDs for the period of January 7, 2004 through January 30, 2004 as the basis for the 24-day cold snap; which included the Company's historical peak days. Adjustments were made to make the adjusted total EDDs for the period to match the 1:33 level. A summary of historical 24-day cold snap analysis is provided in Figure 37 below.

Figure 37: EGMA Cold Snap EDD Analysis
(Data from November 1967 through October 2020)

Brockton 24-Day Cold Snap			
Mean	1,093.8	EDD Level	Rec Per
Stand Dev	119.449		
Maximum	1/07/04 to 1/30/04	1,325	37.8
2nd highest	1/28/15 to 2/20/15	1,287	18.9
3rd highest	1/28/79 to 2/20/79	1,286	18.6
4th highest	1/7/82 to 1/30/82	1,275	15.5
5th highest	1/12/71 to 2/4/71	1,271	14.5
Alternative Standards		1,371.6	100.0
		1,358.5	75.0
		1,339.1	50.0
		1,317.9	33.0
		1,312.8	30.0
		1,302.9	25.0
Proposed Standard		1,318	33.1

Sprinfield 24-Day Cold Snap			
Mean	1,125.5	EDD Level	Rec Per
Stand Dev	119.803		
Maximum	1/07/04 to 1/30/04	1,325	20.9
2nd highest	12/25/80 to 1/17/81	1,325	20.9
3rd highest	1/10/79 to 2/2/79	1,325	20.9
4th highest	1/1/70 to 1/24/70	1,325	20.9
5th highest	1/6/82 to 1/29/82	1,325	20.9
Alternative Standards		1,404.2	100.0
		1,391.0	75.0
		1,371.5	50.0
		1,350.2	33.0
		1,345.2	30.0
		1,335.2	25.0
Proposed Standard		1,350.0	32.8

Lawrence 24-Day Cold Snap			
Mean	1,131.7	EDD Level	Rec Per
Stand Dev	121.198		
Maximum	1/07/04 to 1/30/04	1,371	41.4
2nd highest	1/25/15 to 2/17/15	1,342	24.2
3rd highest	1/4/94 to 1/27/94	1,317	15.8
4th highest	12/26/67 to 1/18/68	1,314	15.1
5th highest	1/6/82 to 1/29/82	1,308	13.7
Alternative Standards		1,413.7	100.0
		1,400.3	75.0
		1,380.6	50.0
		1,359.1	33.0
		1,354.0	30.0
		1,343.9	25.0
Proposed Standard		1,359.0	32.9

The recurrence periods for the 24-day cold snaps ranged from 21 years in Springfield, to 38 years in Brockton, and 42 years in Lawrence. Once the decision was made to retain the 1:33 design winter standard and the 1:33 design day standard, (discussed below) the Company applied the same 1:33 standard to the cold snap analysis. This resulted in an upward adjustment in Springfield, and downward adjustments in Brockton and Lawrence.

The Company also conducted a similar statistical analysis of peak days for each of the EGMA divisions, based on the highest EDD experienced during each winter season. A summary of the five days with the highest EDD level in each division and the calculated recurrence probabilities are provided in Figure 38 below.

The coldest days in each of the three areas are very extreme with large recurrence periods. The analysis shows that the coldest day in Lawrence in the past 53 years (84 EDD) has a recurrence period of 182 years; the coldest day in Springfield (81 EDD) has a recurrence period of 97years, and the coldest day in Brockton (79 EDD) has a recurrence period of 48 years. In Lawrence, the second highest EDD (82 EDD) has a 1 in 75 recurrence probability, the second coldest day in Springfield (80 EDD) has a 1 in 64 recurrence probability; and the second coldest day in Brockton (78 EDD) has a 1 in 33 recurrence probability.

Figure 38: EGMA Design Day EDD Analysis
(Data from November 1967 through October 2020

Brockton Design Day			
Mean	66.3	EDD	
Stand Dev	6.221	Level	Rec Per
Maximum	01/08/68	79	48.8
2nd highest	01/15/04	**78**	33.5
3rd highest	01/17/82	**78**	33.5
4th highest	01/04/81	77	23.5
5th highest	02/13/16	75	12.4
Alternative Standards		80	72.8
		79	48.8
		78	33.5
		77	23.5
		76	16.9
Alternative Standards		80.8	100.0
		80.1	75.0
		79.1	50.0
		78.0	33.0
		77.7	30.0
		77.2	25.0
Proposed Standard		**78**	**33.5**
Note: Brockton Standard exceeded 2 times			
Proposed Brockton standard is:			**78**

Springfield Design Day			
Mean	66.7	EDD	
Stand Dev	6.176	Level	Rec Per
Maximum	01/04/81	81	97.3
2nd highest	01/08/68	80	64.0
3rd highest	01/15/04	**78**	29.7
4th highest	02/13/16	77	21.0
5th highest	12/25/68	74	8.4
Alternative Standards		80	64.0
		79	43.1
		78	29.7
		77	21.0
		76	15.2
Alternative Standards		81.1	100.0
		80.4	75.0
		79.4	50.0
		78.3	33.0
		78.0	30.0
		77.5	25.0
Proposed Standard		**78**	**29.7**
Note: Springfield Standard exceeded 2 times			
Proposed Springfield standard is:			**78**

Lawrence Design Day			
Mean	68.4	EDD	
Stand Dev	6.149	Level	Rec Per
Maximum	01/08/68	84	182.3
2nd highest	01/15/04	82	75.4
3rd highest	12/25/68	78	17.1
4th highest	01/04/81	77	12.5
5th highest	02/13/16	76	9.3
Alternative Standards		83	115.9
		82	75.4
		81	50.3
		80	34.3
		79	23.9
Alternative Standards		82.7	100.0
		82.0	75.0
		81.0	50.0
		79.9	33.0
		79.6	30.0
		79.1	25.0
Proposed Standard		**80**	**34.3**
Note: Lawrence Standard exceeded 2 times			
Proposed Lawrence standard is:			**80**

2. Basis for Selecting Design Winter Planning Standard

While the rationale for establishing a design day standard is straight forward, the need for a design winter standard is less obvious. Because many winter seasonal supplies, such as underground storage, and peak shaving LNG and propane facilities are subject to seasonal capacity constraints and re-supply requirements, a winter seasonal standard is required to insure that supplies are available on the last cold day of the winter. When load requirements can simply be met by increasing purchases of flowing supplies, seasonal volume limitations are not important. However, if the marginal supply is a source that has seasonal capacity constraints, a winter design standard is essential.

A design winter concern could be caused by diminished levels of underground storage or LNG inventories after a period of higher than normal EDDs. These inventories can be stretched by substituting available alternative supplies, such as purchasing flowing supplies in Appalachia to displace withdrawals from nearby underground storage fields. A delivered city-gate supply might be available to be arranged to avoid an LNG inventory shortfall. However, in a capacity constrained market such as New England, a Company cannot assume that such supplies would be available whenever they might be necessary. Such supplies need to be purchased in advance to guarantee their availability. The Company is required to make a trade-off between acquiring expensive winter seasonal supplies and providing an adequate level of reliability to avoid the extreme consequences of a loss of load.

The Company has established a design winter standard of 1:33, which the Department has approved since the Company's order in D.P.U. 06-84.[63] Given the current winter capacity and supply constraints in the New England market and the fact that the constraints will not likely be lessened by the construction of incremental capacity, the retention of the long standing 1:33 standard is appropriate.

Figure 39 provides a summary of the EGMA design winter and design day standards, discussed further below.

Figure 39: EGMA Summary of Design Planning Standards (Data from November 1967 through October 2020)

	Brockton	Springfield	Lawrence
Design Winter (1:33)	5,831	5,908	6,095
Design Day (1:33)	78	78	80

3. Basis for Selecting Design Day Planning Standard

The design day represents the single highest EDD the Company's resource portfolio must be structured to meet. Although the Company may have some flexibility in meeting design winter needs by taking advantage of short-term spot market-area arrangements throughout the winter season on warmer days, the Company does not believe that it is appropriate to rely on spot gas arrangements in meeting design-day conditions.

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63 The Company proposed and the Department approved a 1:25 standard for design winter and design day in previous Company filings in D.T.E 02-75, D.T.E. 98-86, and D.P.U. 93-129, but has consistently approved the 1:33 standard since D.P.U. 06-84.

The choice of the specific design day standard is not simply a matter of "letting the numbers" determine the standard. The recurrence periods for the Company's highest daily EDD levels in each divisions are very large. Because ehe EDD levels differ between the geographical areas, the recurrence probabilities of the coldest days are not the same. As shown in Figure38 , on January 8, 1968, the Lawrence Division experienced an 84 EDD; the Springfield Division experienced an 80 EDD; and the Brockton Division experienced a 79 EDD. The recurrence probabilities for the EDDs experienced that day were 1:187 in Lawrence, 1:64 in Springfield, and 1:49 in Brockton.

The Company has been using and the Department has been approving a 1:33 design day design standard since its filing in D.P.U. 06-84. The 1:33 standard continues to provide a reasonable balance between the high cost of winter seasonal supplies and the extreme costs of a loss of load due to inadequate supplies. The overall lack of pipeline capacity in the New England market, largely the result of electric generators not willing or able to pay for incremental capacity, justifies the high design day standard. Based on the updated EDD data used for the current filing, this standard translates to a 78 EDD design day level in Brockton and Springfield, and an 80 EDD design day in Lawrence, as shown in Figure 39 above.

D. CALCULATING DESIGN WINTER AND DESIGN DAY EFFECTIVE DEGREE DAYS

Once the choice of the standard for design winter and design day was verified by the Company's evaluation of the Company's design standard analysis, the calculation of the actual EDD level for the 1:33 recurrence periods were straightforward. Given the assumption that the winter EDDs, cold snap EDDs, and peak day EDDs were normally distributed, with known mean and standard deviations, the Company used the Excel statistical function to calculate the design EDDs for various probability levels.

The distribution of design year EDDs is derived based on the normal year EDD distributions with adjustments made for the winter season. The total number of winter EDDs was derived statistically, as discussed in the section on design winter EDDs. The total number of January EDDs was derived in a similar manner. The total number or EDDs for the other months were distributed based on the same percentage of non-January winter EDD s as the normal weather

EDDs and are allocated by days within the month by multiplying the normal EDDs by the ratio of design winter month EDDs to normal winter month EDDs. The derived cold snap number of EDDs are distributed according to the actual distribution for the January 7, 2004 through January 30, 2004 period, with minor adjustments such that the total is equal to the 1:33 level of EDDs. The rest of January EDDs are adjusted by a factor that results in the total January EDDs are equal to the January 1:33 EDD level. The design year summer EDDS are the same as the normal year EDDs.

Figure 40 shows the monthly distribution of design year EDDs for each of the EGMA divisions. Figure 41 shows the distribution of EDDs for the January Cold Snap by Division.

Figure 40
EGMA Design Year Monthly EDDs
(November 1967 through October 2020)

	Brockton	Springfield	Lawrence
November	815	824	867
December	1,207	1,226	1,266
January	1,588	1,591	1,640
February	1,177	1,221	1,229
March	1,045	1,047	1,093
April	558	509	598
May	266	210	299
June	60	38	80
July	0	0	0
August	0	0	0
September	96	86	122
October	403	402	452
Winter subtotal	5,832	5,909	6,095
Sumer Subtotal	1,383	1,245	1,551
Annual Total	7,215	7,154	7,646

Figure 41

EGMA 24 -Day January Cold Snap Analysis

(November 1967 through October 2020

Date	Brockton	Springfield	Lawrence
1	34	30	35
2	47	40	47
3	44	39	45
4	26	27	30
5	38	33	39
6	40	35	42
7	**55**	**56**	**57**
8	**60**	**57**	**67**
9	**70**	**70**	**72**
10	**66**	**65**	**67**
11	**45**	**49**	**47**
12	**38**	**38**	**41**
13	**57**	**58**	**61**
14	**70**	**71**	**72**
15	**78**	**78**	**80**
16	**64**	**62**	**64**
17	**37**	**42**	**38**
18	**40**	**44**	**42**
19	**53**	**56**	**52**
20	**55**	**55**	**54**
21	**49**	**50**	**49**
22	**47**	**50**	**48**
23	**60**	**59**	**61**
24	**66**	**67**	**70**
25	**60**	**60**	**65**
26	**53**	**56**	**56**
27	**46**	**50**	**45**
28	**44**	**48**	**46**
29	**54**	**56**	**53**
30	**51**	**53**	**52**
31	41	37	43

Cold Snap Indicated by Bold font & Shading

Design Day is January 15

E. Calculating Design Winter Planning load requirements

The design year load requirements are primarily based on the normal year forecast with some minor adjustments. The process used for determining the EGMA planning load requirements is based on the process that the Company has successfully used in the two most recent NSTAR Gas Long Range Forecasts and Supply Plans.[64] The normal year monthly forecasts are split into daily base loads and monthly temperature sensitive loads, which are subsequently divided by the normal number of EDDs to derive monthly temperature sensitive sendout per EDD factors. The factors based on the unadjusted monthly load forecasts generally require adjustment prior to their being input to the SENDOUT Model and applied to the normal year daily distribution of EDDs to determine the normal year monthly requirements.

Because the unadjusted base factors and sendout per EDD factors are based on econometric models that derive quarterly estimates of loads, they are allocated to monthly totals loads by the load forecasting group. The methods for allocating the quarterly volumes to monthly volumes can be imprecise. Dividing the unadjusted monthly load forecasts into daily base requirements and monthly sendout per EDD factors generally result in sendout per EDD factors that are reasonable for some months, but not reasonable for all months.

When analyzing actual total monthly firm planning load broken down into base loads and sendout per EDD, a very logical and reasonable pattern of sendout per EDD occurs. The highest SO/EDD factor generally occurs in January, followed by December and/or February, then followed by March and/or November. By definition, July and August are total base loads and have sendout/EDD factors of 0. The months of June and September have the next lowest sendout per EDD factors; May is slightly higher than June, and April and October are higher than May and September, but lower than November and March.

When the traditional base and sendout per EDD factors are derived from the unadjusted month load forecasts, some unusual results occur. Sometimes the months of September and or June may have a lower load forecast than either July or August. It's not clear how or why this

[64] See D.P.U. 18-47, filed May 2, 2018, and approved April 18, 2019 and D.P.U 20-76, filed July 15, 2020 and approved June 9, 2021.

happens. It may be the result of differences in the allocation of unbilled revenues to billed sales, where one month's estimates may be too high and cause a too low number in an adjacent month. The reasons for the unusual forecast variations are not known, but it is known that they happen with unadjusted data.

One of the first adjustments is the assumption that July and August forecast have to have the lowest forecast volumes (if not, then the month that has a lower forecast number would have a negative sendout per EDD factor, which is not reasonable or acceptable). The two lowest months are assumed to be July and August and the lower June or September number is swapped for the higher July or August number. This process results in more reasonable sendout per EDD factors for all other months and the same total summer volumes as the original forecast. Summer sendout per EDD factors are not as important factors because the actual loads tend to be small enough such that the entire load can be met with flowing supplies and not impact seasonal supplies.

Winter seasonal loads can be also adjusted if factors differ significantly from reasonable expectations. The January forecast sendout numbers are very carefully analyzed because of their impact on design standards. The sendout per EDD factor for the first January in the forecast period can be compared the most recent actual data to determine if a January adjustment is required. Adjustments can be made to the other winter months if necessary. Adjustments are made in such a way that the total winter seasonal requirements after adjustments match the total winter seasonal requirements before the adjustments. After any adjustment is made for July and August values, the winter Sendout per EDD factors are adjusted as necessary to comply with reasonable expectations. Summer adjustments are made as necessary such that there are reasonable relationships between April and March and between October and November.

Because of the uncertainty associated with the traditional January spreadsheet derived sendout per EDD factors, the Company has developed a design day model that uses estimates of daily planning load from the most recent winter season with actual daily EDDs to develop a forecast of the design day load. Once again, the model used for the current EGMA filing is based on the same approach used by NSTAR Gas in its most recent Forecast and Supply Plans.

V. RESOURCE PORTFOLIO ANALYSES

A. EGMA'S DECISION-MAKING PROCESS

The Department has reviewed and approved the Company's prior F&SP filings, the last five of which were docketed as, D.P.U. 11-89, D.P.U. 13-161, D.P.U. 15-143 , D.P.U. 17-166, and D.P.U 19-135. The Department summarized its findings following its investigation of EGMA's last F&SP, D.P.U. 19-135, as follows:

> The Company has provided evidence that it has a resource planning process that ensures its ability to acquire least-cost supply for its customers. …
>
> The Company has demonstrated that its supply portfolio is adequate to satisfy forecast normal year, design year, and design day sendout requirements under optimistic (high-growth) and base-case conditions throughout the forecast period with the acquisition of incremental resources …
>
> Accordingly, the Department finds that Bay State has established that it possesses adequate supplies to meet its expected normal year, design year, and design day sendout requirements throughout the forecast period.
>
> Finally, based on the Company's analysis, the Department finds that Bay State has demonstrated that it has adequate supplies to meet its firm sendout requirements during a prolonged cold snap.
>
> D.P.U. 19-135, at 42.

Also, the Department has reviewed EGMA's planning process and associated results in its various decisions approving specific resource acquisitions, most recently in D.P.U. 10-49, D.P.U. 10-65, D.P.U. 10-134, D.P.U. 12-04, D.P.U. 12-64, D.P.U. 13-158, D.P.U. 15-39,[65] D.P.U. 15-142, D.P.U. 15-170, D.P.U. 15-175, D.P.U. 17-85, D.P.U. 17-97 and D.P.U. 17-166. In each of these proceedings, the Department found that the Company's demand forecasting and supply planning processes are consistent with the Department's requirements. In these various Department decisions, the Department found that EGMA's resource decisions contributed to meeting the Company's interrelated goals of flexibility, diversity, viability and least-cost. Further, in each of the above proceedings, the Department found EGMA's planning process to be reasonable and appropriate.

[65] The Northeast Energy Direct project was withdrawn by TGP after Department approval.

As explained in this section, EGMA's resource planning process is largely unchanged since its previously approved Plan noting that the process appropriately takes into consideration changing market dynamics at the wholesale and retail levels.

1. EGMA's Planning Goals

EGMA's decision-making process requires the Company to establish appropriate goals and objectives, consistent with both Department policy and sound LDC practice in providing the most beneficial service to its customers. The primary goal of EGMA's planning process is to acquire and manage all available resources in a manner that achieves a best-cost resource portfolio for its customers. A best-cost portfolio appropriately balances lower costs with other important non-cost criteria such as reliability, viability and flexibility. Pursuit of a best-cost portfolio allows EGMA to provide its customers with reliable service at a reasonable cost.

The Company's overall portfolio objective is supported by a number of specific resource planning objectives, which are summarized as follows:

(1) minimize portfolio costs;

(2) maintain portfolio security/reliability (which includes enhancing diversity across pipelines and supply basins);

(3) provide contract flexibility; and

(4) acquire viable resources.

EGMA's resource planning process employs analytical tools, including the SENDOUT® cost optimization model along with its various assessment methods, to perform long-range planning and to evaluate the individual resource decisions it must make. Non-cost resource evaluation is typically performed using spreadsheet-based assessment tools. Taken together, these tools and methods ensure that the planning process is thorough, and that it remains objective in its pursuit of a best-cost portfolio.

2. EGMA's Planning Process

Effective resource planning requires both an excellent understanding of an LDC's own customers and markets, as well as insights into opportunities and developments in wholesale markets. Through its resource planning process, EGMA seeks to match its long-term resource needs with available market opportunities (e.g., new capacity or gas supply options).

EGMA performs long and short-range analyses of its portfolio and potential need for adjustment to achieve its planning objectives on an ongoing basis. Additionally, the Company performs comprehensive analyses any time a decision to modify the portfolio of resources under contract is being considered. This analysis includes a determination of need, and any associated change of need, and an evaluation of potential resource options.

Any decision to modify the portfolio begins with a determination of need based on the current resources under contract, including market (pricing) dynamics, and current demand forecasts. EGMA's portfolio requirements are driven by EGMA's design weather conditions and the associated requirements of its customers as reflected in its forecasts of (normal and design) annual, peak season, cold snap and daily requirements developed using the forecasting models described earlier in Section III. Comparison of the demand forecasts to the existing portfolio establishes whether EGMA's portfolio is projected to be adequate over the planning horizon, and if not, the quantity and duration of any deficiency. Similarly, this comparison also indicates whether there is an imbalance of resources in the portfolio in any of the years over the planning horizon, which may be released, de-contracted or sold in wholesale markets.

At the time that a need is established by a projected deficiency, EGMA compiles a comprehensive set of alternative portfolio options that could meet the anticipated need. EGMA is an active participant in regional capacity markets for both the purchase and sale of capacity resources on a bundled and unbundled basis. EGMA's market participation provides important market intelligence on developments in wholesale markets and is relied upon, in part, to compile resource alternatives. Further, the Company typically may issues a Request for Proposal ("RFP") as part of the competitive process to assure it receives the best bids from the market at that time. EGMA also specifies the criteria to be used in the evaluation of the array of resource options, which entails selecting the appropriate weighting among the price and non-price evaluation criteria incorporated in the planning process. Consistent with its portfolio goals, the resource evaluation criteria employed by EGMA are (1) price, (2) supply security, (3) contract flexibility and (4) supplier viability, which take on varying degrees of importance depending on the type of resource decision being made and anticipated market conditions.

Once the full range of resource options has been analyzed, EGMA selects the best resource alternative or alternatives to pursue. In selecting the best alternative, EGMA evaluates present and anticipated future market conditions as well as risks associated with its decision. Depending on the type of resource, there can be a long lead-time between the decision point and the in-service date. This typically occurs when incremental capacity resources are required, which would be taken into consideration in the Company's Action Plan.

3. Least-Cost Planning Techniques

The first element of the Department's standard of review is whether least-cost planning techniques were used in the decision-making process. The Department has previously indicated that EGMA's planning process appropriately minimizes costs:

> The Company has provided evidence that it has a resource planning process that ensures its ability to acquire least-cost supply for its customers. With the use of the SENDOUT® model, Bay State is able to consider physical limitations and contract constraints, and to determine the minimum cost dispatch for a particular period.
>
> The Department has held that for a gas company's planning process to minimize cost, that process must adequately consider all resource options, including energy efficiency, on an equal basis. D.P.U. 93-13, at 88. The evidence shows that the Company's process adequately considers all resource options on an equal basis, and it has appropriately accounted for the effect of its energy efficiency programs (Exh. CMA-1, at 77-78). Accordingly, the Department finds that the Company has formulated an appropriate process for identifying a comprehensive array of supply options, and it has developed appropriate criteria for screening and comparing supply resources. In addition, we find that Bay State has demonstrated that the contracts for which it requests renewal provide least-cost service to meet the needs of the Company's customers and will continue to provide the same service after renewal
>
> D.P.U. 19-135, at 39.

In Bay State Gas Company, D.T.E. 98-86 (2000) and other Company proceedings, the Department commented on EGMA's use of the SENDOUT® cost optimization model to evaluate the cost effectiveness of various supply options, wherein it stated:

> "Bay State has demonstrated that it has in place processes by which it develops resource planning strategies to maintain reliable, least-cost service to its firm sales customers. The Department therefore finds that Bay State's SENDOUT model allows the Company to identify a variety of capacity and commodity options under multiple planning contingencies and migration scenarios."
>
> D.T.E. 98-86, at 30.

EGMA continues to utilize the SENDOUT® model as its primary tool for designing a least-cost portfolio of supply options.

As explained more fully below, the Company also utilizes an appropriate analytical framework for evaluating the cost-effectiveness of potential EE resources. Thus, EGMA's resource planning process accomplishes the Department's goal of achieving least-cost.

4. Analytical Tools

EGMA utilizes important analytical tools to ensure a comprehensive evaluation of its total portfolio resource alternatives and resultant decisions. Central among these is the use of EGMA's SENDOUT® model that optimizes the utilization of all resources in the portfolio under various weather patterns, including design and normal conditions. EGMA also considers various growth scenarios related to its design day and annual demand forecasts, including base, high and low. This helps ensure that EGMA's planning techniques result in best-cost decisions. As noted above, the Company's use of this model has been cited by the Department in recent F&SP and other proceedings as appropriate to ensure that EGMA's planning techniques are least-cost. SENDOUT® can also select the lowest cost mix of resources from among an array of specified options. EGMA employs other analytical techniques, such as the use of spreadsheets, to enhance the evaluation of resource options. These tools aid in the assessment of non-price criteria when there are a number of similar options available in the marketplace.

EGMA, through its collaborative participation in state-wide energy efficiency initiatives, also employs appropriate analytical tools to evaluate demand-side resource options. In particular, the Company employs a cost-effectiveness screening model developed through a collaborative process. The evaluation of demand-side resources is based on an assessment of avoided energy costs to ensure that supply and demand-side resources are evaluated consistently to yield an overall least-cost resource plan.

B. DESCRIPTION OF THE CURRENT RESOURCE PORTFOLIO

1. Overview of Supply-Side Resources

EGMA's upstream supply and capacity portfolio is comprised of a multitude of supply, transportation, and storage contracts. These contracts are grouped into upstream capacity resource paths, which flow gas from the supply source to the Company's city gates. EGMA's upstream firm capacity paths are listed in Appendix 2 and show all of the Company's firm transportation, storage, and supply resources. EGMA's long-term contracts are listed in Appendix 1, Table G-24 and their peak deliverability is shown below in Table I-1.

Table I-1 EGMA Firm Portfolio Resources	
	Maximum Daily Transportation MMBtu / Day (MDQ)
Algonquin Gas Pipeline	
AGT Firm Capacity with Flowing Supplies (1)	122,413
AGT Firm Capacity from Storage (2)	57,123
AGT Firm Local Transportation Service (3)	30,000
AGT Delivered Supply (4)	23,000
Total Firm AGT Transportation	232,536
Tennessee Gas Pipeline	
TGP Firm Capacity with Flowing US Supplies (5)	133,023
TGP Firm Capacity from Storage Fields (6)	53,696
Total Firm Delivery Tennessee	186,719
Liquefied Natural Gas	
LNG	112,500
LPG	40,000
	152,500
System Total Capacity	
Maximum Peak Day Deliverability	571,755
Maximum Annual Firm Deliverability	
(1) Includes TETCO LH, AGT AIM, AGT Centerville and the NUI Exchange.	
(2) This includes DTI GSS,, a portioon of the Enbridge Storage and all the TETCO SS-1.	
(3) The local trnasportation capacity represents the 20,000 Dth/day from Beverly, MA and the 10,000 Dth/day from the Neptune receipt point to the AGT G lateral.	
(4) Peaking contracts to the AGT G Lateral.	
(5) Includes TGP LH, TGP Niagara, TGP Dawn via TCPL-PNGTS and the NUI Exchange.	
(6) TGP FSMA, National Fuel, a portion of Enbridge Storage	

Although EGMA has three separate service divisions, for planning purposes, the Brockton Division is separated from the Springfield and Lawrence Divisions because it is primarily served by Algonquin Gas Transmission, LLC ("AGT" or "Algonquin"), and the Springfield and Lawrence Divisions are primarily served by Tennessee Gas Pipeline ("TGP" or "Tennessee"). The ability to transfer supplies between divisions is limited, with the only capability being the transfer of up to 6,000 Dth per day to Brockton via a physical interconnect from Tennessee at the Mendon, Massachusetts gate station. Also, EGMA is able to exchange additional volumes on an as-needed basis with Northern Utilities, Inc. ("Northern"), which allows the Brockton, Lawrence and Springfield Divisions to receive in total approximately 12,000 Dth of supply when needed.

EGMA's supply-side resources are grouped into three categories: supply, storage, and peaking. Supply and storage resources are delivered by transportation contracts held on various upstream pipelines. Each group is discussed in greater detail below.

Supply Resources

EGMA acquires firm supply through a combination of term and spot purchases. The majority of EGMA's firm gas supply purchases are made pursuant to winter-only contracts that deliver supplies from the U.S. Gulf Coast and other producing areas, including Marcellus Shale ("Marcellus"), located on the Texas Eastern and Tennessee pipelines as well as supplies delivered from the Dawn Hub into the TransCanada pipeline systems. In the summer, the Texas Eastern and Tennessee pipelines are used primarily for transporting supply to storage facilities. Purchases for storage refill are normally made on a spot basis or by utilizing asset management agreements for ratable storage refill.

For the most part, supply resources are purchased under the North American Energy Standards Board ("NAESB") gas supply contract. This NAESB contract includes standard provisions which the parties supplement with special provisions.

Regarding the structure for supply resource commodity purchases, LDCs can determine the least-cost commodity resource purchase on a day-to-day basis by gathering market intelligence via electronic trading platforms such as Intercontinental Exchange ("ICE") as well as phone and e-mail solicitations. In any case, EGMA would only solicit and trade with those counterparties with which the Company currently has an active NAESB base contract.

EGMA's portfolio diversity includes supply points from the U.S. Gulf Coast, Appalachia and Canada. Consequently, EGMA's ability to purchase commodity on a daily basis, from diverse locations, provides EGMA's customers with not only reliability, but the flexibility to adjust to changing customer demand and market conditions.

TGP Supply Portfolio and Contract Paths

Tennessee Contract FTA 5173 is EGMA's legacy long -haul TGP system transportation contract. It has a MDQ of 12,748 Dth and provides access to the TGP traditional supply areas and the Marcellus production area. It delivers to Springfield and Lawrence and during the summer season to the Company's TGP storage contract FSMA 5178. EGMA generally purchases the TGP supplies and the manages the associated transportation contract.

The TGP FTA 5291 and FTA 39741, with MDQs of 6,171 Dth and 4,081 Dth, respectively provide transportation from the TGP Niagara interconnection with TransCanada Pipeline (TCPL) to Springfield and Lawrence. EGMA generally purchases supplies at Niagara and manages the associated transportation contracts with a competitively bid annual AMA contract.

EGMA has three contracts that receive gas at the TGP Dracut, MA interconnection with PNGTS[66]. These include TGP FTA 98775 (MDQ of 6,100 Dth) that delivers gas to Northampton in the Springfield division; FTA 48427 (MDQ of 17,000 Dth) that delivers gas to the Tewksbury lateral in the Lawrence division (a separate Tewksbury lateral contract FTIL 362252 delivers the gas to the EGMA Andover gate station); and FTA 330904 (MDQ of 96,400 Dth) that delivers gas to both Springfield and Lawrence.

Several different contracts deliver gas to Dracut. These include three PNGTS contracts, two of which (PNGTS 208540 and PNGTS 233301) can deliver a total of 59,800 Dawn purchase supplies and one of which (PNGTS 208540) delivers 16,000 Dth of Dawn storage supplies. There are two Repsol peaking supply contracts, that can deliver a total of 47,000 Dth. The part of TGP FTA 330904 used for the Enbridge storage is generally part of the 16,000 Dth/day Enbridge storage AMA agreement, described below with the Storage AMAs. Part of the FTA 330904 contract is dedicated as part of the Dawn Purchase AMA contract[67], and part of the contract is used to transport winter season Repsol peaking supplies. The FTA 98775 (the Northampton contract) and

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66 The TGP FTA 330904 contract delivers to TGP at Dracut and Haverhill. The Haverhill receipts are delivered to Lawrence, while the Dracut receipts are delivered to Springfield. The Dracut interconnection was constructed when the joint PNGTS and Maritimes and Northeast project was constructed, while the Haverhill interconnection is with Granit State Transmission and was used to deliver TGP system supplies to Northern Utilities prior to Order 636. For the purposes of this report, we will use Dracut as the receipt point for the TGP 330904 contract.

67 The Dawn purchase AMA provides the opportunity to deliver 12,000 Dth to Northern Utilities as part of an exchange agreement. On days when EGMA delivers 12,000 Dth to Northern, Northern delivers an equivalent amount of gas to EGMA's AGT and TGP divisions using Northern's own capacity to EGMA.

FTA 48427 (the contract that feeds the Tewksbury lateral) are Company managed contracts and not part of any AMAs.

Algonquin Supply Portfolio and Contract Paths

The Texas Eastern CDS 800462 contract provides EGMA's Brockton division access to the TETCO long haul supply area and the Marcellus production area. The final deliveries to Brockton are delivered by Algonquin legacy contracts.[68] The TETCO contract has a MDQ of 36,369 Dth and is also used to refill the TETCO storage contracts and the EGTS storage contract during the injection season. EGMA generally purchases TETCO long haul supplies and manages the AGT transportation contracts with a competitively bid annual AMA contract.

The Algonquin AFT-1 510352 contract provides 48,000 Dth of transportation from the AGT interconnection with Transco in Centerville, NJ to the Brockton division. EGMA generally purchases gas at Centerville and manages the transportation contract with a competitively bid annual AMA contract.

The Algonquin AFT-1 510066 contract provides 20,000 Dth of transportation from the AGT Beverly, Ma interconnection with Maritimes & Northeast Pipeline. This contract was part of the AGT Hubline project that was designed to deliver gas from offshore Nova Scotia EGMA does not have any upstream capacity at Beverly. Because of the relatively high price of supplies at Beverly, EGMA uses this contract as part of a winter supplemental supply AMA contract.

The Algonquin AFT-1 AIM contract provides 30,000 Dth of transportation from the AGT interconnection with Millennium Pipeline in Ramapo, NY to Brockton. The Millennium Pipeline provides access to the Marcellus production area in eastern PA. EGMA also has a 15,000 Dth contract with Millennium, contract FT 217524, to supply half of the Company's AIM capacity supplies. EGMA generally purchases and manages the Millennium capacity with the Ramapo purchases under a competitively bid annual AMA contract.

Tennessee Storage Resources and Contract Paths

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68 The Algonquin legacy contracts do not provide a one for one direct tie to the TETCO contracts. The more recent AGT contracts were originally certificated as part of an incremental project where the AGT contracts were tied to specific upstream contracts. The legacy AGT contracts are not tied to specific TETCO contracts.

For the Springfield and Lawrence Divisions, EGMA has storage service contracts with Tennessee, National Fuel and Enbridge. The Tennessee and National Fuel facilities are located in western Pennsylvania, and the Enbridge facilities are located near Dawn, Ontario.

The TGP FSMA storage contract has a MDWQ of 19,755 Dth, annual storage capacity of 1,222,594 Dth, and a MDIQ of 8,151 Dth. It is in Ellisburg, PA. Two TGP FTA contracts provide transportation to Springfield and Lawrence, FTA 5293 (MDQ 12,547 Dth), which receives gas only from the TGP FSMA contract, and FTA 5196 (MDQ 15,375 Dth), which receives 5,500 Dth from the TGP FSMA contract and 9,875 Dth from the National Fuel FSS contract discussed below. EGMA generally manages the FSMA storage contract, related injection supplies, and transportation of FSMA withdrawals.

The National Fuel storage contract has a MDWQ of 10,000 Dth, annual storage capacity of 1,100,000 Dth, and MDIQ of 6,699 Dth. Gas for injection is delivered by a National Fuel FST transportation contract (N12604) that receives gas from TGP at East Aurora, NY. Gas withdrawn from the FSS contract is transported by the same FST contract to the TGP FTA 5196 contract at Rose Lake, PA, which has a maximum daily receipt point quantity of 9,875 Dth (plus fuel). EGMA generally manages the National Fuel storage contract with an AMA contract that provides for injection purchases at the TGP interconnection with TCPL in Niagara at a Niagara based index, transportation on TGP to the National Fuel FST contract for injection into the FSS contract, withdrawals from FSS, transportation on FST to the TGP 5196 contract for ultimate delivery to Springfield and Lawrence.

The Enbridge LST090 storage contract is in Dawn, Ontario. It has a MDWQ of 16,000 Dth, annual storage capacity of 1,600,000 Dth, and a MDIQ of 8,000 Dth. Under the AMA contract, injections are based on the monthly summertime Dawn index. The contract path includes: withdrawals from the LST contract, transportation on TCPL contract 63397 (MDQ 16,000 Dth) from Dawn to PNGTS at East Hereford, Quebec/Pittsburg, NH: transportation on PNGTS contract 208540 (MDQ 16,000) to the interconnection with TGP at Dracut, MA; and transportation on TGP FTA 330904 (MDQ 96,400 Dth, with only 16,000 Dth dedicated to this AMA contract) with final deliveries to Springfield. The AMA delivered MDQ is 16,000 Dth even though the pipeline fuel losses along the contract path would reduce the delivered quantity if the Company were to manage the contract by itself. The annual AMA contract is competitively bid.

The Enbridge LST089 storage contract is also located in Dawn, Ontario. It has a MDWQ of 26,500 Dth, annual storage capacity of 1,820,000 Dth, and a MDIQ of 10,000 Dth. Injections are based on the monthly summertime Dawn index during the injection season. The contract path includes: withdrawals from the LST contract, transportation on Union contract M12204 (MDQ 26,352 Dth) from Dawn to TCPL at Parkway, Ontario: transportation on TCPL contract 63398 (MDQ 26,063 Dth) from Parkway to the Iroquois interconnection point at Waddington, NY; and transportation on IGT contract 182003 (MDQ 28,840) to the interconnection with TGP at Wright, NY. At Wright, two TGP contracts are used to deliver to EGMA's gate stations. The first contract is TGP FTA 95349 (MDQ 9,774 Dth) which delivers to both Springfield and Lawrence. The second contract is TGP FTA 41098 (MDQ 18,733 Dth) which delivers to the TGP/AGT interconnection at Mendon, MA. The final leg of the Brockton division deliveries of the storage contract is Algonquin AFT-1 93001F (MDQ 18,490). The AMA provides for the full delivery of 9,774 Dth to Springfield and Lawrence and 18,490 Dth to Brockton in spite of the fact that upstream pipeline MDQs and pipeline fuel losses along the contract path would reduce the delivered quantity if the Company were to manage the contract by itself. This annual AMA contract is also competitively bid.

Algonquin Storage Resources and Contract Paths

For the Brockton Division, EGMA has storage service contracts with Texas Eastern, Eastern Gas Transportation and Storage (formerly Dominion Transmission), and Enbridge storage as mentioned above with the TGP related Enbridge LST089 contract.

The Texas Eastern SS-1 contract 400193 has a MDWQ of 22,819 Dth, annual storage capacity of 1,588,950 Dth, and a MDIQ of 8,168 Dth. This contract is traditionally Company managed because it is a very flexible contract, providing no-notice service which is essential for providing balancing services for the Brockton Division. Spot gas from the TETCO Marcellus production area is injected during the summer. Withdrawals are delivered under the SS-1 contract directly to AGT contracts at Lamberville, NJ. EGMA generally uses its AFT-E no-notice contract for transportation to the Brockton gate stations to take full advantage of the no-notice service,

The Texas Eastern FSS-1 contract 400502 has a MDWQ of 1,056 Dth, annual storage capacity of 63,360 Dth, and a MDIQ of 326 Dth. This contract is also traditionally Company managed because it is a flexible contract, although it doesn't provide the same level of no-notice service provided by the SS-1 contract.[69] Spot gas from the TETCO Marcellus production area is injected during the summer. Withdrawals are delivered under CDS contract 800414 (MDQ 1,056 Dth) to AGT contracts at Lamberville, NJ. EGMA generally uses its AFT-E no-notice contract for transportation to the Brockton gate stations to take advantage of the CDS and AFT-E no-notice flexible service.

The EGTS Storage contract GSS 600002 has a MDWQ of 14,757 Dth, annual storage capacity of 1,441,753 Dth, and a MDIQ of 8,010 Dth. It has an "incomplete" contract path that compels EGMA to use an AMA contract to manage the storage and related transportation contracts. The specific terms of the AMA contract will vary from year to year, however the AMA storage contract is tied to the Company's' TETCO FT-1 800382 contract (MDQ 4,235 Dth), the Transco FT 1006548 contract (MDQ 1,254 Dth), part of AGT AFT-1 93201AC (the 1,254 Dth that has the Centerville receipt point tied to the Transco 1006548 contract), and part of AFT-1 94501 contract (currently 10,746 Dth). The current AMA contract delivers a total of 12,000 Dth to the Brockton division. EGMA manages the injections, the storage capacity and the transportation contracts with a competitively bid annual AMA contract. The Asset Manager is responsible for providing the "missing" transportation capacity.

Peaking Resources

On-system peaking resources are those that EGMA controls within its service territory and are comprised of LNG and propane facilities located in each service territory. The Company has

69 The FSS-1 contract does not offer the same level of no-notice serve as the SS-1 contract, but the withdrawals are transported under no-notice contracts which provide the maximum amount of flexibility available under the FSS-1 Rate Schedule.

retired its former West Springfield propane facility since its last Forecast and Supply plan. These on-system resources are listed in Appendix 1, Table G-14.

EGMA has contracts for off-system peaking supply, such as from Constellation Energy (owner of the Distrigas LNG facility),[70] from Direct Energy,[71] and Repsol,[72] which stores LNG in New Brunswick, that can be vaporized and delivered into the New England markets. Decisions to procure seasonal peaking supplies are driven by an evaluation of design winter deficiencies that may be identified within the portfolio.

2. Current Contract Status

This section describes the Company's pipeline transportation and storage contracts, their respective termination dates, their respective notification dates, and the steps that EGMA will take in response to the pending termination dates. Because the Company requires all of its current contracts and still requires the purchase of winter season supplemental supplies to meet current and expected future requirements, the Company is planning to renew all of its pipeline contracts when the contract notification dates arise. Table G-24 in Appendix 1, provides the MDQs, the Primary Term Expiration Dates, the current termination dates, termination notification dates, and whether the Company is requesting Departmental approval of the contracts in this proceeding. This section summarizes the renewal status of the contracts.

Algonquin Contracts:

The AGT legacy contracts (93001EC, 93201AC, 93401, 93001F, 94501, 510352, 510066) are scheduled to terminate October 31, 2023, have a notification date of October 31, 2022, and are on evergreen status. These contracts are essential and have no practical alternative. The Company expects these contracts to be automatically renewed. Pursuant to NSTAR Gas Company d/b/a

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70 CMA used a one-year contract to provide this service for the winter of 2019-20. EGMA filed for D.P.U. approval of a three-year, 8,000 Dth/day winter peaking service contract with Constellation LNG on January 29, 2021 in D.P.U. 21-09, which was approved on August 16, 2021.

71 The Company received approval of the contracts for the AGT G-lateral from the Department in D.P.U. 21-09.

72 CMA filed on November 2, 2017 for Departmental approval of the TGP Zone 6 to Zone 6 contract for 96,400 Dth/day, 14,300 Dth/day of PNGTS Portland Express Project (with upstream capacity on Union and TCP)L, and two ten-year peaking services contracts with Repsol for a total of 47,000 Dth/day. The contracts were approved in D.P.U. 17-172 on May 31, 2018.

Eversource Energy, D.P.U. 16-40, at 33 (2017), the Department is not required to approve the renewal of these 1 year extensions for the duration of the planning horizon of this filing.

Algonquin AIM contract 510804-R1 which was approved in D.P.U. 13-158. It does not terminate until 2031. This contract provides for a 1 year notice period before termination to extend the contract for 5 or 10 years which does not occur which two years of this filing. Therefore, the Company is not requesting an extension of these two contracts in this filing.

The Algonquin "Neptune Agreement" contract 806893 for the 10,000 Dth/day for delivery into the AGT G-lateral systems with an original termination date of 10/31/2022 was approved in D.P.U. 21-09. At that time, it is anticipated that AGT may require EGMA to request for service for additional five years in order to continue to receive the service. This contract is essential and has no practical alternative. EGMA request the Department approve the renewal of this contract.

Texas Eastern Contracts:

The TETCO legacy contracts (800462, 800414, 800382) are scheduled to terminate October 31, 2027, have a notification date of October 31, 2022, are on evergreen status for 1 year renewal. These contracts are essential and have no practical alternative. The Company expects these contracts to be automatically renewed. Pursuant to D.P.U. 16-40, the Department is not required to approve the renewal of these 1 year extensions for the duration of the planning horizon of this filing.

TETCO storage contract (400502) is a core storage contract serving the Brockton area is scheduled to terminate 4/30/2027 and has a notification date of 4/30/2022 are on evergreen status for 1 year renewal. The contract is essential and has no practical alternative. The Company expects this contract to be automatically renewed. Pursuant to D.P.U. 16-40, the Department is not required to approve the renewal of this extension.

TETCO storage contract (400193) is a core storage contract serving the Brockton area is scheduled to terminate 10/31/2023 and has a notification date of 4/30/2022. The contract is on evergreen status for a 5 year renewal which will then renew ever year for 1 year. The contract is essential and has no practical alternative. The Company expects this contract to be automatically renewed. Pursuant to D.P.U. 16-40, the Department is not required to approve the renewal of this extension.

Tennessee Contracts:

TGP FTA 5173 (Longhaul) -The longhaul contract provides transportation from the TGP production areas to the Company's gate stations. This contract (MDQ 12,748 Dth) is scheduled to terminate on 10/31/2023 and the notice date is 10/31/2022. The contract is on evergreen status and TGP requires a 5-year contract extension. The contract is essential and has no practical alternative. The Company expects this contract to be automatically renewed. Pursuant to D.P.U. 16-40, the Department is not required to approve the renewal of this extension. .

TGP FSMA 5178- This contract is the core TGP storage contract serving Springfield and Lawrence. This core storage contract is scheduled to terminate 10/31/2023 and has a notification date of 10/31/2022. The contract is on an evergreen status. TGP requires a 5 -year contract extension. The contract is essential and has no practical alternative. The Company expects this contract to be automatically renewed. Pursuant to D.P.U. 16-40, the Department is not required to approve the renewal of this extension.

TGP FTA 5293 – This contract provides transportation from the TGP FSMA storage contract to the Company's Springfield and Lawrence divisions. This core storage transportation contract is scheduled to terminate 10/31/2024 and has a notice date of 10/31/2023. The contract is on evergreen status. TGP requires a 5-year contract extension. The contract is essential and has no practical alternative. The Company expects this contract to be automatically renewed. Pursuant to D.P.U. 16-40, the Department is not required to approve the renewal of these extensions for the duration of the planning horizon of this filing.

All other TGP contracts have notification dates outside the two-year time period for this filing. These include: FTA 5291 and FT 39741 (Niagara FT); TGP FTA 48427 (Dracut to Tewksbury); and TGP FTA 41098 and FTA 95349. These contracts provide transportation from IGT to AGT at Mendon (MDQ 18,733 Dth) and to Springfield and Lawrence (MDQ 9,774 Dth), FTA 5196 (Storage FT): FTA 98775 (Dracut to Northampton); and FTA 330094 (Dracut to Springfield and Lawrence).

TGP FTIL 362252 Tewksbury Lateral- This is a one year contract that took effect 11/1/2021 with a MDQ of 14,000 Dth and replaced a TGP contract with a MDQ of 17,000 dth. The Company will look to renew this contract annually for a term of one year each year. The Department approval of this contract is not required under G.L. c.164, section 94A.

PNGTS Contracts and related Union and TCPL contracts

The Company has three contracts with PNGTS. The first contract, 208540, with a MDQ of 16,000 Dth, transports storage gas from the Enbridge LST090 contract via the TCPL contract 63397 (also with a MDQ of 16,000 Dth). It is scheduled to terminate in 2032 and the related TCPL contract is scheduled to terminate in 2026. Therefore, the Company is not requesting an extension of this contract in this filing.

The other two PNGTS contracts, 208535 (MDQ 45,500 Dth) and 233301 (MDQ 14,300 Dth) transport gas under the PXP project. Union Gas contract M12292 (MDQ 61,218 Dth) and TCPL contract 64198 (MDQ 59,827 Dth) transport the gas from the Dawn Hub to PNGTS for ultimate delivery to TGP at Dracut. The two PNGTS contracts, the Union, and the TCPL contracts all terminate on October 31, 2040. Therefore, the Company is not requesting Department approval of a renewal of these contracts in this filing. However, Union Gas contract M12204, which connect the TCPL capacity to the Dawn storage and supply hub, has a termination of 10/31/2024 and a notice date of 10/31/2022. The contract is essential and has no practical alternative. EGMA requests that the Department approve the renewal of this contract.

Enbridge Storage Contracts:

Enbridge Storage Contract LST 090 for 16,000 Dth/day of Enbridge storage deliverability and 1,600,000 Dth of annual storage capacity in the Dawn Ontario region went into service on April 1, 2018, and will expire on March 31, 2022. The Department approved the renewal of this contract in D.P.U. 19-135. Enbridge contract No. LST089 for 26,500 Dth/day of deliverability and 1,820,000 Dth of annual storage capacity went into service April 1, 2016 and will expire on March 31, 2022. The Department approved the renewal of this contract in D.P.U. 19-135. The Company negotiated an extension of these contracts through March 31, 2024 (now contracts LST 143/144). The continuation of the Enbridge storage contracts, in conjunction with the recently approved PXP project that provides access to substantial amount of flowing gas at Dawn, maintains a good balance between flowing supplies and seasonal storage for the EGMA portfolio. EGMA will conduct a request for proposals for similarly structured storage contracts to the Dawn receipt points of its TCPL contracts. The Company requests that the Department approve the renewal of the Enbridge storage contracts.

National Fuel Storage Contracts:

The National Fuel FSS contract N11117, National Fuel FST storage transportation contract O11116 are scheduled to terminate March 31, 2023, and have a notification date of March 31, 2022. The contracts are on evergreen status. The National Fuel storage gas is delivered by TGP to Springfield and Lawrence. These contracts are essential and have no practical alternatives. The Company expects these contracts to be automatically renewed. Pursuant to D.P.U. 16-40, the Department is not required to approve the renewal of these contracts.

Transcontinental Contracts:

Transco contract 9239453 is part of the contract path to deliver storage gas from the Eastern Gas Transmission & Storage (formerly DTI) GSS storage contract to the Brockton Division. This contract is scheduled to terminate October 7, 2023, and has a notification date of October 8, 2022. The contract is on evergreen status. The contract is essential and have no practical alternative. The Company expects this contract to be automatically renewed. Pursuant to D.P.U. 16-40, the Department is not required to approve the renewal of this contract.

Iroquois Contracts:

The Iroquois contract RTS 182001 provides transportation for the Enbridge storage contracts from the IGT interconnection with TCPL in Waddington, NY to its interconnection with TGP in Wright, NY. Without the IGT link, the storage gas could not be delivered to the related TGP contracts and could not ultimately be delivered to Springfield, Lawrence, or Brockton. The contract is essential and has no practical alternative. The contract does not expire until 2027, and notification date in not until 2026. Therefore, the Company is not seeking Department approval of a renewal of this contract in this filing.

Millennium Contract:

EGMA has entered into contract 217524 for 15,000 Dth/day which will expire on March 31, 2034. This contract is part of a path that delivers purchased supply to EGMA city gate, while also allowing EGMA to directly access Marcellus supply. The Company is not seeking Department approval of a renewal of this contract in this filing.

Granite Contract:

The Company entered into contract No. 22-002-FT-1 for up to 12,000 Dth/day, which will expire on April 30, 2022. The new contract is effectively an extension of the previous contract No. 21-001-FT-1. EGMA has a year-to-year physical exchange agreement with Northern Utilities. Through this exchange agreement, Northern Utilities delivers 12,000 Dth/day directly to the EGMA city gates in Lawrence, Springfield and Brockton divisions. In exchange, EGMA delivers 12,000 Dth/day to the Northern Utilities city gate using this Granite State Gas Transmission ("GSGT") FT-1 capacity. EGMA utilizes flowing supply from PNGTS to fill this GSGT capacity. Because term of the contract is for one year or less, the Company is not seeking Department approval of this contract under G.L. c.164, section 94A.

Eastern Gas Storage Contracts:

Eastern Gas (Formerly DTI) gas storage contract 600002 is scheduled to terminate March 31, 2026, have a notification date of March 31, 2024. Eastern Gas requires a 5 year extension. Although the notification date is more than two years beyond the filing, the Department will likely not have sufficient time to approve the renewal of this contract after the next Forecast and Supply Plan is filed in Fall of 2023. The contract is essential and has no practical alternatives. EGMA requests that the Department approval the renewal of this contract at this time.

On-System Peaking:

The Company has decided to retire its West Springfield LP facility. This retirement reduces the Company's liquid propane capacity by 72,297 gallons, total storage capacity (net of the heel) by 23,583 Dth, and reduces vaporization by 18,000 dth/day. There have not been any other changes to EGMA's On-System Peaking assets since the prior F&SP. EGMA will continue to evaluate the operational capabilities of on-system peaking facilities as each facility continues to age and the operational requirements of the Company's distribution system continue to change. Should the results of ongoing analyses suggest a change in the daily and/or seasonal capability of any of EGMA's peaking facilities, EGMA will provide the updated capabilities within the F&SP process or other appropriate filing with the Department.

Peaking Supply:

EGMA has two transaction confirmations for LNG supplies from Repsol's Canaport LNG terminal for delivery on Tennessee capacity. A 30-day peaking supply for up to 32,900 Dth/day and a 40-day peak supply for up to 14,100 Dth/day are both contracted through March 31, 2028. These were approved by the Department in D.P.U. 17-172. Additionally, the Company entered into a contract with Constellation LNG LLC which provided for the firm delivery of up to 8,000 Dth/day to Company receipt points on AGT's Line G for the winter season, an assignment of an existing firm transportation contract for 10,000 Dth/day of AGT G-System capacity currently held by Neptune to EGMA and for a contract with Direct Energy to provide up to 15,000 Dth/day of a 30- day peaking service for delivery to Taunton and South Attleboro located on the AGT G-system. The Company received approval from the Department for this contract in DPU 21-09. The Company will be assessing its future supply resources for the AGT G lateral as these contracts terminate during the forecast period.

Demand Side/Energy Efficiency Resources:

EGMA offers comprehensive Energy Efficiency ("EE") services aimed at reducing customer demand. All current EE programs through December 31, 2021, as described in the Company's three-year EE plan for 2019-2021, were approved by the Department on January 29, 2019, in D.P.U. 18-110. Each three-year plan is developed, including an annual therm savings goal, with the guidance of the Commonwealth's Energy Efficiency Advisory Council ("EEAC") and in close collaboration with the other gas and electric LDCs. EGMA's EE programs are tested for cost-effectiveness on a total-resource cost basis.

EGMA offers EE services to all customers: residential, residential low-income, and commercial and industrial ("C&I"). EGMA's EE programs have been designed and implemented in coordination with other Massachusetts natural gas LDCs and electric LDCs, and are consistent with the program offered by other Massachusetts natural gas LDCs. The core residential program is Residential Coordinated Delivery, which provides a no-cost home energy efficiency assessment to residential properties. This program provides customers with seventy-five percent of the cost of insulation improvements, no-cost air sealing, and zero percent financing. In addition, EGMA offers rebates for heating and water heating equipment. EGMA also has an Income Eligible program offering all the same benefits and services to customers who are eligible for fuel assistance or the utility discount rate at no cost to the customer.

Other program offerings benefiting residential customers include a Residential New Buildings program that provides incentives to builders of new homes exceeding local building and energy codes, thereby promoting market acceptance of high efficiency design and increasing the penetration of highly efficient new homes. The program also similarly incentivizes customers performing major renovations or additions.

C&I customers are eligible for broad array of energy efficiency services. The New Construction and Major Renovation program offers a range of services, including design and engineering assistance, as well as incentives for the purchase of high efficiency HVAC systems, measures that improve the building envelope, and other major equipment to the developers of new buildings and the owners of buildings undergoing major renovations. The C&I Existing Buildings program encourages building owners to replace functioning equipment with premium efficiency counterparts. Customers are offered incentives for the purchase and installation of HVAC equipment and controls, building energy management system controls, industrial process equipment and controls improvements, spray valves and other equipment specific to a customer's needs. Therefore, in conducting its resource-planning process, the Company carefully considers the actual, cumulative demand reduction resulting from energy efficiency programs.

3. Analyses Utilizing SENDOUT®

In order to assess the cost implications of various resource alternatives, EGMA performs optimization analyses using SENDOUT®. EGMA augments these cost analyses with assessment of non-cost characteristics in order to support its various resource decisions. Also, SENDOUT®

is used to assess the adequacy of the resource portfolio under different levels of firm customer requirements.

This section of EGMA's Plan presents current SENDOUT® results based on its long-range forecast of requirements, existing resources and potential new supply resources. The results of these and recent analyses of the cost-effectiveness of potential EE measures form the basis of the Company's present Action Plan.

The SENDOUT® model is a linear programming software package designed for LDCs to optimize the cost of serving demand while ensuring reliable service to firm customers. Specifically, SENDOUT® incorporates the monthly demand forecast, converts this forecast into a daily interval, and then satisfies daily demand by utilizing the lowest cost resources from among those specified in the available network. EGMA's model includes limitations on the withdrawal of storage and peaking facilities to ensure that these assets are available throughout the heating season as one way to ensure reliable service to firm customers.

SENDOUT® assumes that all demand costs are fixed and all supplies are optimized based on variable costs. However, SENDOUT® can evaluate certain selected resources on a total cost basis. This evaluation is referred to as the Resource Mix option, and can be used to test whether a new contract should be entered into or whether an existing contract should be renewed. The Resource Mix option can also "size" a contract when given a maximum and minimum range from which to select. SENDOUT® is capable of handling several supply, transportation, and storage resources placed into the Resource Mix at one time.

EGMA utilizes SENDOUT® to test the adequacy of its resource portfolio, including any required incremental resources, under various design conditions. As described earlier, EGMA's design conditions include design day, design winter and cold-snap weather conditions.

EGMA's analyses, under a variety of demand scenarios, indicate that the portfolio is sufficient to satisfy EGMA's base case firm demand without the acquisition of incremental resources during the forecast period. The adequacy of the portfolio is due, in part, to the growth of EGMA's firm requirements under its base case scenario. This level of growth is a function of the projection of declining NUPC, somewhat dampening the load growth associated with the impact of projected customer growth

It is important to note that the adequacy of the Company's portfolio to satisfy firm demand under the base and high case scenarios throughout the five-year forecast period (through October 2026), is in part due to EGMA's plan to acquire capacity to attain this portfolio adequacy.

Detailed results showing the resources utilized to meet firm customer requirements under each of the demand growth scenarios are provided in accompanying appendices. Appendix 1, G-22 Tables, provides the winter and summer dispatch results for the base, and high demand growth cases based on normal year requirements. Appendix 1, G-23 Tables, provides the winter and summer dispatch results for the base, and high demand growth cases based on design year requirements.

Table I-2 EGMA Gas Normal Year Adequacy (BBTU) Base Case					
Gas Year	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
Requirements					
Sendout	47,730	47,925	48,370	48,810	49,230
Injection	9,539	9,607	9,630	9,668	9,709
Total	57,268	57,532	58,000	58,477	58,939
Resources					
Pipeline	47,093	47,273	47,702	48,092	48,476
LNG/LPG Trucking	810	879	902	939	981
Storage Withdrawals	8,504	8,501	8,501	8,501	8,501
LNG Withdrawals	861	879	896	945	981
LPG Withdrawals	0	0	0	0	0
Other Supplies	0	0	0	0	0
Total	57,268	57,532	58,000	58,477	58,939
Note: Annual normal year figures are on a Gas Year (November through October) basis, not Calendar Year basis.					

Table I-3 EGMA Gas Design Year Adequacy (BBTU) Base Case					
Gas Year	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
Requirements					
Sendout	52,837	53,069	53,553	54,046	54,520
Injection	10,375	10,459	10,490	10,595	10,648
Total	63,212	63,528	64,044	64,641	65,167
Resources					
Pipeline	51,385	51,572	52,021	52,409	52,830
LNG/LPG Trucking	1,644	1,728	1,759	1,863	1,916
LNG Withdrawals	1,655	1,703	1,738	1,842	1,892
LPG Withdrawals	21	21	21	21	24
Storage Withdrawals	8,506	8,505	8,504	8,505	8,504
Other Supplies	0	0	0	0	0
Total	63,212	63,528	64,044	64,641	65,167
Note: Annual design year figures are on a Gas Year (November through October) basis, not Calendar Year basis.					

Incremental Resources are not required in a Normal Year in either the Base Case or High Case Growth Scenarios. However, in a Design Year, regardless of growth, and in the Cold Snap Scenarios, discrete upstream incremental pipeline and/or supply resources are required in most years of the plan. The Company would expect to cover any Incremental Resource needed with upstream or citygate supply, or a pipeline expansion should one become available and was selected by the Company's planning process as best cost option and also approved in a separate by the

Department. The Design Day Scenarios are outlined below in Tables I-4 through I-7.

Table I-4					
EGMA Gas Design Day Adequacy (BBTU)					
Base Case					
Gas Year	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
Peak Day Sendout	516.0	519.6	523.2	528.6	534.0
Resources					
Pipeline	277.0	280.6	284.2	289.6	293.1
Storage Withdrawals	105.5	105.5	105.5	105.5	105.5
LNG Withdrawals	112.5	112.5	112.5	112.5	112.5
LPG Withdrawals	21.0	21.0	21.0	21.0	22.8
Other Supplies	0.0	0.0	0.0	0.0	0.0
Total	516.0	519.6	523.2	528.6	534.0
Low Growth Scenario					
Gas Year	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
Peak Day Sendout	509.7	511.5	514.8	520.4	526.1
Resources					
Pipeline	277.3	277.3	277.3	277.3	278.6
Storage Withdrawals	105.5	105.5	105.5	105.5	105.5
LNG Withdrawals	112.5	112.5	112.5	112.5	112.5
LPG Withdrawals	14.4	16.2	19.5	25.1	29.5
Other Supplies	0.0	0.0	0.0	0.0	0.0
Total	509.7	511.5	514.8	520.4	526.1
High Growth Scenario					
Gas Year	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
Peak Day Sendout	521.4	525.6	528.9	534.3	539.6
Resources					
Pipeline	277.3	277.7	279.6	282.7	285.9
Storage Withdrawals	105.5	105.5	105.5	105.5	105.5
LNG Withdrawals	112.5	112.5	112.5	112.5	112.5
LPG Withdrawals	26.1	29.8	31.3	33.5	35.7
Other Supplies	0.0	0.0	0.0	0.0	0.0
Total	521.4	525.6	528.9	534.3	539.6

Table I-6
Design Day Adequacy for High and Low Growth Scenarios (BBTU)

Scenario / Gas Year	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
Sendout requirements-High	521.4	525.6	528.9	534.3	539.6
Sendout requirements-Low	509.7	511.5	514.8	520.4	526.1
Resources-High	521.4	525.6	528.9	534.3	539.6
Resources-Low	509.7	511.5	514.8	520.4	526.1
Citygate supplies-High	0.0	0.0	0.0	0.0	0.0
Citygate supplies -Low	0.0	0.0	0.0	0.0	0.0

Table I-7: EGMA Gas Design-Day Firm Requirements (BBtu)
Base Case

Year	Brockton	Lawrence	Springfield	Total
2021-22	283.8	83.2	149.0	516.0
2022-23	285.8	84.1	149.7	519.6
2023-24	287.9	84.9	150.5	523.2
2024-25	291.1	85.8	151.6	528.6
2025-26	294.4	86.8	152.8	534.0

Overall, EGMA is presently projecting a modest resource deficiency in the base case scenario, which will be served through a combination of peaking supplies, via an RFP process, and day-to-day spot supply. Also, as noted above, EGMA will be required to evaluate a number of important contract renewal decisions during the five-year planning horizon. These include capacity on Tennessee, Algonquin, Iroquois, Millennium, National Fuel, Eastern Gas, Transco, TransCanada, Union, PNGTS, and TETCO. Appendix 1, Table G-24, highlights all contracts that terminate during the forecast period, terms and required notice dates for renewal, as well as indicating those contracts having an evergreen provision. Some of these contracts provide important primary delivery point capacity needed to maintain the reliability of EGMA's system.

As the decision time nears for each of these renewal decisions, EGMA will employ its resource planning process to establish the best-cost alternative, which may be renewal, replacement, reduction or termination of all of the existing resources, as explained in Section I, above. The Department will be notified of any long-term renewal decisions and, further, any new long-term capacity contracts, as may be required, will be filed with the Department, along with the appropriate support, for approval under G. L. c. 164, § 94A. In this F&SP, the Company requests specific approval to renew all contracts with renewal notice required within the two-year period from the filing of this document. These contracts are noted on Table G-24.

4. Evaluation of Demand-Side Resources

EGMA considers both supply and demand-side options on an equal footing. The evaluation of demand-side resources on a consistent basis with supply-side resources is accomplished through a separate screening process utilizing appropriate analytical tools. Avoided energy supply costs are the basis for determining the cost-effectiveness of alternative demand-side resources. In Massachusetts, the supply-side avoided costs utilized by all LDCs in their EE Plans are prepared on a regional basis and are updated biannually. The most recent regional avoided cost study is the Avoided Energy Supply Costs in New England: 2018 Report ("AESC 2018"), which was completed on March 30, 2018.

An EE program cost-effectiveness screening model is utilized to evaluate EE resources. The model incorporates an array of descriptive parameters, in addition to the avoided energy costs, to calculate the expected lifetime energy savings of EE measures. Screening is performed on a total-resource cost test basis as currently specified by the Department. The EE program is discussed further in Section II.

5. Non-Cost Analyses

In addition to a cost analysis, EGMA evaluates other attributes of potential resources, including reliability, flexibility and viability. This non-cost evaluation is accomplished through appropriate assessment techniques, and is integrated with cost-considerations in order to arrive at final resource decisions. EGMA will present a comprehensive analysis of both cost and non-cost considerations associated with available alternatives at the time the Company requests Department approval of any specific long-term resource option.

6. Other Information

As reported in its last F&SP, the Company has none of the following: (a) any participation in or service from manufacturing and storage facilities planned outside Massachusetts; (b) an exempt and approved manufacturing or storage facility in Massachusetts not yet in operation; (c) a proposed manufacturing or storage facility in Massachusetts; or (d) a proposed pipeline in Massachusetts over a mile in length and over 100 psi.

C. OPERATIONAL CONSIDERATIONS

Although EGMA's F&SP is a comprehensive plan intended to reliably service the long term demands of its customers, EGMA nonetheless faces operational risks in the day-to-day management of its system. Some of these risks are inherent and quantifiable, such as the risk that the weather could be colder than design day or extends longer in duration than EGMA's planned cold snap. Other risks, however, are outside of EGMA's direct control. For example, a few years ago, TGP installed an electric compressor to support the Northampton lateral. A failure of this singular compressor station due to electrical interruption or mechanical failure could lead to significant pressure drops on the Northampton lateral and potentially result in disruption of service to EGMA's customers.

Electric generation facilities are now the largest consumers of natural gas, larger than the natural gas LDC community. Electric generation facilities tend to burn their daily allotment of gas in a very short period of time, typically in less than a twelve-hour period. The increasing utilization of the natural gas system by electric generating facilities, when the natural gas system was designed for natural gas LDC usage, which is more consistent throughout the day, has resulted at times in very low instantaneous pipeline pressures. This threatens the overall viability of the natural gas system.

The increased demands resulting from (1) new electric loads attaching to the pipeline grid without corresponding pipeline capacity and (2) new customers converting to natural gas have resulted in the natural gas pipeline grid running consistently at or near design peak day levels. Several years ago, when there was more flexibility of available capacity in the pipeline grid, TGP would restrict their pipeline at station 245, the entry point into Massachusetts (Zone 6). Now, due to the increased electric load, changing supply dynamics, and increased overall demand, TGP has begun to restrict their pipeline through every existing compressor station in Massachusetts, something never experienced before. EGMA's planning standards have not traditionally included a gate by gate specific supply/demand balance. EGMA's customers do not take supply on an evenly hourly basis nor does EGMA plan for evenly hourly take restrictions, which the pipeline can institute.

Additionally, when the pipeline runs consistently at or near its design day capabilities, there is a much greater risk that the pipeline grid could experience a widespread interruption of service, due to the fact that the pipeline compressor stations are running at high utilization rates, and are therefore more prone to breakdown. When compressor stations breakdown, this causes overall lower system pressures and throughput. This may result in the pipeline cutting firm pipeline capacity, resulting in EGMA potentially using much more peaking resources than planned. When a compressor fails, it has the immediate effect of lowering pressures downstream of that compressor station and the pipeline is forced to cut flowing gas through that point. The net result is that EGMA must strive to maintain higher levels of on-system peaking resources in the event of pipeline curtailments.

D. Springfield Division – Reliability Plan

Prior F&SPs have discussed a reliability plan for the Springfield Division in detail. The reliability plan consists of four separate projects to accomplish the goal of enhancing the reliable, safe and continuous delivery of natural gas service to approximately 100,000 customers in the Springfield operating area. These projects will not impact Northampton or Easthampton and, as a result, the moratorium on natural gas service in Northampton and Easthampton will remain in place.

Three of these separate projects are part of a contract with TGP, which was approved by the Department in D.P.U. 17-172. The TGP contract entitles EGMA to 96,400 Dth of firm transportation capacity, which eliminates the need to rely on non-firm city-gate delivered supplies to manage supply deficiencies. Much of firm TGP capacity replaced much less reliable and interruptible capacity, significantly improving reliability of supply to customers in both the Springfield and Lawrence Divisions. This capacity will be fully available by November 1, 2021. In addition, the TGP contract provides for increased delivery pressure of 300 psi at EGMA's Agawam point of receipt and an additional point of delivery from TGP. As part of the contract, TGP proposed three construction projects in the Springfield Division and has completed two.

First, pursuant to the Department-approved contract, TGP completed the Agawam Compressor Station Enhancement project, which consisted of upgrading equipment at TGP's existing compressor station to improve operating efficiency, deliver enhanced services and increase reliability to EGMA customers. Second, TGP completed the construction of the Agawam Two-Mile Pipeline Loop, which provides additional capacity and operational pressure that ensures reliable service on the western end of the Springfield operating area. The third project is the Longmeadow Supply Strategy Project in which TGP will install a new Point of Delivery ("POD") in the Town of Longmeadow. As part of this project, EGMA will seek approval from the Energy Facilities Siting Board ("EFSB") to install facilities and new distribution piping from the new POD to its Bliss Street Station. The EGMA portion of this project is known as the Western Mass. Gas Reliability Project.[73] Completion of the Longmeadow Supply Strategy Project and the Western Mass. Gas Reliability Project will permit EGMA to enhance system reliability for 58,000 customers on both sides of the Connecticut River.

The fourth reliability project for the Springfield Division is the ConEd Transmission Line Replacement Project. This project will replace an 8,500 foot existing line with new pipe in Springfield to increase reliability and improve system flexibility. EGMA anticipates starting construction in 2022.

These four separate projects are designed to provide for uninterrupted and reliable service to customers in the Springfield Division. EGMA will engage with the community in an open and transparent manner with respect to the construction of its projects. In addition, EGMA will conduct customer outreach and listening sessions for its Western Mass. Gas Reliability Project in advance of making a filing at the EFSB.

E. TAUNTON & ATTLEBORO – AGT LINE G ISSUE

The Company serves its Taunton and Attleboro areas (part of the Brockton Division) with capacity on AGT. The AGT lateral that serves these areas is AGT's Line G. For decades, the Company has used various AGT contracts to serve Taunton and Attleboro. Historically, EGMA's

[73] EGMA anticipates making a filing with the EFSB for approval of the Western Mass. Gas Reliability Project by the end of 2021.

supply nominations have been made to an Allocation Point and AGT managed all city gates takes in on an aggregate basis accounting for all nominations to EGMA's Algonquin served market.

EGMA has adequate capacity levels on AGT coupled with on-system peaking to meet projected total base case design day demand of its Brockton Division planning load customers for the next two years. In 2019, however, AGT indicated that it may impose Line G specific operational flow orders, including the possibility of requiring 24-hour ratable deliveries or restricting deliveries to a specific point(s). The Company's contracts and system were not designed for such targeted pipeline operations. AGT's actions place the Company at risk of incurring penalties for over taking its contractual entitlements at Taunton and Attleboro, which gas not been an issue until recently. Therefore, the Company received approval from the Department earlier this year for the approval of three contracts to help serve the shortfall on Algonquin's G system. The first contract for 10,000 dekatherms (Dth) per day as an assignment of capacity from Neptune LNG, LLC; the second contract is a peaking agreement for 8,000 Dth per day of seasonal supply with Constellation LNG, LLC; and the third contract is a seasonal city-gate supply for 15,000 Dth per day with Direct Energy Business Marketing, LLC.

These resources, coupled with the Company's existing portfolio, will help ensure adequate supply and capacity for the Brockton Division in total and will reduce the risk of potentially higher costs imposed by overtaking supplies at Taunton and Attleboro while under a Line G specific operational flow order. In addition to the above-described efforts, the Company continues to pursue additional supply resources for its Taunton and Attleboro area markets.

VI. EGMA'S ACTION PLAN

The Company expects to take advantage of roll-over rights for the majority, if not all, of its capacity contracts over the forecast period, thus maintaining the capacity the Company requires to provide reliable service to meet expected customer demands in the aggregate in all growth scenarios and weather conditions considered in this F&SP. EGMA will continue to closely monitor customer requirements so that it can take the necessary actions to ensure reliability if actual usage levels trend closer to the Company's forecast of high growth requirements. Further, as decision time nears for each of these contract decisions, the Company will determine the range of alternatives available in the marketplace, if any, and will employ its resource planning process to establish the least-cost alternative, which may be renewal or replacement of some or all of the existing resources.

The Company requests specific approval of the following contracts that have renewal notification dates that occur within two years of this filing:

> Eastern Gas Storage Capacity Renewal: The Company has a storage and transportation contract with Eastern Gas Transmission that provides delivery of underground storage supplies to Algonquin for transport to the Company's Brockton Division. These legacy capacity contracts provide much needed balancing flexibility and supply reliability for EGMA's customers. EGMA intends to renew these legacy transportation and storage capacity contracts. The Company plans, and requests through this F&SP, approval to renew contract 600002.
>
> Union Gas Transportation Capacity Renewal: Unions contract M12204 is up for renewal during the forecast period and the Company is seeking approval to renew contract M12204. This contract is a very valuable contract as is part of the transportation that delivers the Enbridge storage supply downstream to Portland and TGP contracts in order to deliver to EGMA city-gates. The Company plans, and requests through this F&SP, approval to renew contract M12204.
>
> Enbridge Storage Capacity Renewal: EGMA has storage contracts with Enbridge. The Company plans, and requests through this F&SP, approval to renew contracts LST143 and LST144.
>
> Algonquin "Neptune Agreement" Renewal: This contract for 10,000 Dth/day for delivery into the AGT G-lateral systems. The Company plans, and requests through this F&SP, approval to renew this contract.

VII. CONCLUSIONS REGARDING EGMA'S RESOURCE PLAN

The Company's F&SP, planning process and results have been subject to Department review in several previous filings pursuant to G.L. c. 164, § 69I. Also, requests for approval of long-term contracts have been subject to Department review in several filings pursuant to G.L.

c. 164, § 94A. In this F&SP, the Company continues to utilize essentially the same planning process as has been employed since the time of its most recently approved F&SP, D.P.U. 19-135.

EGMA has demonstrated that this F&SP meets the Department's standards for approval and is reviewable, appropriate and reliable. With respect to the Company's supply resource portfolio, the Plan indicates that EGMA's resource portfolio is adequate to meet the projected base case throughput requirements of its customers over the term of the forecast period, given the rollover and renewal of key existing pipeline transportation and storage capacity contracts and the acquisition of additional pipeline capacity. Further, EGMA's planning process achieves a least-cost portfolio, where resource decisions appropriately balance cost considerations with those related to the reliability and security of supply, contract flexibility and resource viability.

EGMA will carry out the elements of its Action Plan consistent with any guidance or direction from the Department. EGMA will file for Department approval long-term contracts related to specific resources in its portfolio that result from the application of the Company's resource planning process. EGMA has complied with the Department's order in D.P.U. 15-143 to request approval to renew any contract that is due to expire within two years from November 1, 2021. EGMA has specifically identified contracts that it is requesting approval to renew in Appendix 1 G-24. EGMA will rely on the results of this Plan as a guide in completing future resource analyses.

Table FA
MASS EFSC

Forecast Accuracy
Total Gas-Year Normalized Firm Planning Load (BBTU)
(Percent Difference)

Forecast Prepared For the Five-Years Starting:

Gas-Year 11/1-10/31	Actual Normalized Firm Planning Load	2014 (1)	2016 (2)	2018 (3)
2015-2016	42,084	45,584		
%CH		-7.68%		
2016-2017	43,972		46,594	
%CH			-5.63%	
2017-2018	46,557		46,337	
%CH			0.48%	
2018-2019	47,329			48,365
%CH				-2.14%
2019-2020	46,815			48,191
%CH				-2.86%

(1) DPU 14-63
(2) DPU 16-40
(3) DPU 18-47

Table G-1
MASS EFSC

FIRM PLANNING LOAD BY CLASS
RESIDENTIAL WITH GAS HEATING

TOTAL HISTORICAL PLANNING LOAD (BBTU)

		ACTUAL		NORMAL	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2015-2016	260,538	15,153	7,061	16,821	7,135
2016-2017	264,043	16,898	7,464	17,530	7,283
2017-2018	267,467	18,395	7,600	18,439	7,364
2018-2019	271,524	19,375	7,292	18,630	7,498
2019-2020	277,482	17,505	7,852	18,865	7,544

TOTAL FORECAST PLANNING LOAD (BBTU)

		NORMAL		DESIGN [2]	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2020-2021	281,314	19,888	6,581	23,459	6,581
2021-2022	284,209	20,084	6,638	23,686	6,638
2022-2023	287,089	20,224	6,642	23,850	6,642
2023-2024	289,718	20,329	6,695	23,979	6,695
2024-2025	292,345	20,473	6,772	24,154	6,772
2025-2026	294,914	20,634	6,833	24,333	6,833

[1] Average customer counts calculated for the four quarters Q4-Q3 (October through September)
[2] Based on the aggregate ratio of design year to normal year

Table G-2
MASS EFSC

PLANNING LOAD BY CLASS
RESIDENTIAL WITHOUT GAS HEATING

TOTAL HISTORICAL PLANNING LOAD (BBTU)

		ACTUAL		NORMAL	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2015-2016	20,733	189	177	200	179
2016-2017	20,255	196	178	200	176
2017-2018	19,662	203	165	204	164
2018-2019	19,095	198	160	193	162
2019-2020	18,874	183	164	191	162

TOTAL FORECAST PLANNING LOAD (BBTU)

		NORMAL		DESIGN [2]	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2020-2021	18,383	199	143	199	143
2021-2022	17,863	190	136	190	136
2022-2023	17,344	181	133	181	133
2023-2024	16,826	178	130	178	130
2024-2025	16,308	173	126	173	126
2025-2026	15,790	166	120	166	120

[1] Average customer counts calculated for the four quarters Q4-Q3 (October through September)
[2] Based on the aggregate ratio of design year to normal year

Table G-3A
MASS EFSC

PLANNING LOAD BY CLASS
LOW LOAD FACTOR SALES

TOTAL HISTORICAL PLANNING LOAD (BBTU)

		ACTUAL		NORMAL	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2015-2016	21,555	4,670	1,693	5,228	1,714
2016-2017	21,294	5,136	1,705	5,349	1,652
2017-2018	21,495	6,074	1,900	6,079	1,797
2018-2019	21,880	6,167	1,814	5,914	1,876
2019-2020	22,070	5,338	1,836	5,786	1,751

TOTAL FORECAST PLANNING LOAD (BBTU)

		NORMAL		DESIGN [2]	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2020-2021	22,012	5,833	1,560	6,881	1,560
2021-2022	22,548	5,973	1,569	7,043	1,569
2022-2023	22,841	6,039	1,579	7,122	1,579
2023-2024	23,175	6,109	1,612	7,206	1,612
2024-2025	23,527	6,216	1,652	7,333	1,652
2025-2026	23,855	6,312	1,676	7,458	1,676

[1] Average customer counts calculated for the four quarters Q4-Q3 (October through September)
[2] Based on the aggregate ratio of design year to normal year

Table G-3B
MASS EFSC

PLANNING LOAD BY CLASS
HIGH LOAD FACTOR SALES

TOTAL HISTORICAL PLANNING LOAD (BBTU)

		ACTUAL		**NORMAL**	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2015-2016	3,800	1,030	1,142	1,063	1,149
2016-2017	4,368	1,379	1,477	1,402	1,470
2017-2018	4,241	1,531	1,504	1,536	1,502
2018-2019	3,928	1,425	1,459	1,407	1,469
2019-2020	4,074	1,468	1,220	1,512	1,219

TOTAL FORECAST PLANNING LOAD (BBTU)

		NORMAL		**DESIGN [2]**	
Gas-Year 11/1-10/31	**Average No. of Customers [1]**	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2020-2021	4,098	1,460	1,289	1,723	1,289
2021-2022	4,098	1,454	1,283	1,714	1,283
2022-2023	4,091	1,443	1,266	1,701	1,266
2023-2024	4,089	1,435	1,271	1,693	1,271
2024-2025	4,097	1,439	1,278	1,698	1,278
2025-2026	4,101	1,443	1,277	1,704	1,277

[1] Average customer counts calculated for the four quarters Q4-Q3 (October through September)
[2] Based on the aggregate ratio of design year to normal year

Table G-4
MASS EFSC

Planning Load BY CLASS
INTERRUPTIBLE

TOTAL HISTORICAL PLANNING LOAD (BBTU)

ACTUAL

Gas-Year 11/1-10/31	Heating Season	Non-Heating Season
2015-2016	0	0
2016-2017	0	0
2017-2018	0	0
2018-2019	0	0
2019-2020	0	0

TOTAL FORECAST PLANNING LOAD (BBTU)

NORMAL

Gas-Year 11/1-10/31	Heating Season	Non-Heating Season
2020-2021	0	0
2021-2022	0	0
2022-2023	0	0
2023-2024	0	0
2024-2025	0	0
2025-2026	0	0

Table G-4B
MASS EFSC

FIRM PLANNING LOAD BY CLASS
SPECIAL CONTRACTS

TOTAL HISTORICAL PLANNING LOAD (BBTU)

ACTUAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2015-2016		
2016-2017		
2017-2018		
2018-2019		
2019-2020		

TOTAL FORECAST PLANNING LOAD (BBTU)

NORMAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2020-2021		
2021-2022		
2022-2023		
2023-2024		
2024-2025		
2025-2026		

Table G-4A
MASS EFSC

PLANNING LOAD BY CLASS
CAPACITY ELIGIBLE PLANNING LOAD

TOTAL HISTORICAL PLANNING LOAD (BBTU)

ACTUAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2015-2016	4,725	3,111
2016-2017	5,051	3,079
2017-2018	5,361	3,295
2018-2019	5,992	3,352
2019-2020	5,750	3,199

TOTAL FORECAST PLANNING LOAD (BBTU)

NORMAL

Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**
2020-2021	6,274	3,243
2021-2022	6,315	3,217
2022-2023	6,295	3,250
2023-2024	6,428	3,301
2024-2025	6,484	3,307
2025-2026	6,540	3,332

Table G-4C-Sales
MASS EFSC

PLANNING LOAD BY CLASS
NEW PROJECT PLANNING LOAD

TOTAL HISTORICAL NEW PROJECT PLANNING LOAD (BBTU)

ACTUAL

Gas-Year 11/1-10/31	Heating Season	Non-Heating Season
2015-2016	0	0
2016-2017	0	0
2017-2018	0	0
2018-2019	0	0
2019-2020	0	0

TOTAL FORECAST NEW PROJECT PLANNING LOAD (BBTU)

NORMAL

Gas-Year 11/1-10/31	Heating Season	Non-Heating Season
2020-2021	0	0
2021-2022	0	0
2022-2023	0	0
2023-2024	0	0
2024-2025	0	0
2025-2026	0	0

Table G-4D
MASS EFSC

FIRM PLANNING LOAD BY CLASS
COMPANY USE & UNACCOUNTED-FOR-GAS

TOTAL HISTORICAL PLANNING LOAD (BBTU)

	ACTUAL		NORMAL	
Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2015-2016	464	238	520	240
2016-2017	516	250	538	243
2017-2018	569	261	569	246
2018-2019	597	254	573	262
2019-2020	545	257	591	245

TOTAL FORECAST PLANNING LOAD (BBTU)

	NORMAL		DESIGN [1]	
Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2020-2021	612	250	722	250
2021-2022	620	250	731	250
2022-2023	623	251	734	251
2023-2024	628	253	741	253
2024-2025	634	256	748	256
2025-2026	640	258	756	258

[1] Based on the aggregate ratio of design year to normal year

Table G-5
MASS EFSC

COMPANY PLANNING LOAD
TOTAL PLANNING LOAD
(Including Company Use and Unaccounted-for-Gas)

TOTAL HISTORICAL PLANNING LOAD (BBTU)

	ACTUAL		NORMAL	
Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2015-2016	26,231	13,421	28,556	13,527
2016-2017	29,176	14,153	30,070	13,902
2017-2018	32,133	14,724	32,188	14,369
2018-2019	33,755	14,330	32,709	14,620
2019-2020	30,789	14,528	32,695	14,120

TOTAL FORECAST PLANNING LOAD (BBTU)

	NORMAL		DESIGN	
Gas-Year 11/1-10/31	**Heating Season**	**Non-Heating Season**	**Heating Season**	**Non-Heating Season**
2020-2021	34,268	13,066	39,258	13,066
2021-2022	34,635	13,095	39,679	13,095
2022-2023	34,804	13,121	39,883	13,121
2023-2024	35,108	13,262	40,226	13,262
2024-2025	35,418	13,391	40,590	13,391
2025-2026	35,734	13,495	40,957	13,495

TABLE G-14

Columbia Gas of Massachusetts
Exisiting On-System Peaking Resources

LNG Facility	Division	No. Tanks	Gallons Liquid per Tank	Capacity Total MMBtu (net of heel)	Vaporization MDWQ
Easton	Brockton	1	9,393,300	731,704	44,000
Lawrence	Lawrence	5	30,208	11,628	12,500
Ludlow	Springfield	1	12,173,947	948,413	48,000
Marshfield	Brockton	2	49,500	7,622	8,000
Total Brockton				739,326	52,000
Total SP/LAW				960,041	60,500
Total				1,699,367	112,500
Propane Facility					
Meadowlane	Brockton	12	72,297	70,749	21,000
Lawrence	Lawrence	3	53,505	13,033	14,000
N. Hampton	Springfield	**5**	53,505	21,722	5,000
Total Brockton				70,749	21,000
Total SP/LAW				34,755	19,000
Total				105,504	40,000

Table G-22N, Page 1
MASS EFSC

COMPARISON OF RESOURCES AND REQUIREMENTS

NORMAL YEAR (Bbtu)

HEATING SEASON - Base Case

	Season	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
	REQUIREMENTS					
1	FIRM	34,635	34,804	35,108	35,419	35,734
2	Sub Total	34,635	34,804	35,108	35,419	35,734
3	Injections					
4	LNG	0	3	6	10	13
5	LPG	0	0	0	0	0
6	Underground	0	0	0	0	0
7	Sub Total	0	3	6	10	13
8	**Total**	**34,635**	**34,806**	**35,114**	**35,429**	**35,747**
	RESOURCES					
9	Pipeline					
10	TGP	17,389	17,516	17,736	17,990	18,216
11	AGT/TETCO	8,243	8,269	8,337	8,345	8,398
12	LNG Injection	0	3	6	10	13
13	LPG Injection	0	0	0	0	0
14	Sum Total	25,632	25,788	26,079	26,345	26,626
15	Storage Withdrawals					
16	LNG	499	517	534	584	619
17	LPG	0	0	0	0	0
18	AGT/TETCO	2,923	2,923	2,923	2,923	2,923
19	TGP	5,581	5,579	5,579	5,578	5,578
20	Sub Total	9,003	9,019	9,035	9,085	9,120
21	Citygate Supplies	0	0	0	0	0
22	**Total**	**34,635**	**34,806**	**35,114**	**35,429**	**35,747**

Table G-22N, Page 2
MASS EFSC

COMPARISON OF RESOURCES AND REQUIREMENTS

NORMAL YEAR (Bbtu)

NON-HEATING SEASON - Base Case

	Season	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026
	REQUIREMENTS					
1	FIRM	13,095	13,121	13,262	13,391	13,496
2	Sub Total	13,095	13,121	13,262	13,391	13,496
3	Injections					
4	LNG	810	876	896	929	968
5	LPG	0	0	0	0	0
6	Underground	8,728	8,728	8,728	8,728	8,728
7	Sub Total	9,539	9,605	9,624	9,657	9,697
8	**Total**	**22,634**	**22,726**	**22,886**	**23,048**	**23,192**
	RESOURCES					
9	Pipeline					
10	TGP	12,150	12,168	12,249	12,329	12,400
11	AGT/TETCO	9,312	9,320	9,380	9,428	9,463
12	LNG Injection	810	876	896	929	968
13	LPG Injection	0	0	0	0	0
14	Sum Total	22,272	22,364	22,525	22,686	22,831
15	Storage Withdrawals					
16	LNG	362	362	362	362	362
17	LPG	0	0	0	0	0
18	AGT/TETCO	0	0	0	0	0
19	TGP	0	0	0	0	0
20	Sub Total	362	362	362	362	362
21	Citygate Supplies	0	0	0	0	0
22	**Total**	**22,634**	**22,726**	**22,886**	**23,048**	**23,192**

Table G-22D, Page 1
MASS EFSC

COMPARISON OF RESOURCES AND REQUIREMENTS

DESIGN YEAR (Bbtu)

HEATING SEASON - Base Case

	Season	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
	REQUIREMENTS					
1	FIRM	39,679	39,883	40,226	40,590	40,957
2	Sub Total	39,679	39,883	40,226	40,590	40,957
3	Injections					
4	LNG	47	55	60	70	83
5	LPG	21	21	21	21	24
6	Underground	0	0	0	0	0
7	Sub Total	68	76	81	91	108
8	**Total**	**39,747**	**39,959**	**40,307**	**40,680**	**41,065**
	RESOURCES					
9	Pipeline					
10	TGP	20,538	20,646	20,850	20,995	21,173
11	AGT/TETCO	9,320	9,370	9,474	9,589	9,725
12	LNG Injection	47	55	60	70	83
13	LPG Injection	21	21	21	21	24
14	Sum Total	29,926	30,093	30,405	30,674	31,006
15	Storage Withdrawals					
16	LNG	1,294	1,341	1,377	1,481	1,531
17	LPG	21	21	21	21	24
18	AGT/TETCO	2,923	2,923	2,923	2,923	2,923
19	TGP	5,584	5,582	5,582	5,582	5,582
20	Sub Total	9,821	9,867	9,902	10,006	10,059
21	Citygate Supplies	0	0	0	0	0
22	**Total**	**39,747**	**39,959**	**40,307**	**40,680**	**41,065**

Table G-22D, Page 2
MASS EFSC

COMPARISON OF RESOURCES AND REQUIREMENTS

DESIGN YEAR (Bbtu)

NON-HEATING SEASON - Base Case

	Season	Summer 2022	Summer 2023	Summer 2024	Summer 2025	Summer 2026
	REQUIREMENTS					
1	FIRM	13,158	13,185	13,327	13,456	13,562
2	Sub Total	13,158	13,185	13,327	13,456	13,562
3	Injections					
4	LNG	1,575	1,652	1,678	1,773	1,809
5	LPG	0	0	0	0	0
6	Underground	8,731	8,731	8,731	8,731	8,731
7	Sub Total	10,307	10,383	10,410	10,504	10,540
8	**Total**	**23,465**	**23,568**	**23,737**	**23,960**	**24,103**
	RESOURCES					
9	Pipeline					
10	TGP	12,216	12,235	12,317	12,398	12,469
11	AGT/TETCO	9,312	9,320	9,380	9,428	9,463
12	LNG Injection	1,575	1,652	1,678	1,773	1,809
13	LPG Injection	0	0	0	0	0
14	Sum Total	23,103	23,207	23,375	23,599	23,741
15	Storage Withdrawals					
16	LNG	362	362	362	362	362
17	LPG	0	0	0	0	0
18	AGT/TETCO	0	0	0	0	0
19	TGP	0	0	0	0	0
20	Sub Total	362	362	362	362	362
21	Citygate Supplies	0	0	0	0	0
22	**Total**	**23,465**	**23,568**	**23,737**	**23,960**	**24,103**

Tables G-22, Back-up
MASS EFSC

TABLE G-22 BACK-UP DATA - Base Case
Bbtu

A. Design Heating Season Ending Resources

		2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
	STORAGE INVENTORIES					
1	AGT STORAGE	96	96	96	96	96
2	TGP STORAGE	9	9	9	9	9
3	LNG	453	381	354	260	224
4	LPG	106	106	106	106	106
	PIPELINE GAS					
5	TGP	6,537	6,658	6,877	6,866	6,740
6	AGT / TETCO	5,431	5,690	6,002	6,276	6,627
	SUPPLEMENTAL					
7	LNG Optional Volumes					
8	Propane Optional Volumes					

B. THERMAL-VOLUMETRIC CONVERSION FACTORS

9 System Average
10 TGP
11 AGT
12 LNG

13 Propane gal/Btu
14 Propane Btu/cf

C. PERCENT LOSSES ASSOCIATED WITH STORAGE

	Storage Field	Loss Factor
15		
16		
17		

Tables G-23
MASS EFSC

COMPARISON OF RESOURCES AND REQUIREMENTS
PEAK DAY Bbtu

HEATING SEASON - Base Case

	REQUIREMENTS	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
1	Total Peak Day Sendout	516	520	523	529	534
	RESOURCES					
2	TGP-FT	179	181	182	185	185
3	AGT-FT	98	100	102	105	108
4	TGP STORAGE	70	70	70	70	70
5	AGT STORAGE	35	35	35	35	35
6	LNG from Storage	113	113	113	113	113
7	LPG from Storage	21	21	21	21	23
8	Citygate Supplies	0	0	0	0	0
0	TOTAL	516	520	523	529	534

TABLE G-24

Eversource Gas of Massachusetts
Long Term Contracts as of November 1, 2021

Pipeline	Contract	Rate Schedule	MDQ	ACQ	Days	Contract Expiration	Next Renewal Notice Date	EVERGREEN	ROFR Provision (Y/N)	Contracts for which EGMA is requesting approval in this Current Docket /1
Algonquin	93001EC	AFT-E	51,632	15,467,350	365	10/31/2023	10/31/2022	Y	Y	N
Algonquin	93201AC	AFT-1	5,489	2,003,485	365	10/31/2023	10/31/2022	Y	Y	N
Algonquin	93401	AFT-1	5,690	2,076,850	365	10/31/2023	10/31/2022	Y	Y	N
Algonquin	93001F	AFT-1	18,490	6,748,850	365	10/31/2023	10/31/2022	Y	Y	N
Algonquin	94501	AFT-1	14,758	5,386,670	365	10/31/2023	10/31/2022	Y	Y	N
Algonquin	510352	AFT-1(X-35)	48,000	17,520,000	365	10/31/2023	10/31/2022	Y	Y	N
Algonquin	510066	AFT-1	20,000	7,300,000	365	11/30/2023	11/30/2022	Y	Y	N
Algonquin	510804-R1	AFT-1	30,000	10,950,000	365	10/31/2031	10/31/2030	Y	Y	N
Algonquin	806893	AFT-1H	10,000	3,650,000	365	10/31/2022	None	N	N	**Y**
Granite	22-001-FT-1	FT-1	12,000	1,812,000	151	04/30/2022	None	N	N	N
Iroquois	R182001	RTS-1	28,840	10,526,600	365	11/01/2027	11/01/2026	N	Y	N
National Fuel	N11117	FST	10,000	3,650,000	365	03/31/2023	03/31/2022	Y	Y	N
PNGTS	208540	FT	16,000	5,840,000	365	10/31/2033	10/31/2032	Y	N	N
PNGTS	208535	FT	45,500	16,607,500	365	10/31/2040	10/31/2039	Y	N	N
PNGTS	233301	PXP	14,300	2,159,300	151	10/31/2040	10/31/2039	Y	N	N
Texas Eastern	800462	CDS	36,369	13,274,685	365	10/31/2027	10/31/2022	Y	Y	N
Texas Eastern	800414	CDS	1,056	385,440	365	10/31/2027	10/31/2022	Y	Y	N
Texas Eastern	800382	FT-1	4,235	1,545,775	365	10/31/2027	10/31/2022	Y	Y	N
Tennessee	5173-FTATGP	FT-A	12,748	4,653,020	365	10/31/2023	10/31/2022	Y	Y	N
Tennessee	5293-FTATGP	FT-A	12,547	4,579,655	365	10/31/2024	10/31/2023	Y	Y	N
Tennessee	39741-FTATGP	FT-A	4,081	1,489,565	365	03/31/2025	03/31/2024	Y	Y	N
Tennessee	5291-FTATGP	FT-A	6,171	2,252,415	365	03/31/2025	03/31/2024	Y	Y	N
Tennessee	48427-FTATGP	FT-A	17,000	6,205,000	365	10/31/2025	10/31/2024	Y	Y	N
Tennessee	41098-FTATGP	FT-A	18,733	6,837,545	365	10/31/2027	10/31/2026	Y	Y	N
Tennessee	95349-FTATGP	FT-A	9,774	3,567,510	365	10/31/2027	10/31/2026	Y	Y	N
Tennessee	98775-FTAHTGP	FT-A	6,100	2,226,500	365	10/31/2032	10/31/2030	Y	Y	N
Tennessee	330904-FTATGP	FT-A	96,400	35,186,000	365	10/31/2038	10/31/2037	Y	Y	N
Tennessee	5196-FTATGP	FT-A	15,375	5,611,875	365	04/30/2045	04/30/2044	Y	Y	N
Tennessee	362252 -FTILTGP	FT-IL	14,000	5,110,000	365	10/31/2022	None	N	N	N
Tennessee	645-ITTGP	IT	50,000	18,250,000	365	12/31/2049	None	N	N	N
TransCanada SH	41234	FT	26,062	9,512,630	365	10/31/2026	10/31/2025	Y	Y	N
TransCanada MH	33321	FT	16,000	5,840,014	365	10/31/2026	10/31/2025	Y	Y	N
Transco	9239453	FT	1,254	457,710	365	10/07/2023	10/08/2022	Y	Y	N
Union Gas	M12204	M12	26,352	9,618,480	365	10/31/2024	10/31/2022	N	Y	**Y**
Union Gas	M12292	M12	61,218	22,344,425	365	10/31/2040	10/31/2038	N	Y	N
Millennium	217524	FT-1	15,000	5,475,000	365	03/31/2034	03/31/2033	N	Y	N

Underground Storage			MDWQ	Capacity						
Eastern Gas	600002	GSS-TE	14,758	1,441,753	151	03/31/2026	03/31/2024	N	Y	**Y**
National Fuel	O11116	FSS	10,000	1,100,000	151	03/31/2023	03/31/2022	Y	Y	N
Texas Eastern	400502	FSS-1	1,056	63,360	151	04/30/2027	04/30/2022	Y	Y	N
Texas Eastern	400193	SS-1	22,819	1,588,950	151	04/30/2023	04/30/2022	Y	Y	N
Tennessee	5178	FS-MA	19,755	1,222,594	151	10/31/2023	10/31/2022	Y	Y	N
Enbridge	LST143	USS	16,000	1,600,000	100	03/31/2024	None	N	N	**Y**
Enbridge	LST144	USS	26,500	1,820,000	69	03/31/2024	None	N	N	**Y**

/1: EGMA has determined that the contracts for which the Company requests approval have (a) no material changes and (b) no reasonable alternatives.

Appendix 2

Evesource Gas of Massachusetts

Existing Capacity Paths

Path #	Segment #	Contract	Expiration	Supply Source	Volume	Point	Point	Point
A	1	TGP/FT-A	31-Oct-23	*Texas*	4,462			
				Louisiana	8,286			
					12,748	12,748 CMA CITYGATE		
B	1	TENN FSMA Storage	31-Oct-23	NY / Penn	19,755	19,755 TGP ELLISBURG		
	2	TGP/FT-A	30-Apr-45				15,375 CMA CITYGATE	
	3	TGP/FT-A	31-Oct-24				4,171 CMA CITYGATE	
C	1	NAT FUEL Storage	31-Mar-22	NY / Penn	10,000	10,000 Nat Fuel		
	2	NAT FUEL FS-1	31-Mar-22			8,376 TGP ELLISBURG		
	3	TGP/FT-A	31-Oct-24				8,376 CMA CITYGATE	
D	1	TGP/FT-A	31-Mar-25	Niagara, NY	6,171	6,171 CMA CITYGATE		
E	1	TGP/FT-A	31-Mar-25	Niagara, NY	4,081	4,081 CMA CITYGATE		
F & G	1	ENBRIDGE STORAGE	31-Mar-22		26,500			
	2	UNION	31-Oct-22	Dawn	26,352	26,352 Parkway		
	3	TRANSCANADA	31-Oct-26				26,063 TCPL	
			TCPL					
	5	SPOT		Waddington, NY				
	6	IGTS/RST-1	01-Nov-22		28,840	28,840 IROQ WRIGHT		
	7	TGP/FT-A	31-Oct-22				6,068 CMA CITYGATE	
	8	TGP/FT-A	31-Oct-22				3,706 CMA CITYGATE	
	8	TGP/FT-A	31-Oct-22			18,733 AGT MENDON		
	9	AGT/FT-2	31-Oct-22				18,490 CMA CITYGATE	
I & S	1	TETCO/CDS	31-Oct-22	*Texas*	16,408			
				Louisiana	37,687			
					36,369	36,369 AGT LAMBERTVILLE		
			TETCO					
	2	SPOT (**S**)		*Lambertville/Hanover*	36,369			
	2	AGT/AFT-1	31-Oct-22			5,489		
	3	AGT/AFT-1	31-Oct-22			5,690		
	4	AGT/AFT-E/1	31-Oct-22			27,757		
						38,936 CMA CITYGATE		
J	1	TETCO Storage	30-Apr-23	NY / Penn / WV	22,819	22,819 AGT LAMBERTVILLE		
	2	AGT/AFT-E/1	31-Oct-22				22,819 CMA CITYGATE	
K	1	TETCO Storage	30-Apr-27	NY / Penn / WV	1,056	1,056 STOR W/D POINT		
	2	TETCO CDS	31-Oct-27				1,056 AGT LAMBERTVILLE	
	3	AGT/AFT-E/1	31-Oct-19					1,056 CMA CITYGATE
L	1	DOM Storage	31-Mar-26	NY / Penn / WV	14,758	14,758 STOR W/D POINT		
	2	TETCO- FT	31-Oct-22				4,235 AGT LAMBERTVILLE	
	2	TRANSCO/FT	31-Mar-22				1,254 AGT LAMBERTVILLE	
	3	*SECONDARY*					9,269 AMA SECONDARY	
	4	AGT/AFT-1	31-Oct-22					14,758
M	1	ENBRIDGE STORAGE	31-Mar-22	Dawn	16,000			
	2	TRANSCANADA	31-Oct-26			16,000 PNGTS Pittsburgh, NH		
	3	PNGTS/WS	31-Oct-33			16,000 TGP Dracut		
	4	TGP FT	31-Oct-38			16,000 CMA CITYGATE		
N	1	UNION		Dawn	61,509			
	2	TRANSCANADA		Pittsburgh, NH	59,827	TGP Dracut/Haverill		
	3	PNGTS/FT	31-Oct-40			45,500		
	4	PNGTS/FT	31-Oct-40			14,300		
H	5	Repsol Peaking	31-Mar-28	Canaport		47,000		
Q	6	GNST/FT	31-Oct-21				12,000 NUI Exchange	12,000 CMA CITYGATE
	7	TGP FT	31-Oct-32				6,100 CMA CITYGATE	
	7	TGP FT	31-Oct-22				17,000 CMA CITYGATE	
	7	TGP FT	31-Oct-38	11/1/2021 Increase			80,400 CMA CITYGATE	
								103,500
P	1	AGT AFT-1(H)	30-Nov-23	Beverly, MA	20,000	20,000 CMA CITYGATE		
R	1	AGT AFT-1 (X-35)	31-Oct-23	Transco	48,000	48,000 CMA CITYGATE		
T	1	MLP (FT-1)	31-Mar-34	Corning, NY	15,000	Ramapo, NJ	20,000 AGT Sharon Station, MA	
	2	AGT (AFT-1 AIM)	31-Oct-31			30,000	10,000 AGT Taunton/South Attleboro	
								30,000 CMA CITYGATE

Appendix 3: Statistical Techniques and Glossary

Regression modeling techniques were used to generate the demand forecasts for the four divisions. The regression analyses were developed using the EViews software package. Regression modeling techniques were used to develop separate Brockton, Lawrence, and Springfield forecasts of number of customers and use per customer for Residential Heating, Residential Non-Heating, LLF, and HLF customer segments, for sales and transportation combined, and for sales.[1]

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.[2]

Regression equations that included appropriate variables (e.g., weather, natural gas price, economic data, etc.) were identified and tested to develop the forecast models. 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.

"Sound econometric modeling and analysis generally follows a common process: (a) create statement of theory; (b) collect data; (c) specify mathematical model; (d) specify statistical model; (e)

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1 A total of 36 models were developed to forecast customer demand
2 A glossary of statistical terms can be found at the end of this Appendix.

estimate model parameters; (f) check model accuracy; (g) test hypotheses; and (h) use model for forecasting." (Essentials of Econometrics, Damodar Gujarati, p. 3 (1999 Irwin McGraw-Hill)).

The forecast models that were developed for the 2021 F&SP followed this process. First, economic theory and standard utility forecasting practice was used to identify (a) variables that could have an effect on the dependent variable in each equation, and (b) the expected sign of the coefficients for those variables. For example, the EDD variable is expected to affect use per customer, and the EDD coefficient should be positive (i.e., when EDDs increase, demand should increase, and vice versa). The price variable is also expected to affect use per customer and the price coefficient should be negative (i.e., when natural gas prices increase, demand should decrease, and vice versa).

For each of the models, after possible explanatory variables were identified and the data sets were developed, regression equations were estimated to test various combinations of independent variables. A preliminary regression equation was identified for each model 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. If the sign of an independent variable was counter to expectations or if important variables were not significant, either, (a) that model was 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

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

further testing for autocorrelation, heteroskedasticity, stability, multicollinearity, and outliers; the performance of each model was also assessed using an ex post analysis. Lastly, models were evaluated based on the reasonableness of the forecast values by comparing forecast trends and growth rates to historical trends and growth rates for relevant historical periods, while also accounting for the effect of independent variables during these historical and forecast periods.

Autocorrelation

Statistical theory requires that the residuals associated with a regression equation (the "errors") be independent of one another (i.e., there should be no relationship or correlation in the residuals over time) to ensure that the equation is efficient.[4] Correlation of residuals over time is known as "autocorrelation". If the error terms are autocorrelated, the efficiency of ordinary least-squares (OLS) parameter estimates is adversely affected. 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 autocorrelation function ("ACF") and partial autocorrelation function ("PACF") values and graphs can be used to test for higher orders of autocorrelation.[5] Advanced statistical packages correct for higher order autocorrelation, based on user inputs.

The forecast models for this F&SP were examined for autocorrelation from lag(s) 1 through 8 using the ACF and PACF values and graphs. If autocorrelation was identified, the appropriate autoregressive terms ("AR") were added to the regression equation to correct for the autocorrelation

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4 In statistical theory, coefficient estimates are "efficient" if, comparing all unbiased estimates, they 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.

(e.g., autocorrelation at lag 4 could be corrected by adding an AR4 term to the regression equation). The regression equations were re-evaluated after any necessary corrections for autocorrelation were made. If correcting for autocorrelation in residuals decreased an independent variable's t-statistic to the extent that the variable was no longer significant, the equation parameters were re-estimated with the statistically insignificant variables excluded. The ACF and PACF values and graphs for each model are presented in the detailed statistical results appendix.

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 F&SP 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 new regression is multiplied by the number of observations compared against a 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. Results of the White's test for each model are presented in the detailed statistical results appendix.

Stability and Structural Change

The Chow test was used to test for break points or structural changes in each model. The Chow test involves splitting the historical data into two parts and comparing the sum of squared errors from the original model to the sum of squared errors of the two subset models that are based on re-estimating the original model prior to and post the potential structural break. If the two subset models have significantly lower sum of squared errors than the original model, then the original model is considered to have failed the stability test. Models with Chow test results that were not significant at the 0.01 level were considered to be stable.

The Chow test was performed for each regression equation for any break point suspected of being associated with a structural change. If any structural change was determined to be statistically significant on the basis of the Chow test, shifts in either the intercept or a particular slope coefficient associated with the structural change were incorporated into the model with dummy variables and/or interaction terms. Results of the Chow test for each model are presented in the detailed statistical results appendix.

Multicollinearity

A key assumption of multiple regression analysis is that there is no exact linear relationship among the independent variables. In the case of an exact linear relationship (or perfect multicollinearity) estimation of the parameters of the model is not possible. In practice, there is always some degree of less-than-exact multicollinearity among the independent variables of a multiple regression model.

To test for multicollinearity, a correlation matrix of driving variables for each model developed was calculated and evaluated.[6] The correlation matrices did not include (a) dummy variables that apply to one year or less of the historical data (i.e., point dummy variables or very short duration dummy variables) because they are not driving variables and (b) interactive terms (or product terms) if one or more of its component parts were also in the model, because according to Jaccard and Turrisi (2003):

> "… high levels of collinearity between a product term and its component parts generally will not be problematic for interaction analysis unless the collinearity is so high that it disrupts the computer algorithm designed to isolate the relevant standard errors in a standard computer statistical package." (Jaccard, James and Turrisi, Robert, Interaction Effects in Multiple Regression. Sage Publications, 2003, p. 27-28)

The correlation matrices for each model are provided in the detailed statistical appendix.

If a particular equation demonstrated high correlation values among driving variables (i.e., greater than 0.9, or less than -0.9), a Klein test would be performed to further evaluate the presence of multicollinearity. In those instances where the Klein test failed, the equations were re-specified to address the multicollinearity.

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6 "The model shows no multicollinearity in driving variables…" D.P.U. Order 10-100, Berkshire Gas Company, p. 11.

Outliers

Residual values are provided for each customer segment model in the detailed statistical appendix, which contains tables of quarterly values of actuals, fitted values, residuals, percent residuals, and standardized residuals. The values of the standardized residuals express the residuals in terms of their deviations from average values (i.e. standard errors). Models that had standardized residuals over 3.0, which indicates an outlier that is approximately outside the 99.7% confidence interval, were re-specified.

Ex Post Forecast

For this F&SP, ex post forecasts were performed by suppressing the last four quarters of historical data (i.e., 2019Q4 – 2020Q3) and re-estimating the model. The forecast for the suppressed quarters was compared with the actual data for these quarters and the parameter estimates from the "new" models with the suppressed quarters were compared to the parameter estimates from the original models. The results of the ex post forecasts for each model are included in the detailed statistical appendix.

Summary

If the overall explanatory power of the model was drastically reduced after correcting for the 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 detailed statistical appendix.

Glossary of Statistical Terms[7]

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 orders. (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. (Equivalent terms include: t-Statistic, t-Test, Student's t)
Forecast	The dependent variable values predicted by the model for the forecast period.
Independent Variable	A variable used 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)

7 These terms are defined as they relate to the econometric/regression analysis used in this F&SP.

Term	Definition
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.
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 orders, 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)
Standard Error of the Regression ("S.E. of Regression)	A measure of the variability of the residuals. (Other equivalent terms include: Root Mean Square Error or RMSE)
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 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)

RHC Brockton S&T

I. Sales and Transportation - Customers

A. Residential Heating Customers - Sales and Transportation

1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
B_RH_CUST_S_T	5	0.997	16.410

ARIMA Model Parameters

B_RH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	90099.73	735.418	122.52	0.000
	B_RHOIL_NG_SAVE	4.460465	0.068	65.30	0.000
	B_D2015_2019*Q3	-1121.268	142.718	-7.86	0.000
	B_D2016_2017*Q2	-1124.285	208.205	-5.40	0.000
	B_D19Q2	-797.8969	282.720	-2.82	0.012

Variable	Definition	Explanation	Dummy Variable Support
B_RHOIL_NG_SAVE	Cumulative savings from natural gas vs. heating oil for residential heating customers in Brockton ($2020)		
B_D2015_2019*Q3	Binary variable equal to 1 in Q3 from 2015 to 2019		2
B_D2016_2017*Q2	Binary variable equal to 1 in Q2 from 2016 to 2017		2
B_D19Q2	Binary variable equal to 1 in 2019Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)

B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed

C: To account for seasonality

1: Included to address a structural shift

2: Included to address an outlier

N	Adjusted R2	F Statistic
22	0.997591	1269.867

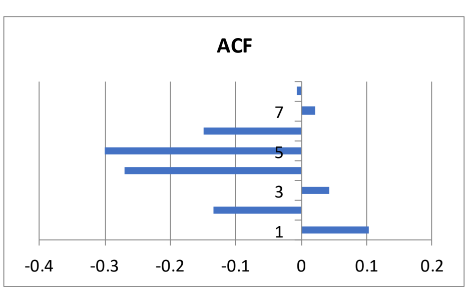
Chow Test Stats	N	k	SSR
Combined	22	5	1,232,760.48
1	11	4	593,942.94
2	11	4	498,809.67

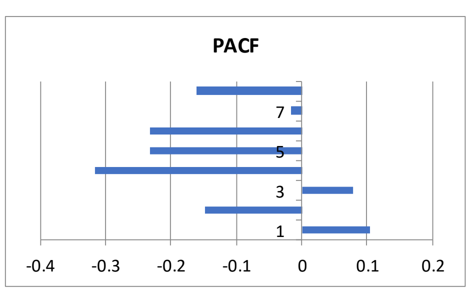
Chow Stat:	0.307
P-Value:	0.899083

Heteroscedasticity - White's Test	
White Stat	1.38
Significance (p-value)	0.28

Correlations

	B_RHOIL_NG_SAVE	B_D2015_2019*Q3	B_D2016_2017*Q2	B_D19Q2
B_RHOIL_NG_SAVE	1	-0.164853	-0.187734	0.198416
B_D2015_2019*Q3	-0.164853	1	-0.171499	-0.118345
B_D2016_2017*Q2	-0.187734	-0.171499	1	-0.069007
B_D19Q2	0.198416	-0.118345	-0.069007	1





Residual ACF								
Model		1	2	3	4	5	6	7
b_rh_cust_s_t Model	ACF	0.104	-0.134	0.044	-0.269	-0.3	-0.15	0.021
	SE	0.426	0.426	0.426	0.426	0.426	0.426	0.426
Residual PACF								
Model		1	2	3	4	5	6	7
b_rh_cust_s_t Model		0.104	-0.147	0.078	-0.316	-0.231	-0.232	-0.017
	SE	0.426	0.426	0.426	0.426	0.426	0.426	0.426

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2015Q2	130470.67	130629.91	-159.25	-0.12%	(0.66)
2015Q3	129940.00	129786.92	153.08	0.12%	0.63
2015Q4	132096.00	131680.09	415.91	0.31%	1.72
2016Q1	133289.33	133249.00	40.34	0.03%	0.17
2016Q2	132701.33	132779.05	-77.71	-0.06%	(0.32)
2016Q3	132573.00	132938.02	-365.02	-0.28%	(1.51)
2016Q4	134335.33	134576.74	-241.41	-0.18%	(1.00)
2017Q1	135337.00	135678.07	-341.07	-0.25%	(1.41)
2017Q2	135123.33	135045.62	77.71	0.06%	0.32
2017Q3	135051.33	135181.75	-130.42	-0.10%	(0.54)
2017Q4	137087.67	136778.90	308.77	0.23%	1.27
2018Q1	138280.33	137930.92	349.41	0.25%	1.44
2018Q2	138064.67	138388.95	-324.28	-0.23%	(1.34)
2018Q3	137696.67	137394.22	302.44	0.22%	1.25
2018Q4	139444.67	139172.28	272.38	0.20%	1.12
2019Q1	140296.00	140475.76	-179.76	-0.13%	(0.74)
2019Q2	140181.67	140181.67	0.00	0.00%	(0.00)
2019Q3	140043.33	140003.42	39.92	0.03%	0.16
2019Q4	141621.67	141773.14	-151.47	-0.11%	(0.63)
2020Q1	142735.33	142952.78	-217.44	-0.15%	(0.90)
2020Q2	143481.33	143531.83	-50.50	-0.04%	(0.21)
2020Q3	143947.33	143668.96	278.37	0.19%	1.15

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	141621.70	141811.10	-189.40	-0.1%
Q1 2020	142735.30	142995.50	-260.20	-0.2%
Q2 2020	143481.30	143576.80	-95.50	-0.1%
Q3 2020	143947.30	143714.50	232.80	0.2%
Total	571785.60	572097.90	-312.30	-0.1%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	90099.73	89929.54	170.19	0%
B_RHOIL_NG_SAVE	4.46	4.48	-0.02	0%
B_D2015_2019*Q3	-1121.27	-1136.69	15.42	-1%
B_D2016_2017*Q2	-1124.29	-1135.09	10.80	-1%
B_D19Q2	-797.90	-832.64	34.74	-4%

RHC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
L_RH_CUST_S_T	7	0.998	7.821

ARIMA Model Parameters

L_RH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	32223.51	174.004	185.19	0.000
	L_RHOIL_NG_SAVE	0.90453	0.014	65.83	0.000
	L_D18Q3	-2657.919	63.887	-41.60	0.000
	L_D18Q4	-2724.449	63.951	-42.60	0.000
	L_D2015_2017*Q3	-515.9826	43.491	-11.86	0.000
	L_D2015_2019*Q2	-252.8734	34.172	-7.40	0.000
	L_D19Q3	-332.0002	64.720	-5.13	0.000

Variable	Definition	Explanation	Dummy Variable Support
L_RHOIL_NG_SAVE	Cumulative savings from natural gas vs. heating oil for residential heating customers in Lawrence ($2020)		
L_D18Q3	Binary variable equal to 1 in 2018Q3		2
L_D18Q4	Binary variable equal to 1 in 2018Q4		2
L_D2015_2017*Q3	Binary variable equal to 1 in Q3 from 2015 to 2017		2
L_D2015_2019*Q2	Binary variable equal to 1 in Q2 from 2015 to 2019		2
L_D19Q3	Binary variable equal to 1 in 2019Q3		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
22	0.997591	1450.145

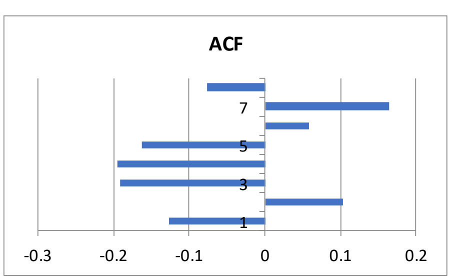
Chow Test Stats	N	k	SSR
Combined	22	7	56,117.67
1	11	4	29,277.31
2	11	6	18,355.72

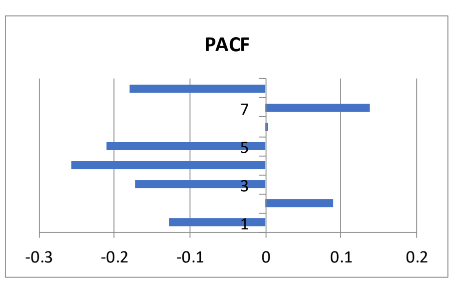
Chow Stat:	0.204
P-Value:	0.975173

Heteroscedasticity - White's Test	
White Stat	0.76
Significance (p-value)	0.62

Correlations

	L_RHOIL_NG_SAVE	L_D18Q3	L_D18Q4	L_D2015_2017*Q3	L_D2015_2019*Q2	L_D19Q3
L_RHOIL_NG_SAVE	1	0.06382	0.09823	-0.365708	-0.187496	0.207702
L_D18Q3	0.06382	1	-0.047619	-0.086711	-0.118345	-0.047619
L_D18Q4	0.09823	-0.047619	1	-0.086711	-0.118345	-0.047619
L_D2015_2017*Q3	-0.365708	-0.086711	-0.086711	1	-0.215499	-0.086711
L_D2015_2019*Q2	-0.187496	-0.118345	-0.118345	-0.215499	1	-0.118345
L_D19Q3	0.207702	-0.047619	-0.047619	-0.086711	-0.118345	1





Residual ACF								
Model		1	2	3	4	5	6	7
l_rh_cust_s_t Model	ACF	-0.127	0.104	-0.191	-0.196	-0.162	0.058	0.165
	SE	0.426	0.426	0.426	0.426	0.426	0.426	0.426
Residual PACF								
Model		1	2	3	4	5	6	7
l_rh_cust_s_t Model		-0.127	0.089	-0.172	-0.257	-0.21	0.004	0.138
	SE	0.426	0.426	0.426	0.426	0.426	0.426	0.426

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2015Q2	41430.00	41448.30	-18.34	-0.04%	(0.35)
2015Q3	41158.70	41251.60	-92.97	-0.23%	(1.80)
2015Q4	41935.70	41958.70	-23.07	-0.06%	(0.45)
2016Q1	42410.30	42340.90	69.45	0.16%	1.34
2016Q2	42239.30	42241.90	-2.61	-0.01%	(0.05)
2016Q3	42128.30	42017.50	110.80	0.26%	2.14
2016Q4	42668.00	42665.80	2.16	0.01%	0.04
2017Q1	43003.70	42939.70	63.95	0.15%	1.24
2017Q2	42761.30	42809.30	-47.96	-0.11%	(0.93)
2017Q3	42562.00	42579.80	-17.83	-0.04%	(0.34)
2017Q4	43201.70	43217.90	-16.20	-0.04%	(0.31)
2018Q1	43540.30	43508.60	31.69	0.07%	0.61
2018Q2	43381.00	43365.30	15.66	0.04%	0.30
2018Q3	40993.70	40993.70	0.00	0.00%	0.00
2018Q4	41081.30	41081.30	0.00	0.00%	0.00
2019Q1	44015.00	44141.10	-126.10	-0.29%	(2.44)
2019Q2	44061.70	44008.40	53.26	0.12%	1.03
2019Q3	43964.30	43964.30	0.00	0.00%	0.00
2019Q4	44443.30	44455.10	-11.80	-0.03%	(0.23)
2020Q1	44764.00	44742.70	21.27	0.05%	0.41
2020Q2	44901.30	44876.30	24.98	0.06%	0.48
2020Q3	44871.70	44908.00	-36.35	-0.08%	(0.70)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	44443.33	44455.89	-12.56	0.0%
Q1 2020	44764.00	44743.58	20.42	0.0%
Q2 2020	44901.33	44877.24	24.09	0.1%
Q3 2020	44871.67	44908.92	-37.25	-0.1%
Total	178980.33	178985.63	-5.30	0.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	32223.51	32220.26	3.25	0%
L_RHOIL_NG_SAVE	0.90	0.90	0.00	0%
L_D18Q3	-2657.92	-2658.41	0.49	0%
L_D18Q4	-2724.45	-2724.99	0.54	0%
L_D2015_2017*Q3	-515.98	-516.09	0.11	0%
L_D2015_2019*Q2	-252.87	-253.16	0.29	0%
L_D19Q3	-332.00	-332.70	0.70	0%

RHC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
S_RH_CUST_S_T	5	0.990	14.869

ARIMA Model Parameters

S_RH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	71542.6	366.000	195.47	0.000
	S_RHOIL_NG_SAVE	1.659368	0.038	43.75	0.000
	S_D2015_2019*Q3	-1076.062	113.392	-9.49	0.000
	S_D2016_2019*Q2	-542.0301	124.484	-4.35	0.000
	B_D15Q1	475.2009	233.068	2.04	0.054

Variable	Definition	Explanation	Dummy Variable Support
S_RHOIL_NG_SAVE	Cumulative savings from natural gas vs. heating oil for residential heating customers in Springfield ($2020)		
S_D2015_2019*Q3	Binary variable equal to 1 in Q3 from 2015 to 2019		2
S_D2016_2019*Q2	Binary variable equal to 1 in Q2 from 2016 to 2019		2
B_D15Q1	Binary variable equal to 1 in 2015Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

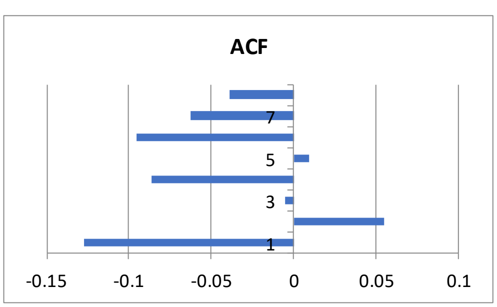
N	Adjusted R2	F Statistic
26	0.997591	505.4981

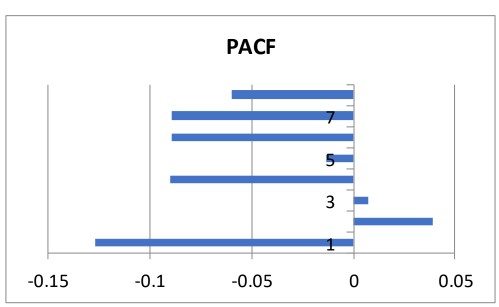
Chow Test Stats	N	k	SSR
Combined	26	5	1,026,557.40
1	13	5	808,823.00
2	13	4	104,894.12

Chow Stat:	0.395
P-Value:	0.844942

Heteroscedasticity - White's Test	
White Stat	2.69
Significance (p-value)	0.06

Correlations	S_RHOIL_NG_SAVE	S_D2015_2019*Q3	S_D2016_2019*Q2	B_D15Q1
S_RHOIL_NG_SAVE	1	0.040233	0.128026	-0.223951
S_D2015_2019*Q3	0.040233	1	-0.208063	-0.09759
S_D2016_2019*Q2	0.128026	-0.208063	1	-0.08528
B_D15Q1	-0.223951	-0.09759	-0.08528	1





Residual ACF								
Model		1	2	3	4	5	6	7
s_rh_cust_s_t Model	ACF	-0.127	0.055	-0.005	-0.086	0.009	-0.095	-0.063
	SE	0.392	0.392	0.392	0.392	0.392	0.392	0.392
Residual PACF								
Model		1	2	3	4	5	6	7
s_rh_cust_s_t Model		-0.127	0.039	0.007	-0.09	-0.013	-0.089	-0.089
	SE	0.392	0.392	0.392	0.392	0.392	0.392	0.392

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q2	83738.30	83475.50	262.81	0.31%	1.30
2014Q3	83399.30	83613.90	-214.55	-0.26%	(1.06)
2014Q4	84745.00	84101.50	643.53	0.76%	3.18
2015Q1	85711.00	85711.00	0.00	0.00%	(0.00)
2015Q2	85104.00	85579.00	-475.01	-0.56%	(2.34)
2015Q3	84478.30	84601.00	-122.67	-0.15%	(0.61)
2015Q4	85681.30	85955.30	-274.01	-0.32%	(1.35)
2016Q1	86546.30	86526.60	19.72	0.02%	0.10
2016Q2	86051.00	86201.10	-150.10	-0.17%	(0.74)
2016Q3	85739.70	85725.50	14.12	0.02%	0.07
2016Q4	86866.70	87005.70	-139.05	-0.16%	(0.69)
2017Q1	87516.00	87425.40	90.55	0.10%	0.45
2017Q2	87023.30	87049.10	-25.81	-0.03%	(0.13)
2017Q3	86537.00	86564.80	-27.83	-0.03%	(0.14)
2017Q4	87660.00	87825.10	-165.15	-0.19%	(0.81)
2018Q1	88439.00	88253.90	185.11	0.21%	0.91
2018Q2	87882.70	87866.40	16.25	0.02%	0.08
2018Q3	87435.70	87379.10	56.61	0.06%	0.28
2018Q4	88710.00	88699.20	10.80	0.01%	0.05
2019Q1	89285.00	89169.00	115.97	0.13%	0.57
2019Q2	88955.00	88795.30	159.66	0.18%	0.79
2019Q3	88394.00	88314.20	79.78	0.09%	0.39
2019Q4	89508.70	89634.60	-125.95	-0.14%	(0.62)
2020Q1	90104.00	90076.20	27.79	0.03%	0.14
2020Q2	90319.30	90271.30	48.02	0.05%	0.24
2020Q3	90310.70	90321.30	-10.59	-0.01%	(0.05)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	89508.67	89648.82	-140.15	-0.2%
Q1 2020	90104.00	90091.69	12.31	0.0%
Q2 2020	90319.33	90287.35	31.98	0.0%
Q3 2020	90310.67	90337.44	-26.77	0.0%
Total	360242.67	360365.30	-122.63	0.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	71542.60	71504.55	38.05	0%
S_RHOIL_NG_SAVE	1.66	1.66	0.00	0%
S_D2015_2019*Q3	-1076.06	-1084.37	8.31	-1%
S_D2016_2019*Q2	-542.03	-551.57	9.54	-2%
B_D15Q1	475.20	473.70	1.50	0%

RNHC Brockton S&T
B. Residential Non-Heating Customers - Sales and Transportation
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
B_RNH_CUST_S_T	7	0.997	5.354

ARIMA Model Parameters

B_RNH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	10812.42	50.882	212.50	0.000
	@TREND	-55.55004	1.010	-55.03	0.000
	B_D20Q3	163.3505	31.769	5.14	0.000
	B_D14Q3	378.8162	31.769	11.92	0.000
	B_D18Q1	-55.14992	29.438	-1.87	0.077
	B_D14Q4	350.3662	31.398	11.16	0.000
	B_D19Q4	49.70037	30.742	1.62	0.123

Variable	Definition	Explanation	Dummy Variable Support
@TREND	Quarterly Trend		
B_D20Q3	Binary variable equal to 1 in 2020Q3		2
B_D14Q3	Binary variable equal to 1 in 2014Q3		2
B_D18Q1	Binary variable equal to 1 in 2018Q1		2
B_D14Q4	Binary variable equal to 1 in 2014Q4		2
B_D19Q4	Binary variable equal to 1 in 2019Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

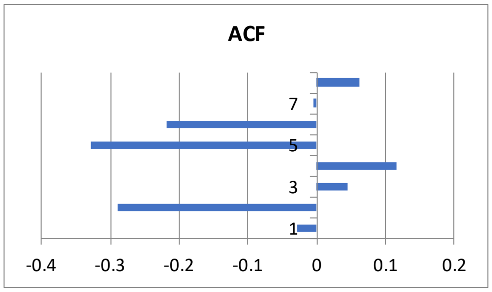
N	Adjusted R2	F Statistic
25	0.996034	1005.66

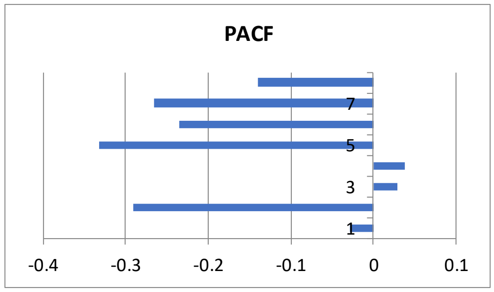
Chow Test Stats	N	k	SSR
Combined	25	7	14,785.90
1	13	4	5,593.91
2	12	5	8,990.72

Chow Stat:	0.022
P-Value:	0.999981

Heteroscedasticity - White's Test	
White Stat	0.56
Significance (p-value)	0.75

Correlations	@TREND	B_D20Q3	B_D14Q3	B_D18Q1	B_D14Q4	B_D19Q4
@TREND	1	0.339683	-0.33968	0.056614	-0.31138	0.254762
B_D20Q3	0.339683	1	-0.04167	-0.041667	-0.04167	-0.041667
B_D14Q3	-0.339683	-0.041667	1	-0.041667	-0.04167	-0.041667
B_D18Q1	0.056614	-0.041667	-0.04167	1	-0.04167	-0.041667
B_D14Q4	-0.311376	-0.041667	-0.04167	-0.041667	1	-0.041667
B_D19Q4	0.254762	-0.041667	-0.04167	-0.041667	-0.04167	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_rnh_cust_s_t Models	ACF	-0.028	-0.289	0.046	0.116	-0.329	-0.217	-0.004	0.063
	SE	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_rnh_cust_s_t Models		-0.028	-0.291	0.03	0.038	-0.332	-0.234	-0.266	-0.14
	SE	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q3	9080.33	9080.33	0.00	0.00%	(0.00)
2014Q4	8996.33	8996.33	0.00	0.00%	(0.00)
2015Q1	8609.67	8590.42	19.25	0.22%	0.78
2015Q2	8527.33	8534.87	-7.53	-0.09%	(0.30)
2015Q3	8473.00	8479.32	-6.32	-0.07%	(0.25)
2015Q4	8466.33	8423.77	42.57	0.50%	1.71
2016Q1	8331.00	8368.22	-37.22	-0.45%	(1.50)
2016Q2	8287.33	8312.67	-25.33	-0.31%	(1.02)
2016Q3	8237.67	8257.12	-19.45	-0.24%	(0.78)
2016Q4	8224.67	8201.57	23.10	0.28%	0.93
2017Q1	8143.00	8146.02	-3.02	-0.04%	(0.12)
2017Q2	8102.33	8090.47	11.87	0.15%	0.48
2017Q3	8051.33	8034.92	16.42	0.20%	0.66
2017Q4	8023.00	7979.37	43.63	0.54%	1.76
2018Q1	7868.67	7868.67	0.00	0.00%	(0.00)
2018Q2	7814.00	7868.27	-54.27	-0.69%	(2.19)
2018Q3	7804.00	7812.72	-8.72	-0.11%	(0.35)
2018Q4	7778.00	7757.17	20.83	0.27%	0.84
2019Q1	7674.00	7701.62	-27.62	-0.36%	(1.11)
2019Q2	7620.33	7646.07	-25.73	-0.34%	(1.04)
2019Q3	7594.00	7590.52	3.48	0.05%	0.14
2019Q4	7584.67	7584.67	0.00	0.00%	(0.00)
2020Q1	7466.67	7479.42	-12.75	-0.17%	(0.51)
2020Q2	7470.67	7423.87	46.80	0.63%	1.89
2020Q3	7531.67	7531.67	0.00	0.00%	(0.00)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Differenc	% Difference
Q4 2019	7584.67	7525.33	59.34	0.8%
Q1 2020	7466.67	7469.02	-2.35	0.0%
Q2 2020	7470.67	7412.71	57.96	0.8%
Q3 2020	7531.67	7356.39	175.27	2.3%
Total	30053.67	29763.44	290.22	1.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Differenc	% Difference
C	10812.42	10847.73	-35.31	0%
@TREND	-55.55	-56.31	0.76	-1%
B_D20Q3	163.35			
B_D14Q3	378.82	372.45	6.36	2%
B_D18Q1	-55.15	-50.85	-4.30	8%
B_D14Q4	350.37	344.77	5.60	2%
B_D19Q4	49.70			

RNHC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
L_RNH_CUST_S_T	7	0.996	3.598

ARIMA Model Parameters

L_RNH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	3022.358	312.084	9.68	0.000
	@TREND	-11.01828	5.096	-2.16	0.045
	L_D18Q3	-171.9274	11.419	-15.06	0.000
	L_D18Q4	-278.2181	12.316	-22.59	0.000
	Q4	24.29905	4.616	5.26	0.000
	L_D15Q1	-34.40288	10.442	-3.29	0.004
	AR(1)	0.836554	0.056	14.87	0.000

Variable	Definition	Explanation	Dummy Variable Support
@TREND	Quarterly Trend		
L_D18Q3	Binary variable equal to 1 in 2018Q3		2
L_D18Q4	Binary variable equal to 1 in 2018Q4		2
Q4	Binary variable equal to 1 in Q4	C	2
L_D15Q1	Binary variable equal to 1 in 2015Q4		2
AR(1)	ARMA		

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C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
24	0.997591	776.8785

Chow Test Stats

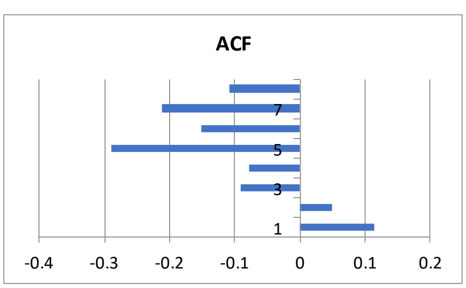
	N	k	SSR
Combined	24	7	2,847.88
1	12	5	1,239.15
2	12	6	956.01

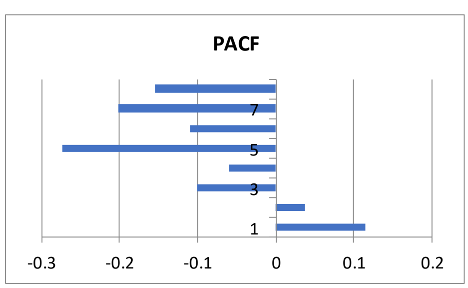
Chow Stat:	0.425
P-Value:	0.86587

Heteroscedasticity - White's Test	
White Stat	1.16
Significance (p-value)	0.37

Correlations

	@TREND	L_D18Q3	L_D18Q4	Q4	L_D15Q1
@TREND	1	0.105429	0.135552	-0.125109	-0.31629
L_D18Q3	0.105429	1	-0.043478	-0.120386	-0.04348
L_D18Q4	0.135552	-0.043478	1	0.361158	-0.04348
Q4	-0.125109	-0.120386	0.361158	1	-0.12039
L_D15Q1	-0.316288	-0.043478	-0.043478	-0.120386	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_rnh_cust_s_t Model	ACF	0.115	0.05	-0.09	-0.077	-0.29	-0.152	-0.212	-0.109
	SE	0.408	0.408	0.408	0.408	0.408	0.408	0.408	0.408
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_rnh_cust_s_t Model		0.115	0.038	-0.101	-0.059	-0.273	-0.109	-0.202	-0.154
	SE	0.408	0.408	0.408	0.408	0.408	0.408	0.408	0.408

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q4	2946.33	2924.80	21.53	0.73%	1.94
2015Q1	2815.33	2822.78	-7.44	-0.26%	(0.67)
2015Q2	2786.00	2794.90	-8.90	-0.32%	(0.80)
2015Q3	2737.33	2739.78	-2.44	-0.09%	(0.22)
2015Q4	2696.33	2721.56	-25.23	-0.94%	(2.27)
2016Q1	2637.67	2640.84	-3.17	-0.12%	(0.28)
2016Q2	2610.00	2610.29	-0.29	-0.01%	(0.03)
2016Q3	2598.67	2585.34	13.33	0.51%	1.20
2016Q4	2600.00	2598.36	1.64	0.06%	0.15
2017Q1	2559.33	2553.04	6.29	0.25%	0.57
2017Q2	2545.67	2537.55	8.11	0.32%	0.73
2017Q3	2541.00	2524.32	16.68	0.66%	1.50
2017Q4	2546.67	2542.91	3.75	0.15%	0.34
2018Q1	2506.67	2501.23	5.44	0.22%	0.49
2018Q2	2471.67	2486.29	-14.62	-0.59%	(1.31)
2018Q3	2278.33	2283.28	-4.95	-0.22%	(0.44)
2018Q4	2175.67	2181.58	-5.92	-0.27%	(0.53)
2019Q1	2409.33	2416.40	-7.07	-0.29%	(0.64)
2019Q2	2390.33	2397.66	-7.33	-0.31%	(0.66)
2019Q3	2393.67	2379.97	13.70	0.57%	1.23
2019Q4	2397.00	2405.25	-8.25	-0.34%	(0.74)
2020Q1	2352.67	2361.61	-8.95	-0.38%	(0.80)
2020Q2	2340.67	2343.05	-2.39	-0.10%	(0.21)
2020Q3	2347.67	2331.21	16.45	0.70%	1.48

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	2397.00	2393.80	3.20	0.1%
Q1 2020	2352.67	2358.64	-5.97	-0.3%
Q2 2020	2340.67	2347.80	-7.13	-0.3%
Q3 2020	2347.67	2336.86	10.81	0.5%
Total	9438.00	9437.09	0.92	0.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	3022.36	3048.38	-26.02	-1%
@TREND	-11.02	-11.44	0.42	-4%
L_D18Q3	-171.93	-172.00	0.07	0%
L_D18Q4	-278.22	-278.44	0.22	0%
Q4	24.30	24.44	-0.14	-1%
L_D15Q1	-34.40	-34.25	-0.16	0%
AR(1)	0.84	0.83	0.00	1%

RNHC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
S_RNH_CUST_S_T	8	0.997	5.667

ARIMA Model Parameters

S_RNH_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	12882.3	43.338	297.25	0.000
	@TREND	-62.81608	0.908	-69.19	0.000
	D_15Q1THR19Q3	-222.9594	16.255	-13.72	0.000
	S_D18Q4	68.21214	33.709	2.02	0.057
	S_D2016	-84.62396	18.714	-4.52	0.000
	S_D20Q1	-120.0002	37.106	-3.23	0.004
	S_D17Q4	111.2811	33.361	3.34	0.004
	S_D19Q4	-123.8162	36.794	-3.37	0.003

Variable	Definition	Explanation	Dummy Variable Support
@TREND	Quarterly Trend		
D_15Q1THR19Q3	Binary variable equal to 1 from 2015Q1 to 2019Q3		1
S_D18Q4	Binary variable equal to 1 in 2018Q4		2
S_D2016	Binary variable equal to 1 in 2016		2
S_D20Q1	Binary variable equal to 1 in 2020Q1		2
S_D17Q4	Binary variable equal to 1 in 2017Q4		2
S_D19Q4	Binary variable equal to 1 in 2019Q4		2

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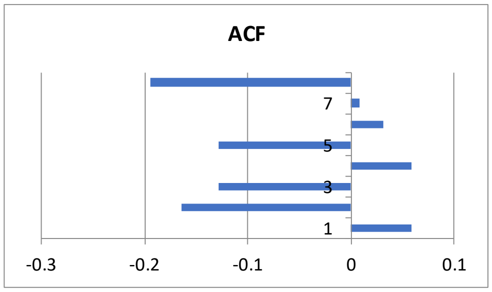
N	Adjusted R2	F Statistic
27	0.996096	948.5818

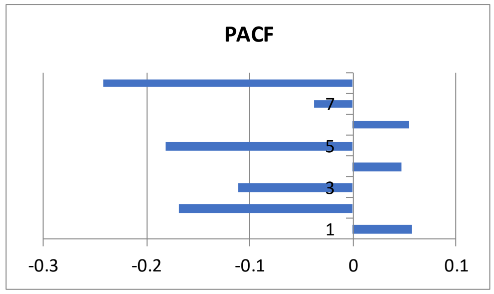
Chow Test Stats	N	k	SSR
Combined	27	8	19,601.38
1	14	4	12,827.54
2	13	7	4,582.14

Chow Stat:	0.173
P-Value:	0.990232

Heteroscedasticity - White's Test	
White Stat	0.40
Significance (p-value)	0.89

Correlations	@TREND	D_15Q1THR19Q3	S_D18Q4	S_D2016	S_D20Q1	S_D17Q4	S_D19Q4
@TREND	1	-1.85E-17	0.151074	-0.187395	0.276969	0.050358	0.25179
D_15Q1THR19Q3	-1.85E-17	1	0.127257	0.270604	-0.30224	0.127257	-0.30224
S_D18Q4	0.151074	0.127257	1	-0.081786	-0.03846	-0.038462	-0.03846
S_D2016	-0.187395	0.270604	-0.081786	1	-0.08179	-0.081786	-0.08179
S_D20Q1	0.276969	-0.302235	-0.038462	-0.081786	1	-0.038462	-0.03846
S_D17Q4	0.050358	0.127257	-0.038462	-0.081786	-0.03846	1	-0.03846
S_D19Q4	0.25179	-0.302235	-0.038462	-0.081786	-0.03846	-0.038462	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_rnh_cust_s_t Model	ACF	0.058	-0.165	-0.129	0.058	-0.129	0.031	0.008	-0.194
	SE	0.385	0.385	0.385	0.385	0.385	0.385	0.385	0.385
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_rnh_cust_s_t Model		0.058	-0.169	-0.111	0.047	-0.181	0.055	-0.038	-0.242
	SE	0.385	0.385	0.385	0.385	0.385	0.385	0.385	0.385

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q1	10662.30	10620.90	41.41	0.39%	1.51
2014Q2	10541.30	10558.10	-16.77	-0.16%	(0.61)
2014Q3	10476.30	10495.30	-18.95	-0.18%	(0.69)
2014Q4	10445.70	10432.50	13.20	0.13%	0.48
2015Q1	10200.70	10146.70	53.97	0.53%	1.97
2015Q2	10080.30	10083.90	-3.55	-0.04%	(0.13)
2015Q3	9968.67	10021.10	-52.40	-0.53%	(1.91)
2015Q4	9919.33	9958.25	-38.91	-0.39%	(1.42)
2016Q1	9780.33	9810.81	-30.47	-0.31%	(1.11)
2016Q2	9729.33	9747.99	-18.66	-0.19%	(0.68)
2016Q3	9685.33	9685.18	0.16	0.00%	0.01
2016Q4	9671.33	9622.36	48.97	0.51%	1.78
2017Q1	9626.00	9644.17	-18.17	-0.19%	(0.66)
2017Q2	9573.67	9581.35	-7.68	-0.08%	(0.28)
2017Q3	9541.33	9518.53	22.80	0.24%	0.83
2017Q4	9567.00	9567.00	0.00	0.00%	(0.00)
2018Q1	9430.00	9392.90	37.10	0.39%	1.35
2018Q2	9332.33	9330.09	2.25	0.02%	0.08
2018Q3	9266.33	9267.27	-0.94	-0.01%	(0.03)
2018Q4	9272.67	9272.67	0.00	0.00%	(0.00)
2019Q1	9161.67	9141.64	20.03	0.22%	0.73
2019Q2	9057.67	9078.82	-21.16	-0.23%	(0.77)
2019Q3	9022.67	9016.01	6.66	0.07%	0.24
2019Q4	9052.33	9052.33	0.00	0.00%	(0.00)
2020Q1	8993.33	8993.33	0.00	0.00%	(0.00)
2020Q2	9003.33	9050.52	-47.18	-0.52%	(1.72)
2020Q3	9016.00	8987.70	28.30	0.31%	1.03

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	9052.33	9199.36	-147.03	-1.6%
Q1 2020	8993.33	9137.40	-144.07	-1.6%
Q2 2020	9003.33	9075.45	-72.11	-0.8%
Q3 2020	9016.00	9013.49	2.51	0.0%
Total	36065.00	36425.69	-360.70	-1.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	12882.30	12854.78	27.52	0%
@TREND	-62.82	-61.96	-0.86	1%
D_15Q1THR19Q3	-222.96	-237.97	15.01	-7%
S_D18Q4	68.21	63.45	4.76	7%
S_D2016	-84.62	-81.22	-3.41	4%
S_D20Q1	-120.00			
S_D17Q4	111.28	109.96	1.32	1%
S_D19Q4	-123.82			

LLFC Brockton S&T
C. Low Load Factor Customers - Sales and Transportation
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_LLF_CUST_S_T	10	0.948	11.500

ARIMA Model Parameters

B_LLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	10718.9	182.662	58.68	0.000
	B_GMP	8.58191	0.451	19.02	0.000
	Q3	-402.7014	49.094	-8.20	0.000
	B_D20Q2_AFT	487.8858	99.327	4.91	0.000
	B_D12Q4_13Q2	-282.2706	84.014	-3.36	0.002
	B_D16Q4_17Q2	-181.3372	82.054	-2.21	0.034
	B_D16Q1	386.408	135.308	2.86	0.007
	B_D14Q1	284.8222	136.293	2.09	0.044
	B_D10Q1	311.4894	140.498	2.22	0.034
	B_D11Q1	242.3627	139.215	1.74	0.091

Variable	Definition	Explanation	Dummy Variable Support
B_GMP	Gross Metro Product (bil. $) in Brockton		
Q3	Binary variable equal to 1 in Q3	C	2
B_D20Q2_AFT	Binary variable equal to 1 from 2020Q2 on		1
B_D12Q4_13Q2	Binary variable equal to 1 from 2012Q4 to 2013Q2		2
B_D16Q4_17Q2	Binary variable equal to 1 from 2016Q4 to 2017Q2		2
B_D16Q1	Binary variable equal to 1 in 2016Q1		2
B_D14Q1	Binary variable equal to 1 in 2014Q1		2
B_D10Q1	Binary variable equal to 1 in 2010Q1		2
B_D11Q1	Binary variable equal to 1 in 2011Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
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C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
43	0.933692	66.71199

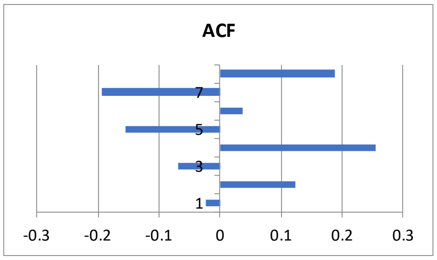
Chow Test Stats	N	k	SSR
Combined	43	10	577,125.83
1	21	7	201,558.91
2	22	6	279,397.66

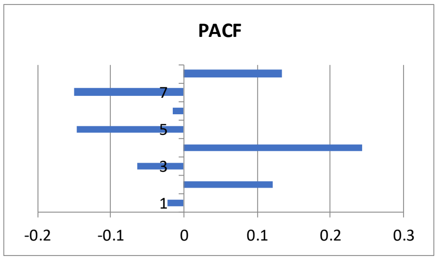
Chow Stat:	0.375
P-Value:	0.933388

Heteroscedasticity - White's Test	
White Stat	0.79
Significance (p-value)	0.63

Correlations

	B_GMP	Q3	B_D20Q2_AFT	B_D12Q4_13Q2	B_D16Q4	B_D16Q1	B_D14Q1	B_D10Q1	B_D11Q1
B_GMP	1	0.048404	0.222818	-0.215774	0.141086	0.031314	-0.09566	-0.24	-0.20576
Q3	0.048404	1	0.123606	-0.160565	-0.16057	-0.090468	-0.09047	-0.09047	-0.09047
B_D20Q2_AFT	0.222818	0.123606	1	-0.060486	-0.06049	-0.03408	-0.03408	-0.03408	-0.03408
B_D12Q4_13Q2	-0.215774	-0.160565	-0.060486	1	-0.075	-0.042258	-0.04226	-0.04226	-0.04226
B_D16Q4_17Q2	0.141086	-0.160565	-0.060486	-0.075	1	-0.042258	-0.04226	-0.04226	-0.04226
B_D16Q1	0.031314	-0.090468	-0.03408	-0.042258	-0.04226	1	-0.02381	-0.02381	-0.02381
B_D14Q1	-0.095659	-0.090468	-0.03408	-0.042258	-0.04226	-0.02381	1	-0.02381	-0.02381
B_D10Q1	-0.239995	-0.090468	-0.03408	-0.042258	-0.04226	-0.02381	-0.02381	1	-0.02381
B_D11Q1	-0.205759	-0.090468	-0.03408	-0.042258	-0.04226	-0.02381	-0.02381	-0.02381	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_llf_cust_s_t Models	ACF	-0.023	0.123	-0.068	0.256	-0.154	0.038	-0.194	0.188
	SE	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_llf_cust_s_t Models		-0.023	0.122	-0.064	0.244	-0.147	-0.015	-0.15	0.134
	SE	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2010Q1	13740.30	13740.30	0.00	0.00%	0.00
2010Q2	13364.30	13457.40	-93.03	-0.70%	(0.79)
2010Q3	13084.30	13080.10	4.25	0.03%	0.04
2010Q4	13490.30	13521.20	-30.87	-0.23%	(0.26)
2011Q1	13767.70	13767.70	0.00	0.00%	0.00
2011Q2	13419.00	13568.50	-149.46	-1.11%	(1.27)
2011Q3	13200.70	13191.10	9.59	0.07%	0.08
2011Q4	13614.00	13638.00	-23.96	-0.18%	(0.20)
2012Q1	13886.30	13688.60	197.72	1.42%	1.69
2012Q2	13587.30	13711.80	-124.42	-0.92%	(1.06)
2012Q3	13251.30	13333.10	-81.78	-0.62%	(0.70)
2012Q4	13412.70	13460.10	-47.44	-0.35%	(0.40)
2013Q1	13658.00	13488.30	169.67	1.24%	1.45
2013Q2	13370.00	13492.20	-122.23	-0.91%	(1.04)
2013Q3	13257.30	13399.60	-142.24	-1.07%	(1.21)
2013Q4	13871.30	13837.30	34.02	0.25%	0.29
2014Q1	14120.30	14120.30	0.00	0.00%	0.00
2014Q2	13843.30	13890.80	-47.51	-0.34%	(0.41)
2014Q3	13588.70	13544.20	44.42	0.33%	0.38
2014Q4	14106.00	14006.10	99.89	0.71%	0.85
2015Q1	14350.00	14052.80	297.18	2.07%	2.54
2015Q2	14081.30	14128.60	-47.25	-0.34%	(0.40)
2015Q3	13866.00	13757.60	108.44	0.78%	0.93
2015Q4	14311.00	14166.40	144.60	1.01%	1.23
2016Q1	14579.70	14579.70	0.00	0.00%	0.00
2016Q2	14371.70	14231.80	139.82	0.97%	1.19
2016Q3	14006.30	13867.60	138.78	0.99%	1.18
2016Q4	14082.00	14116.10	-34.09	-0.24%	(0.29)
2017Q1	14294.30	14152.40	141.89	0.99%	1.21
2017Q2	14066.70	14174.50	-107.80	-0.77%	(0.92)
2017Q3	13910.00	14001.60	-91.60	-0.66%	(0.78)
2017Q4	14321.00	14468.90	-147.86	-1.03%	(1.26)
2018Q1	14565.70	14533.00	32.71	0.22%	0.28
2018Q2	14324.30	14599.20	-274.85	-1.92%	(2.34)
2018Q3	14201.30	14230.10	-28.75	-0.20%	(0.25)
2018Q4	14742.30	14671.60	70.78	0.48%	0.60
2019Q1	14931.70	14720.20	211.50	1.42%	1.80
2019Q2	14667.00	14766.70	-99.71	-0.68%	(0.85)
2019Q3	14440.70	14410.70	30.01	0.21%	0.26
2019Q4	14655.30	14850.50	-195.13	-1.33%	(1.66)
2020Q1	14834.70	14820.00	14.69	0.10%	0.13
2020Q2	14858.70	14867.50	-8.87	-0.06%	(0.08)
2020Q3	14801.70	14792.80	8.87	0.06%	0.08

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	14655.33	14880.13	-224.80	-1.5%
Q1 2020	14834.67	14848.86	-14.19	-0.1%
Q2 2020	14858.67	14397.17	461.50	3.1%
Q3 2020	14801.67	14320.12	481.55	3.3%
Total	59150.34	58446.28	704.06	1.2%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	10718.90	10641.87	77.03	1%
B_GMP	8.58	8.80	-0.22	-3%
Q3	-402.70	-413.47	10.77	-3%
B_D20Q2_AFT	487.89			
B_D12Q4_13Q2	-282.27	-283.85	1.58	-1%
B_D16Q4_17Q2	-181.34	-197.54	16.21	-9%
B_D16Q1	386.41	373.71	12.70	3%
B_D14Q1	284.82	281.36	3.46	1%
B_D10Q1	311.49	318.53	-7.04	-2%
B_D11Q1	242.36	246.91	-4.55	-2%

LLFC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
L_LLF_CUST_S_T	8	0.946	5.552

ARIMA Model Parameters

L_LLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	1826.031	199.325	9.16	0.000
	L_GMP	13.46307	2.249	5.99	0.000
	L_D18Q3+L_D18Q4	-229.9149	24.090	-9.54	0.000
	L_D20Q2+L_D20Q3	166.5177	24.287	6.86	0.000
	Q3	-90.58037	16.998	-5.33	0.000
	L_D16Q1	92.70397	33.726	2.75	0.018
	L_D18Q2	-75.15737	32.294	-2.33	0.038
	L_D17Q2	-61.95355	32.703	-1.89	0.083

Variable	Definition	Explanation	Dummy Variable Support
L_GMP	Gross Metro Product (bil. $) in Lawrence		
L_D18Q3+L_D18Q4	Binary variable equal to 1 in 2018Q3 and 2018Q4		2
L_D20Q2+L_D20Q3	Binary variable equal to 1 in 2020Q2 and 2020Q3		2
Q3	Binary variable equal to 1 in Q3	C	2
L_D16Q1	Binary variable equal to 1 in 2016Q1		2
L_D18Q2	Binary variable equal to 1 in 2018Q2		2
L_D17Q2	Binary variable equal to 1 in 2017Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
20	0.913799	29.77357

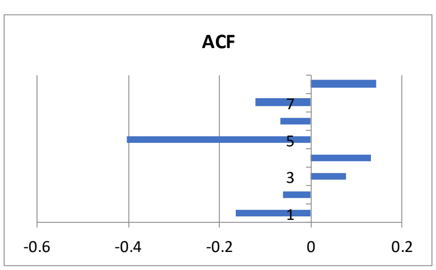
Chow Test Stats	N	k	SSR
Combined	24	8	11,405.18
1	8	5	2,570.59
2	12	6	4,900.72

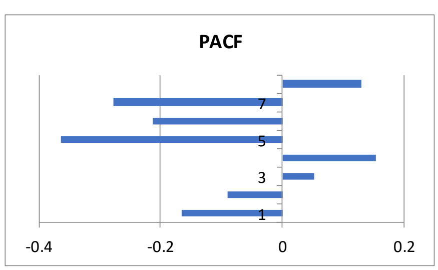
Chow Stat:	0.263
P-Value:	0.948758

Heteroscedasticity - White's Test	
White Stat	0.87
Significance (p-value)	0.56

Correlations

	L_GMP	L_D18Q3+L_D18Q4	L_D20Q2+L_D20Q3	Q3	L_D16Q1	L_D18Q2	L_D17Q2
L_GMP	1	0.195852	-0.151508	0.114196	-0.28624	0.075544	-0.1531
L_D18Q3+L_D18Q4	0.195852	1	-0.111111	0.19245	-0.07647	-0.076472	-0.07647
L_D20Q2+L_D20Q3	-0.151508	-0.111111	1	0.19245	-0.07647	-0.076472	-0.07647
Q3	0.114196	0.19245	0.19245	1	-0.13245	-0.132453	-0.13245
L_D16Q1	-0.286243	-0.076472	-0.076472	-0.132453	1	-0.052632	-0.05263
L_D18Q2	0.075544	-0.076472	-0.076472	-0.132453	-0.05263	1	-0.05263
L_D17Q2	-0.153096	-0.076472	-0.076472	-0.132453	-0.05263	-0.052632	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_llf_cust_s_t Models	ACF	-0.165	-0.061	0.076	0.131	-0.402	-0.068	-0.121	0.144
	SE	0.447	0.447	0.447	0.447	0.447	0.447	0.447	0.447
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_llf_cust_s_t Models		-0.165	-0.09	0.052	0.153	-0.364	-0.212	-0.278	0.13
	SE	0.447	0.447	0.447	0.447	0.447	0.447	0.447	0.447

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2015Q4	2974.00	2955.92	18.08	0.61%	0.74
2016Q1	3051.33	3051.33	0.00	0.00%	0.00
2016Q2	2995.67	2966.23	29.43	0.98%	1.20
2016Q3	2904.67	2879.53	25.13	0.87%	1.03
2016Q4	2927.67	2978.34	-50.68	-1.73%	(2.07)
2017Q1	2981.67	2984.16	-2.50	-0.08%	(0.10)
2017Q2	2923.00	2923.00	0.00	0.00%	0.00
2017Q3	2861.00	2904.10	-43.10	-1.51%	(1.76)
2017Q4	2973.33	3005.99	-32.66	-1.10%	(1.33)
2018Q1	3040.67	3016.37	24.30	0.80%	0.99
2018Q2	2955.00	2955.00	0.00	0.00%	0.00
2018Q3	2727.33	2716.90	10.43	0.38%	0.43
2018Q4	2806.00	2816.43	-10.43	-0.37%	(0.43)
2019Q1	3087.67	3061.20	26.47	0.86%	1.08
2019Q2	3063.67	3070.28	-6.61	-0.22%	(0.27)
2019Q3	3000.67	2990.54	10.13	0.34%	0.41
2019Q4	3065.33	3099.05	-33.72	-1.10%	(1.38)
2020Q1	3110.00	3074.27	35.73	1.15%	1.46
2020Q2	3120.67	3118.07	2.59	0.08%	0.11
2020Q3	3111.00	3113.59	-2.59	-0.08%	(0.11)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	3065.33	3102.86	-37.53	-1.2%
Q1 2020	3110.00	3076.94	33.06	1.1%
Q2 2020	3120.67	2948.55	172.12	5.5%
Q3 2020	3111.00	2948.90	162.10	5.2%
Total	12407.00	12077.25	329.75	2.7%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	1826.03	1771.01	55.02	3%
L_GMP	13.46	14.09	-0.62	-5%
L_D18Q3+L_D18Q4	-229.91	-231.51	1.59	-1%
L_D20Q2+L_D20Q3	166.52			
Q3	-90.58	-89.73	-0.85	1%
L_D16Q1	92.70	95.39	-2.68	-3%
L_D18Q2	-75.16	-75.78	0.62	-1%
L_D17Q2	-61.95	-60.49	-1.47	2%

LLFC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics: R-Squared	RMSE
S_LLF_CUST_S_T	8	0.986	6.996

ARIMA Model Parameters

S_LLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	6633.972	149.841	44.27	0.000
	S_GMP	40.82114	4.170	9.79	0.000
	S_D20Q2+S_D20Q3	254.172	37.314	6.81	0.000
	Q3	-127.2009	23.552	-5.40	0.000
	Q1	129.9135	23.136	5.62	0.000
	S_D2017	-73.01192	27.078	-2.70	0.014
	S_D15Q4+S_D16Q1+S_D16Q2	120.8807	31.738	3.81	0.001
	S_D14Q4	124.6326	52.582	2.37	0.028

Variable	Definition	Explanation	Dummy Variable Support
S_GMP	Gross Metro Product (bil. $) in Springfield		
S_D20Q2+S_D20Q3	Binary variable equal to 1 in 2020Q2 and 2020Q3		2
Q3	Binary variable equal to 1 in Q3	C	2
Q1	Binary variable equal to 1 in Q1	C	2
S_D2017	Binary variable equal to 1 in 2017		2
S_D15Q4+S_D16Q1+S_D16Q2	Binary variable equal to 1 from 2015Q4 to 2016Q2		2
S_D14Q4	Binary variable equal to 1 in 2014Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
28	0.897154	34.647

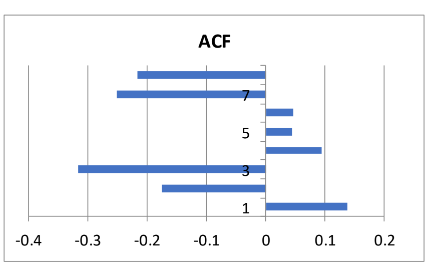
Chow Test Stats	N	k	SSR
Combined	28	8	47,907.07
1	15	7	14,527.37
2	13	6	13,707.33

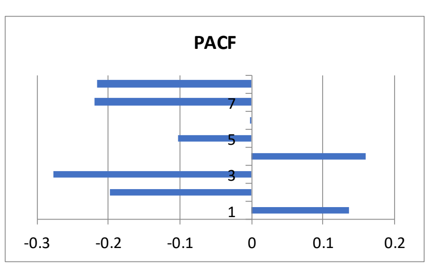
Chow Stat:	1.045
P-Value:	0.456066

Heteroscedasticity - White's Test	
White Stat	0.60
Significance (p-value)	0.75

Correlations

	S_GMP	S_D20Q2+S_D20Q3	Q3	Q1	S_D2017	S_D15Q4+S_D16Q1+S_D16Q2	S_D14Q4
S_GMP	1	0.136756	0.121445	-0.011535	0.048269	-0.199108	-0.21214
S_D20Q2+S_D20Q3	0.136756	1	0.160128	-0.160128	-0.11323	-0.096077	-0.05338
Q3	0.121445	0.160128	1	-0.333333	-1.3E-17	-0.2	-0.11111
Q1	-0.011535	-0.160128	-0.333333	1	-1.3E-17	0.066667	-0.11111
S_D2017	0.048269	-0.113228	-1.31E-17	-1.31E-17	1	-0.141421	-0.07857
S_D15Q4+S_D16Q1+S_D16Q2	-0.199108	-0.096077	-0.2	0.066667	-0.14142	1	-0.06667
S_D14Q4	-0.212143	-0.053376	-0.111111	-0.111111	-0.07857	-0.066667	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_llf_cust_s_t Model	ACF	0.137	-0.176	-0.317	0.093	0.043	0.045	-0.251	-0.218
	SE	0.378	0.378	0.378	0.378	0.378	0.378	0.378	0.378
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_llf_cust_s_t Model	PACF	0.137	-0.198	-0.277	0.16	-0.102	-0.001	-0.22	-0.216
	SE	0.378	0.378	0.378	0.378	0.378	0.378	0.378	0.378

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2013Q4	7906.00	7930.03	-24.03	-0.30%	(0.57)
2014Q1	8043.00	8050.38	-7.38	-0.09%	(0.18)
2014Q2	7896.67	7933.87	-37.20	-0.47%	(0.88)
2014Q3	7820.00	7848.72	-28.72	-0.37%	(0.68)
2014Q4	8108.00	8108.00	0.00	0.00%	0.00
2015Q1	8239.00	8130.17	108.83	1.32%	2.58
2015Q2	8065.00	8028.64	36.36	0.45%	0.86
2015Q3	7934.00	7906.80	27.20	0.34%	0.65
2015Q4	8159.67	8154.13	5.54	0.07%	0.13
2016Q1	8285.00	8283.23	1.77	0.02%	0.04
2016Q2	8149.33	8156.64	-7.31	-0.09%	(0.17)
2016Q3	7978.67	7928.82	49.85	0.62%	1.18
2016Q4	8017.67	8069.53	-51.86	-0.65%	(1.23)
2017Q1	8106.67	8137.67	-31.01	-0.38%	(0.74)
2017Q2	7980.00	8016.41	-36.41	-0.46%	(0.86)
2017Q3	7906.00	7904.74	1.26	0.02%	0.03
2017Q4	8118.33	8052.18	66.15	0.81%	1.57
2018Q1	8217.00	8268.12	-51.12	-0.62%	(1.21)
2018Q2	8081.33	8156.86	-75.53	-0.93%	(1.79)
2018Q3	8007.67	8046.58	-38.91	-0.49%	(0.92)
2018Q4	8274.67	8185.82	88.85	1.07%	2.11
2019Q1	8340.33	8331.96	8.37	0.10%	0.20
2019Q2	8233.00	8214.72	18.28	0.22%	0.43
2019Q3	8094.67	8100.66	-5.99	-0.07%	(0.14)
2019Q4	8259.33	8246.87	12.46	0.15%	0.30
2020Q1	8334.33	8363.81	-29.47	-0.35%	(0.70)
2020Q2	8341.00	8336.31	4.69	0.06%	0.11
2020Q3	8312.00	8316.69	-4.69	-0.06%	(0.11)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	8259.33	8248.85	10.48	0.1%
Q1 2020	8334.33	8372.19	-37.86	-0.5%
Q2 2020	8341.00	8081.03	259.97	3.1%
Q3 2020	8312.00	8065.29	246.71	3.0%
Total	33246.67	32767.37	479.29	1.4%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	6633.97	6605.75	28.22	0%
S_GMP	40.82	41.59	-0.76	-2%
S_D20Q2+S_D20Q3	254.17			
Q3	-127.20	-125.34	-1.86	1%
Q1	129.91	136.56	-6.65	-5%
S_D2017	-73.01	-74.37	1.36	-2%
S_D15Q4+S_D16Q1+S_D16Q2	120.88	120.67	0.21	0%
S_D14Q4	124.63	127.59	-2.95	-2%

HLFC Brockton S&T
D. High Load Factor Customers - Sales and Transportation
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_HLF_CUST_S_T	11	0.935	6.913

ARIMA Model Parameters

B_HLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	3737.568	337.449	11.08	0.000
	B_HLFNGP_ST	-118.9022	45.552	-2.61	0.014
	B_D12Q4	257.8424	41.482	6.22	0.000
	B_D13Q1+B_D13Q2	178.5561	40.269	4.43	0.000
	B_D16Q4	83.47521	39.836	2.10	0.045
	B_D19Q4	68.96862	40.109	1.72	0.096
	B_D16Q2	-89.90808	36.895	-2.44	0.021
	D_AFTER18Q4*B_HLFNGP_ST	-25.36804	7.364	-3.44	0.002
	D_13Q4THR16Q3	-166.4722	30.774	-5.41	0.000
	AR(1)	0.75374	0.092	8.15	0.000
	AR(5)	-0.369465	0.092	-4.01	0.000

Variable	Definition	Explanation	Dummy Variable Support
B_HLFNGP_ST	Natural gas price for high load factor sales and transport customers in Brockton ($2020/MMBtu)		
B_D12Q4	Binary variable equal to 1 in 2012Q4		2
B_D13Q1+B_D13Q2	Binary variable equal to 1 in 2013Q1 and 2013Q2		2
B_D16Q4	Binary variable equal to 1 in 2016Q4		2
B_D19Q4	Binary variable equal to 1 in 2019Q4		2
B_D16Q2	Binary variable equal to 1 in 2016Q2		2
D_AFTER18Q4*B_HLFNGP_ST	Natural gas price for high load factor sales and transport customers in Brockton ($2019/MMBtu) after 2018Q4	B	
D_13Q4THR16Q3	Binary variable equal to 1 from 2013Q4 to 2016Q3		1
AR(1)	ARMA		
AR(5)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
40	0.912959	41.9064

Chow Test Stats

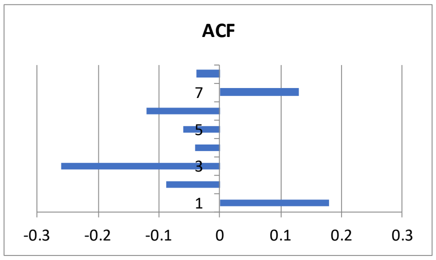
	N	k	SSR
Combined	40	11	66,228.47
1	20	7	42,068.33
2	20	9	16,391.99

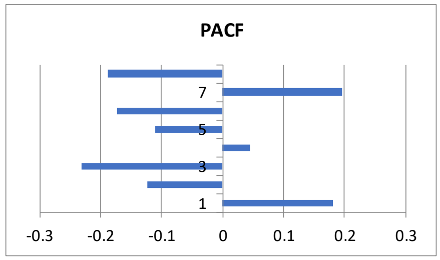
Chow Stat:	0.217
P-Value:	0.993389

Heteroscedasticity - White's Test	
White Stat	1.15
Significance (p-value)	0.36

Correlations

	B_HLFNGP_ST	B_D12Q4	B_D13Q1+B_D13Q2	B_D16Q4	B_D19Q4	B_D16Q2	D_AFTER18Q4*B_HLFNGP_ST	D_13Q4THR16Q3
B_HLFNGP_ST	1	0.137662	0.178662	-0.032381	-0.25119	0.005771	-0.750493	0.209444
B_D12Q4	0.137662	1	-0.036736	-0.025641	-0.02564	-0.025641	-0.08006	-0.10483
B_D13Q1+B_D13Q2	0.178662	-0.036736	1	-0.036736	-0.03674	-0.036736	-0.114702	-0.15019
B_D16Q4	-0.032381	-0.025641	-0.036736	1	-0.02564	-0.025641	-0.08006	-0.10483
B_D19Q4	-0.251191	-0.025641	-0.036736	-0.025641	1	-0.025641	0.318743	-0.10483
B_D16Q2	0.005771	-0.025641	-0.036736	-0.025641	-0.02564	1	-0.08006	0.2446
D_AFTER18Q4*B_HLFNGP_ST	-0.750493	-0.08006	-0.114702	-0.08006	0.318743	-0.08006	1	-0.32731
D_13Q4THR16Q3	0.209444	-0.104828	-0.150188	-0.104828	-0.10483	0.2446	-0.327309	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_hlf_cust_s_t Model	ACF	0.18	-0.087	-0.261	-0.041	-0.059	-0.12	0.129	-0.039
	SE	0.316	0.316	0.316	0.316	0.316	0.316	0.316	0.316
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_hlf_cust_s_t Model		0.18	-0.123	-0.232	0.044	-0.111	-0.172	0.195	-0.189
	SE	0.316	0.316	0.316	0.316	0.316	0.316	0.316	0.316

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2010Q4	2833.33	2760.58	72.76	2.57%	1.77
2011Q1	2844.33	2857.21	-12.88	-0.45%	(0.31)
2011Q2	2810.67	2863.91	-53.25	-1.89%	(1.29)
2011Q3	2766.67	2850.02	-83.35	-3.01%	(2.02)
2011Q4	2750.67	2813.98	-63.32	-2.30%	(1.54)
2012Q1	2751.67	2764.57	-12.90	-0.47%	(0.31)
2012Q2	2716.67	2761.46	-44.80	-1.65%	(1.09)
2012Q3	2836.67	2750.55	86.12	3.04%	2.09
2012Q4	3137.67	3119.00	18.67	0.59%	0.45
2013Q1	3127.33	3080.57	46.76	1.50%	1.13
2013Q2	3086.67	3133.91	-47.24	-1.53%	(1.15)
2013Q3	2985.67	2939.31	46.36	1.55%	1.12
2013Q4	2819.33	2788.03	31.31	1.11%	0.76
2014Q1	2819.67	2774.80	44.87	1.59%	1.09
2014Q2	2780.67	2752.91	27.76	1.00%	0.67
2014Q3	2711.67	2739.93	-28.27	-1.04%	(0.69)
2014Q4	2653.00	2660.17	-7.17	-0.27%	(0.17)
2015Q1	2654.00	2614.91	39.09	1.47%	0.95
2015Q2	2626.00	2617.05	8.95	0.34%	0.22
2015Q3	2576.00	2612.63	-36.63	-1.42%	(0.89)
2015Q4	2559.33	2603.44	-44.11	-1.72%	(1.07)
2016Q1	2594.33	2615.06	-20.73	-0.80%	(0.50)
2016Q2	2573.33	2553.91	19.42	0.75%	0.47
2016Q3	2709.33	2708.16	1.17	0.04%	0.03
2016Q4	3043.00	3012.98	30.02	0.99%	0.73
2017Q1	3066.00	3002.39	63.61	2.07%	1.54
2017Q2	3049.33	3070.80	-21.47	-0.70%	(0.52)
2017Q3	2985.67	3035.84	-50.17	-1.68%	(1.22)
2017Q4	2959.00	2974.55	-15.55	-0.53%	(0.38)
2018Q1	2975.67	2927.16	48.51	1.63%	1.18
2018Q2	2936.67	2904.93	31.74	1.08%	0.77
2018Q3	2827.33	2884.91	-57.58	-2.04%	(1.40)
2018Q4	2671.00	2657.33	13.67	0.51%	0.33
2019Q1	2672.00	2681.16	-9.16	-0.34%	(0.22)
2019Q2	2636.33	2679.11	-42.78	-1.62%	(1.04)
2019Q3	2681.00	2669.37	11.63	0.43%	0.28
2019Q4	2842.00	2816.51	25.49	0.90%	0.62
2020Q1	2849.00	2815.19	33.81	1.19%	0.82
2020Q2	2847.67	2870.09	-22.42	-0.79%	(0.54)
2020Q3	2857.00	2884.93	-27.93	-0.98%	(0.68)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	2842.00	2729.78	112.22	3.9%
Q1 2020	2849.00	2783.90	65.10	2.3%
Q2 2020	2847.67	2823.90	23.77	0.8%
Q3 2020	2857.00	2870.66	-13.66	-0.5%
Total	11395.67	11208.24	187.43	1.6%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	3737.57	3674.23	63.34	2%
B_HLFNGP_ST	-118.90	-110.49	-8.41	7%
B_D12Q4	257.84	255.28	2.56	1%
B_D13Q1+B_D13Q2	178.56	175.94	2.61	1%
B_D16Q4	83.48	84.15	-0.68	-1%
B_D19Q4	68.97			
B_D16Q2	-89.91	-89.02	-0.89	1%
D_AFTER18Q4*B_HLFNGP_ST	-25.37	-23.36	-2.01	8%
D_13Q4THR16Q3	-166.47	-165.21	-1.26	1%
AR(1)	0.75	0.78	-0.03	-4%
AR(5)	-0.37	-0.36	-0.01	1%

HLFC Lawrence S&T
2. Lawrence

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
L_HLF_CUST_S_T	10	0.916	3.318

ARIMA Model Parameters

L_HLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	783.0583	7.637	102.53	0.000
	L_HLFNGP_ST_ROLL12(-3)	-4.166735	2.001	-2.08	0.044
	D_AFTER19Q1*L_HLFNGP_ST_ROLL12(-1)	-10.64789	1.893	-5.62	0.000
	D_09Q2THR12Q3	-50.40066	5.829	-8.65	0.000
	D_14Q3THR16Q3*L_HLFNGP_ST_ROLL12(-1)	-15.53163	1.672	-9.29	0.000
	L_D18Q4	-107.1266	11.073	-9.67	0.000
	L_D18Q3	-61.69501	10.582	-5.83	0.000
	L_D14Q3	32.94155	10.347	3.18	0.003
	AR(1)	0.515441	0.130	3.97	0.000
	AR(4)	-0.295749	0.118	-2.50	0.016

Variable	Definition	Explanation	Dummy Variable Support
L_HLFNGP_ST_ROLL12(-3)	Rolling 12-quarter natural gas price for high load factor sales and transport customers in Lawrence ($2020) lagged three quarters		
D_AFTER19Q1*L_HLFNGP_ST_ROLL12(-1)	Rolling 12-quarter natural gas price for high load factor sales and transport customers in Lawrence ($2020) lagged one quarter after 2019Q1	B	
D_09Q2THR12Q3	Binary variable equal to 1 from 2009Q2 to 2012Q3		1
D_14Q3THR16Q3*L_HLFNGP_ST_ROLL12(-1)	Rolling 12-quarter natural gas price for high load factor sales and transport customers in Lawrence ($2020) lagged one quarter from 2014Q3 to 2016Q3	B	
L_D18Q4	Binary variable equal to 1 in 2018Q4		2
L_D18Q3	Binary variable equal to 1 in 2018Q3		2
L_D14Q3	Binary variable equal to 1 in 2014Q3		2
AR(1)	ARMA		
AR(4)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
52	0.898525	51.17631

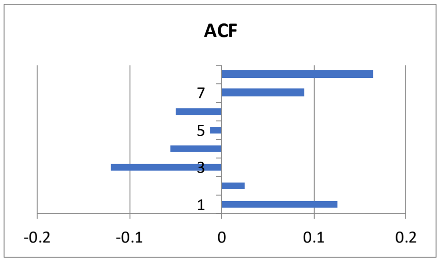
Chow Test Stats	N	k	SSR
Combined	52	10	5,088.91
1	25	5	2,096.51
2	27	9	1,382.05

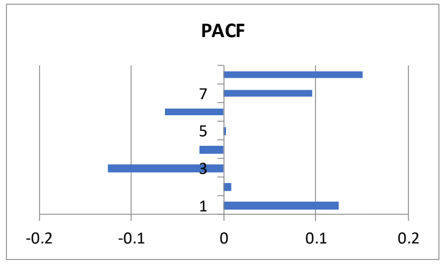
Chow Stat:	1.481
P-Value:	0.191763

Heteroscedasticity - White's Test	
White Stat	0.77
Significance (p-value)	0.64

Correlations

	L_HLFNGP_ST_ROLL12(-3)	D_AFTER19Q1*L_HLFNGP_ST_ROLL12(-1)	D_09Q2THR12Q3	D_14Q3THR16Q3*L_HLFNGP_ST_ROLL12(-1)	L_D18Q4	L_D18Q3	L_D14Q3
L_HLFNGP_ST_ROLL12(-3)	1	-0.051334	0.288209	0.078496	-0.00445	-0.00107	0.031363
D_AFTER19Q1*L_HLFNGP_ST_ROLL12(-1)	-0.051334	1	-0.239375	-0.180418	-0.05522	-0.055223	-0.05522
D_09Q2THR12Q3	0.288209	-0.239375	1	-0.27768	-0.08499	-0.084994	-0.08499
D_14Q3THR16Q3*L_HLFNGP_ST_ROLL12(-1)	0.078496	-0.180418	-0.27768	1	-0.06406	-0.06406	0.310373
L_D18Q4	-0.004451	-0.055223	-0.084994	-0.06406	1	-0.019608	-0.01961
L_D18Q3	-0.00107	-0.055223	-0.084994	-0.06406	-0.01961	1	-0.01961
L_D14Q3	0.031363	-0.055223	-0.084994	0.310373	-0.01961	-0.019608	1





Residual ACF								
Model		1	2	3	4	5	6	7
l_hlf_cust_s_t Model	ACF	0.125	0.025	-0.12	-0.056	-0.013	-0.05	0.089
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277
Residual PACF								
Model		1	2	3	4	5	6	7
l_hlf_cust_s_t Model		0.125	0.009	-0.126	-0.026	0.003	-0.063	0.096
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2007Q4	782.00	781.30	0.70	0.09%	0.07
2008Q1	794.00	785.78	8.22	1.03%	0.82
2008Q2	782.00	792.17	-10.17	-1.30%	(1.02)
2008Q3	759.33	766.75	-7.42	-0.98%	(0.74)
2008Q4	739.67	761.74	-22.07	-2.98%	(2.21)
2009Q1	732.33	748.13	-15.80	-2.16%	(1.58)
2009Q2	718.00	697.58	20.42	2.84%	2.04
2009Q3	709.00	717.07	-8.07	-1.14%	(0.81)
2009Q4	724.00	718.33	5.67	0.78%	0.57
2010Q1	721.00	728.31	-7.31	-1.01%	(0.73)
2010Q2	715.67	716.18	-0.52	-0.07%	(0.05)
2010Q3	711.67	716.19	-4.53	-0.64%	(0.45)
2010Q4	718.00	709.76	8.24	1.15%	0.82
2011Q1	721.00	713.97	7.03	0.98%	0.70
2011Q2	709.33	717.15	-7.81	-1.10%	(0.78)
2011Q3	703.67	712.37	-8.70	-1.24%	(0.87)
2011Q4	706.67	707.63	-0.96	-0.14%	(0.10)
2012Q1	708.67	708.33	0.34	0.05%	0.03
2012Q2	692.67	712.84	-20.17	-2.91%	(2.02)
2012Q3	717.67	706.34	11.33	1.58%	1.13
2012Q4	776.33	768.81	7.52	0.97%	0.75
2013Q1	781.33	772.54	8.80	1.13%	0.88
2013Q2	773.00	779.89	-6.89	-0.89%	(0.69)
2013Q3	760.33	768.26	-7.92	-1.04%	(0.79)
2013Q4	747.33	759.35	-12.01	-1.61%	(1.20)
2014Q1	757.33	751.23	6.11	0.81%	0.61
2014Q2	752.33	758.91	-6.58	-0.87%	(0.66)
2014Q3	738.33	727.82	10.51	1.42%	1.05
2014Q4	722.00	708.43	13.57	1.88%	1.36
2015Q1	713.00	714.16	-1.16	-0.16%	(0.12)
2015Q2	706.67	711.10	-4.43	-0.63%	(0.44)
2015Q3	690.67	702.57	-11.90	-1.72%	(1.19)
2015Q4	679.00	689.60	-10.60	-1.56%	(1.06)
2016Q1	685.00	686.44	-1.44	-0.21%	(0.14)
2016Q2	678.33	691.56	-13.22	-1.95%	(1.32)
2016Q3	710.00	693.12	16.89	2.38%	1.69
2016Q4	790.67	776.57	14.10	1.78%	1.41
2017Q1	795.33	783.64	11.69	1.47%	1.17
2017Q2	787.67	788.12	-0.45	-0.06%	(0.05)
2017Q3	778.67	774.93	3.74	0.48%	0.37
2017Q4	781.33	765.32	16.01	2.05%	1.60
2018Q1	780.67	765.37	15.29	1.96%	1.53
2018Q2	771.33	767.36	3.98	0.52%	0.40
2018Q3	707.67	703.58	4.08	0.58%	0.41
2018Q4	658.33	656.42	1.91	0.29%	0.19

2019Q1	729.67	720.35	9.32	1.28%	0.93
2019Q2	718.67	726.38	-7.71	-1.07%	(0.77)
2019Q3	711.00	721.48	-10.48	-1.47%	(1.05)
2019Q4	728.67	718.88	9.79	1.34%	0.98
2020Q1	725.33	726.51	-1.17	-0.16%	(0.12)
2020Q2	725.33	728.31	-2.98	-0.41%	(0.30)
2020Q3	728.00	730.79	-2.79	-0.38%	(0.28)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	728.67	722.77	5.89	0.8%
Q1 2020	725.33	723.26	2.07	0.3%
Q2 2020	725.33	726.98	-1.64	-0.2%
Q3 2020	728.00	728.58	-0.58	-0.1%
Total	2907.33	2901.60	5.73	0.2%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	783.06	783.40	-0.34	0%
L_HLFNGP_ST_ROLL12(-3)	-4.17	-4.34	0.17	-4%
D_AFTER19Q1*L_HLFNGP_ST_ROLL12(-1)	-10.65	-10.61	-0.04	0%
D_09Q2THR12Q3	-50.40	-49.71	-0.69	1%
D_14Q3THR16Q3*L_HLFNGP_ST_ROLL12(-1)	-15.53	-15.39	-0.14	1%

HLFC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
S_HLF_CUST_S_T	14	0.939	5.369

ARIMA Model Parameters

S_HLF_CUST_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	1969.35	8.670	227.13	0.000
	S_HLFNGP_ST_ROLL12(-4)	-27.93719	2.188	-12.77	0.000
	S_D12Q2	-70.98923	29.440	-2.41	0.020
	S_D12Q4	94.74625	29.434	3.22	0.002
	S_D16Q4	222.8431	33.291	6.69	0.000
	S_D14Q4	-164.801	29.394	-5.61	0.000
	S_D13Q1	89.82065	29.429	3.05	0.004
	S_D18Q1	108.2662	30.475	3.55	0.001
	S_D2015	-184.4293	15.490	-11.91	0.000
	S_D2016	-193.8143	17.561	-11.04	0.000
	D_AFTER17Q4*S_HLFNGP_ST_ROLL12(-1)	-28.85156	2.619	-11.02	0.000
	S_D18Q2	90.29304	30.464	2.96	0.005
	S_D17Q4	97.50144	30.484	3.20	0.003
	S_D13Q2	75.25073	29.424	2.56	0.014

Variable	Definition	Explanation	Dummy Variable Support
S_HLFNGP_ST_ROLL12(-4)	Rolling 12-quarter natural gas price for high load factor sales and transport customers in Springfield ($2020) lagged four quarters		
S_D12Q2	Binary variable equal to 1 in 2012Q2		2
S_D12Q4	Binary variable equal to 1 in 2012Q4		2
S_D16Q4	Binary variable equal to 1 in 2016Q4		2
S_D14Q4	Binary variable equal to 1 in 2014Q4		2
S_D13Q1	Binary variable equal to 1 in 2013Q1		2
S_D18Q1	Binary variable equal to 1 in 2018Q1		2
S_D2015	Binary variable equal to 1 in 2015		2
S_D2016	Binary variable equal to 1 in 2016Q4		2
D_AFTER17Q4*S_HLFNGP_ST_ROLL12(-1)	Rolling 12-quarter natural gas price for high load factor sales and transport customers in Springfield ($2020) lagged one quarter after 2017Q4	B	
S_D18Q2	Binary variable equal to 1 in 2018Q2		2
S_D17Q4	Binary variable equal to 1 in 2017Q4		2
S_D13Q2	Binary variable equal to 1 in 2013Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

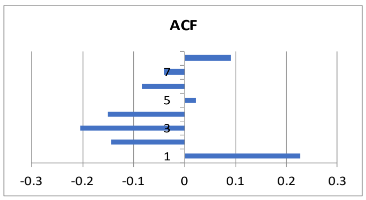
N	Adjusted R2	F Statistic
59	0.92136	53.27247

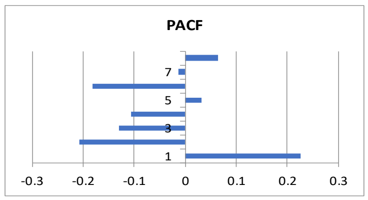
Chow Test Stats	N	k	SSR
Combined	59	14	37,403.81
1	30	6	17,521.53
2	29	10	19,462.29

Chow Stat:	0.025
P-Value:	1

Heteroscedasticity - White's Test	
White Stat	0.60
Significance (p-value)	0.84

Correlations													
	S_HLFNGP_ST_ROLL12(-4)	S_D12Q2	S_D12Q4	S_D16Q4	S_D14Q4	S_D13Q1	S_D18Q1	S_D2015	S_D2016	D_AFTER17Q4*S_HLFNGP_ST_ROLL12(-1)	S_D18Q2	S_D17Q4	S_D13Q2
S_HLFNGP_ST_ROLL12(-4)	1	0.073581	0.072033	0.047737	0.059397	0.0705	0.04334	0.113776	0.102215	0.150222	0.042826	0.044005	0.069024
S_D12Q2	0.073581	1	-0.017241	-0.017241	-0.01724	-0.017241	-0.01724	-0.03541	-0.03541	-0.066336	-0.01724	-0.01724	-0.01724
S_D12Q4	0.072033	-0.017241	1	-0.017241	-0.01724	-0.017241	-0.01724	-0.03541	-0.03541	-0.066336	-0.01724	-0.01724	-0.01724
S_D16Q4	0.047737	-0.017241	-0.017241	1	-0.01724	-0.017241	-0.01724	-0.03541	0.486897	-0.066336	-0.01724	-0.01724	-0.01724
S_D14Q4	0.059397	-0.017241	-0.017241	-0.017241	1	-0.017241	-0.01724	-0.03541	-0.03541	-0.066336	-0.01724	-0.01724	-0.01724
S_D13Q1	0.0705	-0.017241	-0.017241	-0.017241	-0.01724	1	-0.01724	-0.03541	-0.03541	-0.066336	-0.01724	-0.01724	-0.01724
S_D18Q1	0.04334	-0.017241	-0.017241	-0.017241	-0.01724	-0.017241	1	-0.03541	-0.03541	0.266581	-0.01724	-0.01724	-0.01724
S_D2015	0.113776	-0.035411	-0.035411	-0.035411	-0.03541	-0.035411	-0.03541	1	-0.07273	-0.136243	-0.03541	-0.03541	-0.03541
S_D2016	0.102215	-0.035411	-0.035411	0.486897	-0.03541	-0.035411	-0.03541	-0.07273	1	-0.136243	-0.03541	-0.03541	-0.03541
D_AFTER17Q4*S_HLFNGP_ST_ROLL12(-1)	0.150222	-0.066336	-0.066336	-0.066336	-0.06634	-0.066336	0.266581	-0.13624	-0.13624	1	0.265404	0.267411	-0.06634
S_D18Q2	0.042826	-0.017241	-0.017241	-0.017241	-0.01724	-0.017241	-0.01724	-0.03541	-0.03541	0.265404	1	-0.01724	-0.01724
S_D17Q4	0.044005	-0.017241	-0.017241	-0.017241	-0.01724	-0.017241	-0.01724	-0.03541	-0.03541	0.267411	-0.01724	1	-0.01724
S_D13Q2	0.069024	-0.017241	-0.017241	-0.017241	-0.01724	-0.017241	-0.01724	-0.03541	-0.03541	-0.066336	-0.01724	-0.01724	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_hlf_cust_s_t Model	ACF	0.227	-0.145	-0.204	-0.15	0.022	-0.083	-0.041	0.091
	SE	0.260	0.260	0.260	0.260	0.260	0.260	0.260	0.260
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_hlf_cust_s_t Model		0.227	-0.207	-0.129	-0.106	0.031	-0.182	-0.013	0.065
	SE	0.260	0.260	0.260	0.260	0.260	0.260	0.260	0.260

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2006Q1	1992.67	1969.35	23.32	1.17%	0.92
2006Q2	1978.33	1969.35	8.98	0.45%	0.35
2006Q3	1972.33	1969.35	2.98	0.15%	0.12
2006Q4	1967.67	1969.35	-1.68	-0.09%	(0.07)
2007Q1	1978.67	1969.35	9.32	0.47%	0.37
2007Q2	1953.33	1969.35	-16.02	-0.82%	(0.63)
2007Q3	1951.33	1969.35	-18.02	-0.92%	(0.71)
2007Q4	1994.00	1969.35	24.65	1.24%	0.97
2008Q1	1988.67	1969.35	19.32	0.97%	0.76
2008Q2	1962.00	1969.35	-7.35	-0.37%	(0.29)
2008Q3	1928.33	1969.35	-41.02	-2.13%	(1.62)
2008Q4	1861.33	1823.11	38.22	2.05%	1.51
2009Q1	1851.67	1824.55	27.11	1.46%	1.07
2009Q2	1815.33	1826.14	-10.81	-0.60%	(0.43)
2009Q3	1803.00	1827.69	-24.69	-1.37%	(0.97)
2009Q4	1837.00	1828.87	8.13	0.44%	0.32
2010Q1	1846.67	1829.90	16.77	0.91%	0.66
2010Q2	1829.33	1830.85	-1.52	-0.08%	(0.06)
2010Q3	1825.33	1831.75	-6.42	-0.35%	(0.25)
2010Q4	1870.33	1832.76	37.57	2.01%	1.48
2011Q1	1880.00	1833.61	46.39	2.47%	1.83
2011Q2	1850.00	1834.29	15.71	0.85%	0.62
2011Q3	1812.33	1834.89	-22.56	-1.24%	(0.89)
2011Q4	1786.00	1835.35	-49.35	-2.76%	(1.94)
2012Q1	1781.33	1835.72	-54.39	-3.05%	(2.14)
2012Q2	1765.00	1765.00	0.00	0.00%	0.00
2012Q3	1814.33	1836.15	-21.82	-1.20%	(0.86)
2012Q4	1931.33	1931.33	0.00	0.00%	0.00
2013Q1	1927.00	1927.00	0.00	0.00%	0.00
2013Q2	1913.00	1913.00	0.00	0.00%	0.00
2013Q3	1886.00	1838.30	47.70	2.53%	1.88
2013Q4	1838.00	1838.83	-0.83	-0.05%	(0.03)
2014Q1	1830.67	1839.46	-8.80	-0.48%	(0.35)
2014Q2	1814.33	1840.12	-25.79	-1.42%	(1.02)
2014Q3	1761.00	1840.81	-79.81	-4.53%	(3.14)
2014Q4	1676.67	1676.67	0.00	0.00%	0.00
2015Q1	1681.33	1657.68	23.65	1.41%	0.93
2015Q2	1662.00	1658.28	3.72	0.22%	0.15
2015Q3	1648.00	1658.90	-10.90	-0.66%	(0.43)
2015Q4	1643.00	1659.47	-16.47	-1.00%	(0.65)
2016Q1	1633.67	1650.54	-16.88	-1.03%	(0.66)
2016Q2	1622.67	1651.10	-28.44	-1.75%	(1.12)
2016Q3	1697.00	1651.68	45.32	2.67%	1.78
2016Q4	1875.00	1875.00	0.00	0.00%	0.00
2017Q1	1885.00	1846.30	38.70	2.05%	1.52
2017Q2	1874.00	1846.71	27.29	1.46%	1.07
2017Q3	1846.33	1847.08	-0.75	-0.04%	(0.03)
2017Q4	1819.67	1819.67	0.00	0.00%	0.00
2018Q1	1831.00	1831.00	0.00	0.00%	0.00

2018Q2	1813.67	1813.67	0.00	0.00%	0.00
2018Q3	1771.67	1724.05	47.61	2.69%	1.87
2018Q4	1710.67	1724.86	-14.20	-0.83%	(0.56)
2019Q1	1711.33	1725.87	-14.53	-0.85%	(0.57)
2019Q2	1703.67	1726.97	-23.31	-1.37%	(0.92)
2019Q3	1717.67	1728.12	-10.45	-0.61%	(0.41)
2019Q4	1755.67	1729.35	26.32	1.50%	1.04
2020Q1	1733.33	1730.67	2.66	0.15%	0.10
2020Q2	1724.00	1732.03	-8.03	-0.47%	(0.32)
2020Q3	1726.67	1733.28	-6.61	-0.38%	(0.26)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	1755.67	1726.54	29.13	1.7%
Q1 2020	1733.33	1727.87	5.46	0.3%
Q2 2020	1724.00	1729.25	-5.25	-0.3%
Q3 2020	1726.67	1730.51	-3.85	-0.2%
Total	6939.67	6914.17	25.50	0.4%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	1969.35	1969.35	0.00	0%
S_HLFNGP_ST_ROLL12(-4)	-27.94	-27.94	0.00	0%
S_D12Q2	-70.99	-70.99	0.00	0%
S_D12Q4	94.75	94.75	0.00	0%
S_D16Q4	222.84	222.84	0.00	0%
S_D14Q4	-164.80	-164.80	0.00	0%
S_D13Q1	89.82	89.82	0.00	0%
S_D18Q1	108.27	111.17	-2.91	-3%
S_D2015	-184.43	-184.43	0.00	0%
S_D2016	-193.81	-193.81	0.00	0%
D_AFTER17Q4*S_HLFNGP_ST_ROLL12(-1)	-28.85	-29.52	0.67	-2%
S_D18Q2	90.29	93.19	-2.90	-3%
S_D17Q4	97.50	100.42	-2.91	-3%
S_D13Q2	75.25	75.25	0.00	0%

II. Sales and Transportation - Use Per Customer

A. Residential Heating Use Per Customer - Sales & Transportation

1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
B_RH_UPC_S_T	7	0.999	0.772

ARIMA Model Parameters

B_RH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	10.48018	2.451	4.28	0.000
	B_RHNGP_ROLL12	-0.323138	0.163	-1.98	0.059
	B_Q1_EDD	0.01275	0.000	135.78	0.000
	B_Q2_EDD	0.010983	0.000	49.07	0.000
	B_Q4_EDD	0.00994	0.000	52.75	0.000
	B_D15Q1	1.806085	0.684	2.64	0.014
	B_D15Q4	-1.763533	0.654	-2.70	0.013

Variable	Definition	Explanation	Dummy Variable Support
B_RHNGP_ROLL12	Rolling 12 quarter natural gas price for residential heating customers in Brockton ($2020)		
B_Q1_EDD	Effective Degree Days in Brockton in Q1	A	
B_Q2_EDD	Effective Degree Days in Brockton in Q2	A	
B_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
B_D15Q1	Binary variable equal to 1 in 2015Q1		2
B_D15Q4	Binary variable equal to 1 in 2015Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)

B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed

C: To account for seasonality

1: Included to address a structural shift

2: Included to address an outlier

N	Adjusted R2	F Statistic
31	0.998661	3728.749

Chow Test Stats

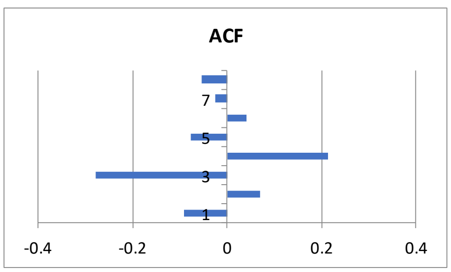
		N	k	SSR
Combined		31	7	8.54
	1	15	7	2.99
	2	16	6	3.69

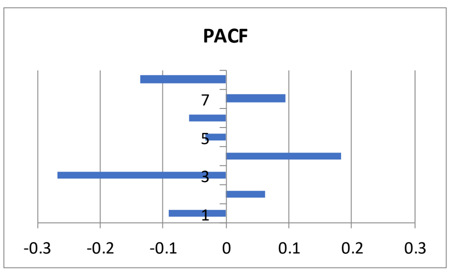
Chow Stat:	0.674
P-Value:	0.691992

Heteroscedasticity - White's Test	
White Stat	2.62
Significance (p-value)	0.04

Correlations

	B_RHNGP_ROLL12	B_Q1_EDD	B_Q2_EDD	B_Q4_EDD	B_D15Q1	B_D15Q4
B_RHNGP_ROLL12	1	0.00136	0.016308	-0.023239	0.249997	0.22445
B_Q1_EDD	0.00136	1	-0.344814	-0.314504	0.383459	-0.106852
B_Q2_EDD	0.016308	-0.344814	1	-0.316608	-0.10757	-0.107567
B_Q4_EDD	-0.023239	-0.314504	-0.316608	1	-0.09811	0.285561
B_D15Q1	0.249997	0.383459	-0.107567	-0.098112	1	-0.033333
B_D15Q4	0.22445	-0.106852	-0.107567	0.285561	-0.03333	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_rh_upc_s_t Model	ACF	-0.092	0.07	-0.277	0.214	-0.077	0.041	-0.025	-0.054
	SE	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_rh_upc_s_t Model		-0.092	0.063	-0.269	0.182	-0.033	-0.058	0.094	-0.137
	SE	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2013Q1	48.37	48.42	-0.06	-0.12%	(0.11)
2013Q2	19.16	19.93	-0.76	-3.98%	(1.43)
2013Q3	6.03	5.55	0.48	7.89%	0.89
2013Q4	23.96	24.00	-0.04	-0.15%	(0.07)
2014Q1	54.77	53.90	0.87	1.59%	1.63
2014Q2	20.69	20.32	0.37	1.78%	0.69
2014Q3	5.91	5.43	0.47	8.03%	0.89
2014Q4	21.44	22.60	-1.16	-5.40%	(2.17)
2015Q1	57.90	57.90	0.00	0.00%	0.00
2015Q2	20.46	20.16	0.30	1.47%	0.56
2015Q3	5.84	5.33	0.51	8.79%	0.96
2015Q4	18.28	18.28	0.00	0.00%	0.00
2016Q1	42.67	43.30	-0.63	-1.48%	(1.18)
2016Q2	19.37	19.52	-0.15	-0.79%	(0.29)
2016Q3	5.59	5.67	-0.08	-1.50%	(0.16)
2016Q4	21.01	22.01	-1.00	-4.75%	(1.87)
2017Q1	45.28	45.92	-0.64	-1.42%	(1.20)
2017Q2	21.03	20.98	0.05	0.23%	0.09
2017Q3	5.83	6.04	-0.21	-3.56%	(0.39)
2017Q4	20.81	20.48	0.34	1.61%	0.63
2018Q1	49.51	49.67	-0.15	-0.31%	(0.29)
2018Q2	21.21	20.76	0.45	2.13%	0.85
2018Q3	5.27	5.96	-0.69	-13.15%	(1.30)
2018Q4	25.04	23.91	1.13	4.51%	2.12
2019Q1	48.88	48.98	-0.09	-0.19%	(0.18)
2019Q2	19.13	19.15	-0.02	-0.12%	(0.04)
2019Q3	5.36	5.61	-0.25	-4.70%	(0.47)
2019Q4	23.58	22.90	0.68	2.87%	1.27
2020Q1	42.43	41.85	0.58	1.36%	1.08
2020Q2	20.64	20.90	-0.26	-1.24%	(0.48)
2020Q3	5.51	5.53	-0.02	-0.29%	(0.03)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	23.58	22.75	0.83	3.5%
Q1 2020	42.43	41.77	0.66	1.5%
Q2 2020	20.64	20.93	-0.29	-1.4%
Q3 2020	5.51	5.50	0.01	0.1%
Total	92.16	90.95	1.20	1.3%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	10.48	10.88	-0.40	-4%
B_RHNGP_ROLL12	-0.32	-0.35	0.03	-9%
B_Q1_EDD	0.01	0.01	0.00	0%
B_Q2_EDD	0.01	0.01	0.00	0%
B_Q4_EDD	0.01	0.01	0.00	1%
B_D15Q1	1.81	1.93	-0.13	-7%
B_D15Q4	-1.76	-1.61	-0.15	9%

RHUPC Lawrence S&T
2. Lawrence

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
L_RH_UPC_S_T	9	0.999	0.816

ARIMA Model Parameters

L_RH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	7.812835	0.334	23.42	0.000
	L_RHNGP_ROLL12(-2)	-0.072158	0.019	-3.85	0.000
	L_Q1_EDD	0.013368	0.000	187.61	0.000
	L_Q2_EDD	0.010708	0.000	59.21	0.000
	L_Q4_EDD	0.00973	0.000	68.40	0.000
	D_AFTER_15Q3*L_RHNGP_ROLL12(-4)	-0.058424	0.013	-4.34	0.000
	L_D12Q1	-1.510467	0.690	-2.19	0.034
	L_D17Q4	1.96226	0.697	2.82	0.007
	L_D12Q2	-1.795675	0.687	-2.62	0.012

Variable	Definition	Explanation	Dummy Variable Support
L_RHNGP_ROLL12(-2)	Rolling 12 quarter natural gas price for residential heating customers in Lawrence ($2020) lagged two quarters		
L_Q1_EDD	Effective Degree Days in Lawrence in Q1	A	
L_Q2_EDD	Effective Degree Days in Lawrence in Q2	A	
L_Q4_EDD	Effective Degree Days in Lawrence in Q4	A	
D_AFTER_15Q3*L_RHNGP_ROLL12(-4)	Rolling 12 quarter natural gas price for residential heating customers in Lawrence ($2020) lagged four quarters after 2015Q3	B	
L_D12Q1	Binary variable equal to 1 in 2012Q1		2
L_D17Q4	Binary variable equal to 1 in 2017Q4		2
L_D12Q2	Binary variable equal to 1 in 2012Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
55	0.998602	4821.491

Chow Test Stats

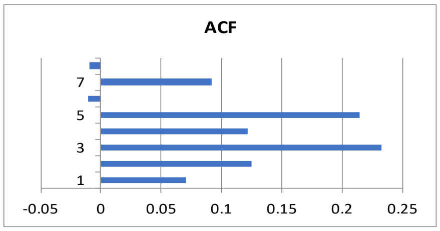
	N	k	SSR
Combined	55	9	20.36
1	27	7	8.44
2	28	7	9.79

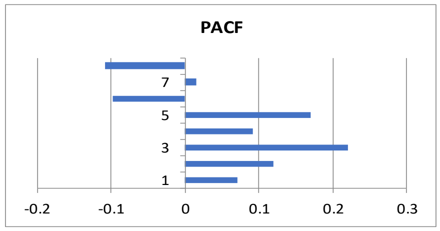
Chow Stat:	0.479
P-Value:	0.879075

Heteroscedasticity - White's Test	
White Stat	1.35
Significance (p-value)	0.24

Correlations

	L_RHNGP_ROLL12(-2)	L_Q1_EDD	L_Q2_EDD	L_Q4_EDD	D_AFTER_15Q3*L_RHNGP_ROLL12(-4)	L_D12Q1	L_D17Q4	L_D12Q2
L_RHNGP_ROLL12(-2)	1	-0.104512	0.032391	0.021751	0.003693	0.039339	-0.02491	0.030152
L_Q1_EDD	-0.104512	1	-0.337797	-0.322147	-0.054981	0.194684	-0.07913	-0.07913
L_Q2_EDD	0.032391	-0.337797	1	-0.321869	-0.01926	-0.079058	-0.07906	0.171821
L_Q4_EDD	0.021751	-0.322147	-0.321869	1	-0.006553	-0.075395	0.202255	-0.0754
D_AFTER_15Q3*L_RHNGP_ROLL12(-4)	0.003693	-0.054981	-0.01926	-0.006553	1	-0.106671	0.17081	-0.10667
L_D12Q1	0.039339	0.194684	-0.079058	-0.075395	-0.106671	1	-0.01852	-0.01852
L_D17Q4	-0.024914	-0.079126	-0.079058	0.202255	0.17081	-0.018519	1	-0.01852
L_D12Q2	0.030152	-0.079126	0.171821	-0.075395	-0.106671	-0.018519	-0.01852	1





Residual ACF								
Model		1	2	3	4	5	6	7
l_rh_upc_s_t Model	ACF	0.071	0.125	0.233	0.122	0.215	-0.011	0.092
	SE	0.270	0.270	0.270	0.270	0.270	0.270	0.270
Residual PACF								
Model		1	2	3	4	5	6	7
l_rh_upc_s_t Model		0.071	0.12	0.221	0.091	0.17	-0.098	0.016
	SE	0.270	0.270	0.270	0.270	0.270	0.270	0.270

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2007Q1	56.84	56.49	0.35	0.61%	0.57
2007Q2	23.88	23.67	0.21	0.86%	0.33
2007Q3	7.14	7.81	-0.67	-9.39%	(1.09)
2007Q4	26.19	25.72	0.47	1.80%	0.77
2008Q1	55.29	54.59	0.70	1.27%	1.14
2008Q2	22.80	21.90	0.90	3.96%	1.47
2008Q3	6.93	6.41	0.52	7.46%	0.84
2008Q4	25.27	24.93	0.34	1.35%	0.56
2009Q1	58.41	57.28	1.14	1.95%	1.85
2009Q2	20.33	20.66	-0.33	-1.64%	(0.54)
2009Q3	7.39	6.43	0.96	12.95%	1.56
2009Q4	23.87	23.98	-0.11	-0.48%	(0.19)
2010Q1	53.99	53.99	-0.01	-0.01%	(0.01)
2010Q2	17.78	17.92	-0.15	-0.83%	(0.24)
2010Q3	6.45	6.56	-0.11	-1.66%	(0.17)
2010Q4	25.95	25.19	0.76	2.94%	1.24
2011Q1	57.02	56.43	0.59	1.04%	0.97
2011Q2	21.87	22.09	-0.22	-1.01%	(0.36)
2011Q3	6.69	6.62	0.07	1.12%	0.12
2011Q4	21.24	21.52	-0.28	-1.33%	(0.46)
2012Q1	47.09	47.09	0.00	0.00%	0.00
2012Q2	16.91	16.91	0.00	0.00%	0.00
2012Q3	6.34	6.74	-0.40	-6.30%	(0.65)
2012Q4	23.52	24.28	-0.75	-3.20%	(1.23)
2013Q1	52.83	54.02	-1.19	-2.26%	(1.94)
2013Q2	21.06	22.00	-0.95	-4.50%	(1.54)
2013Q3	6.60	6.77	-0.17	-2.57%	(0.28)
2013Q4	25.72	26.34	-0.62	-2.43%	(1.02)
2014Q1	59.88	60.10	-0.22	-0.37%	(0.36)
2014Q2	23.00	22.74	0.26	1.13%	0.42
2014Q3	6.59	6.76	-0.18	-2.66%	(0.29)
2014Q4	24.28	24.94	-0.66	-2.74%	(1.08)
2015Q1	62.33	62.46	-0.13	-0.21%	(0.21)
2015Q2	22.12	22.50	-0.37	-1.68%	(0.61)
2015Q3	6.41	5.85	0.56	8.80%	0.92
2015Q4	20.58	21.78	-1.20	-5.83%	(1.95)
2016Q1	46.81	47.88	-1.07	-2.29%	(1.74)
2016Q2	20.51	20.71	-0.20	-0.97%	(0.32)
2016Q3	6.16	5.86	0.30	4.91%	0.49
2016Q4	23.59	23.32	0.26	1.12%	0.43
2017Q1	49.41	50.31	-0.90	-1.83%	(1.47)
2017Q2	22.91	22.06	0.84	3.69%	1.38
2017Q3	6.44	5.99	0.45	7.02%	0.74
2017Q4	23.36	23.36	0.00	0.00%	0.00

2018Q1	54.61	54.73	-0.12	-0.22%	(0.19)
2018Q2	21.89	21.80	0.09	0.41%	0.15
2018Q3	6.06	6.12	-0.06	-1.04%	(0.10)
2018Q4	25.90	25.67	0.24	0.92%	0.39
2019Q1	55.52	54.13	1.39	2.50%	2.26
2019Q2	20.13	20.77	-0.64	-3.16%	(1.03)
2019Q3	5.74	6.03	-0.29	-5.13%	(0.48)
2019Q4	25.65	24.31	1.34	5.23%	2.18
2020Q1	46.01	46.92	-0.91	-1.98%	(1.49)
2020Q2	21.30	20.89	0.40	1.90%	0.66
2020Q3	5.69	5.93	-0.24	-4.16%	(0.39)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	25.65	24.15	1.50	5.8%
Q1 2020	46.01	46.96	-0.94	-2.1%
Q2 2020	21.30	20.83	0.47	2.2%
Q3 2020	5.69	5.93	-0.24	-4.3%
Total	98.65	97.87	0.78	0.8%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	7.81	7.85	-0.04	0%
L_RHNGP_ROLL12(-2)	-0.07	-0.07	0.00	1%
L_Q1_EDD	0.01	0.01	0.00	0%
L_Q2_EDD	0.01	0.01	0.00	0%
L_Q4_EDD	0.01	0.01	0.00	1%
D_AFTER_15Q3*L_RHNGP_ROLL12(-4)	-0.06	-0.06	0.00	-5%
L_D12Q1	-1.51	-1.59	0.08	-5%
L_D17Q4	1.96	2.10	-0.13	-7%
L_D12Q2	-1.80	-1.79	0.00	0%

RHUPC Springfield S&T
3. Springfield

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
S_RH_UPC_S_T	8	0.999	0.763

ARIMA Model Parameters

S_RH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	6.807885	0.214	31.81	0.000
	S_RHNGP_ROLL12	-0.061475	0.012	-5.01	0.000
	S_Q1_EDD+S_Q4_EDD	0.01426	0.000	120.58	0.000
	S_Q2_EDD	0.009944	0.000	56.57	0.000
	S_D07Q4	2.603545	0.614	4.24	0.000
	S_D08Q1	1.975588	0.610	3.24	0.002
	Q1+Q4	-7.864313	0.354	-22.20	0.000
	D_AFTER_15Q3*S_RHNGP_ROLL12	-0.043387	0.011	-3.89	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_RHNGP_ROLL12	Rolling 12 quarter natural gas price for residential heating customers in Springfield ($2020)		
S_Q1_EDD+S_Q4_EDD	Effective Degree Days in Lawrence in Q1 and Q4	A	
S_Q2_EDD	Effective Degree Days in Lawrence in Q2	A	
S_D07Q4	Binary variable equal to 1 in 2007Q4		2
S_D08Q1	Binary variable equal to 1 in 2008Q1		2
Q1+Q4	Binary variable equal to 1 in Q1 and Q4	C	2
D_AFTER_15Q3*S_RHNGP_ROLL12	Rolling 12 quarter natural gas price for residential heating customers in Springfield ($2020) after 2015Q3	B	

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
63	0.998585	6252.91

Chow Test Stats

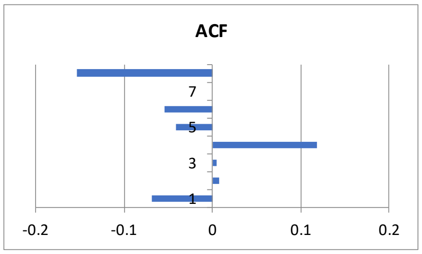
	N	k	SSR
Combined	63	8	18.67
1	31	7	7.27
2	32	6	9.34

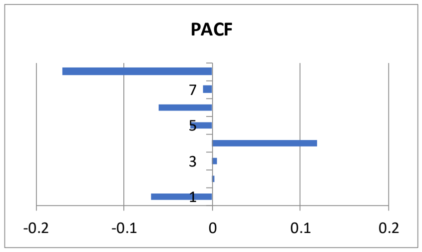
Chow Stat:	0.732
P-Value:	0.6625

Heteroscedasticity - White's Test	
White Stat	0.86
Significance (p-value)	0.54

Correlations

	S_RHNGP_ROLL12	S_Q1_EDD+S_Q4_EDD	S_Q2_EDD	S_D07Q4	S_D08Q1	Q1+Q4	D_AFTER_15Q3*S_RHNGP_ROLL12
S_RHNGP_ROLL12	1	0.017904	-0.041721	0.146023	0.143176	0.044925	0.157812
S_Q1_EDD+S_Q4_EDD	0.017904	1	-0.5088	0.030898	0.182668	0.894792	-0.049361
S_Q2_EDD	-0.041721	-0.5088	1	-0.073371	-0.07337	-0.568624	-0.002863
S_D07Q4	0.146023	0.030898	-0.073371	1	-0.01613	0.129032	-0.089657
S_D08Q1	0.143176	0.182668	-0.073371	-0.016129	1	0.129032	-0.089657
Q1+Q4	0.044925	0.894792	-0.568624	0.129032	0.129032	1	-0.024399
D_AFTER_15Q3*S_RHNGP_ROLL12	0.157812	-0.049361	-0.002863	-0.089657	-0.08966	-0.024399	1





Residual ACF								
Model		1	2	3	4	5	6	7
s_rh_upc_s_t Model	ACF	-0.069	0.007	0.005	0.118	-0.041	-0.054	0
	SE	0.252	0.252	0.252	0.252	0.252	0.252	0.252
Residual PACF								
Model		1	2	3	4	5	6	7
s_rh_upc_s_t Model		-0.069	0.002	0.006	0.119	-0.025	-0.061	-0.01
	SE	0.252	0.252	0.252	0.252	0.252	0.252	0.252

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2005Q1	52.72	51.39	1.33	2.53%	2.43
2005Q2	19.57	19.90	-0.33	-1.67%	(0.60)
2005Q3	6.52	6.81	-0.29	-4.47%	(0.53)
2005Q4	23.69	23.64	0.05	0.20%	0.09
2006Q1	46.81	45.92	0.89	1.90%	1.62
2006Q2	16.91	17.83	-0.92	-5.41%	(1.67)
2006Q3	6.42	6.81	-0.39	-6.05%	(0.71)
2006Q4	19.91	20.01	-0.10	-0.52%	(0.19)
2007Q1	48.89	48.44	0.45	0.92%	0.82
2007Q2	19.33	19.00	0.33	1.69%	0.60
2007Q3	6.41	6.81	-0.40	-6.19%	(0.72)
2007Q4	23.33	23.33	0.00	0.00%	(0.00)
2008Q1	47.19	47.19	0.00	0.00%	(0.00)
2008Q2	18.02	17.08	0.94	5.20%	1.71
2008Q3	6.22	5.56	0.66	10.65%	1.21
2008Q4	23.09	22.88	0.21	0.91%	0.38
2009Q1	50.11	49.86	0.25	0.51%	0.46
2009Q2	16.37	16.96	-0.59	-3.61%	(1.08)
2009Q3	6.35	5.69	0.67	10.52%	1.22
2009Q4	21.26	21.65	-0.39	-1.81%	(0.70)
2010Q1	46.12	46.30	-0.18	-0.39%	(0.33)
2010Q2	14.06	13.95	0.11	0.80%	0.21
2010Q3	5.95	5.76	0.19	3.13%	0.34
2010Q4	22.95	22.97	-0.02	-0.08%	(0.03)
2011Q1	49.35	49.85	-0.50	-1.01%	(0.91)
2011Q2	17.69	17.49	0.20	1.13%	0.36
2011Q3	5.93	5.85	0.08	1.43%	0.15
2011Q4	18.94	18.68	0.26	1.37%	0.47
2012Q1	39.73	39.43	0.30	0.75%	0.54
2012Q2	13.30	14.38	-1.07	-8.08%	(1.96)
2012Q3	5.64	5.89	-0.25	-4.48%	(0.46)
2012Q4	20.90	21.32	-0.42	-2.01%	(0.77)
2013Q1	45.27	46.29	-1.02	-2.24%	(1.85)
2013Q2	17.59	17.76	-0.17	-0.95%	(0.31)
2013Q3	5.75	5.89	-0.15	-2.54%	(0.27)
2013Q4	22.96	24.14	-1.18	-5.15%	(2.15)
2014Q1	52.51	53.00	-0.49	-0.93%	(0.89)
2014Q2	18.63	17.85	0.78	4.20%	1.43
2014Q3	5.77	5.88	-0.11	-1.98%	(0.21)
2014Q4	21.40	21.34	0.06	0.30%	0.12
2015Q1	54.73	54.34	0.39	0.71%	0.71
2015Q2	18.05	17.31	0.74	4.11%	1.35
2015Q3	5.61	5.20	0.41	7.25%	0.74
2015Q4	17.56	17.81	-0.25	-1.42%	(0.46)
2016Q1	40.70	40.28	0.42	1.04%	0.77
2016Q2	16.66	16.82	-0.16	-0.93%	(0.28)
2016Q3	5.36	5.31	0.06	1.07%	0.10
2016Q4	20.89	21.31	-0.42	-2.03%	(0.77)

2017Q1	43.24	42.93	0.31	0.72%	0.57
2017Q2	17.68	17.78	-0.10	-0.59%	(0.19)
2017Q3	5.49	5.40	0.09	1.57%	0.16
2017Q4	20.52	19.21	1.31	6.40%	2.39
2018Q1	47.30	47.89	-0.59	-1.24%	(1.07)
2018Q2	18.47	18.12	0.35	1.87%	0.63
2018Q3	5.07	5.36	-0.29	-5.74%	(0.53)
2018Q4	24.51	24.59	-0.08	-0.33%	(0.15)
2019Q1	46.29	47.32	-1.04	-2.24%	(1.89)
2019Q2	16.71	15.96	0.76	4.52%	1.38
2019Q3	5.11	5.25	-0.14	-2.76%	(0.26)
2019Q4	22.87	22.20	0.67	2.92%	1.22
2020Q1	41.02	41.26	-0.25	-0.60%	(0.45)
2020Q2	17.96	18.92	-0.96	-5.34%	(1.75)
2020Q3	5.19	5.23	-0.04	-0.78%	(0.07)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	22.87	22.19	0.68	3.0%
Q1 2020	41.02	41.30	-0.28	-0.7%
Q2 2020	17.96	19.04	-1.09	-6.1%
Q3 2020	5.19	5.25	-0.06	-1.2%
Total	87.03	87.77	-0.75	-0.9%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	6.81	6.78	0.03	0%
S_RHNGP_ROLL12	-0.06	-0.06	0.00	1%
S_Q1_EDD+S_Q4_EDD	0.01	0.01	0.00	0%
S_Q2_EDD	0.01	0.01	0.00	-1%
S_D07Q4	2.60	2.66	-0.05	-2%
S_D08Q1	1.98	1.98	0.00	0%
Q1+Q4	-7.86	-7.95	0.09	-1%
D_AFTER_15Q3*S_RHNGP_ROLL12	-0.04	-0.04	0.00	7%

RNHUPC Brockton S&T
B. Residential Non-Heating User per Customer - Sales & Transportation
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
B_RNH_UPC_S_T	10	0.994	0.346

ARIMA Model Parameters

B_RNH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	4.75937	0.465	10.23	0.000
	B_RRNGP	-0.088973	0.021	-4.18	0.000
	B_Q1_EDD	0.001021	0.000	48.56	0.000
	B_Q2_EDD	0.001125	0.000	22.40	0.000
	B_Q4_EDD	0.000926	0.000	23.17	0.000
	B_D14Q1	0.307476	0.135	2.27	0.034
	B_D14Q2	0.35318	0.129	2.75	0.012
	B_D16Q1	-0.302986	0.129	-2.34	0.029
	B_D20Q1	0.268368	0.128	2.10	0.048
	B_D15Q3+B_D14Q3	0.338873	0.100	3.38	0.003

Variable	Definition	Explanation	Dummy Variable Support
B_RRNGP	Natural gas price for residential non heating customers in Brockton ($2020)		
B_Q1_EDD	Effective Degree Days in Brockton in Q1	A	
B_Q2_EDD	Effective Degree Days in Brockton in Q2	A	
B_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
B_D14Q1	Binary variable equal to 1 in 2014Q1		2
B_D14Q2	Binary variable equal to 1 in 2014Q2		2
B_D16Q1	Binary variable equal to 1 in 2016Q1		2
B_D20Q1	Binary variable equal to 1 in 2020Q1		2
B_D15Q3+B_D14Q3	Binary variable equal to 1 in 2015Q3 and 2014Q3		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
31	0.991153	374.4459

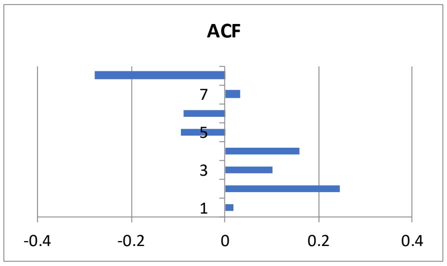
Chow Test Stats	N	k	SSR
Combined	31	10	0.30
1	15	9	0.12
2	16	6	0.11

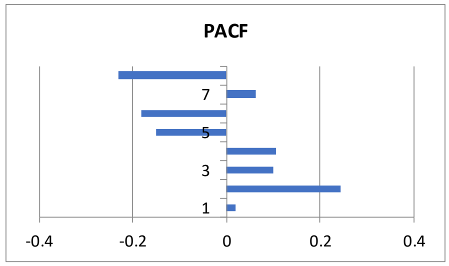
Chow Stat:	0.375
P-Value:	0.933388

Heteroscedasticity - White's Test	
White Stat	1.36
Significance (p-value)	0.27

Correlations

	B_RRNGP	B_Q1_EDD	B_Q2_EDD	B_Q4_EDD	B_D14Q1	B_D14Q2	B_D16Q1	B_D20Q1	B_D15Q3+ B_D14Q3
B_RRNGP	1	-0.029279	-0.029617	0.093052	-0.14475	0.035376	-0.10033	0.024211	0.182928
B_Q1_EDD	-0.029279	1	-0.344814	-0.314504	0.359929	-0.106852	0.25877	0.243421	-0.153695
B_Q2_EDD	-0.029617	-0.344814	1	-0.316608	-0.10757	0.317319	-0.10757	-0.10757	-0.154723
B_Q4_EDD	0.093052	-0.314504	-0.316608	1	-0.09811	-0.098112	-0.09811	-0.09811	-0.141123
B_D14Q1	-0.144747	0.359929	-0.107567	-0.098112	1	-0.033333	-0.03333	-0.03333	-0.047946
B_D14Q2	0.035376	-0.106852	0.317319	-0.098112	-0.03333	1	-0.03333	-0.03333	-0.047946
B_D16Q1	-0.100327	0.25877	-0.107567	-0.098112	-0.03333	-0.033333	1	-0.03333	-0.047946
B_D20Q1	0.024211	0.243421	-0.107567	-0.098112	-0.03333	-0.033333	-0.03333	1	-0.047946
B_D15Q3+B_D14Q3	0.182928	-0.153695	-0.154723	-0.141123	-0.04795	-0.047946	-0.04795	-0.04795	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_rnh_upc_s_t Model	ACF	0.019	0.246	0.102	0.159	-0.094	-0.089	0.032	-0.278
	SE	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_rnh_upc_s_t Model		0.019	0.245	0.1	0.105	-0.151	-0.181	0.062	-0.232
	SE	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2013Q1	6.44	6.42	0.02	0.38%	0.24
2013Q2	4.34	4.42	-0.08	-1.89%	(0.82)
2013Q3	2.99	2.92	0.06	2.05%	0.61
2013Q4	4.87	4.62	0.25	5.15%	2.50
2014Q1	7.05	7.05	0.00	0.00%	0.00
2014Q2	4.65	4.65	0.00	0.00%	(0.00)
2014Q3	3.08	3.09	-0.01	-0.21%	(0.06)
2014Q4	4.33	4.27	0.06	1.41%	0.61
2015Q1	6.55	6.67	-0.12	-1.78%	(1.16)
2015Q2	4.20	4.20	0.00	0.08%	0.03
2015Q3	3.06	3.05	0.01	0.21%	0.06
2015Q4	3.93	4.13	-0.21	-5.26%	(2.06)
2016Q1	5.58	5.58	0.00	0.00%	(0.00)
2016Q2	4.16	4.33	-0.16	-3.93%	(1.63)
2016Q3	2.84	2.86	-0.03	-0.94%	(0.27)
2016Q4	4.10	4.38	-0.27	-6.65%	(2.72)
2017Q1	6.05	6.06	-0.01	-0.12%	(0.07)
2017Q2	4.39	4.38	0.01	0.25%	0.11
2017Q3	2.95	2.87	0.08	2.75%	0.81
2017Q4	4.23	4.21	0.02	0.51%	0.22
2018Q1	6.38	6.30	0.08	1.30%	0.83
2018Q2	4.27	4.22	0.05	1.11%	0.47
2018Q3	2.69	2.68	0.01	0.28%	0.07
2018Q4	4.40	4.35	0.05	1.10%	0.49
2019Q1	6.18	6.15	0.04	0.57%	0.35
2019Q2	4.11	4.11	-0.01	-0.16%	(0.07)
2019Q3	2.77	2.72	0.05	1.77%	0.49
2019Q4	4.39	4.35	0.04	0.81%	0.35
2020Q1	5.96	5.96	0.00	0.00%	(0.00)
2020Q2	4.57	4.40	0.17	3.74%	1.71
2020Q3	2.73	2.84	-0.11	-4.06%	(1.11)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	23.58	22.75	0.83	3.5%
Q1 2020	42.43	41.77	0.66	1.5%
Q2 2020	20.64	20.93	-0.29	-1.4%
Q3 2020	5.51	5.50	0.01	0.1%
Total	92.16	90.95	1.20	1.3%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	10.48	10.88	-0.40	-4%
B_RHNGP_ROLL12	-0.32	-0.35	0.03	-9%
B_Q1_EDD	0.01	0.01	0.00	0%
B_Q2_EDD	0.01	0.01	0.00	0%
B_Q4_EDD	0.01	0.01	0.00	1%
B_D15Q1	1.81	1.93	-0.13	-7%
B_D15Q4	-1.76	-1.61	-0.15	9%

RNHUPC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
L_RNH_UPC_S_T	8	0.984	0.461

ARIMA Model Parameters

L_RNH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	6.698577	0.702	9.54	0.000
	L_RRNGP	-0.16665	0.035	-4.82	0.000
	L_Q1_EDD	0.001096	0.000	40.79	0.000
	L_Q2_EDD	0.001436	0.000	22.04	0.000
	L_Q4_EDD	0.001071	0.000	20.91	0.000
	L_D13Q1	1.055782	0.235	4.49	0.000
	L_D19Q1	1.013586	0.230	4.41	0.000
	L_D15Q4_17Q2	-0.434624	0.089	-4.86	0.000

Variable	Definition	Explanation	Dummy Variable Support
L_RRNGP	Natural gas price for residential non heating customers in Lawrence ($2020)		
L_Q1_EDD	Effective Degree Days in Lawrence in Q1	A	
L_Q2_EDD	Effective Degree Days in Lawrence in Q2	A	
L_Q4_EDD	Effective Degree Days in Lawrence in Q4	A	
L_D13Q1	Binary variable equal to 1 in 2013Q1		2
L_D19Q1	Binary variable equal to 1 in 2019Q1		2
L_D15Q4_17Q2	Binary variable equal to 1 from 2015Q4 to 2017Q2		1

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
43	0.980505	302.7759

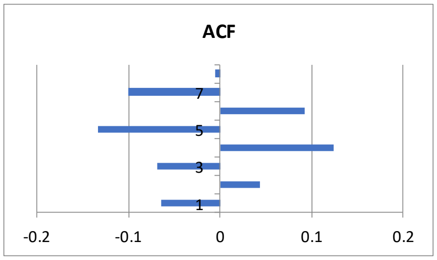
Chow Test Stats	N	k	SSR
Combined	43	8	1.58
1	19	6	0.35
2	24	7	0.85

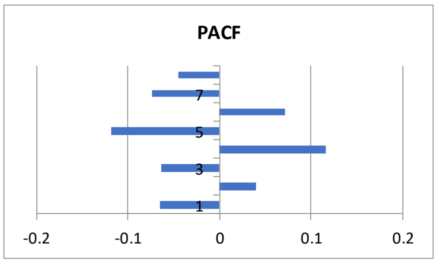
Chow Stat:	1.088
P-Value:	0.400728

Heteroscedasticity - White's Test	
White Stat	0.98
Significance (p-value)	0.46

Correlations

	L_RRNGP	L_Q1_EDD	L_Q2_EDD	L_Q4_EDD	L_D13Q1	L_D19Q1	L_D15Q4_17Q2
L_RRNGP	1	-0.003758	-0.000437	0.051012	-0.28697	0.223018	-0.10995
L_Q1_EDD	-0.003758	1	-0.339305	-0.319132	0.261798	0.267482	0.005596
L_Q2_EDD	-0.000437	-0.339305	1	-0.318826	-0.08984	-0.089838	0.044422
L_Q4_EDD	0.051012	-0.319132	-0.318826	1	-0.0845	-0.084497	0.040742
L_D13Q1	-0.286966	0.261798	-0.089838	-0.084497	1	-0.02381	-0.068041
L_D19Q1	0.223018	0.267482	-0.089838	-0.084497	-0.02381	1	-0.068041
L_D15Q4_17Q2	-0.10995	0.005596	0.044422	0.040742	-0.06804	-0.068041	1





Residual ACF								
Model		1	2	3	4	5	6	7
l_rnh_cust_s_t Model	ACF	-0.065	0.044	-0.068	0.124	-0.134	0.093	-0.1
	SE	0.305	0.305	0.305	0.305	0.305	0.305	0.305
Residual PACF								
Model		1	2	3	4	5	6	7
l_rnh_cust_s_t Model		-0.065	0.04	-0.063	0.116	-0.118	0.071	-0.074
	SE	0.305	0.305	0.305	0.305	0.305	0.305	0.305

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2010Q1	7.25	7.34	-0.09	-1.21%	(0.45)
2010Q2	5.07	5.00	0.07	1.44%	0.38
2010Q3	3.31	3.29	0.02	0.65%	0.11
2010Q4	5.35	5.26	0.09	1.68%	0.46
2011Q1	7.38	7.33	0.05	0.63%	0.24
2011Q2	5.43	5.32	0.11	2.06%	0.58
2011Q3	3.47	3.33	0.14	4.06%	0.72
2011Q4	5.38	5.03	0.36	6.62%	1.84
2012Q1	6.84	6.90	-0.05	-0.74%	(0.26)
2012Q2	5.02	5.14	-0.12	-2.44%	(0.63)
2012Q3	3.13	3.56	-0.43	-13.75%	(2.22)
2012Q4	5.56	5.54	0.03	0.47%	0.13
2013Q1	8.57	8.57	0.00	0.00%	(0.00)
2013Q2	5.79	5.65	0.14	2.39%	0.71
2013Q3	3.43	3.58	-0.15	-4.22%	(0.75)
2013Q4	5.92	5.72	0.20	3.37%	1.03
2014Q1	7.85	7.86	0.00	-0.04%	(0.01)
2014Q2	5.55	5.42	0.13	2.38%	0.68
2014Q3	3.60	3.22	0.37	10.42%	1.93
2014Q4	5.32	5.09	0.24	4.48%	1.23
2015Q1	7.30	7.54	-0.24	-3.30%	(1.24)
2015Q2	5.22	5.26	-0.04	-0.80%	(0.21)
2015Q3	3.26	3.16	0.10	3.06%	0.51
2015Q4	4.66	4.55	0.11	2.34%	0.56
2016Q1	6.45	6.40	0.04	0.67%	0.22
2016Q2	4.91	5.03	-0.12	-2.34%	(0.59)
2016Q3	3.13	2.98	0.15	4.72%	0.76
2016Q4	4.68	4.87	-0.19	-4.09%	(0.99)
2017Q1	6.50	6.54	-0.04	-0.62%	(0.21)
2017Q2	5.09	5.05	0.05	0.92%	0.24
2017Q3	3.32	3.39	-0.07	-2.11%	(0.36)
2017Q4	4.87	5.08	-0.21	-4.35%	(1.09)
2018Q1	7.37	7.30	0.07	1.01%	0.38
2018Q2	4.82	5.21	-0.39	-8.03%	(2.00)
2018Q3	3.24	3.06	0.18	5.55%	0.93
2018Q4	4.73	5.23	-0.50	-10.67%	(2.60)
2019Q1	8.03	8.03	0.00	0.00%	(0.00)
2019Q2	5.23	5.15	0.08	1.56%	0.42
2019Q3	3.00	3.14	-0.14	-4.72%	(0.73)
2019Q4	5.11	5.16	-0.05	-1.02%	(0.27)
2020Q1	6.96	6.62	0.34	4.88%	1.75
2020Q2	5.39	5.32	0.08	1.46%	0.40
2020Q3	3.05	3.36	-0.31	-10.27%	(1.61)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	5.11	5.16	-0.05	-1.0%
Q1 2020	6.96	6.59	0.37	5.3%
Q2 2020	5.39	5.31	0.09	1.6%
Q3 2020	3.05	3.39	-0.34	-11.1%
Total	20.51	20.44	0.07	0.3%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	6.70	6.79	-0.09	-1%
L_RRNGP	-0.17	-0.17	0.00	-2%
L_Q1_EDD	0.00	0.00	0.00	2%
L_Q2_EDD	0.00	0.00	0.00	2%
L_Q4_EDD	0.00	0.00	0.00	1%
L_D13Q1	1.06	1.09	-0.03	-3%
L_D19Q1	1.01	1.06	-0.04	-4%
L_D15Q4_17Q2	-0.43	-0.43	-0.01	1%

RNHUPC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_RNH_UPC_S_T	6	0.978	0.459

ARIMA Model Parameters

S_RNH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	4.049814	0.321	12.63	0.000
	S_RHNGP	-0.035175	0.020	-1.72	0.093
	S_Q1_EDD+S_Q4_EDD	0.001004	0.000	39.33	0.000
	S_Q2_EDD	0.001329	0.000	18.72	0.000
	S_D13Q1	1.18911	0.224	5.31	0.000
	D_AFTER15Q2*S_RHNGP	-0.029619	0.005	-6.24	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_RHNGP	Natural gas price for residential non heating customers in Springfield ($2020)		
S_Q1_EDD+S_Q4_EDD	Effective Degree Days in Springfield in Q1 and Q4	A	
S_Q2_EDD	Effective Degree Days in Springfield in Q2	A	
S_D13Q1	Binary variable equal to 1 in 2013Q1		2
D_AFTER15Q2*S_RHNGP	Natural gas price for residential non heating customers in Springfield ($2020) after 2015Q2	B	

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

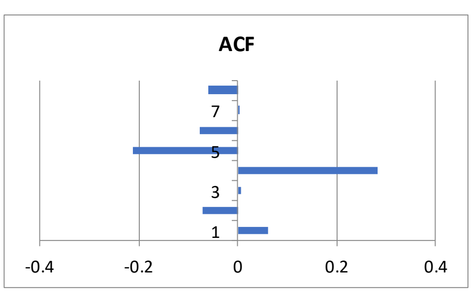
N	Adjusted R2	F Statistic
48	0.975194	370.5374

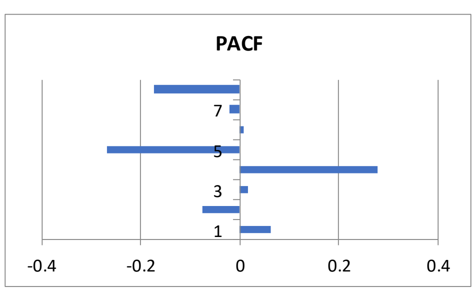
Chow Test Stats	N	k	SSR
Combined	48	6	1.86
1	24	5	1.05
2	24	5	0.38

Chow Stat:	1.762
P-Value:	0.13497

Heteroscedasticity - White's Test	
White Stat	1.89
Significance (p-value)	0.12

Correlations	S_RHNGP	S_Q1_EDD+S_Q4_EDD	S_Q2_EDD	S_D13Q1	D_AFTER15Q2*S_RHNGP
S_RHNGP	1	0.105992	-0.011113	-0.112944	-0.39415
S_Q1_EDD+S_Q4_EDD	0.105992	1	-0.508971	0.215774	-0.102197
S_Q2_EDD	-0.011113	-0.508971	1	-0.083218	0.089149
S_D13Q1	-0.112944	0.215774	-0.083218	1	-0.133158
D_AFTER15Q2*S_RHNGP	-0.39415	-0.102197	0.089149	-0.133158	1





Residual ACF							
Model		1	2	3	4	5	6
s_rnh_upc_s_t Model	ACF	0.062	-0.071	0.007	0.282	-0.211	-0.076
	SE	0.289	0.289	0.289	0.289	0.289	0.289
Residual PACF							
Model		1	2	3	4	5	6
s_rnh_upc_s_t Model		0.062	-0.076	0.017	0.278	-0.268	0.008
	SE	0.289	0.289	0.289	0.289	0.289	0.289

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2008Q4	5.07	5.12	-0.05	-1.06%	(0.27)
2009Q1	6.53	7.02	-0.49	-7.48%	(2.46)
2009Q2	5.06	4.90	0.16	3.17%	0.81
2009Q3	3.68	3.47	0.21	5.64%	1.04
2009Q4	4.98	5.19	-0.20	-4.10%	(1.03)
2010Q1	6.31	6.94	-0.63	-10.07%	(3.19)
2010Q2	4.72	4.64	0.08	1.69%	0.40
2010Q3	3.50	3.52	-0.02	-0.64%	(0.11)
2010Q4	5.09	5.27	-0.18	-3.63%	(0.93)
2011Q1	7.20	7.16	0.04	0.50%	0.18
2011Q2	5.13	5.06	0.07	1.32%	0.34
2011Q3	3.61	3.50	0.11	3.05%	0.55
2011Q4	5.28	4.97	0.31	5.95%	1.58
2012Q1	6.71	6.44	0.27	4.05%	1.37
2012Q2	4.69	4.67	0.02	0.42%	0.10
2012Q3	3.36	3.55	-0.19	-5.67%	(0.96)
2012Q4	5.51	5.20	0.31	5.57%	1.54
2013Q1	8.15	8.15	0.00	0.00%	0.00
2013Q2	5.32	5.14	0.18	3.40%	0.91
2013Q3	3.43	3.53	-0.10	-2.91%	(0.50)
2013Q4	5.63	5.36	0.27	4.80%	1.36
2014Q1	7.35	7.37	-0.02	-0.32%	(0.12)
2014Q2	5.01	5.06	-0.05	-1.06%	(0.27)
2014Q3	3.50	3.48	0.02	0.64%	0.11
2014Q4	4.97	5.11	-0.13	-2.70%	(0.68)
2015Q1	7.60	7.43	0.17	2.21%	0.85
2015Q2	4.79	4.59	0.20	4.08%	0.98
2015Q3	3.29	3.09	0.20	6.13%	1.02
2015Q4	4.51	4.60	-0.09	-2.05%	(0.46)
2016Q1	6.21	6.26	-0.04	-0.72%	(0.22)
2016Q2	4.60	4.83	-0.23	-4.97%	(1.15)
2016Q3	3.15	3.28	-0.13	-4.07%	(0.64)
2016Q4	4.64	4.93	-0.30	-6.39%	(1.49)
2017Q1	6.63	6.42	0.21	3.19%	1.06
2017Q2	4.89	4.84	0.05	1.09%	0.27
2017Q3	3.17	3.18	-0.01	-0.40%	(0.06)
2017Q4	4.74	4.69	0.05	1.06%	0.25
2018Q1	6.98	6.66	0.31	4.49%	1.58
2018Q2	4.69	4.73	-0.05	-1.00%	(0.24)
2018Q3	3.05	3.02	0.04	1.15%	0.18
2018Q4	4.99	4.92	0.07	1.38%	0.35
2019Q1	6.75	6.53	0.21	3.17%	1.07
2019Q2	4.41	4.50	-0.09	-2.03%	(0.45)
2019Q3	3.01	3.07	-0.05	-1.74%	(0.26)
2019Q4	4.70	4.83	-0.13	-2.68%	(0.63)
2020Q1	6.27	6.20	0.07	1.15%	0.36
2020Q2	4.68	4.95	-0.27	-5.68%	(1.34)
2020Q3	2.98	3.14	-0.16	-5.32%	(0.80)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	4.70	4.85	-0.15	-3.1%
Q1 2020	6.27	6.21	0.06	0.9%
Q2 2020	4.68	5.00	-0.31	-6.7%
Q3 2020	2.98	3.16	-0.18	-6.2%
Total	18.63	19.22	-0.59	-3.2%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	4.05	4.03	0.01	0%
S_RHNGP	-0.04	-0.03	0.00	3%
S_Q1_EDD+S_Q4_EDD	0.00	0.00	0.00	0%
S_Q2_EDD	0.00	0.00	0.00	-1%
S_D13Q1	1.19	1.20	-0.01	-1%
D_AFTER15Q2*S_RHNGP	-0.03	-0.03	0.00	6%

RNHUPC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
L_RNH_UPC_S_T	8	0.984	0.461

ARIMA Model Parameters

L_RNH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	6.698577	0.702	9.54	0.000
	L_RRNGP	-0.16665	0.035	-4.82	0.000
	L_Q1_EDD	0.001096	0.000	40.79	0.000
	L_Q2_EDD	0.001436	0.000	22.04	0.000
	L_Q4_EDD	0.001071	0.000	20.91	0.000
	L_D13Q1	1.055782	0.235	4.49	0.000
	L_D19Q1	1.013586	0.230	4.41	0.000
	L_D15Q4_17Q2	-0.434624	0.089	-4.86	0.000

Variable	Definition	Explanation	Dummy Variable Support
L_RRNGP	Natural gas price for residential non heating customers in Lawrence ($2020)		
L_Q1_EDD	Effective Degree Days in Lawrence in Q1	A	
L_Q2_EDD	Effective Degree Days in Lawrence in Q2	A	
L_Q4_EDD	Effective Degree Days in Lawrence in Q4	A	
L_D13Q1	Binary variable equal to 1 in 2013Q1		2
L_D19Q1	Binary variable equal to 1 in 2019Q1		2
L_D15Q4_17Q2	Binary variable equal to 1 from 2015Q4 to 2017Q2		1

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
43	0.980505	302.7759

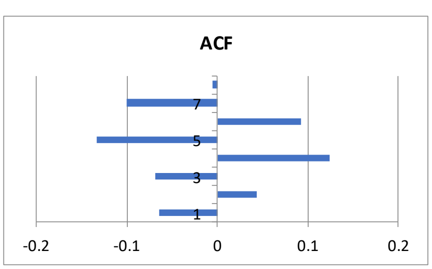
Chow Test Stats	N	k	SSR
Combined	43	8	1.58
1	19	6	0.35
2	24	7	0.85

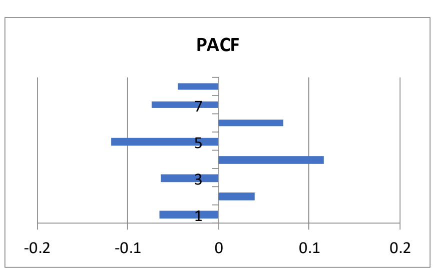
Chow Stat:	1.088
P-Value:	0.400728

Heteroscedasticity - White's Test	
White Stat	0.98
Significance (p-value)	0.46

Correlations

	L_RRNGP	L_Q1_EDD	L_Q2_EDD	L_Q4_EDD	L_D13Q1	L_D19Q1	L_D15Q4_17Q2
L_RRNGP	1	-0.003758	-0.000437	0.051012	-0.28697	0.223018	-0.10995
L_Q1_EDD	-0.003758	1	-0.339305	-0.319132	0.261798	0.267482	0.005596
L_Q2_EDD	-0.000437	-0.339305	1	-0.318826	-0.08984	-0.089838	0.044422
L_Q4_EDD	0.051012	-0.319132	-0.318826	1	-0.0845	-0.084497	0.040742
L_D13Q1	-0.286966	0.261798	-0.089838	-0.084497	1	-0.02381	-0.068041
L_D19Q1	0.223018	0.267482	-0.089838	-0.084497	-0.02381	1	-0.068041
L_D15Q4_17Q2	-0.10995	0.005596	0.044422	0.040742	-0.06804	-0.068041	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_rnh_cust_s_t Model	ACF	-0.065	0.044	-0.068	0.124	-0.134	0.093	-0.1	-0.005
	SE	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_rnh_cust_s_t Model		-0.065	0.04	-0.063	0.116	-0.118	0.071	-0.074	-0.045
	SE	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2010Q1	7.25	7.34	-0.09	-1.21%	(0.45)
2010Q2	5.07	5.00	0.07	1.44%	0.38
2010Q3	3.31	3.29	0.02	0.65%	0.11
2010Q4	5.35	5.26	0.09	1.68%	0.46
2011Q1	7.38	7.33	0.05	0.63%	0.24
2011Q2	5.43	5.32	0.11	2.06%	0.58
2011Q3	3.47	3.33	0.14	4.06%	0.72
2011Q4	5.38	5.03	0.36	6.62%	1.84
2012Q1	6.84	6.90	-0.05	-0.74%	(0.26)
2012Q2	5.02	5.14	-0.12	-2.44%	(0.63)
2012Q3	3.13	3.56	-0.43	-13.75%	(2.22)
2012Q4	5.56	5.54	0.03	0.47%	0.13
2013Q1	8.57	8.57	0.00	0.00%	(0.00)
2013Q2	5.79	5.65	0.14	2.39%	0.71
2013Q3	3.43	3.58	-0.15	-4.22%	(0.75)
2013Q4	5.92	5.72	0.20	3.37%	1.03
2014Q1	7.85	7.86	0.00	-0.04%	(0.01)
2014Q2	5.55	5.42	0.13	2.38%	0.68
2014Q3	3.60	3.22	0.37	10.42%	1.93
2014Q4	5.32	5.09	0.24	4.48%	1.23
2015Q1	7.30	7.54	-0.24	-3.30%	(1.24)
2015Q2	5.22	5.26	-0.04	-0.80%	(0.21)
2015Q3	3.26	3.16	0.10	3.06%	0.51
2015Q4	4.66	4.55	0.11	2.34%	0.56
2016Q1	6.45	6.40	0.04	0.67%	0.22
2016Q2	4.91	5.03	-0.12	-2.34%	(0.59)
2016Q3	3.13	2.98	0.15	4.72%	0.76
2016Q4	4.68	4.87	-0.19	-4.09%	(0.99)
2017Q1	6.50	6.54	-0.04	-0.62%	(0.21)
2017Q2	5.09	5.05	0.05	0.92%	0.24
2017Q3	3.32	3.39	-0.07	-2.11%	(0.36)
2017Q4	4.87	5.08	-0.21	-4.35%	(1.09)
2018Q1	7.37	7.30	0.07	1.01%	0.38
2018Q2	4.82	5.21	-0.39	-8.03%	(2.00)
2018Q3	3.24	3.06	0.18	5.55%	0.93
2018Q4	4.73	5.23	-0.50	-10.67%	(2.60)
2019Q1	8.03	8.03	0.00	0.00%	(0.00)
2019Q2	5.23	5.15	0.08	1.56%	0.42
2019Q3	3.00	3.14	-0.14	-4.72%	(0.73)
2019Q4	5.11	5.16	-0.05	-1.02%	(0.27)
2020Q1	6.96	6.62	0.34	4.88%	1.75
2020Q2	5.39	5.32	0.08	1.46%	0.40
2020Q3	3.05	3.36	-0.31	-10.27%	(1.61)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	5.11	5.16	-0.05	-1.0%
Q1 2020	6.96	6.59	0.37	5.3%
Q2 2020	5.39	5.31	0.09	1.6%
Q3 2020	3.05	3.39	-0.34	-11.1%
Total	20.51	20.44	0.07	0.3%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	6.70	6.79	-0.09	-1%
L_RRNGP	-0.17	-0.17	0.00	-2%
L_Q1_EDD	0.00	0.00	0.00	2%
L_Q2_EDD	0.00	0.00	0.00	2%
L_Q4_EDD	0.00	0.00	0.00	1%
L_D13Q1	1.06	1.09	-0.03	-3%
L_D19Q1	1.01	1.06	-0.04	-4%
L_D15Q4_17Q2	-0.43	-0.43	-0.01	1%

RNHUPC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_RNH_UPC_S_T	6	0.978	0.459

ARIMA Model Parameters

S_RNH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	4.049814	0.321	12.63	0.000
	S_RHNGP	-0.035175	0.020	-1.72	0.093
	S_Q1_EDD+S_Q4_EDD	0.001004	0.000	39.33	0.000
	S_Q2_EDD	0.001329	0.000	18.72	0.000
	S_D13Q1	1.18911	0.224	5.31	0.000
	D_AFTER15Q2*S_RHNGP	-0.029619	0.005	-6.24	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_RHNGP	Natural gas price for residential non heating customers in Springfield ($2020)		
S_Q1_EDD+S_Q4_EDD	Effective Degree Days in Springfield in Q1 and Q4	A	
S_Q2_EDD	Effective Degree Days in Springfield in Q2	A	
S_D13Q1	Binary variable equal to 1 in 2013Q1		2
D_AFTER15Q2*S_RHNGP	Natural gas price for residential non heating customers in Springfield ($2020) after 2015Q2	B	

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
48	0.975194	370.5374

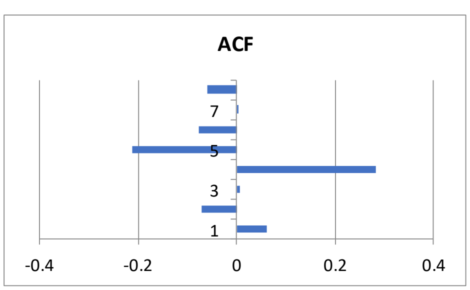
Chow Test Stats	N	k	SSR
Combined	48	6	1.86
1	24	5	1.05
2	24	5	0.38

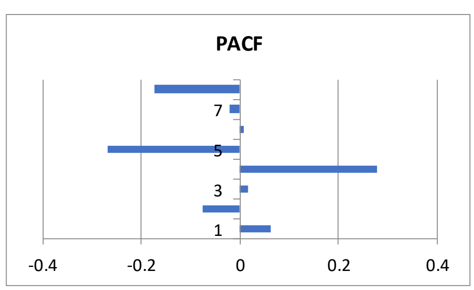
Chow Stat:	1.762
P-Value:	0.13497

Heteroscedasticity - White's Test	
White Stat	1.89
Significance (p-value)	0.12

Correlations

	S_RHNGP	S_Q1_EDD+S_Q4_EDD	S_Q2_EDD	S_D13Q1	D_AFTER15Q2*S_RHNGP
S_RHNGP	1	0.105992	-0.011113	-0.112944	-0.39415
S_Q1_EDD+S_Q4_EDD	0.105992	1	-0.508971	0.215774	-0.102197
S_Q2_EDD	-0.011113	-0.508971	1	-0.083218	0.089149
S_D13Q1	-0.112944	0.215774	-0.083218	1	-0.133158
D_AFTER15Q2*S_RHNGP	-0.39415	-0.102197	0.089149	-0.133158	1





Residual ACF							
Model		1	2	3	4	5	6
s_rnh_upc_s_t Model	ACF	0.062	-0.071	0.007	0.282	-0.211	-0.076
	SE	0.289	0.289	0.289	0.289	0.289	0.289

Residual PACF							
Model		1	2	3	4	5	6
s_rnh_upc_s_t Model		0.062	-0.076	0.017	0.278	-0.268	0.008
	SE	0.289	0.289	0.289	0.289	0.289	0.289

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2008Q4	5.07	5.12	-0.05	-1.06%	(0.27)
2009Q1	6.53	7.02	-0.49	-7.48%	(2.46)
2009Q2	5.06	4.90	0.16	3.17%	0.81
2009Q3	3.68	3.47	0.21	5.64%	1.04
2009Q4	4.98	5.19	-0.20	-4.10%	(1.03)
2010Q1	6.31	6.94	-0.63	-10.07%	(3.19)
2010Q2	4.72	4.64	0.08	1.69%	0.40
2010Q3	3.50	3.52	-0.02	-0.64%	(0.11)
2010Q4	5.09	5.27	-0.18	-3.63%	(0.93)
2011Q1	7.20	7.16	0.04	0.50%	0.18
2011Q2	5.13	5.06	0.07	1.32%	0.34
2011Q3	3.61	3.50	0.11	3.05%	0.55
2011Q4	5.28	4.97	0.31	5.95%	1.58
2012Q1	6.71	6.44	0.27	4.05%	1.37
2012Q2	4.69	4.67	0.02	0.42%	0.10
2012Q3	3.36	3.55	-0.19	-5.67%	(0.96)
2012Q4	5.51	5.20	0.31	5.57%	1.54
2013Q1	8.15	8.15	0.00	0.00%	0.00
2013Q2	5.32	5.14	0.18	3.40%	0.91
2013Q3	3.43	3.53	-0.10	-2.91%	(0.50)
2013Q4	5.63	5.36	0.27	4.80%	1.36
2014Q1	7.35	7.37	-0.02	-0.32%	(0.12)
2014Q2	5.01	5.06	-0.05	-1.06%	(0.27)
2014Q3	3.50	3.48	0.02	0.64%	0.11
2014Q4	4.97	5.11	-0.13	-2.70%	(0.68)
2015Q1	7.60	7.43	0.17	2.21%	0.85
2015Q2	4.79	4.59	0.20	4.08%	0.98
2015Q3	3.29	3.09	0.20	6.13%	1.02
2015Q4	4.51	4.60	-0.09	-2.05%	(0.46)
2016Q1	6.21	6.26	-0.04	-0.72%	(0.22)
2016Q2	4.60	4.83	-0.23	-4.97%	(1.15)
2016Q3	3.15	3.28	-0.13	-4.07%	(0.64)
2016Q4	4.64	4.93	-0.30	-6.39%	(1.49)
2017Q1	6.63	6.42	0.21	3.19%	1.06
2017Q2	4.89	4.84	0.05	1.09%	0.27
2017Q3	3.17	3.18	-0.01	-0.40%	(0.06)
2017Q4	4.74	4.69	0.05	1.06%	0.25
2018Q1	6.98	6.66	0.31	4.49%	1.58
2018Q2	4.69	4.73	-0.05	-1.00%	(0.24)
2018Q3	3.05	3.02	0.04	1.15%	0.18
2018Q4	4.99	4.92	0.07	1.38%	0.35
2019Q1	6.75	6.53	0.21	3.17%	1.07
2019Q2	4.41	4.50	-0.09	-2.03%	(0.45)
2019Q3	3.01	3.07	-0.05	-1.74%	(0.26)
2019Q4	4.70	4.83	-0.13	-2.68%	(0.63)
2020Q1	6.27	6.20	0.07	1.15%	0.36
2020Q2	4.68	4.95	-0.27	-5.68%	(1.34)
2020Q3	2.98	3.14	-0.16	-5.32%	(0.80)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	4.70	4.85	-0.15	-3.1%
Q1 2020	6.27	6.21	0.06	0.9%
Q2 2020	4.68	5.00	-0.31	-6.7%
Q3 2020	2.98	3.16	-0.18	-6.2%
Total	18.63	19.22	-0.59	-3.2%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	4.05	4.03	0.01	0%
S_RHNGP	-0.04	-0.03	0.00	3%
S_Q1_EDD+S_Q4_EDD	0.00	0.00	0.00	0%
S_Q2_EDD	0.00	0.00	0.00	-1%
S_D13Q1	1.19	1.20	-0.01	-1%
D_AFTER15Q2*S_RHNGP	-0.03	-0.03	0.00	6%

LLFUPC Brockton S&T
C. Low Load Factor User Per Customer - Sales & Transportation
1. Brockton

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
B_LLF_UPC_S_T	5	0.996	2.498

ARIMA Model Parameters

B_LLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	72.34755	14.400	5.02	0.000
	B_LLFNGP_ST_ROLL12	-4.50078	1.267	-3.55	0.001
	B_Q1_EDD	0.07619	0.001	105.86	0.000
	B_Q4_EDD	0.05367	0.001	36.10	0.000
	B_Q2_EDD	0.065809	0.002	34.49	0.000

Variable	Definition	Explanation	Dummy Variable Support
B_LLFNGP_ST_ROLL12	Rolling 12 quarter natural gas price for low load factor customers in Brockton ($2020/MMBtu)		
B_Q1_EDD	Effective Degree Days in Brockton in Q1	A	
B_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
B_Q2_EDD	Effective Degree Days in Brockton in Q2	A	

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

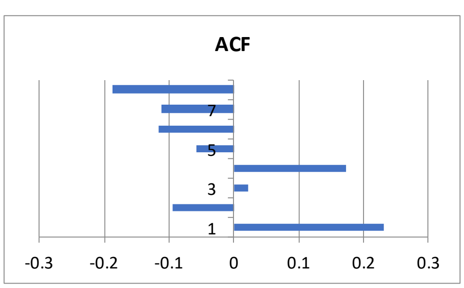
N	Adjusted R2	F Statistic
51	0.995757	2934.799

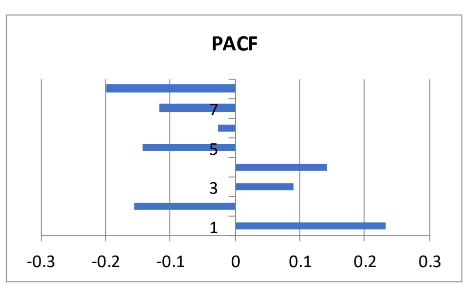
Chow Test Stats	N	k	SSR
Combined	51	5	1,791.23
1	29	5	667.83
2	22	5	853.28

Chow Stat:	1.456
P-Value:	0.225104

Heteroscedasticity - White's Test	
White Stat	2.57
Significance (p-value)	0.05

Correlations	B_LLFNGP_ST_ROLL12	B_Q1_EDD	B_Q4_EDD	B_Q2_EDD
B_LLFNGP_ST_ROLL12	1	0.059006	-0.001724	-0.025317
B_Q1_EDD	0.059006	1	-0.32101	-0.337562
B_Q4_EDD	-0.001724	-0.32101	1	-0.320635
B_Q2_EDD	-0.025317	-0.337562	-0.320635	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_llf_upc_s_t Model	ACF	0.232	-0.094	0.022	0.173	-0.057	-0.115	-0.112	-0.188
	SE	0.280	0.280	0.280	0.280	0.280	0.280	0.280	0.280
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_llf_upc_s_t Model		0.232	-0.156	0.09	0.141	-0.143	-0.027	-0.117	-0.198
	SE	0.280	0.280	0.280	0.280	0.280	0.280	0.280	0.280

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2008Q1	267.17	263.86	3.30	1.24%	0.55
2008Q2	102.13	101.36	0.78	0.76%	0.13
2008Q3	23.97	16.40	7.56	31.56%	1.26
2008Q4	113.67	111.42	2.25	1.98%	0.38
2009Q1	284.03	292.74	-8.71	-3.07%	(1.46)
2009Q2	102.74	99.24	3.50	3.41%	0.58
2009Q3	28.92	17.49	11.43	39.51%	1.91
2009Q4	103.01	105.86	-2.85	-2.76%	(0.48)
2010Q1	280.10	277.99	2.11	0.75%	0.35
2010Q2	78.99	80.08	-1.10	-1.39%	(0.18)
2010Q3	21.34	18.49	2.85	13.35%	0.48
2010Q4	111.52	113.10	-1.58	-1.42%	(0.26)
2011Q1	292.63	291.14	1.49	0.51%	0.25
2011Q2	105.08	106.17	-1.08	-1.03%	(0.18)
2011Q3	20.52	19.07	1.45	7.08%	0.24
2011Q4	93.63	95.51	-1.88	-2.01%	(0.31)
2012Q1	234.84	243.30	-8.46	-3.60%	(1.41)
2012Q2	77.96	86.45	-8.49	-10.89%	(1.42)
2012Q3	21.21	20.04	1.16	5.49%	0.19
2012Q4	108.42	109.12	-0.70	-0.65%	(0.12)
2013Q1	268.83	276.31	-7.48	-2.78%	(1.25)
2013Q2	100.79	106.63	-5.84	-5.80%	(0.98)
2013Q3	20.35	20.90	-0.55	-2.71%	(0.09)
2013Q4	118.26	120.57	-2.31	-1.96%	(0.39)
2014Q1	304.78	310.07	-5.28	-1.73%	(0.88)
2014Q2	108.04	110.48	-2.44	-2.26%	(0.41)
2014Q3	20.77	21.65	-0.88	-4.22%	(0.15)
2014Q4	110.97	114.74	-3.77	-3.40%	(0.63)
2015Q1	339.29	325.23	14.06	4.15%	2.35
2015Q2	120.44	110.78	9.66	8.02%	1.61
2015Q3	25.75	22.20	3.55	13.79%	0.59
2015Q4	95.18	101.56	-6.38	-6.70%	(1.07)
2016Q1	246.41	248.65	-2.24	-0.91%	(0.37)
2016Q2	109.97	106.12	3.85	3.50%	0.64
2016Q3	22.93	22.88	0.05	0.24%	0.01
2016Q4	106.15	111.08	-4.93	-4.65%	(0.82)
2017Q1	251.20	263.16	-11.96	-4.76%	(2.00)
2017Q2	108.93	113.30	-4.37	-4.01%	(0.73)
2017Q3	17.90	23.72	-5.82	-32.53%	(0.97)
2017Q4	102.80	101.60	1.21	1.17%	0.20
2018Q1	294.06	284.54	9.52	3.24%	1.59
2018Q2	121.78	113.10	8.69	7.13%	1.45
2018Q3	20.85	24.90	-4.05	-19.42%	(0.68)
2018Q4	134.20	122.52	11.68	8.70%	1.95
2019Q1	287.92	283.70	4.21	1.46%	0.70
2019Q2	110.86	106.79	4.08	3.68%	0.68
2019Q3	21.26	26.08	-4.82	-22.65%	(0.80)
2019Q4	127.09	119.79	7.31	5.75%	1.22
2020Q1	250.26	243.32	6.94	2.77%	1.16
2020Q2	110.31	118.91	-8.60	-7.79%	(1.44)
2020Q3	20.92	27.04	-6.12	-29.25%	(1.02)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	127.09	119.13	7.97	6.3%
Q1 2020	250.26	243.07	7.19	2.9%
Q2 2020	110.31	119.84	-9.53	-8.6%
Q3 2020	20.92	27.49	-6.57	-31.4%
Total	508.58	509.52	-0.94	-0.2%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	72.35	73.50	-1.16	-2%
B_LLFNGP_ST_ROLL12	-4.50	-4.57	0.07	-2%
B_Q1_EDD	0.08	0.08	0.00	0%
B_Q4_EDD	0.05	0.05	0.00	1%
B_Q2_EDD	0.07	0.07	0.00	-1%

LLFUPC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
L_LLF_UPC_S_T	6	0.995	3.211

ARIMA Model Parameters

L_LLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	35.72429	2.735	13.06	0.000
	L_LLFNGP_ST_ROLL12*L_D15Q4_AFT	-0.550297	0.267	-2.06	0.045
	L_Q1Q2_EDD	0.105498	0.001	88.92	0.000
	L_Q4_EDD	0.078235	0.002	37.65	0.000
	L_D09Q1	47.26298	10.871	4.35	0.000
	L_D11Q1	32.52522	10.848	3.00	0.004

Variable	Definition	Explanation	Dummy Variable Support
L_LLFNGP_ST_ROLL12*L_D15Q4_AFT	Rolling 12 quarter natural gas price for low load factor customers in Lawrence ($2020/MMBtu) after 2015Q4		
L_Q1Q2_EDD	Effective Degree Days in Brockton in Q1 and Q2	A	
L_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
L_D09Q1	Binary variable equal to 1 in 2009Q1		2
L_D11Q1	Binary variable equal to 1 in 2011Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
52	0.994598	1878.886

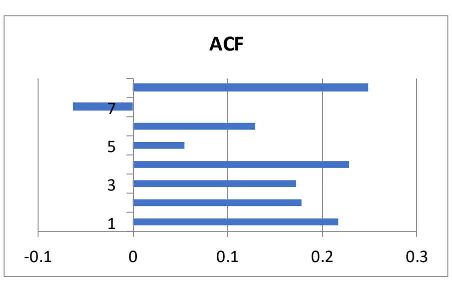
Chow Test Stats	N	k	SSR
Combined	52	6	4,890.80
1	28	5	2,893.22
2	24	4	1,742.64

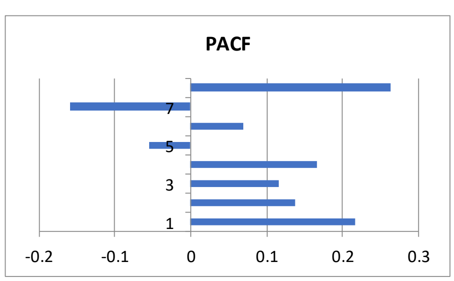
Chow Stat:	0.367
P-Value:	0.895719

Heteroscedasticity - White's Test	
White Stat	0.28
Significance (p-value)	0.92

Correlations

	L_LLFNGP_ST_ROLL12*L_D15Q4_AFT	L_Q1Q2_EDD	L_Q4_EDD	L_D09Q1	L_D11Q1
L_LLFNGP_ST_ROLL12*L_D15Q4_AFT	1	-0.019892	-0.005641	-0.110612	-0.11061
L_Q1Q2_EDD	-0.019892	1	-0.484483	0.246511	0.238839
L_Q4_EDD	-0.005641	-0.484483	1	-0.080503	-0.0805
L_D09Q1	-0.110612	0.246511	-0.080503	1	-0.01961
L_D11Q1	-0.110612	0.238839	-0.080503	-0.019608	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_llf_upc_s_t Model	ACF	0.217	0.178	0.172	0.229	0.055	0.129	-0.063	0.249
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277	0.277
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_llf_upc_s_t Model		0.217	0.137	0.116	0.167	-0.054	0.069	-0.159	0.264
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277	0.277

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2007Q4	180.79	179.71	1.08	0.60%	0.11
2008Q1	421.01	404.87	16.13	3.83%	1.65
2008Q2	184.22	188.37	-4.14	-2.25%	(0.42)
2008Q3	38.62	35.72	2.90	7.50%	0.30
2008Q4	186.76	184.68	2.07	1.11%	0.21
2009Q1	484.71	484.71	0.00	0.00%	(0.00)
2009Q2	199.89	176.15	23.74	11.88%	2.42
2009Q3	59.14	35.72	23.42	39.60%	2.39
2009Q4	180.56	176.61	3.95	2.19%	0.40
2010Q1	430.85	410.47	20.38	4.73%	2.08
2010Q2	143.89	147.90	-4.01	-2.79%	(0.41)
2010Q3	36.23	35.72	0.51	1.41%	0.05
2010Q4	184.28	185.32	-1.04	-0.56%	(0.11)
2011Q1	461.52	461.52	0.00	0.00%	(0.00)
2011Q2	187.96	188.31	-0.35	-0.18%	(0.04)
2011Q3	39.76	35.72	4.04	10.16%	0.41
2011Q4	152.71	155.32	-2.60	-1.70%	(0.27)
2012Q1	369.33	366.42	2.91	0.79%	0.30
2012Q2	138.15	153.83	-15.68	-11.35%	(1.60)
2012Q3	37.49	35.72	1.76	4.70%	0.18
2012Q4	169.69	176.54	-6.85	-4.04%	(0.70)
2013Q1	394.03	408.75	-14.72	-3.73%	(1.50)
2013Q2	168.33	185.88	-17.56	-10.43%	(1.79)
2013Q3	31.33	35.72	-4.39	-14.01%	(0.45)
2013Q4	176.73	193.10	-16.37	-9.26%	(1.67)
2014Q1	453.90	456.68	-2.78	-0.61%	(0.28)
2014Q2	191.77	193.13	-1.36	-0.71%	(0.14)
2014Q3	33.89	35.72	-1.83	-5.40%	(0.19)
2014Q4	177.97	182.08	-4.10	-2.31%	(0.42)
2015Q1	479.21	475.48	3.74	0.78%	0.38
2015Q2	183.01	191.08	-8.06	-4.41%	(0.82)
2015Q3	33.64	35.72	-2.08	-6.18%	(0.21)
2015Q4	150.66	157.43	-6.78	-4.50%	(0.69)
2016Q1	369.81	361.18	8.63	2.33%	0.88
2016Q2	169.16	175.78	-6.63	-3.92%	(0.68)
2016Q3	38.66	29.36	9.30	24.06%	0.95
2016Q4	163.82	169.52	-5.70	-3.48%	(0.58)
2017Q1	367.38	379.69	-12.31	-3.35%	(1.26)
2017Q2	174.66	188.08	-13.41	-7.68%	(1.37)
2017Q3	30.33	29.47	0.85	2.82%	0.09
2017Q4	157.72	152.96	4.76	3.02%	0.49
2018Q1	415.52	413.62	1.90	0.46%	0.19
2018Q2	168.12	184.13	-16.01	-9.52%	(1.63)
2018Q3	33.80	29.62	4.18	12.37%	0.43
2018Q4	199.94	186.93	13.01	6.51%	1.33
2019Q1	417.58	408.76	8.82	2.11%	0.90
2019Q2	172.45	174.62	-2.17	-1.26%	(0.22)
2019Q3	34.25	29.78	4.47	13.05%	0.46
2019Q4	194.91	177.11	17.81	9.14%	1.82
2020Q1	352.32	353.11	-0.79	-0.22%	(0.08)
2020Q2	161.86	177.22	-15.36	-9.49%	(1.57)
2020Q3	36.64	29.90	6.74	18.39%	0.69

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	194.91	175.16	19.76	10.1%
Q1 2020	352.32	353.27	-0.95	-0.3%
Q2 2020	161.86	177.18	-15.32	-9.5%
Q3 2020	36.64	29.68	6.96	19.0%
Total	745.73	735.29	10.45	1.4%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	35.72	36.02	-0.29	-1%
L_LLFNGP_ST_ROLL12*L_D15Q4_AFT	-0.55	-0.60	0.05	-9%
L_Q1Q2_EDD	0.11	0.11	0.00	0%
L_Q4_EDD	0.08	0.08	0.00	1%
L_D09Q1	47.26	46.48	0.78	2%
L_D11Q1	32.53	31.76	0.77	2%

LLFUPC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_LLF_UPC_S_T	7	0.997	2.668

ARIMA Model Parameters

S_LLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	120.3297	20.058	6.00	0.000
	S_LLFNGP_ST_ROLL12	-9.523289	2.121	-4.49	0.000
	S_Q1_EDD	0.09245	0.001	112.00	0.000
	S_Q4_EDD	0.074825	0.002	44.05	0.000
	S_Q2_EDD	0.081174	0.002	33.66	0.000
	D_AFTER20Q1	-15.54624	4.948	-3.14	0.003
	D_13Q1THR17Q2	-7.164696	2.284	-3.14	0.003

Variable	Definition	Explanation	Dummy Variable Support
S_LLFNGP_ST_ROLL12	Rolling 12 quarter natural gas price for low load factor customers in Springfield ($2020/MMBtu)		
S_Q1_EDD	Effective Degree Days in Springfield in Q1	A	
S_Q4_EDD	Effective Degree Days in Springfield in Q4	A	
S_Q2_EDD	Effective Degree Days in Springfield in Q2	A	
D_AFTER20Q1	Binary variable equal to 1 in 2020Q1		2
D_13Q1THR17Q2	Binary variable equal to 1 from 2013Q1 to 2017Q2		1

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
50	0.996295	2196.976

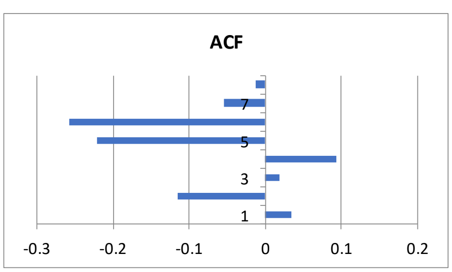
Chow Test Stats	N	k	SSR
Combined	50	7	2,177.78
1	16	5	180.65
2	34	7	1,621.61

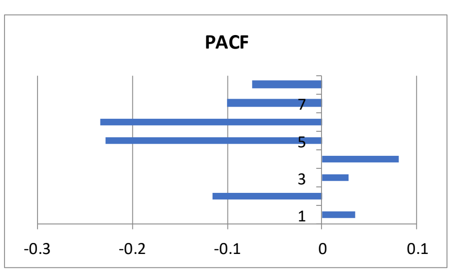
Chow Stat:	1.072
P-Value:	0.401331

Heteroscedasticity - White's Test	
White Stat	0.63
Significance (p-value)	0.70

Correlations

	S_LLFNGP_ST_ROLL12	S_Q1_EDD	S_Q4_EDD	S_Q2_EDD	D_AFTER20Q1	D_13Q1THR17Q2
S_LLFNGP_ST_ROLL12	1	-0.016921	0.014714	-0.00791	-0.401775	-0.21867
S_Q1_EDD	-0.016921	1	-0.312615	-0.327572	0.035068	0.073495
S_Q4_EDD	0.014714	-0.312615	1	-0.327923	-0.141335	-0.036619
S_Q2_EDD	-0.00791	-0.327572	-0.327923	1	0.080964	0.050377
D_AFTER20Q1	-0.401775	0.035068	-0.141335	0.080964	1	-0.189484
D_13Q1THR17Q2	-0.21867	0.073495	-0.036619	0.050377	-0.189484	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_llf_upc_s_t Model	ACF	0.035	-0.115	0.019	0.094	-0.221	-0.257	-0.054	-0.012
	SE	0.283	0.283	0.283	0.283	0.283	0.283	0.283	0.283
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_llf_upc_s_t Model		0.035	-0.116	0.028	0.08	-0.228	-0.234	-0.1	-0.073
	SE	0.283	0.283	0.283	0.283	0.283	0.283	0.283	0.283

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2008Q2	102.49	115.46	-12.97	-12.65%	(1.95)
2008Q3	25.89	22.63	3.26	12.61%	0.49
2008Q4	151.44	155.46	-4.01	-2.65%	(0.60)
2009Q1	359.92	361.97	-2.05	-0.57%	(0.31)
2009Q2	118.90	117.23	1.66	1.40%	0.25
2009Q3	33.56	25.43	8.13	24.23%	1.22
2009Q4	148.75	150.99	-2.23	-1.50%	(0.33)
2010Q1	339.00	340.68	-1.68	-0.50%	(0.25)
2010Q2	98.19	94.10	4.09	4.17%	0.61
2010Q3	33.58	27.60	5.99	17.82%	0.90
2010Q4	160.15	159.43	0.72	0.45%	0.11
2011Q1	356.53	364.82	-8.29	-2.33%	(1.24)
2011Q2	127.98	123.73	4.25	3.32%	0.64
2011Q3	32.97	28.46	4.51	13.67%	0.68
2011Q4	140.99	137.28	3.71	2.63%	0.56
2012Q1	302.78	297.62	5.15	1.70%	0.77
2012Q2	98.46	98.80	-0.34	-0.34%	(0.05)
2012Q3	35.23	29.95	5.28	15.00%	0.79
2012Q4	156.26	152.51	3.75	2.40%	0.56
2013Q1	319.39	336.36	-16.96	-5.31%	(2.54)
2013Q2	110.31	120.85	-10.54	-9.56%	(1.58)
2013Q3	23.78	24.51	-0.73	-3.09%	(0.11)
2013Q4	157.72	161.94	-4.22	-2.68%	(0.63)
2014Q1	383.04	381.71	1.33	0.35%	0.20
2014Q2	132.69	123.51	9.18	6.92%	1.38
2014Q3	29.25	26.25	3.00	10.26%	0.45
2014Q4	150.10	149.05	1.05	0.70%	0.16
2015Q1	405.18	392.22	12.96	3.20%	1.94
2015Q2	132.74	120.74	12.00	9.04%	1.80
2015Q3	30.07	27.75	2.33	7.74%	0.35
2015Q4	125.20	135.40	-10.20	-8.14%	(1.53)
2016Q1	304.33	306.42	-2.10	-0.69%	(0.31)
2016Q2	121.11	122.74	-1.63	-1.35%	(0.24)
2016Q3	29.84	28.84	1.00	3.35%	0.15
2016Q4	151.86	154.26	-2.40	-1.58%	(0.36)
2017Q1	327.69	323.93	3.75	1.15%	0.56
2017Q2	132.66	130.48	2.18	1.65%	0.33
2017Q3	25.74	36.69	-10.94	-42.51%	(1.64)
2017Q4	152.59	150.49	2.10	1.38%	0.32
2018Q1	362.06	363.50	-1.44	-0.40%	(0.22)
2018Q2	140.01	141.54	-1.53	-1.09%	(0.23)
2018Q3	25.80	37.85	-12.04	-46.68%	(1.81)
2018Q4	187.31	180.49	6.82	3.64%	1.02
2019Q1	361.20	362.06	-0.86	-0.24%	(0.13)
2019Q2	132.67	126.42	6.25	4.71%	0.94
2019Q3	28.51	39.55	-11.04	-38.73%	(1.66)
2019Q4	173.97	170.22	3.75	2.16%	0.56
2020Q1	319.83	309.45	10.38	3.24%	1.56
2020Q2	127.76	137.10	-9.33	-7.30%	(1.40)
2020Q3	24.71	25.76	-1.05	-4.24%	(0.16)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	173.97	169.52	4.45	2.6%
Q1 2020	319.83	323.88	-4.05	-1.3%
Q2 2020	127.76	153.45	-25.69	-20.1%
Q3 2020	24.71	40.79	-16.08	-65.1%
Total	646.28	687.65	-41.37	-6.4%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	120.33	117.44	2.89	2%
S_LLFNGP_ST_ROLL12	-9.52	-9.24	-0.29	3%
S_Q1_EDD	0.09	0.09	0.00	0%
S_Q4_EDD	0.07	0.07	0.00	0%
S_Q2_EDD	0.08	0.08	0.00	-1%
D_AFTER20Q1	-15.55			
D_13Q1THR17Q2	-7.16	-6.94	-0.22	3%

RNHUPC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_RNH_UPC_S_T	6	0.978	0.459

ARIMA Model Parameters

S_RNH_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	4.049814	0.321	12.63	0.000
	S_RHNGP	-0.035175	0.020	-1.72	0.093
	S_Q1_EDD+S_Q4_EDD	0.001004	0.000	39.33	0.000
	S_Q2_EDD	0.001329	0.000	18.72	0.000
	S_D13Q1	1.18911	0.224	5.31	0.000
	D_AFTER15Q2*S_RHNGP	-0.029619	0.005	-6.24	0.000

Variable	Definition	Explanation	Dummy Variable Support
S_RHNGP	Natural gas price for residential non heating customers in Springfield ($2020)		
S_Q1_EDD+S_Q4_EDD	Effective Degree Days in Springfield in Q1 and Q4	A	
S_Q2_EDD	Effective Degree Days in Springfield in Q2	A	
S_D13Q1	Binary variable equal to 1 in 2013Q1		2
D_AFTER15Q2*S_RHNGP	Natural gas price for residential non heating customers in Springfield ($2020) after 2015Q2	B	

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

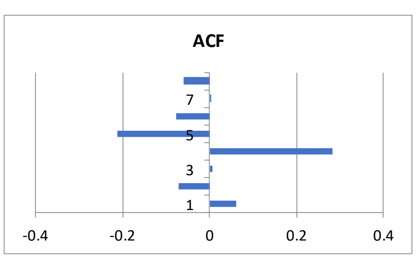
N	Adjusted R2	F Statistic
48	0.975194	370.5374

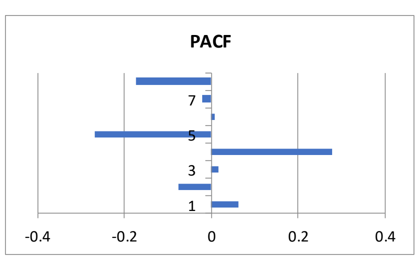
Chow Test Stats	N	k	SSR
Combined	48	6	1.86
1	24	5	1.05
2	24	5	0.38

Chow Stat:	1.762
P-Value:	0.13497

Heteroscedasticity - White's Test	
White Stat	1.89
Significance (p-value)	0.12

Correlations	S_RHNGP	S_Q1_EDD+S_Q4_EDD	S_Q2_EDD	S_D13Q1	D_AFTER15Q2*S_RHNGP
S_RHNGP	1	0.105992	-0.011113	-0.112944	-0.39415
S_Q1_EDD+S_Q4_EDD	0.105992	1	-0.508971	0.215774	-0.102197
S_Q2_EDD	-0.011113	-0.508971	1	-0.083218	0.089149
S_D13Q1	-0.112944	0.215774	-0.083218	1	-0.133158
D_AFTER15Q2*S_RHNGP	-0.39415	-0.102197	0.089149	-0.133158	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_rnh_upc_s_t Model	ACF	0.062	-0.071	0.007	0.282	-0.211	-0.076	0.002	-0.061
	SE	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_rnh_upc_s_t Model		0.062	-0.076	0.017	0.278	-0.268	0.008	-0.02	-0.174
	SE	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2008Q4	5.07	5.12	-0.05	-1.06%	(0.27)
2009Q1	6.53	7.02	-0.49	-7.48%	(2.46)
2009Q2	5.06	4.90	0.16	3.17%	0.81
2009Q3	3.68	3.47	0.21	5.64%	1.04
2009Q4	4.98	5.19	-0.20	-4.10%	(1.03)
2010Q1	6.31	6.94	-0.63	-10.07%	(3.19)
2010Q2	4.72	4.64	0.08	1.69%	0.40
2010Q3	3.50	3.52	-0.02	-0.64%	(0.11)
2010Q4	5.09	5.27	-0.18	-3.63%	(0.93)
2011Q1	7.20	7.16	0.04	0.50%	0.18
2011Q2	5.13	5.06	0.07	1.32%	0.34
2011Q3	3.61	3.50	0.11	3.05%	0.55
2011Q4	5.28	4.97	0.31	5.95%	1.58
2012Q1	6.71	6.44	0.27	4.05%	1.37
2012Q2	4.69	4.67	0.02	0.42%	0.10
2012Q3	3.36	3.55	-0.19	-5.67%	(0.96)
2012Q4	5.51	5.20	0.31	5.57%	1.54
2013Q1	8.15	8.15	0.00	0.00%	0.00
2013Q2	5.32	5.14	0.18	3.40%	0.91
2013Q3	3.43	3.53	-0.10	-2.91%	(0.50)
2013Q4	5.63	5.36	0.27	4.80%	1.36
2014Q1	7.35	7.37	-0.02	-0.32%	(0.12)
2014Q2	5.01	5.06	-0.05	-1.06%	(0.27)
2014Q3	3.50	3.48	0.02	0.64%	0.11
2014Q4	4.97	5.11	-0.13	-2.70%	(0.68)
2015Q1	7.60	7.43	0.17	2.21%	0.85
2015Q2	4.79	4.59	0.20	4.08%	0.98
2015Q3	3.29	3.09	0.20	6.13%	1.02
2015Q4	4.51	4.60	-0.09	-2.05%	(0.46)
2016Q1	6.21	6.26	-0.04	-0.72%	(0.22)
2016Q2	4.60	4.83	-0.23	-4.97%	(1.15)
2016Q3	3.15	3.28	-0.13	-4.07%	(0.64)
2016Q4	4.64	4.93	-0.30	-6.39%	(1.49)
2017Q1	6.63	6.42	0.21	3.19%	1.06
2017Q2	4.89	4.84	0.05	1.09%	0.27
2017Q3	3.17	3.18	-0.01	-0.40%	(0.06)
2017Q4	4.74	4.69	0.05	1.06%	0.25
2018Q1	6.98	6.66	0.31	4.49%	1.58
2018Q2	4.69	4.73	-0.05	-1.00%	(0.24)
2018Q3	3.05	3.02	0.04	1.15%	0.18
2018Q4	4.99	4.92	0.07	1.38%	0.35
2019Q1	6.75	6.53	0.21	3.17%	1.07
2019Q2	4.41	4.50	-0.09	-2.03%	(0.45)
2019Q3	3.01	3.07	-0.05	-1.74%	(0.26)
2019Q4	4.70	4.83	-0.13	-2.68%	(0.63)
2020Q1	6.27	6.20	0.07	1.15%	0.36
2020Q2	4.68	4.95	-0.27	-5.68%	(1.34)
2020Q3	2.98	3.14	-0.16	-5.32%	(0.80)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	4.70	4.85	-0.15	-3.1%
Q1 2020	6.27	6.21	0.06	0.9%
Q2 2020	4.68	5.00	-0.31	-6.7%
Q3 2020	2.98	3.16	-0.18	-6.2%
Total	18.63	19.22	-0.59	-3.2%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	4.05	4.03	0.01	0%
S_RHNGP	-0.04	-0.03	0.00	3%
S_Q1_EDD+S_Q4_EDD	0.00	0.00	0.00	0%
S_Q2_EDD	0.00	0.00	0.00	-1%
S_D13Q1	1.19	1.20	-0.01	-1%
D_AFTER15Q2*S_RHNGP	-0.03	-0.03	0.00	6%

LLFUPC Brockton S&T
C. Low Load Factor User Per Customer - Sales & Transportation
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
B_LLF_UPC_S_T	5	0.996	2.498

ARIMA Model Parameters

B_LLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	72.34755	14.400	5.02	0.000
	B_LLFNGP_ST_ROLL12	-4.50078	1.267	-3.55	0.001
	B_Q1_EDD	0.07619	0.001	105.86	0.000
	B_Q4_EDD	0.05367	0.001	36.10	0.000
	B_Q2_EDD	0.065809	0.002	34.49	0.000

Variable	Definition	Explanation	Dummy Variable Support
B_LLFNGP_ST_ROLL12	Rolling 12 quarter natural gas price for low load factor customers in Brockton ($2020/MMBtu)		
B_Q1_EDD	Effective Degree Days in Brockton in Q1	A	
B_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
B_Q2_EDD	Effective Degree Days in Brockton in Q2	A	

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

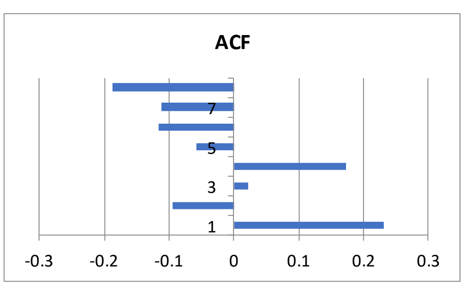
N	Adjusted R2	F Statistic
51	0.995757	2934.799

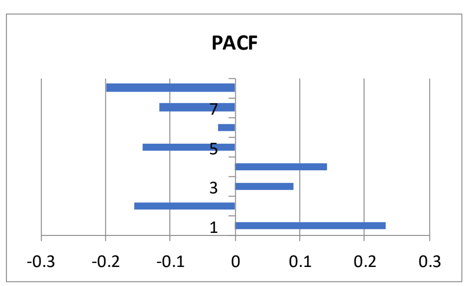
Chow Test Stats	N	k	SSR
Combined	51	5	1,791.23
1	29	5	667.83
2	22	5	853.28

Chow Stat:	1.456
P-Value:	0.225104

Heteroscedasticity - White's Test	
White Stat	2.57
Significance (p-value)	0.05

Correlations	B_LLFNGP_ST_ROLL12	B_Q1_EDD	B_Q4_EDD	B_Q2_EDD
B_LLFNGP_ST_ROLL12	1	0.059006	-0.001724	-0.025317
B_Q1_EDD	0.059006	1	-0.32101	-0.337562
B_Q4_EDD	-0.001724	-0.32101	1	-0.320635
B_Q2_EDD	-0.025317	-0.337562	-0.320635	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_llf_upc_s_t Model	ACF	0.232	-0.094	0.022	0.173	-0.057	-0.115	-0.112	-0.188
	SE	0.280	0.280	0.280	0.280	0.280	0.280	0.280	0.280
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_llf_upc_s_t Model		0.232	-0.156	0.09	0.141	-0.143	-0.027	-0.117	-0.198
	SE	0.280	0.280	0.280	0.280	0.280	0.280	0.280	0.280

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2008Q1	267.17	263.86	3.30	1.24%	0.55
2008Q2	102.13	101.36	0.78	0.76%	0.13
2008Q3	23.97	16.40	7.56	31.56%	1.26
2008Q4	113.67	111.42	2.25	1.98%	0.38
2009Q1	284.03	292.74	-8.71	-3.07%	(1.46)
2009Q2	102.74	99.24	3.50	3.41%	0.58
2009Q3	28.92	17.49	11.43	39.51%	1.91
2009Q4	103.01	105.86	-2.85	-2.76%	(0.48)
2010Q1	280.10	277.99	2.11	0.75%	0.35
2010Q2	78.99	80.08	-1.10	-1.39%	(0.18)
2010Q3	21.34	18.49	2.85	13.35%	0.48
2010Q4	111.52	113.10	-1.58	-1.42%	(0.26)
2011Q1	292.63	291.14	1.49	0.51%	0.25
2011Q2	105.08	106.17	-1.08	-1.03%	(0.18)
2011Q3	20.52	19.07	1.45	7.08%	0.24
2011Q4	93.63	95.51	-1.88	-2.01%	(0.31)
2012Q1	234.84	243.30	-8.46	-3.60%	(1.41)
2012Q2	77.96	86.45	-8.49	-10.89%	(1.42)
2012Q3	21.21	20.04	1.16	5.49%	0.19
2012Q4	108.42	109.12	-0.70	-0.65%	(0.12)
2013Q1	268.83	276.31	-7.48	-2.78%	(1.25)
2013Q2	100.79	106.63	-5.84	-5.80%	(0.98)
2013Q3	20.35	20.90	-0.55	-2.71%	(0.09)
2013Q4	118.26	120.57	-2.31	-1.96%	(0.39)
2014Q1	304.78	310.07	-5.28	-1.73%	(0.88)
2014Q2	108.04	110.48	-2.44	-2.26%	(0.41)
2014Q3	20.77	21.65	-0.88	-4.22%	(0.15)
2014Q4	110.97	114.74	-3.77	-3.40%	(0.63)
2015Q1	339.29	325.23	14.06	4.15%	2.35
2015Q2	120.44	110.78	9.66	8.02%	1.61
2015Q3	25.75	22.20	3.55	13.79%	0.59
2015Q4	95.18	101.56	-6.38	-6.70%	(1.07)
2016Q1	246.41	248.65	-2.24	-0.91%	(0.37)
2016Q2	109.97	106.12	3.85	3.50%	0.64
2016Q3	22.93	22.88	0.05	0.24%	0.01
2016Q4	106.15	111.08	-4.93	-4.65%	(0.82)
2017Q1	251.20	263.16	-11.96	-4.76%	(2.00)
2017Q2	108.93	113.30	-4.37	-4.01%	(0.73)
2017Q3	17.90	23.72	-5.82	-32.53%	(0.97)
2017Q4	102.80	101.60	1.21	1.17%	0.20
2018Q1	294.06	284.54	9.52	3.24%	1.59
2018Q2	121.78	113.10	8.69	7.13%	1.45
2018Q3	20.85	24.90	-4.05	-19.42%	(0.68)
2018Q4	134.20	122.52	11.68	8.70%	1.95
2019Q1	287.92	283.70	4.21	1.46%	0.70
2019Q2	110.86	106.79	4.08	3.68%	0.68
2019Q3	21.26	26.08	-4.82	-22.65%	(0.80)
2019Q4	127.09	119.79	7.31	5.75%	1.22
2020Q1	250.26	243.32	6.94	2.77%	1.16
2020Q2	110.31	118.91	-8.60	-7.79%	(1.44)
2020Q3	20.92	27.04	-6.12	-29.25%	(1.02)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	127.09	119.13	7.97	6.3%
Q1 2020	250.26	243.07	7.19	2.9%
Q2 2020	110.31	119.84	-9.53	-8.6%
Q3 2020	20.92	27.49	-6.57	-31.4%
Total	508.58	509.52	-0.94	-0.2%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	72.35	73.50	-1.16	-2%
B_LLFNGP_ST_ROLL12	-4.50	-4.57	0.07	-2%
B_Q1_EDD	0.08	0.08	0.00	0%
B_Q4_EDD	0.05	0.05	0.00	1%
B_Q2_EDD	0.07	0.07	0.00	-1%

LLFUPC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
L_LLF_UPC_S_T	6	0.995	3.211

ARIMA Model Parameters

L_LLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	35.72429	2.735	13.06	0.000
	L_LLFNGP_ST_ROLL12* L_D15Q4_AFT	-0.550297	0.267	-2.06	0.045
	L_Q1Q2_EDD	0.105498	0.001	88.92	0.000
	L_Q4_EDD	0.078235	0.002	37.65	0.000
	L_D09Q1	47.26298	10.871	4.35	0.000
	L_D11Q1	32.52522	10.848	3.00	0.004

Variable	Definition	Explanation	Dummy Variable Support
L_LLFNGP_ST_ROLL12*L_D15Q4_AFT	Rolling 12 quarter natural gas price for low load factor customers in Lawrence ($2020/MMBtu) after 2015Q4		
L_Q1Q2_EDD	Effective Degree Days in Brockton in Q1 and Q2	A	
L_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
L_D09Q1	Binary variable equal to 1 in 2009Q1		2
L_D11Q1	Binary variable equal to 1 in 2011Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
52	0.994598	1878.886

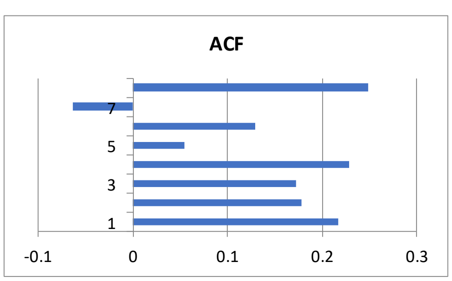
Chow Test Stats	N	k	SSR
Combined	52	6	4,890.80
1	28	5	2,893.22
2	24	4	1,742.64

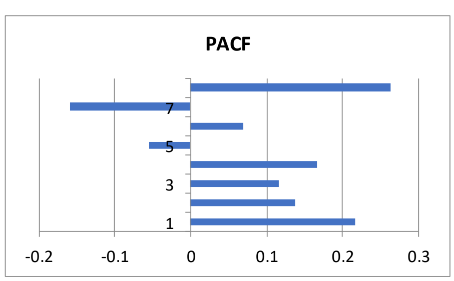
Chow Stat:	0.367
P-Value:	0.895719

Heteroscedasticity - White's Test	
White Stat	0.28
Significance (p-value)	0.92

Correlations

	L_LLFNGP_ST_ROLL12* L_D15Q4_AFT	L_Q1Q2_EDD	L_Q4_EDD	L_D09Q1	L_D11Q1
L_LLFNGP_ST_ROLL12*L_D15Q4_AFT	1	-0.019892	-0.005641	-0.110612	-0.11061
L_Q1Q2_EDD	-0.019892	1	-0.484483	0.246511	0.238839
L_Q4_EDD	-0.005641	-0.484483	1	-0.080503	-0.0805
L_D09Q1	-0.110612	0.246511	-0.080503	1	-0.01961
L_D11Q1	-0.110612	0.238839	-0.080503	-0.019608	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_llf_upc_s_t Model	ACF	0.217	0.178	0.172	0.229	0.055	0.129	-0.063	0.249
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277	0.277
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_llf_upc_s_t Model		0.217	0.137	0.116	0.167	-0.054	0.069	-0.159	0.264
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277	0.277

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2007Q4	180.79	179.71	1.08	0.60%	0.11
2008Q1	421.01	404.87	16.13	3.83%	1.65
2008Q2	184.22	188.37	-4.14	-2.25%	(0.42)
2008Q3	38.62	35.72	2.90	7.50%	0.30
2008Q4	186.76	184.68	2.07	1.11%	0.21
2009Q1	484.71	484.71	0.00	0.00%	(0.00)
2009Q2	199.89	176.15	23.74	11.88%	2.42
2009Q3	59.14	35.72	23.42	39.60%	2.39
2009Q4	180.56	176.61	3.95	2.19%	0.40
2010Q1	430.85	410.47	20.38	4.73%	2.08
2010Q2	143.89	147.90	-4.01	-2.79%	(0.41)
2010Q3	36.23	35.72	0.51	1.41%	0.05
2010Q4	184.28	185.32	-1.04	-0.56%	(0.11)
2011Q1	461.52	461.52	0.00	0.00%	(0.00)
2011Q2	187.96	188.31	-0.35	-0.18%	(0.04)
2011Q3	39.76	35.72	4.04	10.16%	0.41
2011Q4	152.71	155.32	-2.60	-1.70%	(0.27)
2012Q1	369.33	366.42	2.91	0.79%	0.30
2012Q2	138.15	153.83	-15.68	-11.35%	(1.60)
2012Q3	37.49	35.72	1.76	4.70%	0.18
2012Q4	169.69	176.54	-6.85	-4.04%	(0.70)
2013Q1	394.03	408.75	-14.72	-3.73%	(1.50)
2013Q2	168.33	185.88	-17.56	-10.43%	(1.79)
2013Q3	31.33	35.72	-4.39	-14.01%	(0.45)
2013Q4	176.73	193.10	-16.37	-9.26%	(1.67)
2014Q1	453.90	456.68	-2.78	-0.61%	(0.28)
2014Q2	191.77	193.13	-1.36	-0.71%	(0.14)
2014Q3	33.89	35.72	-1.83	-5.40%	(0.19)
2014Q4	177.97	182.08	-4.10	-2.31%	(0.42)
2015Q1	479.21	475.48	3.74	0.78%	0.38
2015Q2	183.01	191.08	-8.06	-4.41%	(0.82)
2015Q3	33.64	35.72	-2.08	-6.18%	(0.21)
2015Q4	150.66	157.43	-6.78	-4.50%	(0.69)
2016Q1	369.81	361.18	8.63	2.33%	0.88
2016Q2	169.16	175.78	-6.63	-3.92%	(0.68)
2016Q3	38.66	29.36	9.30	24.06%	0.95
2016Q4	163.82	169.52	-5.70	-3.48%	(0.58)
2017Q1	367.38	379.69	-12.31	-3.35%	(1.26)
2017Q2	174.66	188.08	-13.41	-7.68%	(1.37)
2017Q3	30.33	29.47	0.85	2.82%	0.09
2017Q4	157.72	152.96	4.76	3.02%	0.49
2018Q1	415.52	413.62	1.90	0.46%	0.19
2018Q2	168.12	184.13	-16.01	-9.52%	(1.63)
2018Q3	33.80	29.62	4.18	12.37%	0.43
2018Q4	199.94	186.93	13.01	6.51%	1.33
2019Q1	417.58	408.76	8.82	2.11%	0.90
2019Q2	172.45	174.62	-2.17	-1.26%	(0.22)
2019Q3	34.25	29.78	4.47	13.05%	0.46
2019Q4	194.91	177.11	17.81	9.14%	1.82
2020Q1	352.32	353.11	-0.79	-0.22%	(0.08)
2020Q2	161.86	177.22	-15.36	-9.49%	(1.57)
2020Q3	36.64	29.90	6.74	18.39%	0.69

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	194.91	175.16	19.76	10.1%
Q1 2020	352.32	353.27	-0.95	-0.3%
Q2 2020	161.86	177.18	-15.32	-9.5%
Q3 2020	36.64	29.68	6.96	19.0%
Total	745.73	735.29	10.45	1.4%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	35.72	36.02	-0.29	-1%
L_LLFNGP_ST_ROLL12*L_D15Q4_AFT	-0.55	-0.60	0.05	-9%
L_Q1Q2_EDD	0.11	0.11	0.00	0%
L_Q4_EDD	0.08	0.08	0.00	1%
L_D09Q1	47.26	46.48	0.78	2%
L_D11Q1	32.53	31.76	0.77	2%

LLFUPC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
S_LLF_UPC_S_T	7	0.997	2.668

ARIMA Model Parameters

S_LLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	120.3297	20.058	6.00	0.000
	S_LLFNGP_ST_ROLL12	-9.523289	2.121	-4.49	0.000
	S_Q1_EDD	0.09245	0.001	112.00	0.000
	S_Q4_EDD	0.074825	0.002	44.05	0.000
	S_Q2_EDD	0.081174	0.002	33.66	0.000
	D_AFTER20Q1	-15.54624	4.948	-3.14	0.003
	D_13Q1THR17Q2	-7.164696	2.284	-3.14	0.003

Variable	Definition	Explanation	Dummy Variable Support
S_LLFNGP_ST_ROLL12	Rolling 12 quarter natural gas price for low load factor customers in Springfield ($2020/MMBtu)		
S_Q1_EDD	Effective Degree Days in Springfield in Q1	A	
S_Q4_EDD	Effective Degree Days in Springfield in Q4	A	
S_Q2_EDD	Effective Degree Days in Springfield in Q2	A	
D_AFTER20Q1	Binary variable equal to 1 in 2020Q1		2
D_13Q1THR17Q2	Binary variable equal to 1 from 2013Q1 to 2017Q2		1

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
50	0.996295	2196.976

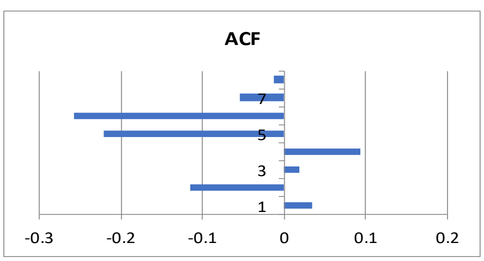
Chow Test Stats	N	k	SSR
Combined	50	7	2,177.78
1	16	5	180.65
2	34	7	1,621.61

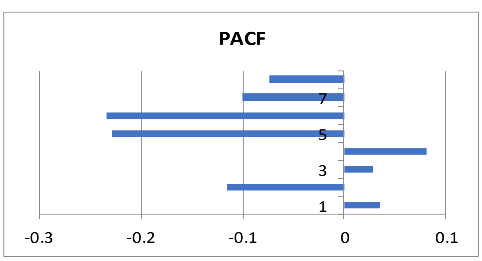
Chow Stat:	1.072
P-Value:	0.401331

Heteroscedasticity - White's Test	
White Stat	0.63
Significance (p-value)	0.70

Correlations

	S_LLFNGP_ST_ROLL12	S_Q1_EDD	S_Q4_EDD	S_Q2_EDD	D_AFTER20Q1	D_13Q1THR17Q2
S_LLFNGP_ST_ROLL12	1	-0.016921	0.014714	-0.00791	-0.401775	-0.21867
S_Q1_EDD	-0.016921	1	-0.312615	-0.327572	0.035068	0.073495
S_Q4_EDD	0.014714	-0.312615	1	-0.327923	-0.141335	-0.036619
S_Q2_EDD	-0.00791	-0.327572	-0.327923	1	0.080964	0.050377
D_AFTER20Q1	-0.401775	0.035068	-0.141335	0.080964	1	-0.189484
D_13Q1THR17Q2	-0.21867	0.073495	-0.036619	0.050377	-0.189484	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_llf_upc_s_t Model	ACF	0.035	-0.115	0.019	0.094	-0.221	-0.257	-0.054	-0.012
	SE	0.283	0.283	0.283	0.283	0.283	0.283	0.283	0.283
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_llf_upc_s_t Model		0.035	-0.116	0.028	0.08	-0.228	-0.234	-0.1	-0.073
	SE	0.283	0.283	0.283	0.283	0.283	0.283	0.283	0.283

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2008Q2	102.49	115.46	-12.97	-12.65%	(1.95)
2008Q3	25.89	22.63	3.26	12.61%	0.49
2008Q4	151.44	155.46	-4.01	-2.65%	(0.60)
2009Q1	359.92	361.97	-2.05	-0.57%	(0.31)
2009Q2	118.90	117.23	1.66	1.40%	0.25
2009Q3	33.56	25.43	8.13	24.23%	1.22
2009Q4	148.75	150.99	-2.23	-1.50%	(0.33)
2010Q1	339.00	340.68	-1.68	-0.50%	(0.25)
2010Q2	98.19	94.10	4.09	4.17%	0.61
2010Q3	33.58	27.60	5.99	17.82%	0.90
2010Q4	160.15	159.43	0.72	0.45%	0.11
2011Q1	356.53	364.82	-8.29	-2.33%	(1.24)
2011Q2	127.98	123.73	4.25	3.32%	0.64
2011Q3	32.97	28.46	4.51	13.67%	0.68
2011Q4	140.99	137.28	3.71	2.63%	0.56
2012Q1	302.78	297.62	5.15	1.70%	0.77
2012Q2	98.46	98.80	-0.34	-0.34%	(0.05)
2012Q3	35.23	29.95	5.28	15.00%	0.79
2012Q4	156.26	152.51	3.75	2.40%	0.56
2013Q1	319.39	336.36	-16.96	-5.31%	(2.54)
2013Q2	110.31	120.85	-10.54	-9.56%	(1.58)
2013Q3	23.78	24.51	-0.73	-3.09%	(0.11)
2013Q4	157.72	161.94	-4.22	-2.68%	(0.63)
2014Q1	383.04	381.71	1.33	0.35%	0.20
2014Q2	132.69	123.51	9.18	6.92%	1.38
2014Q3	29.25	26.25	3.00	10.26%	0.45
2014Q4	150.10	149.05	1.05	0.70%	0.16
2015Q1	405.18	392.22	12.96	3.20%	1.94
2015Q2	132.74	120.74	12.00	9.04%	1.80
2015Q3	30.07	27.75	2.33	7.74%	0.35
2015Q4	125.20	135.40	-10.20	-8.14%	(1.53)
2016Q1	304.33	306.42	-2.10	-0.69%	(0.31)
2016Q2	121.11	122.74	-1.63	-1.35%	(0.24)
2016Q3	29.84	28.84	1.00	3.35%	0.15
2016Q4	151.86	154.26	-2.40	-1.58%	(0.36)
2017Q1	327.69	323.93	3.75	1.15%	0.56
2017Q2	132.66	130.48	2.18	1.65%	0.33
2017Q3	25.74	36.69	-10.94	-42.51%	(1.64)
2017Q4	152.59	150.49	2.10	1.38%	0.32
2018Q1	362.06	363.50	-1.44	-0.40%	(0.22)
2018Q2	140.01	141.54	-1.53	-1.09%	(0.23)
2018Q3	25.80	37.85	-12.04	-46.68%	(1.81)
2018Q4	187.31	180.49	6.82	3.64%	1.02
2019Q1	361.20	362.06	-0.86	-0.24%	(0.13)
2019Q2	132.67	126.42	6.25	4.71%	0.94
2019Q3	28.51	39.55	-11.04	-38.73%	(1.66)
2019Q4	173.97	170.22	3.75	2.16%	0.56
2020Q1	319.83	309.45	10.38	3.24%	1.56
2020Q2	127.76	137.10	-9.33	-7.30%	(1.40)
2020Q3	24.71	25.76	-1.05	-4.24%	(0.16)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	173.97	169.52	4.45	2.6%
Q1 2020	319.83	323.88	-4.05	-1.3%
Q2 2020	127.76	153.45	-25.69	-20.1%
Q3 2020	24.71	40.79	-16.08	-65.1%
Total	646.28	687.65	-41.37	-6.4%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	120.33	117.44	2.89	2%
S_LLFNGP_ST_ROLL12	-9.52	-9.24	-0.29	3%
S_Q1_EDD	0.09	0.09	0.00	0%
S_Q4_EDD	0.07	0.07	0.00	0%
S_Q2_EDD	0.08	0.08	0.00	-1%
D_AFTER20Q1	-15.55			
D_13Q1THR17Q2	-7.16	-6.94	-0.22	3%

HLFUPC Brockton S&T
D. High Load Factor User Per Customer - Sales & Transportation
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
B_HLF_UPC_S_T	13	0.983	3.254

ARIMA Model Parameters

B_HLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	641.824	39.856	16.10	0.000
	B_HLFNGP_ST_ROLL12	-46.93347	5.362	-8.75	0.000
	B_Q1_EDD	0.05195	0.001	36.48	0.000
	B_Q2_EDD	0.060766	0.004	15.18	0.000
	B_Q4_EDD	0.040353	0.003	12.62	0.000
	B_D20Q2	-78.80682	11.945	-6.60	0.000
	B_D20Q3	-61.30262	11.779	-5.20	0.000
	B_D2014	27.89165	5.714	4.88	0.000
	B_D16Q4	-28.48168	11.361	-2.51	0.018
	B_D12Q4	-29.94414	11.537	-2.60	0.015
	B_D11Q2	25.19521	11.693	2.15	0.040
	B_D18Q2+B_D18Q1	-21.88076	8.188	-2.67	0.012
	B_D13Q4	25.39844	11.641	2.18	0.038

Variable	Definition	Explanation	Dummy Variable Support
B_HLFNGP_ST_ROLL12	Rolling 12 quarter natural gas price for high load factor sales customers in Brockton ($2020/MMBtu)		
B_Q1_EDD	Effective Degree Days in Brockton in Q1	A	
B_Q2_EDD	Effective Degree Days in Brockton in Q2	A	
B_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
B_D20Q2	Binary variable equal to 1 in 2020Q2		2
B_D20Q3	Binary variable equal to 1 in 2020Q3		2
B_D2014	Binary variable equal to 1 in 2014		2
B_D16Q4	Binary variable equal to 1 in 2016Q4		2
B_D12Q4	Binary variable equal to 1 in 2012Q4		2
B_D11Q2	Binary variable equal to 1 in 2011Q2		2
B_D18Q2+B_D18Q1	Binary variable equal to 1 in 2018Q2 and 2018Q1		2
B_D13Q4	Binary variable equal to 1 in 2013Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
41	0.976398	138.8988

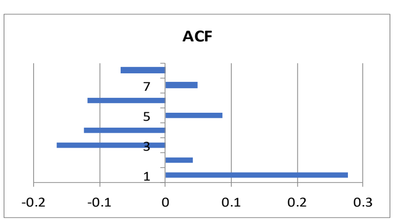
Chow Test Stats	N	k	SSR
Combined	41	13	3,139.55
1	20	9	798.79
2	21	9	985.39

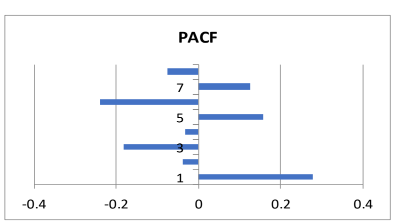
Chow Stat:	0.877
P-Value:	0.590254

Heteroscedasticity - White's Test	
White Stat	1.08
Significance (p-value)	0.41

Correlations

	B_HLFNGP_ST_ROLL12	B_Q1_EDD	B_Q2_EDD	B_Q4_EDD	B_D20Q2	B_D20Q3	B_D2014	B_D16Q4	B_D12Q4	B_D11Q2	B_D18Q2+B_D18Q1	B_D13Q4
B_HLFNGP_ST_ROLL12	1	0.018526	-0.063974	0.044125	-0.2807	-0.293453	0.115191	-0.04181	0.138651	0.220816	-0.18196	0.083816
B_Q1_EDD	0.018526	1	-0.318821	-0.318514	-0.08914	-0.08914	0.030193	-0.08914	-0.08914	-0.08914	0.139968	-0.08914
B_Q2_EDD	-0.063974	-0.318821	1	-0.319502	0.306584	-0.089416	0.013069	-0.08942	-0.08942	0.285665	0.144581	-0.08942
B_Q4_EDD	0.044125	-0.318514	-0.319502	1	-0.08933	-0.08933	0.013627	0.273784	0.277402	-0.08933	-0.127941	0.321097
B_D20Q2	-0.280696	-0.08914	0.306584	-0.08933	1	-0.025	-0.05199	-0.025	-0.025	-0.025	-0.035806	-0.025
B_D20Q3	-0.293453	-0.08914	-0.089416	-0.08933	-0.025	1	-0.05199	-0.025	-0.025	-0.025	-0.035806	-0.025
B_D2014	0.115191	0.030193	0.013069	0.013627	-0.05199	-0.051988	1	-0.05199	-0.05199	-0.05199	-0.074458	-0.05199
B_D16Q4	-0.04181	-0.08914	-0.089416	0.273784	-0.025	-0.025	-0.05199	1	-0.025	-0.025	-0.035806	-0.025
B_D12Q4	0.138651	-0.08914	-0.089416	0.277402	-0.025	-0.025	-0.05199	-0.025	1	-0.025	-0.035806	-0.025
B_D11Q2	0.220816	-0.08914	0.285665	-0.08933	-0.025	-0.025	-0.05199	-0.025	-0.025	1	-0.035806	-0.025
B_D18Q2+B_D18Q1	-0.18196	0.139968	0.144581	-0.127941	-0.03581	-0.035806	-0.07446	-0.03581	-0.03581	-0.03581	1	-0.03581
B_D13Q4	0.083816	-0.08914	-0.089416	0.321097	-0.025	-0.025	-0.05199	-0.025	-0.025	-0.025	-0.035806	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_hlf_upc_s_t Model	ACF	0.277	0.041	-0.166	-0.124	0.087	-0.119	0.049	-0.069
	SE	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_hlf_upc_s_t Model		0.277	-0.039	-0.181	-0.032	0.157	-0.239	0.127	-0.075
	SE	0.312	0.312	0.312	0.312	0.312	0.312	0.312	0.312

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2010Q3	283.26	269.59	13.67	4.82%	1.54
2010Q4	352.28	341.74	10.55	2.99%	1.19
2011Q1	475.11	457.51	17.60	3.70%	1.99
2011Q2	378.56	378.56	0.00	0.00%	0.00
2011Q3	279.47	273.55	5.92	2.12%	0.67
2011Q4	328.75	332.32	-3.57	-1.08%	(0.40)
2012Q1	424.62	429.42	-4.81	-1.13%	(0.54)
2012Q2	339.77	340.19	-0.42	-0.12%	(0.05)
2012Q3	268.16	280.30	-12.14	-4.53%	(1.37)
2012Q4	318.63	318.63	0.00	0.00%	0.00
2013Q1	440.45	457.73	-17.28	-3.92%	(1.95)
2013Q2	350.96	364.06	-13.10	-3.73%	(1.48)
2013Q3	288.61	286.25	2.36	0.82%	0.27
2013Q4	387.89	387.89	0.00	0.00%	0.00
2014Q1	521.64	513.86	7.78	1.49%	0.88
2014Q2	406.18	400.31	5.87	1.45%	0.66
2014Q3	320.47	319.29	1.18	0.37%	0.13
2014Q4	375.41	390.23	-14.83	-3.95%	(1.67)
2015Q1	483.15	500.08	-16.92	-3.50%	(1.91)
2015Q2	368.21	376.15	-7.93	-2.15%	(0.90)
2015Q3	305.03	295.23	9.80	3.21%	1.11
2015Q4	360.71	355.77	4.94	1.37%	0.56
2016Q1	440.86	451.32	-10.46	-2.37%	(1.18)
2016Q2	375.52	375.52	0.00	0.00%	0.00
2016Q3	298.07	299.90	-1.83	-0.61%	(0.21)
2016Q4	339.02	339.02	0.00	0.00%	0.00
2017Q1	476.25	466.30	9.95	2.09%	1.12
2017Q2	384.79	387.10	-2.31	-0.60%	(0.26)
2017Q3	305.34	305.72	-0.38	-0.13%	(0.04)
2017Q4	365.58	365.82	-0.25	-0.07%	(0.03)
2018Q1	462.91	465.11	-2.20	-0.48%	(0.25)
2018Q2	373.72	371.52	2.20	0.59%	0.25
2018Q3	298.46	313.84	-15.38	-5.15%	(1.74)
2018Q4	398.54	389.13	9.41	2.36%	1.06
2019Q1	505.28	494.16	11.12	2.20%	1.26
2019Q2	411.54	394.90	16.64	4.04%	1.88
2019Q3	317.78	322.03	-4.26	-1.34%	(0.48)
2019Q4	387.44	394.23	-6.79	-1.75%	(0.77)
2020Q1	479.48	473.61	5.87	1.22%	0.66
2020Q2	333.48	333.48	0.00	0.00%	0.00
2020Q3	267.35	267.35	0.00	0.00%	0.00

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	387.44	395.62	-8.18	-2.1%
Q1 2020	479.48	473.16	6.32	1.3%
Q2 2020	333.48	412.31	-78.84	-23.6%
Q3 2020	267.35	328.57	-61.21	-22.9%
Total	1467.74	1609.66	-141.92	-9.7%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	641.82	642.13	-0.31	0%
B_HLFNGP_ST_ROLL12	-46.93	-46.99	0.06	0%
B_Q1_EDD	0.05	0.05	0.00	0%
B_Q2_EDD	0.06	0.06	0.00	0%
B_Q4_EDD	0.04	0.04	0.00	-2%
B_D20Q2	-78.81			
B_D20Q3	-61.30			
B_D2014	27.89	27.75	0.14	1%
B_D16Q4	-28.48	-29.76	1.27	-4%
B_D12Q4	-29.94	-31.21	1.26	-4%
B_D11Q2	25.20	25.24	-0.04	0%
B_D18Q2+B_D18Q1	-21.88	-21.62	-0.26	1%
B_D13Q4	25.40	23.96	1.44	6%

HLFUPC Lawrence S&T
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics: R-Squared	RMSE
L_HLF_UPC_S_T	7	0.977	4.888

ARIMA Model Parameters

L_HLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	480.206	8.891	54.01	0.000
	L_HLFNGP_ST_ROLL12 *L_D2017_AFT	-34.79339	2.325	-14.97	0.000
	L_Q1Q2_EDD	0.088992	0.003	31.28	0.000
	L_Q4_EDD	0.049054	0.006	8.66	0.000
	L_D2016	-73.75652	13.553	-5.44	0.000
	L_D10Q1_12Q2	38.80079	9.955	3.90	0.000
	L_D2010_2017*Q2	50.1568	10.081	4.98	0.000

Variable	Definition	Explanation	Dummy Variable Support
L_HLFNGP_ST_ROLL12*L_D2017_AFT	Rolling 12 quarter natural gas price for low load factor sales customers in Lawrence ($2020/MMBtu) after		
L_Q1Q2_EDD	Effective Degree Days in Lawrence in Q1 and Q2	A	
L_Q4_EDD	Effective Degree Days in Lawrence in Q4	A	
L_D2016	Binary variable equal to 1 in 2016		2
L_D10Q1_12Q2	Binary variable equal to 1 from 2010Q1 to 2012Q2		2
L_D2010_2017*Q2	Binary variable equal to 1 in Q2 from 2010 to 2017		1

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
43	0.972731	250.7005

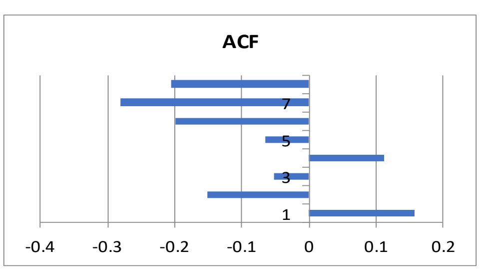
Chow Test Stats	N	k	SSR
Combined	43	7	20,548.30
1	19	5	4,275.63
2	24	6	14,202.93

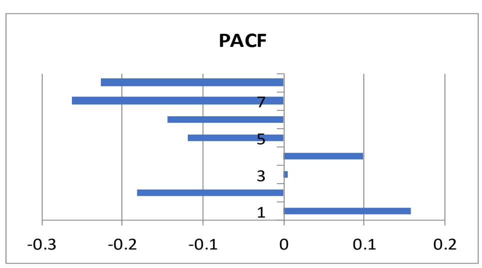
Chow Stat:	0.464
P-Value:	0.852321

Heteroscedasticity - White's Test	
White Stat	1.28
Significance (p-value)	0.29

Correlations

	L_HLFNGP_ST_ROLL12 *L_D2017_AFT	L_Q1Q2_EDD	L_Q4_EDD	L_D2016	L_D10Q1_	L_D2010_2017*Q2
L_HLFNGP_ST_ROLL12*L_D2017_AFT	1	0.020094	-0.052493	-0.234283	-0.40271	-0.219949
L_Q1Q2_EDD	0.020094	1	-0.470743	-0.026896	0.055813	0.03514
L_Q4_EDD	-0.052493	-0.470743	1	0.011986	-0.05399	-0.261805
L_D2016	-0.234283	-0.026896	0.011986	1	-0.1763	0.052632
L_D10Q1_12Q2	-0.402705	0.055813	-0.053989	-0.176295	1	0.161198
L_D2010_2017*Q2	-0.219949	0.03514	-0.261805	0.052632	0.161198	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_hlf_upc_s_t Model	ACF	0.158	-0.152	-0.051	0.113	-0.064	-0.199	-0.281	-0.206
	SE	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_hlf_upc_s_t Model		0.158	-0.181	0.006	0.099	-0.119	-0.143	-0.262	-0.227
	SE	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2010Q1	841.34	835.12	6.22	0.74%	0.28
2010Q2	646.57	663.79	-17.22	-2.66%	(0.78)
2010Q3	520.20	519.01	1.19	0.23%	0.05
2010Q4	615.08	612.80	2.28	0.37%	0.10
2011Q1	870.81	850.74	20.06	2.30%	0.91
2011Q2	699.56	697.87	1.69	0.24%	0.08
2011Q3	520.35	519.01	1.35	0.26%	0.06
2011Q4	588.20	593.99	-5.79	-0.98%	(0.26)
2012Q1	807.18	797.96	9.22	1.14%	0.42
2012Q2	649.79	668.79	-19.00	-2.92%	(0.86)
2012Q3	452.83	480.21	-27.38	-6.05%	(1.24)
2012Q4	521.81	568.50	-46.69	-8.95%	(2.11)
2013Q1	788.48	794.87	-6.39	-0.81%	(0.29)
2013Q2	653.80	657.03	-3.23	-0.49%	(0.15)
2013Q3	480.06	480.21	-0.14	-0.03%	(0.01)
2013Q4	587.58	578.88	8.70	1.48%	0.39
2014Q1	855.20	835.30	19.90	2.33%	0.90
2014Q2	679.17	663.14	16.03	2.36%	0.72
2014Q3	500.76	480.21	20.55	4.10%	0.93
2014Q4	594.40	571.97	22.43	3.77%	1.01
2015Q1	860.98	851.15	9.82	1.14%	0.44
2015Q2	686.01	661.41	24.60	3.59%	1.11
2015Q3	485.18	480.21	4.98	1.03%	0.22
2015Q4	519.52	560.55	-41.03	-7.90%	(1.85)
2016Q1	697.75	686.39	11.36	1.63%	0.51
2016Q2	590.70	580.14	10.56	1.79%	0.48
2016Q3	409.17	406.45	2.72	0.67%	0.12
2016Q4	469.67	494.31	-24.64	-5.25%	(1.11)
2017Q1	659.40	634.69	24.71	3.75%	1.12
2017Q2	510.36	523.79	-13.42	-2.63%	(0.61)
2017Q3	351.95	340.46	11.49	3.27%	0.52
2017Q4	435.71	418.59	17.11	3.93%	0.77
2018Q1	625.05	666.02	-40.97	-6.55%	(1.85)
2018Q2	457.85	473.30	-15.45	-3.38%	(0.70)
2018Q3	369.24	343.84	25.40	6.88%	1.15
2018Q4	475.44	443.32	32.12	6.76%	1.45
2019Q1	631.33	665.36	-34.03	-5.39%	(1.54)
2019Q2	483.54	468.66	14.88	3.08%	0.67
2019Q3	375.02	347.24	27.78	7.41%	1.26
2019Q4	466.36	440.41	25.95	5.57%	1.17
2020Q1	621.78	621.52	0.27	0.04%	0.01
2020Q2	415.42	473.71	-58.29	-14.03%	(2.64)
2020Q3	330.32	350.00	-19.68	-5.96%	(0.89)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	466.36	439.62	26.74	5.7%
Q1 2020	621.78	626.05	-4.27	-0.7%
Q2 2020	415.42	479.64	-64.22	-15.5%
Q3 2020	330.31	357.09	-26.77	-8.1%
Total	1833.88	1902.40	-68.52	-3.7%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	480.21	484.22	-4.01	-1%
L_HLFNGP_ST_ROLL12*L_D 2017_AFT	-34.79	-33.97	-0.82	2%
L_Q1Q2_EDD	0.09	0.09	0.00	1%
L_Q4_EDD	0.05	0.04	0.00	9%
L_D2016	-73.76	-74.17	0.41	-1%
L_D10Q1_12Q2	38.80	38.34	0.47	1%
L_D2010_2017*Q2	50.16	47.10	3.05	6%

HLFUPC Springfield S&T
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_HLF_UPC_S_T	11	0.953	5.630

ARIMA Model Parameters

S_HLF_UPC_S_T	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	608.2483	82.402	7.38	0.000
	S_HLFNGP_ST(-1)	-45.62422	17.196	-2.65	0.011
	S_Q1_EDD	0.059631	0.004	16.34	0.000
	S_Q4_EDD	0.054652	0.007	7.73	0.000
	S_Q2_EDD	0.098013	0.010	9.52	0.000
	D_AFTER15Q4*S_HLFNGP_ST(-4)	43.95941	3.006	14.63	0.000
	S_D09Q1	-129.7127	33.384	-3.89	0.000
	S_D08Q1	95.51972	33.401	2.86	0.006
	S_D20Q2	-137.7514	34.225	-4.02	0.000
	S_D19Q1	60.51842	33.935	1.78	0.081
	S_D20Q1	57.08197	33.723	1.69	0.097

Variable	Definition	Explanation	Dummy Variable Support
S_HLFNGP_ST(-1)	Natural gas price for high load factor customers in Springfield ($2020) lagged one quarter		
S_Q1_EDD	Effective Degree Days in Springfield in Q1	A	
S_Q4_EDD	Effective Degree Days in Springfield in Q4	A	
S_Q2_EDD	Effective Degree Days in Springfield in Q2	A	
D_AFTER15Q4*S_HLFNGP_ST(-4)	Natural gas price for high load factor customers in Springfield ($2020) lagged four quarters after 2015Q4	B	
S_D09Q1	Binary variable equal to 1 in 2009Q1		2
S_D08Q1	Binary variable equal to 1 in 2008Q1		2
S_D20Q2	Binary variable equal to 1 in 2020Q2		2
S_D19Q1	Binary variable equal to 1 in 2019Q1		2
S_D20Q1	Binary variable equal to 1 in 2020Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
59	0.9432	97.31307

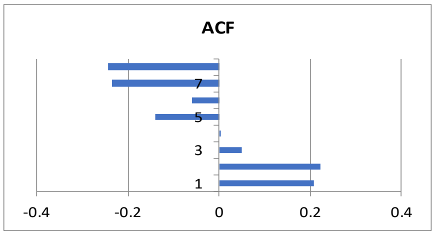
Chow Test Stats	N	k	SSR
Combined	47	10	1,065.66
1	23	5	382.83
2	24	10	417.58

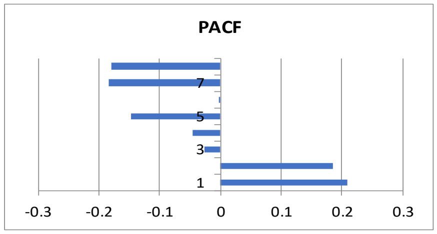
Chow Stat:	0.895
P-Value:	0.550385

Heteroscedasticity - White's Test	
White Stat	1.09
Significance (p-value)	0.39

Correlations

	S_HLFNGP_ST(-1)	S_Q1_EDD	S_Q4_EDD	S_Q2_EDD	D_AFTER15Q4*S_HLFNGP_ST(-4)	S_D09Q1	S_D08Q1	S_D20Q2	S_D19Q1	S_D20Q1
S_HLFNGP_ST(-1)	1	0.044094	-0.022549	-0.018867	-0.730011	0.068908	0.164155	-0.20501	-0.16434	-0.19723
S_Q1_EDD	0.044094	1	-0.32268	-0.336004	-0.024321	0.245123	0.216685	-0.07631	0.231409	0.194395
S_Q4_EDD	-0.022549	-0.32268	1	-0.321033	0.024147	-0.072908	-0.07291	-0.07291	-0.07291	-0.07291
S_Q2_EDD	-0.018867	-0.336004	-0.321033	1	0.021492	-0.075918	-0.07592	0.283235	-0.07592	-0.07592
D_AFTER15Q4*S_HLFNGP_ST(-4)	-0.730011	-0.024321	0.024147	0.021492	1	-0.093992	-0.09399	0.171314	0.182359	0.172887
S_D09Q1	0.068908	0.245123	-0.072908	-0.075918	-0.093992	1	-0.01724	-0.01724	-0.01724	-0.01724
S_D08Q1	0.164155	0.216685	-0.072908	-0.075918	-0.093992	-0.017241	1	-0.01724	-0.01724	-0.01724
S_D20Q2	-0.205011	-0.076308	-0.072908	0.283235	0.171314	-0.017241	-0.01724	1	-0.01724	-0.01724
S_D19Q1	-0.164336	0.231409	-0.072908	-0.075918	0.182359	-0.017241	-0.01724	-0.01724	1	-0.01724
S_D20Q1	-0.197225	0.194395	-0.072908	-0.075918	0.172887	-0.017241	-0.01724	-0.01724	-0.01724	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_hlf_upc_s_t Model	ACF	0.209	0.221	0.051	0.003	-0.14	-0.059	-0.236	-0.244
	SE	0.260	0.260	0.260	0.260	0.260	0.260	0.260	0.260
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_hlf_upc_s_t Model		0.209	0.185	-0.027	-0.046	-0.148	-0.002	-0.183	-0.179
	SE	0.260	0.260	0.260	0.260	0.260	0.260	0.260	0.260

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2006Q1	574.241	557.909	16.332	2.84%	0.57
2006Q2	477.437	472.247	5.18966	1.09%	0.18
2006Q3	357.838	365.92	-8.08175	-2.26%	(0.28)
2006Q4	494.407	448.615	45.792	9.26%	1.59
2007Q1	575.717	576.101	-0.38394	-0.07%	(0.01)
2007Q2	498.215	490.998	7.2171	1.45%	0.25
2007Q3	362.071	372.763	-10.6926	-2.95%	(0.37)
2007Q4	493.445	462.916	30.529	6.19%	1.06
2008Q1	671.825	671.825	1.1E-13	0.00%	0.00
2008Q2	528.137	494.29	33.8466	6.41%	1.17
2008Q3	389.502	384.425	5.07662	1.30%	0.18
2008Q4	463.476	484.568	-21.0919	-4.55%	(0.73)
2009Q1	477.814	477.814	1.4E-13	0.00%	0.00
2009Q2	435.499	501.404	-65.9046	-15.13%	(2.29)
2009Q3	409.397	389.019	20.3772	4.98%	0.71
2009Q4	449.844	478.984	-29.1397	-6.48%	(1.01)
2010Q1	549.002	590.747	-41.7457	-7.60%	(1.45)
2010Q2	438.143	469.81	-31.6678	-7.23%	(1.10)
2010Q3	372.987	389.594	-16.607	-4.45%	(0.58)
2010Q4	461.016	486.12	-25.1039	-5.45%	(0.87)
2011Q1	621.761	607.533	14.2281	2.29%	0.49
2011Q2	499.021	506.416	-7.39533	-1.48%	(0.26)
2011Q3	399.582	392.765	6.81699	1.71%	0.24
2011Q4	489.504	473.557	15.9475	3.26%	0.55
2012Q1	538.753	568.837	-30.0833	-5.58%	(1.04)
2012Q2	456.139	480.536	-24.3963	-5.35%	(0.85)
2012Q3	382.128	397.638	-15.5096	-4.06%	(0.54)
2012Q4	467.46	487.579	-20.1192	-4.30%	(0.70)
2013Q1	607.117	600.975	6.14237	1.01%	0.21
2013Q2	530.804	517.099	13.7056	2.58%	0.48
2013Q3	409.988	401.201	8.78675	2.14%	0.30
2013Q4	539.663	502.407	37.2553	6.90%	1.29
2014Q1	660.474	633.106	27.3678	4.14%	0.95
2014Q2	524.73	522.187	2.54358	0.48%	0.09
2014Q3	424.573	405.467	19.1061	4.50%	0.66
2014Q4	523.247	496.053	27.194	5.20%	0.94
2015Q1	638.225	643.187	-4.96163	-0.78%	(0.17)
2015Q2	518.824	520.711	-1.88648	-0.36%	(0.07)
2015Q3	420.317	408.455	11.8621	2.82%	0.41
2015Q4	653.469	680.678	-27.2096	-4.16%	(0.94)
2016Q1	820.748	781.769	38.9789	4.75%	1.35
2016Q2	756.356	715.894	40.4616	5.35%	1.40
2016Q3	610.708	602.003	8.70565	1.43%	0.30
2016Q4	626.174	693.167	-66.993	-10.70%	(2.32)
2017Q1	775.263	791.743	-16.4807	-2.13%	(0.57)
2017Q2	693.127	724.045	-30.9176	-4.46%	(1.07)
2017Q3	591.754	602.036	-10.2815	-1.74%	(0.36)
2017Q4	649.543	685.125	-35.582	-5.48%	(1.23)
2018Q1	799.693	812.879	-13.186	-1.65%	(0.46)

2019Q1	875.644	875.644	1.6E-13	0.00%	0.00
2019Q2	772.071	711.523	60.5473	7.84%	2.10
2019Q3	636.339	605.36	30.9785	4.87%	1.07
2019Q4	732.405	699.763	32.6422	4.46%	1.13
2020Q1	844.81	844.81	7.8E-14	0.00%	0.00
2020Q2	601.302	601.302	2.8E-14	0.00%	0.00
2020Q3	520.492	603.18	-82.6873	-15.89%	(2.87)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	732.41	699.69	32.72	4.5%
Q1 2020	844.81	791.65	53.16	6.3%
Q2 2020	601.30	741.08	-139.78	-23.2%
Q3 2020	520.49	612.27	-91.78	-17.6%
Total	2699.01	2844.69	-145.68	-5.4%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	608.25	634.10	-25.86	-4%
S_HLFNGP_ST(-1)	-45.62	-49.99	4.37	-10%
S_Q1_EDD	0.06	0.06	0.00	3%
S_Q4_EDD	0.05	0.05	0.01	9%
S_Q2_EDD	0.10	0.09	0.01	5%
D_AFTER15Q4*S_HLFNGP_ST(-4)	43.96	44.18	-0.22	0%
S_D09Q1	-129.71	-128.58	-1.13	1%
S_D08Q1	95.52	97.26	-1.74	-2%
S_D20Q2	-137.75	0.00	-137.75	100%
S_D19Q1	60.52	57.66	2.86	5%
S_D20Q1	57.08			

LLFC Sales Brockton
III. Sales - Customers
D. Low Load Factor Customers - Sales
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
B_LLF_CUST_SALES	9	0.941	8.369

ARIMA Model Parameters

B_LLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	10415.73	294.136	35.41	0.000
	B_GMP	4.713918	0.676	6.97	0.000
	Q3	-284.2585	36.500	-7.79	0.000
	B_D20Q2+B_D20Q3	300.696	53.574	5.61	0.000
	B_D16Q1	304.1881	76.190	3.99	0.002
	B_D19Q4	-149.8022	80.396	-1.86	0.087
	B_D18Q2	-137.4469	74.690	-1.84	0.091
	B_D19Q1	223.0984	76.856	2.90	0.013
	B_D18Q1	205.5977	74.000	2.78	0.017

Variable	Definition	Explanation	Dummy Variable Support
B_GMP	Gross Metro Product (bil. $) in Brockton		
Q3	Binary variable equal to 1 in Q3	C	2
B_D20Q2+B_D20Q3	Binary variable equal to 1 in 2020Q2 and 2020Q3		2
B_D16Q1	Binary variable equal to 1 in 2016Q1		2
B_D19Q4	Binary variable equal to 1 in 2019Q4		2
B_D18Q2	Binary variable equal to 1 in 2018Q2		2
B_D19Q1	Binary variable equal to 1 in 2019Q1		2
B_D18Q1	Binary variable equal to 1 in 2018Q1		2
B_D11Q1	Binary variable equal to 1 in 2011Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

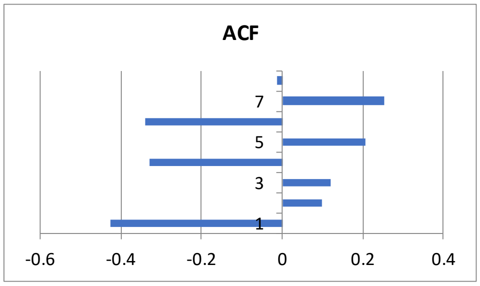
N	Adjusted R2	F Statistic
21	0.902487	24.13757

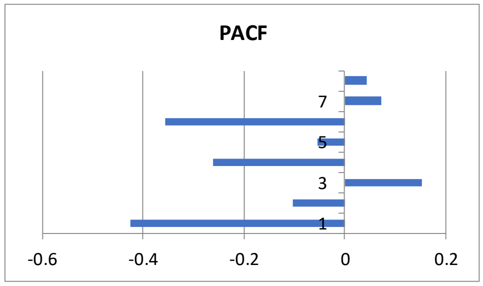
Chow Test Stats	N	k	SSR
Combined	21	9	58,857.76
1	11	5	48,103.80
2	10	7	6,689.97

Chow Stat:	0.025
P-Value:	0.999985

Heteroscedasticity - White's Test	
White Stat	0.94
Significance (p-value)	0.52

Correlations	B_GMP	Q3	B_D20Q2+B_D20Q3	B_D16Q1	B_D19Q4	B_D18Q2	B_D19Q1	B_D18Q1
B_GMP	1	0.010958	0.070089	-0.293557	0.34768	0.102508	0.220553	0.037889
Q3	0.010958	1	0.153897	-0.141421	-0.14142	-0.141421	-0.14142	-0.14142
B_D20Q2+B_D20Q3	0.070089	0.153897	1	-0.072548	-0.07255	-0.072548	-0.07255	-0.07255
B_D16Q1	-0.293557	-0.141421	-0.072548	1	-0.05	-0.05	-0.05	-0.05
B_D19Q4	0.34768	-0.141421	-0.072548	-0.05	1	-0.05	-0.05	-0.05
B_D18Q2	0.102508	-0.141421	-0.072548	-0.05	-0.05	1	-0.05	-0.05
B_D19Q1	0.220553	-0.141421	-0.072548	-0.05	-0.05	-0.05	1	-0.05
B_D18Q1	0.037889	-0.141421	-0.072548	-0.05	-0.05	-0.05	-0.05	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_llf_cust_sales Models	ACF	-0.426	0.097	0.121	-0.329	0.206	-0.339	0.252	-0.011
	SE	0.436	0.436	0.436	0.436	0.436	0.436	0.436	0.436
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_llf_cust_sales Models		-0.426	-0.103	0.152	-0.261	-0.054	-0.356	0.074	0.044
	SE	0.436	0.436	0.436	0.436	0.436	0.436	0.436	0.436

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2015Q3	12017.00	12021.80	-4.76	-0.04%	(0.09)
2015Q4	12373.70	12309.40	64.27	0.52%	1.18
2016Q1	12628.30	12628.30	0.00	0.00%	(0.00)
2016Q2	12411.30	12345.30	65.99	0.53%	1.22
2016Q3	12104.00	12082.20	21.82	0.18%	0.40
2016Q4	12252.30	12381.40	-129.03	-1.05%	(2.38)
2017Q1	12477.00	12401.30	75.67	0.61%	1.39
2017Q2	12289.30	12413.40	-124.09	-1.01%	(2.29)
2017Q3	12147.30	12155.80	-8.47	-0.07%	(0.16)
2017Q4	12524.30	12475.50	48.81	0.39%	0.90
2018Q1	12716.30	12716.30	0.00	0.00%	(0.00)
2018Q2	12409.70	12409.70	0.00	0.00%	(0.00)
2018Q3	12227.00	12281.30	-54.31	-0.44%	(1.00)
2018Q4	12634.70	12586.90	47.80	0.38%	0.88
2019Q1	12836.70	12836.70	0.00	0.00%	(0.00)
2019Q2	12596.30	12639.10	-42.80	-0.34%	(0.79)
2019Q3	12396.30	12380.50	15.83	0.13%	0.29
2019Q4	12535.30	12535.30	0.00	0.00%	(0.00)
2020Q1	12691.70	12668.40	23.28	0.18%	0.43
2020Q2	12697.30	12727.20	-29.89	-0.24%	(0.55)
2020Q3	12653.00	12623.10	29.89	0.24%	0.55

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	12535.33	12672.71	-137.38	-1.1%
Q1 2020	12691.67	12656.88	34.79	0.3%
Q2 2020	12697.33	12428.32	269.01	2.1%
Q3 2020	12653.00	12308.84	344.16	2.7%
Total	50577.33	50066.75	510.58	1.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	10415.73	10528.08	-112.35	-1%
B_GMP	4.71	4.45	0.26	5%
Q3	-284.26	-289.72	5.46	-2%
B_D20Q2+B_D20Q3	300.70	0.00	300.70	100%
B_D16Q1	304.19	296.77	7.42	2%
B_D19Q4	-149.80			
B_D18Q2	-137.45	-132.61	-4.84	4%
B_D19Q1	223.10	231.59	-8.49	-4%
B_D18Q1	205.60	208.44	-2.84	-1%

LLFC Sales Lawrence
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
L_LLF_CUST_SALES	6	0.849	6.482

ARIMA Model Parameters

L_LLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	1403.178	204.677	6.86	0.000
	L_GMP	12.24176	2.351	5.21	0.000
	L_D20Q2+L_D20Q3	159.1918	31.875	4.99	0.000
	Q3	-93.54071	21.960	-4.26	0.001
	L_D18Q4	-208.7909	44.140	-4.73	0.000
	L_D18Q3	-190.4486	46.719	-4.08	0.001

Variable	Definition	Explanation	Dummy Variable Support
L_GMP	Gross Metro Product (bil. $) in Lawrence		
L_D20Q2+L_D20Q3	Binary variable equal to 1 in 2020Q2 and 2020Q3		2
Q3	Binary variable equal to 1 in Q3	C	2
L_D18Q4	Binary variable equal to 1 in 2018Q4		2
L_D18Q3	Binary variable equal to 1 in 2018Q3		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

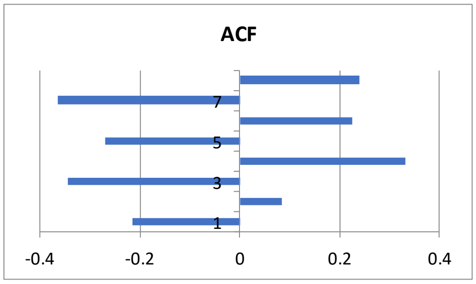
N	Adjusted R2	F Statistic
24	0.807351	20.27764

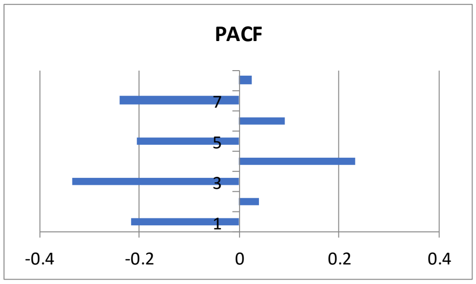
Chow Test Stats	N	k	SSR
Combined	24	6	31,775.91
1	12	3	17,983.94
2	12	6	10,309.59

Chow Stat:	0.246
P-Value:	0.951734

Heteroscedasticity - White's Test	
White Stat	0.90
Significance (p-value)	0.50

Correlations	L_GMP	L_D20Q2+L_D20Q3	Q3	L_D18Q4	L_D18Q3
L_GMP	1	-0.045727	0.118631	0.18064	0.143936
L_D20Q2+L_D20Q3	-0.045727	1	0.174078	-0.062869	-0.06287
Q3	0.118631	0.174078	1	-0.120386	0.361158
L_D18Q4	0.18064	-0.062869	-0.120386	1	-0.04348
L_D18Q3	0.143936	-0.062869	0.361158	-0.043478	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_llf_cust_sales Models	ACF	-0.215	0.084	-0.344	0.333	-0.27	0.224	-0.364	0.239
	SE	0.408	0.408	0.408	0.408	0.408	0.408	0.408	0.408
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_llf_cust_sales Models		-0.215	0.04	-0.334	0.232	-0.206	0.091	-0.238	0.026
	SE	0.408	0.408	0.408	0.408	0.408	0.408	0.408	0.408

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q4	2385.67	2398.66	-13.00	-0.54%	(0.34)
2015Q1	2477.33	2403.43	73.90	2.98%	1.94
2015Q2	2370.67	2423.92	-53.26	-2.25%	(1.40)
2015Q3	2306.00	2336.72	-30.72	-1.33%	(0.81)
2015Q4	2442.33	2430.57	11.76	0.48%	0.31
2016Q1	2510.33	2433.03	77.30	3.08%	2.03
2016Q2	2449.67	2439.95	9.72	0.40%	0.26
2016Q3	2363.67	2349.93	13.73	0.58%	0.36
2016Q4	2404.00	2450.96	-46.96	-1.95%	(1.24)
2017Q1	2463.67	2456.25	7.42	0.30%	0.20
2017Q2	2412.67	2456.97	-44.30	-1.84%	(1.17)
2017Q3	2351.33	2372.27	-20.94	-0.89%	(0.55)
2017Q4	2450.67	2476.10	-25.43	-1.04%	(0.67)
2018Q1	2519.33	2485.53	33.80	1.34%	0.89
2018Q2	2432.33	2498.07	-65.74	-2.70%	(1.73)
2018Q3	2220.67	2220.67			
2018Q4	2304.00	2304.00	0.00	0.00%	0.00
2019Q1	2567.00	2526.30	40.70	1.59%	1.07
2019Q2	2542.33	2534.55	7.78	0.31%	0.20
2019Q3	2482.00	2450.87	31.13	1.25%	0.82
2019Q4	2522.67	2560.72	-38.05	-1.51%	(1.00)
2020Q1	2569.33	2538.19	31.15	1.21%	0.82
2020Q2	2579.00	2585.79	-6.79	-0.26%	(0.18)
2020Q3	2577.33	2570.54	6.79	0.26%	0.18

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	2522.67	2564.95	-42.28	-1.7%
Q1 2020	2569.33	2541.70	27.63	1.1%
Q2 2020	2579.00	2426.58	152.42	5.9%
Q3 2020	2577.33	2410.73	166.61	6.5%
Total	10248.33	9943.95	304.38	3.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	1403.18	1370.73	32.45	2%
L_GMP	12.24	12.63	-0.39	-3%
L_D20Q2+L_D20Q3	159.19			
Q3	-93.54	-96.62	3.08	-3%
L_D18Q4	-208.79	-211.50	2.71	-1%
L_D18Q3	-190.45	-189.82	-0.63	0%

LLFC Sales Springfield
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics R-Squared	RMSE
S_LLF_CUST_SALES	8	0.932	7.309

ARIMA Model Parameters

S_LLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	4677.91	160.839	29.08	0.000
	S_GMP	54.43524	4.523	12.03	0.000
	S_D20Q2+S_D20Q3	271.0174	40.676	6.66	0.000
	Q3	-167.2574	27.300	-6.13	0.000
	Q1	114.8859	25.303	4.54	0.000
	S_D15Q4+S_D16Q1+ S_D16Q2	176.6515	33.994	5.20	0.000
	B_D16Q3	249.3747	58.410	4.27	0.000
	S_D18Q2	-121.6886	56.462	-2.16	0.044

Variable	Definition	Explanation	Dummy Variable Support
S_GMP	Gross Metro Product (bil. $) in Springfield		
S_D20Q2+S_D20Q3	Binary variable equal to 1 in 2020Q2 and 2020Q3		2
Q3	Binary variable equal to 1 in Q3	C	2
Q1	Binary variable equal to 1 in Q1	C	2
S_D15Q4+S_D16Q1+S_D16Q2	Binary variable equal to 1 in 2015Q4, 2016Q1 and 2016Q2		2
B_D16Q3	Binary variable equal to 1 in 2016Q3		2
S_D18Q2	Binary variable equal to 1 in 2018Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
28	0.908217	39.1673

Chow Test Stats

	N	k	SSR
Combined	28	8	57,076.45
1	15	6	33,473.03
2	13	7	19,737.05

Chow Stat:	0.109
P-Value:	0.997989

Heteroscedasticity - White's Test	
White Stat	0.73
Significance (p-value)	0.65

Correlations

	S_GMP	S_D20Q2+S_D20Q3	Q3	Q1	S_D15Q4+S_D16Q1+S_D16Q2	B_D16Q3	S_D18Q2
S_GMP	1	0.136756	0.121445	-0.011535	-0.199108	-0.065932	0.137016
S_D20Q2+S_D20Q3	0.136756	1	0.160128	-0.160128	-0.096077	-0.053376	-0.05338
Q3	0.121445	0.160128	1	-0.333333	-0.2	0.333333	-0.11111
Q1	-0.011535	-0.160128	-0.333333	1	0.066667	-0.111111	-0.11111
S_D15Q4+S_D16Q1+S_D16Q2	-0.199108	-0.096077	-0.2	0.066667	1	-0.066667	-0.06667
B_D16Q3	-0.065932	-0.053376	0.333333	-0.111111	-0.066667	1	-0.03704
S_D18Q2	0.137016	-0.053376	-0.111111	-0.111111	-0.066667	-0.037037	1

Residual ACF									
Model		1	2	3	4	5	6	7	8
s_llf_cust_sales Model	ACF	0.221	-0.083	-0.147	-0.35	0.042	0.181	-0.098	-0.125
	SE	0.378	0.378	0.378	0.378	0.378	0.378	0.378	0.378
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_llf_cust_sales Model		0.221	-0.139	-0.102	-0.327	0.196	0.058	-0.238	-0.161
	SE	0.378	0.378	0.378	0.378	0.378	0.378	0.378	0.378

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2013Q4	6361.00	6406.21	-45.21	-0.71%	(0.98)
2014Q1	6509.33	6508.34	0.99	0.02%	0.02
2014Q2	6364.67	6411.33	-46.66	-0.73%	(1.01)
2014Q3	6272.67	6300.15	-27.48	-0.44%	(0.60)
2014Q4	6550.67	6477.34	73.33	1.12%	1.59
2015Q1	6709.33	6614.74	94.59	1.41%	2.06
2015Q2	6545.67	6537.71	7.96	0.12%	0.17
2015Q3	6411.33	6377.60	33.74	0.53%	0.73
2015Q4	6675.33	6720.51	-45.17	-0.68%	(0.98)
2016Q1	6825.00	6834.31	-9.31	-0.14%	(0.20)
2016Q2	6778.33	6723.85	54.48	0.80%	1.18
2016Q3	6656.33	6656.33	0.00	0.00%	(0.00)
2016Q4	6658.33	6592.23	66.10	0.99%	1.44
2017Q1	6671.00	6722.11	-51.11	-0.77%	(1.11)
2017Q2	6577.00	6618.76	-41.76	-0.63%	(0.91)
2017Q3	6472.33	6472.21	0.12	0.00%	0.00
2017Q4	6641.67	6666.46	-24.79	-0.37%	(0.54)
2018Q1	6751.33	6798.70	-47.36	-0.70%	(1.03)
2018Q2	6587.00	6587.00	0.00	0.00%	(0.00)
2018Q3	6500.67	6564.00	-63.33	-0.97%	(1.38)
2018Q4	6683.33	6747.31	-63.98	-0.96%	(1.39)
2019Q1	6940.67	6883.84	56.83	0.82%	1.24
2019Q2	6845.00	6785.84	59.16	0.86%	1.29
2019Q3	6690.67	6636.11	54.55	0.82%	1.19
2019Q4	6837.67	6828.72	8.94	0.13%	0.19
2020Q1	6881.67	6926.30	-44.63	-0.65%	(0.97)
2020Q2	6877.67	6880.06	-2.40	-0.03%	(0.05)
2020Q3	6858.67	6856.27	2.40	0.03%	0.05

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	6837.67	6834.48	3.18	0.0%
Q1 2020	6881.67	6939.49	-57.82	-0.8%
Q2 2020	6877.67	6609.53	268.14	3.9%
Q3 2020	6858.67	6587.54	271.13	4.0%
Total	27455.67	26971.05	484.62	1.8%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	4677.91	4632.02	45.89	1%
S_GMP	54.44	55.74	-1.31	-2%
S_D20Q2+S_D20Q3	271.02			
Q3	-167.26	-168.90	1.64	-1%
Q1	114.89	122.73	-7.85	-7%
S_D15Q4+S_D16Q1+S_D16Q2	176.65	175.10	1.55	1%
B_D16Q3	249.37	251.37	-1.99	-1%
S_D18Q2	-121.69	-124.57	2.88	-2%

HLFC Sales Brockton

A. High Load Factor Customers - Sales

1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
B_HLF_CUST_SALES	8	0.880	6.879

ARIMA Model Parameters

B_HLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	2472.79	105.669	23.40	0.000
	B_HLFNGP_S(-3)	-27.63107	10.076	-2.74	0.009
	B_D13Q1	101.7151	41.338	2.46	0.018
	B_D13Q4	-155.7994	40.958	-3.80	0.001
	B_D12Q4	175.284	41.388	4.24	0.000
	D_18Q2THR19Q3	-74.28785	35.029	-2.12	0.040
	D_14Q1THR16Q3	-158.6407	41.343	-3.84	0.000
	AR(1)	0.868072	0.079	11.00	0.000

Variable	Definition	Explanation	Dummy Variable Support
B_HLFNGP_S(-3)	Natural gas price for high load factor customers in Brockton ($2020) lagged three quarters		
B_D13Q1	Binary variable equal to 1 in 2013Q1		2
B_D13Q4	Binary variable equal to 1 in 2013Q4		2
B_D12Q4	Binary variable equal to 1 in 2012Q4		2
D_18Q2THR19Q3	Binary variable equal to 1 from 2018Q2 to		2
D_14Q1THR16Q3	Binary variable equal to 1 from 2014Q1 to		1
AR(1)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)

B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed

C: To account for seasonality

1: Included to address a structural shift

2: Included to address an outlier

N	Adjusted R2	F Statistic
47	0.858876	40.99366

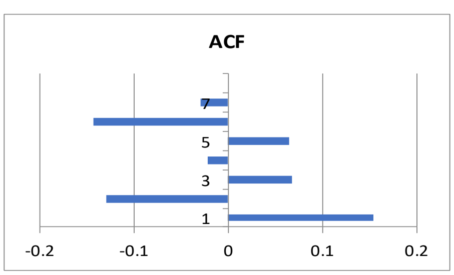
Chow Test Stats	N	k	SSR
Combined	47	8	87,351.42
1	22	7	39,764.86
2	25	5	30,687.97

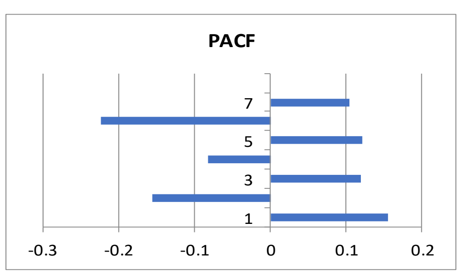
Chow Stat:	0.929
P-Value:	0.506486

Heteroscedasticity - White's Test	
White Stat	1.50
Significance (p-value)	0.20

Correlations

	B_HLFNGP_S(-3)	B_D13Q1	B_D13Q4	B_D12Q4	D_18Q2THR19Q3	D_14Q1THR16Q3
B_HLFNGP_S(-3)	1	-0.00769	-0.052073	0.0269	-0.336269	0.131355
B_D13Q1	-0.00769	1	-0.021739	-0.021739	-0.056403	-0.081502
B_D13Q4	-0.052073	-0.021739	1	-0.021739	-0.056403	-0.081502
B_D12Q4	0.0269	-0.021739	-0.021739	1	-0.056403	-0.081502
D_18Q2THR19Q3	-0.336269	-0.056403	-0.056403	-0.056403	1	-0.21146
D_14Q1THR16Q3	0.131355	-0.081502	-0.081502	-0.081502	-0.21146	1





Residual ACF								
Model		1	2	3	4	5	6	7
b_hlf_cust_sales Model	ACF	0.155	-0.129	0.067	-0.022	0.065	-0.144	-0.03
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292
Residual PACF								
Model		1	2	3	4	5	6	7
b_hlf_cust_sales Model		0.155	-0.156	0.12	-0.082	0.121	-0.224	0.105
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2009Q1	2287.33	2243.97	43.37	1.90%	1.00
2009Q2	2227.67	2220.49	7.17	0.32%	0.16
2009Q3	2185.00	2189.37	-4.37	-0.20%	(0.10)
2009Q4	2155.33	2161.83	-6.49	-0.30%	(0.15)
2010Q1	2171.33	2170.80	0.53	0.02%	0.01
2010Q2	2144.67	2222.86	-78.19	-3.65%	(1.79)
2010Q3	2152.67	2174.26	-21.59	-1.00%	(0.50)
2010Q4	2233.33	2170.82	62.51	2.80%	1.43
2011Q1	2234.00	2239.67	-5.67	-0.25%	(0.13)
2011Q2	2205.67	2211.34	-5.67	-0.26%	(0.13)
2011Q3	2172.67	2188.67	-16.01	-0.74%	(0.37)
2011Q4	2162.00	2171.47	-9.47	-0.44%	(0.22)
2012Q1	2157.00	2150.93	6.07	0.28%	0.14
2012Q2	2114.33	2161.71	-47.38	-2.24%	(1.09)
2012Q3	2205.67	2127.07	78.59	3.56%	1.80
2012Q4	2451.00	2387.42	63.58	2.59%	1.46
2013Q1	2453.67	2380.43	73.24	2.98%	1.68
2013Q2	2427.00	2342.63	84.37	3.48%	1.94
2013Q3	2350.33	2405.32	-54.98	-2.34%	(1.26)
2013Q4	2230.67	2177.10	53.56	2.40%	1.23
2014Q1	2253.00	2191.30	61.71	2.74%	1.42
2014Q2	2187.33	2208.45	-21.12	-0.97%	(0.48)
2014Q3	2093.00	2157.25	-64.25	-3.07%	(1.47)
2014Q4	2043.00	2066.20	-23.20	-1.14%	(0.53)
2015Q1	2041.00	2012.28	28.72	1.41%	0.66
2015Q2	2005.67	2040.03	-34.36	-1.71%	(0.79)
2015Q3	1948.00	1999.12	-51.12	-2.62%	(1.17)
2015Q4	1947.33	1951.53	-4.20	-0.22%	(0.10)
2016Q1	1989.00	1994.47	-5.47	-0.27%	(0.13)
2016Q2	1971.33	2014.33	-43.00	-2.18%	(0.99)
2016Q3	2072.00	2012.13	59.87	2.89%	1.37
2016Q4	2317.33	2270.28	47.05	2.03%	1.08
2017Q1	2343.33	2333.13	10.20	0.44%	0.23
2017Q2	2335.33	2339.20	-3.86	-0.17%	(0.09)
2017Q3	2301.33	2327.26	-25.93	-1.13%	(0.60)
2017Q4	2295.67	2295.14	0.52	0.02%	0.01
2018Q1	2295.00	2290.86	4.14	0.18%	0.10
2018Q2	2241.00	2219.71	21.29	0.95%	0.49
2018Q3	2153.33	2234.02	-80.69	-3.75%	(1.85)
2018Q4	2038.00	2139.30	-101.30	-4.97%	(2.32)
2019Q1	2053.67	2022.04	31.63	1.54%	0.73
2019Q2	2046.67	2063.14	-16.47	-0.80%	(0.38)
2019Q3	2088.33	2053.41	34.92	1.67%	0.80
2019Q4	2177.00	2172.53	4.47	0.21%	0.10
2020Q1	2155.33	2196.75	-41.41	-1.92%	(0.95)
2020Q2	2152.67	2161.98	-9.32	-0.43%	(0.21)
2020Q3	2166.00	2168.00	-2.00	-0.09%	(0.05)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	2177.00	2149.49	27.51	1.3%
Q1 2020	2155.33	2176.01	-20.68	-1.0%
Q2 2020	2152.67	2182.65	-29.98	-1.4%
Q3 2020	2166.00	2196.73	-30.73	-1.4%
Total	8651.00	8704.88	-53.88	-0.6%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	2472.79	2490.54	-17.75	-1%
B_HLFNGP_S(-3)	-27.63	-28.09	0.46	-2%
B_D13Q1	101.72	102.04	-0.32	0%
B_D13Q4	-155.80	-155.78	-0.02	0%
B_D12Q4	175.28	175.56	-0.28	0%
D_18Q2THR19Q3	-74.29	-76.07	1.78	-2%
D_14Q1THR16Q3	-158.64	-158.86	0.22	0%
AR(1)	0.87	0.85	0.01	2%

HLFC Sales Lawrence
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
L_HLF_CUST_SALES	9	0.911	2.999

ARIMA Model Parameters

L_HLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	727.8714	26.553	27.41	0.000
	L_HLFNGP_S_ROLL12(-4)	-10.90273	2.439	-4.47	0.000
	D_AFTER18Q3	-58.36026	8.941	-6.53	0.000
	D_14Q3THR16Q3	-47.23631	7.492	-6.30	0.000
	D_11Q2THR14Q2	-24.74764	7.340	-3.37	0.002
	L_D18Q4	-49.53834	7.295	-6.79	0.000
	L_D12Q4	18.32419	7.388	2.48	0.018
	L_D12Q2	-17.06619	7.282	-2.34	0.024
	AR(1)	0.730954	0.101	7.25	0.000

Variable	Definition	Explanation	Dummy Variable Support
L_HLFNGP_S_ROLL12(-4)	Rolling 12 quarter natural gas price for high load factor customers in Lawrence ($2020) lagged four quarters		
D_AFTER18Q3	Binary variable equal to 1 from 2018Q3 on		1
D_14Q3THR16Q3	Binary variable equal to 1 from 2014Q3 to 2016Q3		1
D_11Q2THR14Q2	Binary variable equal to 1 from 2011Q2 to 2014Q2		1
L_D18Q4	Binary variable equal to 1 in 2018Q4		2
L_D12Q4	Binary variable equal to 1 in 2012Q4		2
L_D12Q2	Binary variable equal to 1 in 2012Q2		2
AR(1)	ARMA		

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

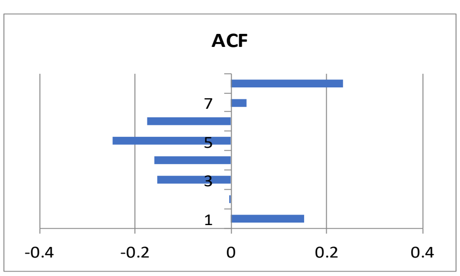
N	Adjusted R2	F Statistic
47	0.892447	48.71195

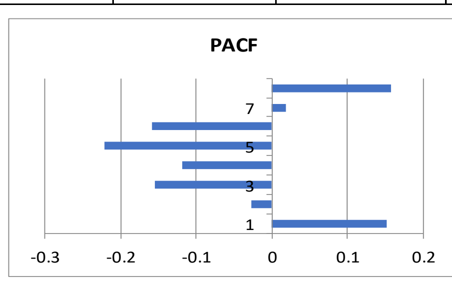
Chow Test Stats	N	k	SSR
Combined	47	9	3,073.70
1	22	6	1,142.16
2	25	6	2,307.92

Chow Stat:	-0.352
P-Value:	1

Heteroscedasticity - White's Test	
White Stat	2.72
Significance (p-value)	0.02

Correlations	L_HLFNGP_S_ROLL12(-4)	D_AFTER18Q3	D_14Q3THR16Q3	D_11Q2THR14Q2	L_D18Q4	L_D12Q4	L_D12Q2
L_HLFNGP_S_ROLL12(-4)	1	-0.633992	-0.084697	0.148931	-0.20531	0.016604	0.078097
D_AFTER18Q3	-0.633992	1	-0.236842	-0.300927	0.302964	-0.071755	-0.07176
D_14Q3THR16Q3	-0.084697	-0.236842	1	-0.300927	-0.07176	-0.071755	-0.07176
D_11Q2THR14Q2	0.148931	-0.300927	-0.300927	1	-0.09117	0.238445	0.238445
L_D18Q4	-0.205309	0.302964	-0.071755	-0.09117	1	-0.021739	-0.02174
L_D12Q4	0.016604	-0.071755	-0.071755	0.238445	-0.02174	1	-0.02174
L_D12Q2	0.078097	-0.071755	-0.071755	0.238445	-0.02174	-0.021739	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_hlf_cust_sales Model	ACF	0.152	-0.004	-0.155	-0.159	-0.246	-0.175	0.032	0.235
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_hlf_cust_sales Model		0.152	-0.028	-0.154	-0.118	-0.222	-0.159	0.018	0.157
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residua
2009Q1	601.00	594.54	6.46	1.07%	0.79
2009Q2	588.33	586.61	1.73	0.29%	0.21
2009Q3	578.00	573.84	4.16	0.72%	0.51
2009Q4	569.67	573.59	-3.93	-0.69%	(0.48)
2010Q1	567.00	569.29	-2.29	-0.40%	(0.28)
2010Q2	559.67	568.86	-9.19	-1.64%	(1.12)
2010Q3	558.33	566.12	-7.79	-1.40%	(0.95)
2010Q4	569.67	565.38	4.29	0.75%	0.52
2011Q1	567.33	573.66	-6.33	-1.12%	(0.77)
2011Q2	555.67	548.73	6.93	1.25%	0.85
2011Q3	549.33	557.45	-8.11	-1.48%	(0.99)
2011Q4	550.00	552.65	-2.65	-0.48%	(0.32)
2012Q1	553.33	554.53	-1.19	-0.22%	(0.15)
2012Q2	537.33	543.24	-5.90	-1.10%	(0.72)
2012Q3	557.33	565.41	-8.08	-1.45%	(0.99)
2012Q4	599.33	583.95	15.39	2.57%	1.88
2013Q1	605.33	584.28	21.05	3.48%	2.58
2013Q2	602.33	601.91	0.42	0.07%	0.05
2013Q3	598.00	598.35	-0.35	-0.06%	(0.04)
2013Q4	593.67	595.16	-1.49	-0.25%	(0.18)
2014Q1	600.67	593.64	7.03	1.17%	0.86
2014Q2	591.67	596.72	-5.05	-0.85%	(0.62)
2014Q3	582.00	568.44	13.56	2.33%	1.66
2014Q4	579.00	578.36	0.64	0.11%	0.08
2015Q1	575.00	575.27	-0.27	-0.05%	(0.03)
2015Q2	563.67	569.38	-5.71	-1.01%	(0.70)
2015Q3	548.00	563.60	-15.60	-2.85%	(1.91)
2015Q4	544.00	551.37	-7.37	-1.35%	(0.90)
2016Q1	548.67	546.79	1.87	0.34%	0.23
2016Q2	540.33	552.35	-12.01	-2.22%	(1.47)
2016Q3	565.67	547.19	18.48	3.27%	2.26
2016Q4	625.33	614.14	11.20	1.79%	1.37
2017Q1	637.67	624.43	13.23	2.08%	1.62
2017Q2	632.33	636.44	-4.10	-0.65%	(0.50)
2017Q3	625.67	632.75	-7.08	-1.13%	(0.87)
2017Q4	627.00	628.30	-1.30	-0.21%	(0.16)
2018Q1	628.67	631.28	-2.62	-0.42%	(0.32)
2018Q2	622.00	637.26	-15.26	-2.45%	(1.87)
2018Q3	568.67	571.33	-2.66	-0.47%	(0.33)
2018Q4	531.67	526.61	5.05	0.95%	0.62
2019Q1	591.67	584.75	6.92	1.17%	0.85
2019Q2	584.33	588.69	-4.35	-0.74%	(0.53)
2019Q3	580.67	585.22	-4.55	-0.78%	(0.56)
2019Q4	586.00	581.23	4.77	0.81%	0.58
2020Q1	579.00	583.12	-4.12	-0.71%	(0.50)
2020Q2	577.00	576.71	0.29	0.05%	0.04
2020Q3	582.67	576.77	5.90	1.01%	0.72

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	586.00	583.65	2.35	0.4%
Q1 2020	579.00	580.90	-1.90	-0.3%
Q2 2020	577.00	577.62	-0.62	-0.1%
Q3 2020	582.67	576.72	5.94	1.0%
Total	2324.67	2318.89	5.78	0.2%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	727.87	725.94	1.93	0%
L_HLFNGP_S_ROLL12(-4)	-10.90	-10.78	-0.12	1%
D_AFTER18Q3	-58.36	-59.29	0.93	-2%
D_14Q3THR16Q3	-47.24	-46.93	-0.31	1%
D_11Q2THR14Q2	-24.75	-24.46	-0.29	1%
L_D18Q4	-49.54	-49.43	-0.11	0%
L_D12Q4	18.32	18.33	-0.01	0%
L_D12Q2	-17.07	-17.06	0.00	0%
AR(1)	0.73	0.73	0.00	0%

HLFC Sales Springfield
3. Springfield

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
S_HLF_CUST_SALES	9	0.723	5.647

ARIMA Model Parameters

S_HLF_CUST_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	1536.871	40.139	38.29	0.000
	S_HLFNGP_S_ROLL12(-4)	-12.31317	2.948	-4.18	0.000
	D_AFTER17Q4*S_HLFNGP_S_ROLL12	-13.00754	2.423	-5.37	0.000
	D_11Q2THR12Q3*S_HLFNGP_S_ROLL12	-4.51509	1.294	-3.49	0.001
	S_D2016	-143.4478	21.175	-6.77	0.000
	S_D2015	-150.2698	19.289	-7.79	0.000
	S_D2014	-78.28487	19.403	-4.03	0.000
	S_D16Q4	165.2449	36.835	4.49	0.000
	S_D18Q1	80.64138	33.155	2.43	0.020

Variable	Definition	Explanation	Dummy Variable Support
S_HLFNGP_S_ROLL12(-4)	Rolling 12 quarter natural gas price for high load factor customers in Springfield ($2020) lagged four quarters		
D_AFTER17Q4*S_HLFNGP_S_ROLL12	Rolling 12 quarter natural gas price for high load factor customers in Springfield ($2020) after 2017Q4	B	
D_11Q2THR12Q3*S_HLFNGP_S_ROLL12	Rolling 12 quarter natural gas price for high load factor customers in Springfield ($2020) from 2011Q2 to 2012Q3	B	
S_D2016	Binary variable equal to 1 in 2016		2
S_D2015	Binary variable equal to 1 in 2015		2
S_D2014	Binary variable equal to 1 in 2014		2
S_D16Q4	Binary variable equal to 1 in 2016Q4		2
S_D18Q1	Binary variable equal to 1 in 2018Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
47	0.664083	12.36732

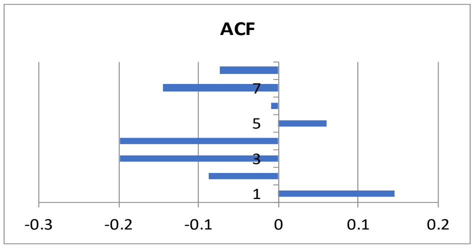
Chow Test Stats	N	k	SSR
Combined	47	9	38,645.97
1	24	4	18,660.37
2	23	7	10,560.79

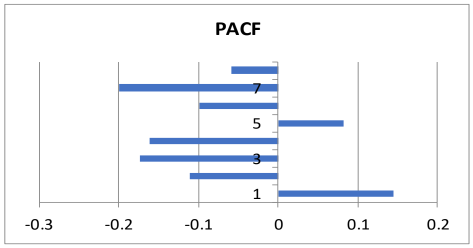
Chow Stat:	1.039
P-Value:	0.43406

Heteroscedasticity - White's Test	
White Stat	1.45
Significance (p-value)	0.21

Correlations

	S_HLFNGP_S_ROLL12(-4)	D_AFTER17Q4*S_HLFNGP_S_ROLL12	D_11Q2THR12Q3*S_HLFNGP_S_ROLL12	S_D2016	S_D2015	S_D2014	S_D16Q4	S_D18Q1
S_HLFNGP_S_ROLL12(-4)	1	-0.702852	0.26377	-0.053133	-0.06678	-0.077781	-0.03836	-0.12876
D_AFTER17Q4*S_HLFNGP_S_ROLL12	-0.702852	1	-0.223271	-0.17829	-0.17829	-0.17829	-0.08619	0.228611
D_11Q2THR12Q3*S_HLFNGP_S_ROLL12	0.26377	-0.223271	1	-0.116492	-0.11649	-0.116492	-0.05632	-0.05632
S_D2016	-0.053133	-0.17829	-0.116492	1	-0.09302	-0.093023	0.483421	-0.04497
S_D2015	-0.066782	-0.17829	-0.116492	-0.093023	1	-0.093023	-0.04497	-0.04497
S_D2014	-0.077781	-0.17829	-0.116492	-0.093023	-0.09302	1	-0.04497	-0.04497
S_D16Q4	-0.038357	-0.086189	-0.056315	0.483421	-0.04497	-0.044969	1	-0.02174
S_D18Q1	-0.128762	0.228611	-0.056315	-0.044969	-0.04497	-0.044969	-0.02174	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_hlf_cust_sales Model	ACF	0.145	-0.087	-0.198	-0.198	0.061	-0.01	-0.144	-0.074
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_hlf_cust_sales Model		0.145	-0.111	-0.174	-0.162	0.082	-0.099	-0.2	-0.058
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2009Q1	1356.67	1334.79	21.88	1.61%	0.75
2009Q2	1317.00	1333.71	-16.71	-1.27%	(0.58)
2009Q3	1314.00	1329.54	-15.54	-1.18%	(0.54)
2009Q4	1330.67	1334.80	-4.13	-0.31%	(0.14)
2010Q1	1342.33	1340.58	1.76	0.13%	0.06
2010Q2	1322.00	1346.30	-24.31	-1.84%	(0.84)
2010Q3	1320.33	1353.58	-33.24	-2.52%	(1.15)
2010Q4	1359.00	1358.97	0.03	0.00%	0.00
2011Q1	1379.67	1362.67	17.00	1.23%	0.59
2011Q2	1350.67	1309.45	41.22	3.05%	1.42
2011Q3	1324.33	1314.74	9.59	0.72%	0.33
2011Q4	1318.33	1317.81	0.52	0.04%	0.02
2012Q1	1308.67	1322.11	-13.44	-1.03%	(0.46)
2012Q2	1292.33	1329.19	-36.86	-2.85%	(1.27)
2012Q3	1330.33	1338.27	-7.94	-0.60%	(0.27)
2012Q4	1419.67	1392.43	27.24	1.92%	0.94
2013Q1	1432.33	1396.95	35.38	2.47%	1.22
2013Q2	1426.67	1400.20	26.47	1.86%	0.91
2013Q3	1411.00	1400.91	10.09	0.72%	0.35
2013Q4	1373.67	1401.74	-28.07	-2.04%	(0.97)
2014Q1	1376.00	1326.18	49.82	3.62%	1.72
2014Q2	1360.33	1326.26	34.07	2.50%	1.18
2014Q3	1317.67	1327.11	-9.44	-0.72%	(0.33)
2014Q4	1254.33	1328.78	-74.44	-5.94%	(2.57)
2015Q1	1273.67	1256.42	17.25	1.35%	0.60
2015Q2	1255.00	1253.23	1.77	0.14%	0.06
2015Q3	1241.00	1253.31	-12.31	-0.99%	(0.42)
2015Q4	1246.00	1252.71	-6.71	-0.54%	(0.23)
2016Q1	1238.67	1257.48	-18.81	-1.52%	(0.65)
2016Q2	1232.67	1258.03	-25.36	-2.06%	(0.88)
2016Q3	1303.67	1259.49	44.17	3.39%	1.52
2016Q4	1427.33	1427.33	0.00	0.00%	0.00
2017Q1	1420.67	1408.56	12.10	0.85%	0.42
2017Q2	1409.33	1413.40	-4.06	-0.29%	(0.14)
2017Q3	1394.33	1417.68	-23.35	-1.67%	(0.81)
2017Q4	1393.33	1320.63	72.70	5.22%	2.51
2018Q1	1407.67	1407.67	0.00	0.00%	0.00
2018Q2	1388.67	1333.81	54.86	3.95%	1.89
2018Q3	1344.67	1338.39	6.28	0.47%	0.22
2018Q4	1285.33	1340.95	-55.62	-4.33%	(1.92)
2019Q1	1297.00	1338.79	-41.79	-3.22%	(1.44)
2019Q2	1297.00	1333.37	-36.37	-2.80%	(1.25)
2019Q3	1317.00	1333.32	-16.32	-1.24%	(0.56)
2019Q4	1349.00	1331.54	17.46	1.29%	0.60
2020Q1	1322.33	1327.47	-5.14	-0.39%	(0.18)
2020Q2	1318.33	1321.51	-3.18	-0.24%	(0.11)
2020Q3	1331.33	1319.86	11.48	0.86%	0.40

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	1349.00	1328.18	20.82	1.5%
Q1 2020	1322.33	1324.07	-1.74	-0.1%
Q2 2020	1318.33	1318.01	0.33	0.0%
Q3 2020	1331.33	1316.32	15.01	1.1%
Total	5321.00	5286.58	34.42	0.6%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	1536.87	1537.69	-0.82	0%
S_HLFNGP_S_ROLL12(-4)	-12.31	-12.37	0.05	0%
D_AFTER17Q4*S_HLFNGP_S_ROLL12	-13.01	-13.45	0.45	-3%
D_11Q2THR12Q3*S_HLFNGP_S_ROLL12	-4.52	-4.52	0.01	0%
S_D2016	-143.45	-143.67	0.22	0%
S_D2015	-150.27	-150.50	0.23	0%
S_D2014	-78.28	-78.52	0.24	0%
S_D16Q4	165.24	165.23	0.02	0%
S_D18Q1	80.64	83.69	-3.05	-4%

LLFUPC Sales Cambridge
IV. Sales - Use Per Customer
A. Low Load Factor Use Per Customer - Sales
1. Cambridge

Model Statistics

Model		Model Fit Statistics	
	Number of Predictors	R-Squared	RMSE
B_LLF_UPC_SALES	7	0.997	2.074

ARIMA Model Parameters

B_LLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	23.12338	7.115	3.25	0.004
	B_LLFNGP_S(-4)	-1.02276	0.512	-2.00	0.059
	B_Q1_EDD	0.051984	0.001	71.45	0.000
	B_Q2_EDD+B_Q4_EDD	0.034608	0.001	24.24	0.000
	Q2	10.07905	2.172	4.64	0.000
	B_D19Q4_AFT*Q4	8.773462	4.731	1.85	0.078
	B_D15Q1	16.76139	4.843	3.46	0.002

Variable	Definition	Explanation	Dummy Variable Support
B_LLFNGP_S(-4)	Natural gas price for low load factor sales customers in Brockton ($2020) lagged four quarters		
B_Q1_EDD	Effective Degree Days in Brockton in Q1	A	
B_Q2_EDD+B_Q4_EDD	Effective Degree Days in Brockton in Q2 and Q4	A	
Q2	Binary variable equal to 1 in Q1	C	2
B_D19Q4_AFT*Q4	Binary variable equal to 1 in Q4 after 2019Q4		1
B_D15Q1	Binary variable equal to 1 in 2015Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
28	0.995889	1091.169

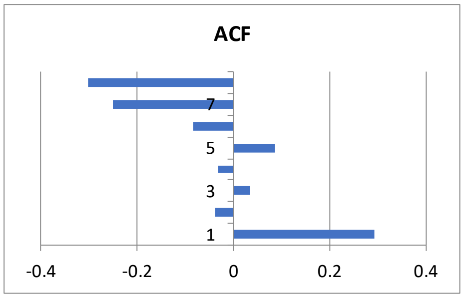
Chow Test Stats	N	k	SSR
Combined	28	7	388.57
1	14	6	135.06
2	14	6	102.95

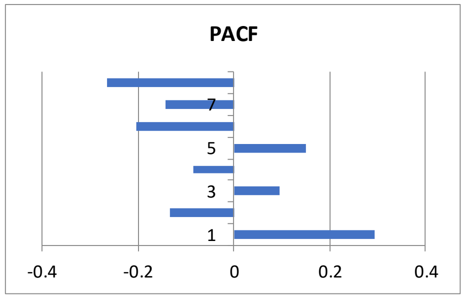
Chow Stat:	1.265
P-Value:	0.334227

Heteroscedasticity - White's Test	
White Stat	1.22
Significance (p-value)	0.34

Correlations

	B_LLFNGP_S(-4)	B_Q1_EDD	B_Q2_EDD+ B_Q4_EDD	Q2	B_D19Q4 _AFT*Q4	B_D15Q1
B_LLFNGP_S(-4)	1	-0.00565	-0.000593	-0.002472	0.141421	0.095818
B_Q1_EDD	-0.00565	1	-0.562095	-0.330454	-0.11015	0.411516
B_Q2_EDD+B_Q4_EDD	-0.000593	-0.562095	1	0.437828	0.249482	-0.188997
Q2	-0.002472	-0.330454	0.437828	1	-0.11111	-0.111111
B_D19Q4_AFT*Q4	0.141421	-0.110151	0.249482	-0.111111	1	-0.037037
B_D15Q1	0.095818	0.411516	-0.188997	-0.111111	-0.03704	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_llf_upc_sales Model	ACF	0.292	-0.037	0.034	-0.032	0.086	-0.084	-0.25	-0.302
	SE	0.378	0.378	0.378	0.378	0.378	0.378	0.378	0.378
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_llf_upc_sales Model		0.292	-0.133	0.095	-0.086	0.15	-0.203	-0.142	-0.265
	SE	0.378	0.378	0.378	0.378	0.378	0.378	0.378	0.378

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2013Q4	72.95	73.22	-0.28	-0.38%	(0.07)
2014Q1	208.21	206.14	2.07	0.99%	0.55
2014Q2	67.71	65.83	1.88	2.78%	0.50
2014Q3	11.31	9.03	2.29	20.21%	0.60
2014Q4	69.87	68.86	1.01	1.45%	0.27
2015Q1	232.21	232.21	0.00	0.00%	0.00
2015Q2	68.27	63.95	4.32	6.33%	1.14
2015Q3	10.86	6.99	3.87	35.66%	1.02
2015Q4	51.48	57.57	-6.09	-11.83%	(1.61)
2016Q1	155.20	160.77	-5.57	-3.59%	(1.47)
2016Q2	59.89	62.26	-2.36	-3.94%	(0.62)
2016Q3	9.44	8.48	0.95	10.10%	0.25
2016Q4	62.66	66.48	-3.82	-6.09%	(1.01)
2017Q1	167.17	174.92	-7.75	-4.64%	(2.04)
2017Q2	65.28	69.65	-4.37	-6.70%	(1.15)
2017Q3	8.33	12.25	-3.92	-47.06%	(1.03)
2017Q4	64.05	62.11	1.94	3.03%	0.51
2018Q1	197.84	189.12	8.71	4.40%	2.30
2018Q2	70.36	67.70	2.66	3.79%	0.70
2018Q3	8.20	10.98	-2.78	-33.87%	(0.73)
2018Q4	79.72	73.51	6.22	7.80%	1.64
2019Q1	184.51	186.25	-1.74	-0.94%	(0.46)
2019Q2	61.59	61.05	0.55	0.89%	0.14
2019Q3	9.94	8.24	1.70	17.07%	0.45
2019Q4	77.13	77.13	0.00	0.00%	0.00
2020Q1	159.27	156.02	3.24	2.04%	0.86
2020Q2	64.93	67.61	-2.67	-4.12%	(0.70)
2020Q3	9.51	9.58	-0.07	-0.71%	(0.02)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	77.13	68.30	8.83	11.4%
Q1 2020	159.27	155.46	3.81	2.4%
Q2 2020	64.93	68.04	-3.11	-4.8%
Q3 2020	9.51	9.51	0.01	0.1%
Total	310.84	301.31	9.54	3.1%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	23.123	23.823	-0.700	-3%
B_LLFNGP_S(-4)	-1.023	-1.081	0.058	-6%
B_Q1_EDD	0.052	0.052	0.000	0%
B_Q2_EDD+B_Q4_EDD	0.035	0.035	0.000	0%
Q2	10.079	10.533	-0.454	-5%
B_D19Q4_AFT*Q4	8.773			
B_D15Q1	16.761	17.473	-0.712	-4%

LLFUPC Sales Lawrence
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
L_LLF_UPC_SALES	11	0.994	2.509

ARIMA Model Parameters

L_LLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	18.1201	1.822	9.94	0.000
	L_LLFNGP_S*L_D15Q2_AFT	-0.340221	0.159	-2.14	0.037
	L_Q1_EDD	0.056661	0.001	81.97	0.000
	L_Q2_EDD	0.046065	0.002	27.38	0.000
	L_Q4_EDD	0.038158	0.001	28.83	0.000
	L_D15Q1	28.06617	6.713	4.18	0.000
	L_D15Q2	16.21595	6.710	2.42	0.020
	L_D19Q4	17.55677	6.695	2.62	0.012
	L_D11Q4_13Q2	-15.30868	2.662	-5.75	0.000
	L_D17Q1	-15.06085	6.594	-2.28	0.027
	L_D07Q1	28.20814	6.624	4.26	0.000

Variable	Definition	Explanation	Dummy Variable Support
L_LLFNGP_S*L_D15Q2_AFT	Natural gas price for low load factor sales customers in Lawrence ($2020) after 2015Q2		
L_Q1_EDD	Effective Degree Days in Lawrence in Q1	A	
L_Q2_EDD	Effective Degree Days in Lawrence in Q2	A	
L_Q4_EDD	Effective Degree Days in Lawrence in Q4	A	
L_D15Q1	Binary variable equal to 1 in 2015Q1		2
L_D15Q2	Binary variable equal to 1 in 2015Q2		2
L_D19Q4	Binary variable equal to 1 in 2019Q4		2
L_D11Q4_13Q2	Binary variable equal to 1 in 2011Q4 to 2013Q2		2
L_D17Q1	Binary variable equal to 1 in 2017Q1		2
L_D07Q1	Binary variable equal to 1 in 2007Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
59	0.993308	861.8856

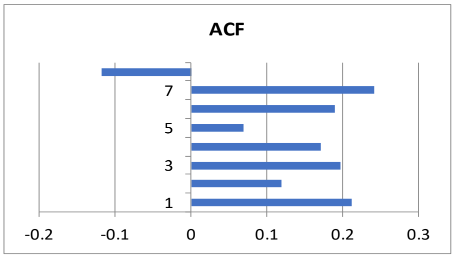
Chow Test Stats	N	k	SSR
Combined	59	11	1,903.32
1	31	6	1,501.13
2	28	9	296.65

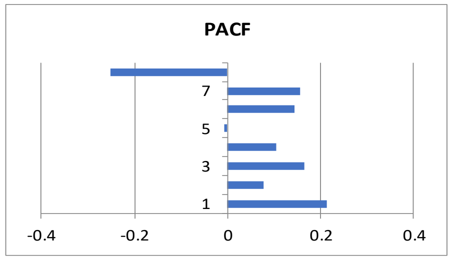
Chow Stat:	0.197
P-Value:	0.996782

Heteroscedasticity - White's Test	
White Stat	0.69
Significance (p-value)	0.73

Correlations

	L_LLFNGP_S*L_D15Q2_AFT	L_Q1_EDD	L_Q2_EDD	L_Q4_EDD	L_D15Q1	L_D15Q2	L_D19Q4	L_D11Q4_13Q2	L_D17Q1	L_D07Q1
L_LLFNGP_S*L_D15Q2_AFT	1	-0.074037	0.057303	-0.020891	-0.10001	0.216601	0.181283	-0.279453	0.127344	-0.10001
L_Q1_EDD	-0.074037	1	-0.33745	-0.32269	0.276166	-0.076305	-0.07631	0.011939	0.204444	0.231607
L_Q2_EDD	0.057303	-0.33745	1	-0.322447	-0.07625	0.242888	-0.07625	0.006923	-0.07625	-0.07625
L_Q4_EDD	-0.020891	-0.32269	-0.322447	1	-0.07291	-0.072913	0.248725	0.023254	-0.07291	-0.07291
L_D15Q1	-0.100011	0.276166	-0.076248	-0.072913	1	-0.017241	-0.01724	-0.048176	-0.01724	-0.01724
L_D15Q2	0.216601	-0.076305	0.242888	-0.072913	-0.01724	1	-0.01724	-0.048176	-0.01724	-0.01724
L_D19Q4	0.181283	-0.076305	-0.076248	0.248725	-0.01724	-0.017241	1	-0.048176	-0.01724	-0.01724
L_D11Q4_13Q2	-0.279453	0.011939	0.006923	0.023254	-0.04818	-0.048176	-0.04818	1	-0.04818	-0.04818
L_D17Q1	0.127344	0.204444	-0.076248	-0.072913	-0.01724	-0.017241	-0.01724	-0.048176	1	-0.01724
L_D07Q1	-0.100011	0.231607	-0.076248	-0.072913	-0.01724	-0.017241	-0.01724	-0.048176	-0.01724	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_llf_upc_sales Model	ACF	0.212	0.119	0.198	0.172	0.069	0.19	0.241	-0.117
	SE	0.260	0.260	0.260	0.260	0.260	0.260	0.260	0.260
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_llf_upc_sales Model		0.212	0.078	0.166	0.103	-0.008	0.144	0.156	-0.251
	SE	0.260	0.260	0.260	0.260	0.260	0.260	0.260	0.260

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2006Q1	230.45	211.91	18.54	8.04%	3.24
2006Q2	91.63	80.55	11.08	12.09%	1.93
2006Q3	20.61	18.12	2.49	12.10%	0.44
2006Q4	83.48	79.66	3.82	4.58%	0.67
2007Q1	252.65	252.65	0.00	0.00%	(0.00)
2007Q2	102.78	86.34	16.45	16.00%	2.87
2007Q3	20.13	18.12	2.01	10.00%	0.35
2007Q4	98.79	88.35	10.44	10.57%	1.82
2008Q1	219.00	216.38	2.62	1.20%	0.46
2008Q2	80.76	84.77	-4.01	-4.96%	(0.70)
2008Q3	14.60	18.12	-3.52	-24.15%	(0.62)
2008Q4	89.35	90.77	-1.43	-1.60%	(0.25)
2009Q1	235.68	233.88	1.80	0.76%	0.31
2009Q2	78.01	79.44	-1.43	-1.83%	(0.25)
2009Q3	21.46	18.12	3.33	15.54%	0.58
2009Q4	78.85	86.84	-7.99	-10.13%	(1.39)
2010Q1	214.63	219.39	-4.76	-2.22%	(0.83)
2010Q2	58.38	67.10	-8.72	-14.95%	(1.52)
2010Q3	15.30	18.12	-2.82	-18.46%	(0.49)
2010Q4	86.13	91.08	-4.95	-5.75%	(0.86)
2011Q1	231.11	229.34	1.77	0.77%	0.31
2011Q2	78.39	84.74	-6.35	-8.10%	(1.11)
2011Q3	15.47	18.12	-2.65	-17.15%	(0.46)
2011Q4	68.19	61.14	7.05	10.34%	1.23
2012Q1	171.45	180.42	-8.97	-5.23%	(1.57)
2012Q2	50.16	54.38	-4.22	-8.41%	(0.74)
2012Q3	13.54	2.81	10.72	79.23%	1.87
2012Q4	75.18	71.49	3.68	4.90%	0.64
2013Q1	195.89	203.16	-7.27	-3.71%	(1.27)
2013Q2	67.39	68.38	-0.99	-1.47%	(0.17)
2013Q3	13.18	18.12	-4.94	-37.46%	(0.86)
2013Q4	85.72	94.88	-9.16	-10.68%	(1.60)
2014Q1	240.87	244.21	-3.34	-1.39%	(0.58)
2014Q2	88.18	86.85	1.33	1.51%	0.23
2014Q3	14.18	18.12	-3.94	-27.81%	(0.69)
2014Q4	85.32	89.50	-4.18	-4.90%	(0.73)
2015Q1	282.37	282.37	0.00	0.00%	(0.00)
2015Q2	97.47	97.47	0.00	0.00%	(0.00)
2015Q3	13.44	13.49	-0.05	-0.40%	(0.01)
2015Q4	73.95	76.45	-2.50	-3.38%	(0.44)
2016Q1	192.46	192.70	-0.24	-0.13%	(0.04)
2016Q2	74.03	78.75	-4.72	-6.38%	(0.82)
2016Q3	16.65	15.03	1.62	9.76%	0.28
2016Q4	77.06	83.27	-6.22	-8.07%	(1.09)
2017Q1	187.81	187.81	0.00	0.00%	(0.00)
2017Q2	80.83	83.85	-3.03	-3.75%	(0.53)
2017Q3	13.62	14.51	-0.88	-6.47%	(0.15)
2017Q4	80.55	74.64	5.90	7.33%	1.03

2018Q1	223.85	220.49	3.36	1.50%	0.59
2018Q2	78.18	81.13	-2.94	-3.77%	(0.51)
2018Q3	12.21	13.53	-1.32	-10.80%	(0.23)
2018Q4	98.14	90.20	7.93	8.08%	1.38
2019Q1	215.25	217.10	-1.84	-0.86%	(0.32)
2019Q2	75.80	77.07	-1.27	-1.68%	(0.22)
2019Q3	12.83	13.85	-1.02	-7.95%	(0.18)
2019Q4	103.34	103.34	0.00	0.00%	(0.00)
2020Q1	185.49	187.72	-2.22	-1.20%	(0.39)
2020Q2	84.33	78.52	5.81	6.89%	1.01
2020Q3	16.57	14.42	2.14	12.94%	0.37

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	103.34	85.55	17.79	17.2%
Q1 2020	185.49	187.62	-2.13	-1.1%
Q2 2020	84.33	77.85	6.48	7.7%
Q3 2020	16.57	14.12	2.45	14.8%
Total	389.74	365.14	24.59	6.3%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	18.12	18.11	0.01	0%
L_LLFNGP_S*L_D15Q2_AFT	-0.34	-0.37	0.03	-8%
L_Q1_EDD	0.06	0.06	0.00	0%
L_Q2_EDD	0.05	0.05	0.00	1%
L_Q4_EDD	0.04	0.04	0.00	0%
L_D15Q1	28.07	27.76	0.31	1%
L_D15Q2	16.22	16.96	-0.75	-5%
L_D19Q4	17.56	0.00	17.56	100%
L_D11Q4_13Q2	-15.31	-15.31	0.00	0%
L_D17Q1	-15.06	-15.03	-0.03	0%
L_D07Q1	28.21	27.94	0.27	1%

LLFUPC Sales Springfield
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
S_LLF_UPC_SALES	10	0.995	2.317

ARIMA Model Parameters

S_LLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	37.85424	6.107	6.20	0.000
	S_LLFNGP_S_ROLL12	-1.909378	0.421	-4.54	0.000
	S_Q1_EDD	0.048235	0.001	58.57	0.000
	S_Q2_EDD+S_Q4_EDD	0.038272	0.001	28.32	0.000
	D_Q1_14THR19	22.00363	4.097	5.37	0.000
	S_D16Q1	-11.33951	6.228	-1.82	0.077
	S_D18Q1	16.90623	6.239	2.71	0.010
	S_D15Q1	20.47097	6.237	3.28	0.002
	S_D18Q4	18.46915	5.764	3.20	0.003
	S_D17Q4	11.01017	5.689	1.94	0.061

Variable	Definition	Explanation	Dummy Variable Support
S_LLFNGP_S_ROLL12	Rolling 12 quarter natural gas price for low load factor sales customers in Springfield ($2020)		
S_Q1_EDD	Effective Degree Days in Springfield in Q1	A	
S_Q2_EDD+S_Q4_EDD	Effective Degree Days in Springfield in Q2	A	
D_Q1_14THR19	Effective Degree Days in Springfield in Q4	A	
S_D16Q1	Binary variable equal to 1 in 2016Q1		2
S_D18Q1	Binary variable equal to 1 in 2018Q1		2
S_D15Q1	Binary variable equal to 1 in 2015Q1		2
S_D18Q4	Binary variable equal to 1 in 2018Q4		2
S_D17Q4	Binary variable equal to 1 in 2017Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
47	0.993957	841.6454

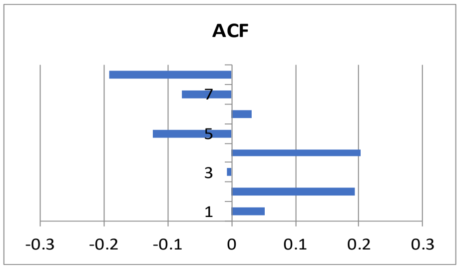
Chow Test Stats	N	k	SSR
Combined	47	10	1,065.66
1	23	5	382.83
2	24	10	417.58

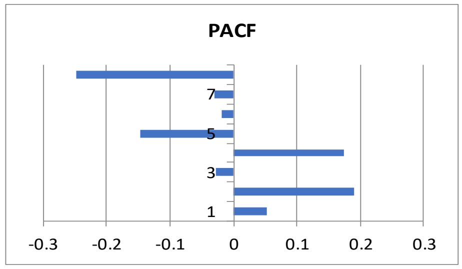
Chow Stat:	0.895
P-Value:	0.550385

Heteroscedasticity - White's Test	
White Stat	0.78
Significance (p-value)	0.64

Correlations

	S_LLFNGP_S_ROLL12	S_Q1_EDD	S_Q2_EDD+S_Q4_EDD	D_Q1_14THR19	S_D16Q1	S_D18Q1	S_D15Q1	S_D18Q4	S_D17Q4
S_LLFNGP_S_ROLL12	1	0.065153	-0.052433	-0.227481	-0.03957	-0.2148	0.020153	-0.1841	-0.20992
S_Q1_EDD	0.065153	1	-0.545803	0.670261	0.209589	0.260776	0.302143	-0.08584	-0.08584
S_Q2_EDD+S_Q4_EDD	-0.052433	-0.545803	1	-0.358623	-0.13822	-0.138222	-0.13822	0.248722	0.170754
D_Q1_14THR19	-0.227481	0.670261	-0.358623	1	0.385423	0.385423	0.385423	-0.0564	-0.0564
S_D16Q1	-0.039565	0.209589	-0.138222	0.385423	1	-0.021739	-0.02174	-0.02174	-0.02174
S_D18Q1	-0.2148	0.260776	-0.138222	0.385423	-0.02174	1	-0.02174	-0.02174	-0.02174
S_D15Q1	0.020153	0.302143	-0.138222	0.385423	-0.02174	-0.021739	1	-0.02174	-0.02174
S_D18Q4	-0.184102	-0.085842	0.248722	-0.056403	-0.02174	-0.021739	-0.02174	1	-0.02174
S_D17Q4	-0.209916	-0.085842	0.170754	-0.056403	-0.02174	-0.021739	-0.02174	-0.02174	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_llf_upc_sales Model	ACF	0.053	0.193	-0.008	0.202	-0.124	0.032	-0.077	-0.192
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_llf_upc_sales Model		0.053	0.191	-0.028	0.174	-0.146	-0.018	-0.03	-0.248
	SE	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2009Q1	183.31	177.58	5.73	3.13%	1.19
2009Q2	41.78	45.60	-3.82	-9.14%	(0.79)
2009Q3	12.57	3.21	9.36	74.49%	1.95
2009Q4	66.66	67.91	-1.24	-1.86%	(0.26)
2010Q1	168.77	168.41	0.35	0.21%	0.07
2010Q2	32.92	36.77	-3.85	-11.69%	(0.80)
2010Q3	10.27	5.34	4.93	48.01%	1.02
2010Q4	71.86	72.93	-1.06	-1.48%	(0.22)
2011Q1	177.58	181.67	-4.09	-2.30%	(0.85)
2011Q2	48.52	51.70	-3.18	-6.54%	(0.66)
2011Q3	9.90	7.93	1.97	19.86%	0.41
2011Q4	59.13	64.06	-4.93	-8.34%	(1.02)
2012Q1	147.04	149.29	-2.25	-1.53%	(0.47)
2012Q2	32.90	42.20	-9.30	-28.26%	(1.93)
2012Q3	10.53	9.69	0.84	7.97%	0.17
2012Q4	66.69	72.31	-5.62	-8.43%	(1.17)
2013Q1	168.61	173.28	-4.67	-2.77%	(0.97)
2013Q2	46.14	55.68	-9.54	-20.68%	(1.98)
2013Q3	10.58	10.40	0.18	1.74%	0.04
2013Q4	84.03	80.77	3.26	3.88%	0.68
2014Q1	218.95	218.65	0.30	0.14%	0.06
2014Q2	62.48	56.26	6.22	9.96%	1.29
2014Q3	12.46	10.52	1.95	15.63%	0.40
2014Q4	79.11	72.98	6.13	7.75%	1.27
2015Q1	243.24	243.24	0.00	0.00%	(0.00)
2015Q2	63.72	54.68	9.04	14.18%	1.88
2015Q3	11.91	10.67	1.25	10.46%	0.26
2015Q4	61.62	66.05	-4.43	-7.19%	(0.92)
2016Q1	167.62	167.62	0.00	0.00%	(0.00)
2016Q2	55.75	57.29	-1.54	-2.76%	(0.32)
2016Q3	12.66	13.46	-0.80	-6.28%	(0.17)
2016Q4	80.38	77.85	2.54	3.16%	0.53
2017Q1	187.58	190.18	-2.60	-1.39%	(0.54)
2017Q2	61.47	63.55	-2.09	-3.39%	(0.43)
2017Q3	10.91	16.05	-5.14	-47.07%	(1.07)
2017Q4	85.69	85.69	0.00	0.00%	(0.00)
2018Q1	225.87	225.87	0.00	0.00%	(0.00)
2018Q2	72.58	65.12	7.46	10.28%	1.55
2018Q3	12.76	16.22	-3.46	-27.13%	(0.72)
2018Q4	107.09	107.09	0.00	0.00%	(0.00)
2019Q1	208.21	205.91	2.30	1.11%	0.48
2019Q2	62.15	55.60	6.55	10.53%	1.36
2019Q3	14.19	14.54	-0.36	-2.52%	(0.07)
2019Q4	92.25	81.04	11.21	12.15%	2.33
2020Q1	167.36	162.75	4.61	2.76%	0.96
2020Q2	57.38	66.57	-9.19	-16.01%	(1.91)
2020Q3	10.87	13.89	-3.02	-27.77%	(0.63)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	92.25	80.18	12.07	13.1%
Q1 2020	167.36	161.36	6.00	3.6%
Q2 2020	57.38	65.96	-8.58	-15.0%
Q3 2020	10.87	14.07	-3.20	-29.4%
Total	327.86	321.57	6.29	1.9%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	37.85	35.95	1.91	5%
S_LLFNGP_S_ROLL12	-1.91	-1.74	-0.17	9%
S_Q1_EDD	0.05	0.05	0.00	1%
S_Q2_EDD+S_Q4_EDD	0.04	0.04	0.00	1%
D_Q1_14THR19	22.00	23.53	-1.53	-7%
S_D16Q1	-11.34	-11.73	0.39	-3%
S_D18Q1	16.91	17.20	-0.29	-2%
S_D15Q1	20.47	20.40	0.07	0%
S_D18Q4	18.47	19.55	-1.08	-6%
S_D17Q4	11.01	11.93	-0.92	-8%

HLFUPC Sales Brockton
A. High Load Factor Use Per Customer - Sales
1. Brockton

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
B_HLF_UPC_SALES	10	0.960	3.099

ARIMA Model Parameters

B_HLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	184.9764	14.208	13.02	0.000
	B_HLFNGP_S_ROLL12	-6.30144	1.578	-3.99	0.001
	B_Q1_EDD	0.030766	0.002	18.46	0.000
	B_Q2_EDD	0.028128	0.004	6.38	0.000
	B_Q4_EDD	0.023067	0.004	6.04	0.000
	B_D20Q2	-22.75722	10.651	-2.14	0.048
	B_D19Q4	26.55081	10.976	2.42	0.028
	B_D15Q3	32.09591	10.903	2.94	0.010
	B_D16Q4	-21.2311	10.756	-1.97	0.066
	B_D15Q2	24.7714	11.083	2.24	0.040

Variable	Definition	Explanation	Dummy Variable Support
B_HLFNGP_S_ROLL12	Rolling 12 quarter natural gas price for high load factor sales customers in Brockton ($2020)		
B_Q1_EDD	Effective Degree Days in Brockton in Q1	A	
B_Q2_EDD	Effective Degree Days in Brockton in Q2	A	
B_Q4_EDD	Effective Degree Days in Brockton in Q4	A	
B_D20Q2	Binary variable equal to 1 in 2020Q2		2
B_D19Q4	Binary variable equal to 1 in 2019Q4		2
B_D15Q3	Binary variable equal to 1 in 2015Q3		2
B_D16Q4	Binary variable equal to 1 in 2016Q4		2
B_D15Q2	Binary variable equal to 1 in 2015Q2		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

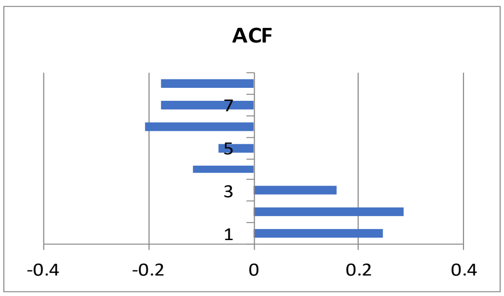
N	Adjusted R2	F Statistic
26	0.93807	43.07544

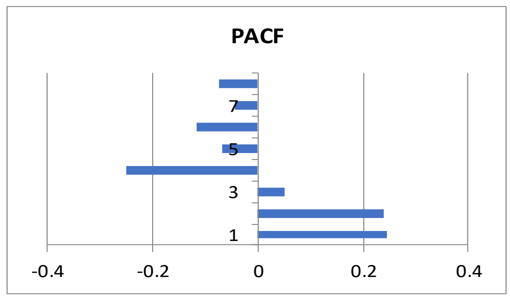
Chow Test Stats	N	k	SSR
Combined	26	10	1,475.38
1	13	8	309.40
2	13	7	608.50

Chow Stat:	0.364
P-Value:	0.923614

Heteroscedasticity - White's Test	
White Stat	0.75
Significance (p-value)	0.66

Correlations									
	B_HLFNGP_S_ROLL12	B_Q1_EDD	B_Q2_EDD	B_Q4_EDD	B_D20Q2	B_D19Q4	B_D15Q3	B_D16Q4	B_D15Q2
B_HLFNGP_S_ROLL12	1	-0.015931	0.049382	-0.018164	-0.06829	-0.107101	0.273346	0.019363	0.296683
B_Q1_EDD	-0.015931	1	-0.329366	-0.296211	-0.10865	-0.108651	-0.10865	-0.10865	-0.10865
B_Q2_EDD	0.049382	-0.329366	1	-0.330576	0.352606	-0.121256	-0.12126	-0.12126	0.335396
B_Q4_EDD	-0.018164	-0.296211	-0.330576	1	-0.10905	0.392137	-0.10905	0.362989	-0.10905
B_D20Q2	-0.068291	-0.108651	0.352606	-0.10905	1	-0.04	-0.04	-0.04	-0.04
B_D19Q4	-0.107101	-0.108651	-0.121256	0.392137	-0.04	1	-0.04	-0.04	-0.04
B_D15Q3	0.273346	-0.108651	-0.121256	-0.10905	-0.04	-0.04	1	-0.04	-0.04
B_D16Q4	0.019363	-0.108651	-0.121256	0.362989	-0.04	-0.04	-0.04	1	-0.04
B_D15Q2	0.296683	-0.108651	0.335396	-0.10905	-0.04	-0.04	-0.04	-0.04	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
b_hlf_upc_sales Model	ACF	0.246	0.284	0.157	-0.116	-0.068	-0.208	-0.177	-0.177
	SE	0.392	0.392	0.392	0.392	0.392	0.392	0.392	0.392
Residual PACF									
Model		1	2	3	4	5	6	7	8
b_hlf_upc_sales Model		0.246	0.238	0.051	-0.249	-0.068	-0.117	-0.045	-0.075
	SE	0.392	0.392	0.392	0.392	0.392	0.392	0.392	0.392

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q2	150.40	154.66	-4.26	-2.83%	(0.54)
2014Q3	120.20	116.91	3.29	2.74%	0.42
2014Q4	152.93	156.57	-3.65	-2.39%	(0.47)
2015Q1	246.91	237.91	8.99	3.64%	1.15
2015Q2	178.51	178.51			
2015Q3	148.89	148.89	0.00	0.00%	0.00
2015Q4	151.76	152.35	-0.58	-0.38%	(0.07)
2016Q1	197.36	211.35	-14.00	-7.09%	(1.79)
2016Q2	159.45	158.75	0.70	0.44%	0.09
2016Q3	128.16	125.49	2.67	2.09%	0.34
2016Q4	144.00	144.00	0.00	0.00%	0.00
2017Q1	218.94	226.86	-7.92	-3.62%	(1.01)
2017Q2	169.75	173.04	-3.29	-1.94%	(0.42)
2017Q3	129.42	136.49	-7.07	-5.46%	(0.90)
2017Q4	167.72	171.81	-4.09	-2.44%	(0.52)
2018Q1	234.30	244.55	-10.26	-4.38%	(1.31)
2018Q2	172.04	175.97	-3.93	-2.28%	(0.50)
2018Q3	133.44	138.10	-4.66	-3.49%	(0.59)
2018Q4	186.22	179.00	7.22	3.88%	0.92
2019Q1	244.23	239.66	4.57	1.87%	0.58
2019Q2	180.02	168.12	11.90	6.61%	1.52
2019Q3	148.94	133.02	15.92	10.69%	2.03
2019Q4	199.41	199.41	0.00	0.00%	0.00
2020Q1	237.55	219.88	17.67	7.44%	2.25
2020Q2	147.68	147.68	0.00	0.00%	0.00
2020Q3	121.54	130.78	-9.24	-7.60%	(1.18)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	199.41	172.53	26.88	13.5%
Q1 2020	237.55	217.42	20.13	8.5%
Q2 2020	147.67	170.26	-22.59	-15.3%
Q3 2020	121.54	131.99	-10.45	-8.6%
Total	706.17	692.20	13.98	2.0%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	184.98	183.64	1.34	1%
B_HLFNGP_S_ROLL12	-6.30	-6.01	-0.30	5%
B_Q1_EDD	0.03	0.03	0.00	4%
B_Q2_EDD	0.03	0.03	0.00	3%
B_Q4_EDD	0.02	0.02	0.00	4%
B_D20Q2	-22.76			
B_D19Q4	26.55			
B_D15Q3	32.10	30.23	1.86	6%
B_D16Q4	-21.23	-21.24	0.01	0%
B_D15Q2	24.77	24.18	0.60	2%

HLFUPC Sales Lawrence
2. Lawrence

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
L_HLF_UPC_SALES	6	0.912	4.076

ARIMA Model Parameters

L_HLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	156.1314	16.710	9.34	0.000
	L_HLFNGP_S(-2)	-4.181439	1.745	-2.40	0.026
	L_Q1Q2_EDD	0.035514	0.003	13.10	0.000
	L_Q4_EDD	0.021037	0.005	4.34	0.000
	L_D2019	39.71139	9.081	4.37	0.000
	L_D16Q1	-51.32258	17.808	-2.88	0.009

Variable	Definition	Explanation	Dummy Variable Support
L_HLFNGP_S(-2)	Natural gas price for high load factor sales customers in Lawrence ($2020) lagged two		
L_Q1Q2_EDD	Effective Degree Days in Lawrence in Q1 and Q2	A	
L_Q4_EDD	Effective Degree Days in Lawrence in Q4	A	
L_D2019	Binary variable equal to 1 in 2019		2
L_D16Q1	Binary variable equal to 1 in 2016Q1		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

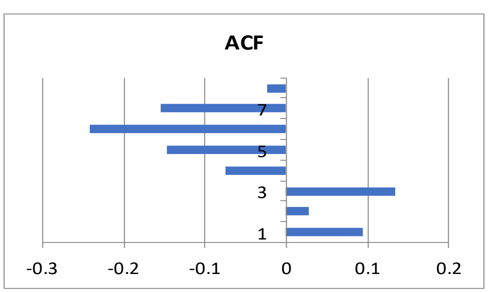
N	Adjusted R2	F Statistic
26	0.890034	41.46873

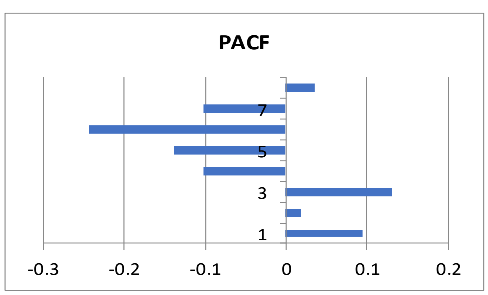
Chow Test Stats	N	k	SSR
Combined	26	6	5,521.10
1	14	5	2,025.39
2	12	5	1,443.87

Chow Stat:	1.38
P-Value:	0.288882

Heteroscedasticity - White's Test	
White Stat	0.52
Significance (p-value)	0.76

Correlations	L_HLFNGP_S(-2)	L_Q1Q2_EDD	L_Q4_EDD	L_D2019	L_D16Q1
L_HLFNGP_S(-2)	1	0.004141	0.019236	-0.000551	0.096105
L_Q1Q2_EDD	0.004141	1	-0.462797	0.01467	0.277749
L_Q4_EDD	0.019236	-0.462797	1	0.03167	-0.10906
L_D2019	-0.000551	0.01467	0.03167	1	-0.08528
L_D16Q1	0.096105	0.277749	-0.109063	-0.08528	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
l_hlf_upc_sales Model	ACF	0.094	0.027	0.134	-0.075	-0.147	-0.241	-0.155	-0.023
	SE	0.392	0.392	0.392	0.392	0.392	0.392	0.392	0.392
Residual PACF									
Model		1	2	3	4	5	6	7	8
l_hlf_upc_sales Model		0.094	0.018	0.131	-0.102	-0.139	-0.243	-0.102	0.036
	SE	0.392	0.392	0.392	0.392	0.392	0.392	0.392	0.392

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2014Q2	152.15	163.63	-11.48	-7.54%	(0.77)
2014Q3	116.18	108.37	7.81	6.72%	0.53
2014Q4	143.97	143.77	0.20	0.14%	0.01
2015Q1	232.53	253.59	-21.05	-9.05%	(1.42)
2015Q2	176.83	157.31	19.52	11.04%	1.31
2015Q3	125.91	104.69	21.22	16.85%	1.43
2015Q4	133.32	145.90	-12.57	-9.43%	(0.85)
2016Q1	174.84	174.84	0.00	0.00%	(0.00)
2016Q2	141.44	168.19	-26.75	-18.91%	(1.80)
2016Q3	114.81	124.72	-9.91	-8.63%	(0.67)
2016Q4	144.18	165.40	-21.22	-14.72%	(1.43)
2017Q1	244.33	245.98	-1.65	-0.67%	(0.11)
2017Q2	193.04	181.33	11.71	6.07%	0.79
2017Q3	124.84	127.48	-2.64	-2.12%	(0.18)
2017Q4	177.87	160.11	17.76	9.99%	1.20
2018Q1	274.01	256.46	17.56	6.41%	1.18
2018Q2	175.75	178.84	-3.09	-1.76%	(0.21)
2018Q3	143.82	123.67	20.15	14.01%	1.36
2018Q4	174.51	160.89	13.62	7.80%	0.92
2019Q1	304.12	285.57	18.56	6.10%	1.25
2019Q2	194.83	205.91	-11.08	-5.68%	(0.75)
2019Q3	148.46	157.45	-8.98	-6.05%	(0.60)
2019Q4	200.31	198.81	1.50	0.75%	0.10
2020Q1	235.65	227.32	8.32	3.53%	0.56
2020Q2	143.22	168.44	-25.22	-17.61%	(1.70)
2020Q3	118.57	120.84	-2.27	-1.91%	(0.15)
Ex Post					

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	200.31	196.41	3.90	1.9%
Q1 2020	235.65	228.05	7.60	3.2%
Q2 2020	143.22	170.04	-26.82	-18.7%
Q3 2020	118.57	123.20	-4.62	-3.9%
Total	697.75	717.70	-19.95	-2.9%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	156.13	158.80	-2.67	-2%
L_HLFNGP_S(-2)	-4.18	-4.22	0.04	-1%
L_Q1Q2_EDD	0.04	0.03	0.00	1%
L_Q4_EDD	0.02	0.02	0.00	7%
L_D2019	39.71	37.75	1.96	5%
L_D16Q1	-51.32	-51.97	0.65	-1%

HLFUPC Sales Springfield
3. Springfield

Model Statistics

Model	Number of Predictors	Model Fit Statistics	
		R-Squared	RMSE
S_HLF_UPC_SALES	12	0.908	3.309

ARIMA Model Parameters

S_HLF_UPC_SALES	Variable	Coefficient	Std. Error	t-Statistic	Prob.
	C	125.3552	10.542	11.89	0.000
	S_HLFNGP_S(-3)	-3.10957	0.784	-3.97	0.000
	S_Q1_EDD	0.020581	0.001	16.06	0.000
	S_Q4_EDD	0.017605	0.003	6.54	0.000
	S_Q2_EDD	0.028734	0.004	7.12	0.000
	D_AFTER15Q4*S_HLFNGP_S(-4)	2.862876	0.597	4.80	0.000
	S_D18Q3	32.24132	11.627	2.77	0.008
	S_D16Q1	-43.62187	12.592	-3.46	0.001
	S_D20Q2	-38.77822	12.087	-3.21	0.003
	S_D16Q2	-42.1844	12.358	-3.41	0.002
	S_D16Q4	-32.31641	11.803	-2.74	0.009
	S_D15Q4	-30.16225	13.019	-2.32	0.026

Variable	Definition	Explanation	Dummy Variable Support
S_HLFNGP_S(-3)	Natural gas price for high load factor sales customers in Springfield ($2020) lagged three quarters		
S_Q1_EDD	Effective Degree Days in Springfield in Q1	A	
S_Q4_EDD	Effective Degree Days in Springfield in Q4	A	
S_Q2_EDD	Effective Degree Days in Springfield in Q2	A	
D_AFTER15Q4*S_HLFNGP_S(-4)	Natural gas price for high load factor sales customers in Springfield ($2020) lagged four quarters after 2015Q4	B	
S_D18Q3	Binary variable equal to 1 in 2018Q3		2
S_D16Q1	Binary variable equal to 1 in 2016Q1		2
S_D20Q2	Binary variable equal to 1 in 2020Q2		2
S_D16Q2	Binary variable equal to 1 in 2016Q2		2
S_D16Q4	Binary variable equal to 1 in 2016Q4		2
S_D15Q4	Binary variable equal to 1 in 2015Q4		2

A: To account for customer responsiveness to EDDs in the indicated quarter(s)
B: Starting at the specified date, the data indicated that relationship between the independent variable and the dependent variable changed
C: To account for seasonality
1: Included to address a structural shift
2: Included to address an outlier

N	Adjusted R2	F Statistic
52	0.882697	35.88832

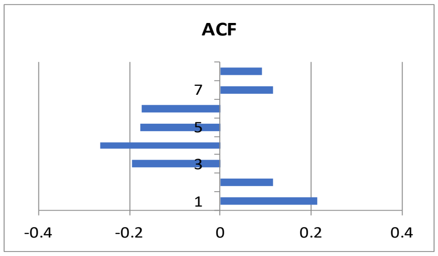
Chow Test Stats	N	k	SSR
Combined	52	12	4,797.64
1	26	5	1,757.00
2	26	12	2,357.60

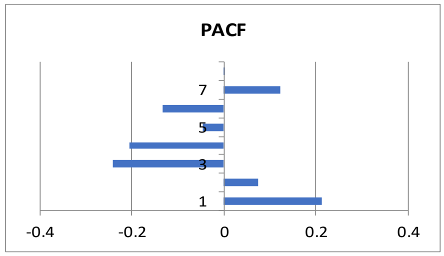
Chow Stat:	0.895
P-Value:	0.550385

Heteroscedasticity - White's Test	
White Stat	0.81
Significance (p-value)	0.63

Correlations

	S_HLFNGP_S(-3)	S_Q1_EDD	S_Q4_EDD	S_Q2_EDD	D_AFTER15Q4*S_HLFNGP_S(-4)	S_D18Q3	S_D16Q1	S_D20Q2	S_D16Q2	S_D16Q4	S_D15Q4
S_HLFNGP_S(-3)	1	0.022414	0.042685	-0.048406	-0.622715	-0.195588	-0.01271	-0.1015	-0.04713	-0.16542	0.060189
S_Q1_EDD	0.022414	1	-0.330155	-0.327953	-0.017796	-0.080419	0.202828	-0.08042	-0.08042	-0.08042	-0.08042
S_Q4_EDD	0.042685	-0.330155	1	-0.328277	0.004529	-0.080499	-0.0805	-0.0805	-0.0805	0.243416	0.197192
S_Q2_EDD	-0.048406	-0.327953	-0.328277	1	0.023602	-0.079962	-0.07996	0.305908	0.245174	-0.07996	-0.07996
D_AFTER15Q4*S_HLFNGP_S(-4	-0.622715	-0.017796	0.004529	0.023602	1	0.120573	0.287442	0.174739	0.24012	0.183332	0.288995
S_D18Q3	-0.195588	-0.080419	-0.080499	-0.079962	0.120573	1	-0.01961	-0.01961	-0.01961	-0.01961	-0.01961
S_D16Q1	-0.012708	0.202828	-0.080499	-0.079962	0.287442	-0.019608	1	-0.01961	-0.01961	-0.01961	-0.01961
S_D20Q2	-0.101502	-0.080419	-0.080499	0.305908	0.174739	-0.019608	-0.01961	1	-0.01961	-0.01961	-0.01961
S_D16Q2	-0.047128	-0.080419	-0.080499	0.245174	0.24012	-0.019608	-0.01961	-0.01961	1	-0.01961	-0.01961
S_D16Q4	-0.165415	-0.080419	0.243416	-0.079962	0.183332	-0.019608	-0.01961	-0.01961	-0.01961	1	-0.01961
S_D15Q4	0.060189	-0.080419	0.197192	-0.079962	0.288995	-0.019608	-0.01961	-0.01961	-0.01961	-0.01961	1





Residual ACF									
Model		1	2	3	4	5	6	7	8
s_hlf_upc_sales Model	ACF	0.213	0.116	-0.193	-0.264	-0.177	-0.173	0.117	0.093
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277	0.277
Residual PACF									
Model		1	2	3	4	5	6	7	8
s_hlf_upc_sales Model		0.213	0.073	-0.243	-0.207	-0.045	-0.133	0.121	0.002
	SE	0.277	0.277	0.277	0.277	0.277	0.277	0.277	0.277

Table of Actual, Fitted and Residual Values

Yr QTR	Actual	Fitted	Residual	% Variation	Standardized Residual
2007Q4	106.11	101.57	4.54	4.28%	0.46
2008Q1	152.20	143.94	8.26	5.43%	0.84
2008Q2	103.21	110.79	-7.59	-7.35%	(0.77)
2008Q3	82.94	79.23	3.71	4.47%	0.38
2008Q4	108.22	111.51	-3.29	-3.04%	(0.34)
2009Q1	157.64	154.00	3.63	2.30%	0.37
2009Q2	112.08	107.61	4.47	3.99%	0.46
2009Q3	85.54	73.77	11.77	13.76%	1.20
2009Q4	101.08	103.14	-2.06	-2.04%	(0.21)
2010Q1	129.86	147.40	-17.54	-13.51%	(1.79)
2010Q2	95.89	108.44	-12.55	-13.08%	(1.28)
2010Q3	80.30	88.28	-7.98	-9.93%	(0.81)
2010Q4	106.74	120.83	-14.09	-13.20%	(1.44)
2011Q1	155.07	166.19	-11.12	-7.17%	(1.14)
2011Q2	123.47	123.21	0.26	0.21%	0.03
2011Q3	101.71	88.18	13.53	13.31%	1.38
2011Q4	119.19	114.12	5.07	4.25%	0.52
2012Q1	149.28	147.71	1.57	1.05%	0.16
2012Q2	109.51	113.68	-4.17	-3.81%	(0.43)
2012Q3	87.65	90.17	-2.52	-2.88%	(0.26)
2012Q4	107.48	120.35	-12.86	-11.97%	(1.31)
2013Q1	159.93	162.96	-3.03	-1.89%	(0.31)
2013Q2	148.39	128.70	19.69	13.27%	2.01
2013Q3	96.85	95.34	1.51	1.56%	0.15
2013Q4	124.89	127.80	-2.91	-2.33%	(0.30)
2014Q1	171.23	173.86	-2.63	-1.53%	(0.27)
2014Q2	116.88	127.43	-10.55	-9.03%	(1.08)
2014Q3	92.96	92.21	0.75	0.80%	0.08
2014Q4	114.33	119.07	-4.74	-4.14%	(0.48)
2015Q1	188.26	168.47	19.79	10.51%	2.02
2015Q2	119.05	120.86	-1.80	-1.52%	(0.18)
2015Q3	100.89	87.08	13.81	13.69%	1.41
2015Q4	117.56	117.56	0.00	0.00%	(0.00)
2016Q1	145.19	145.19	0.00	0.00%	(0.00)
2016Q2	115.99	115.99			
2016Q3	104.74	126.19	-21.45	-20.48%	(2.19)
2016Q4	124.35	124.35	0.00	0.00%	(0.00)
2017Q1	176.22	191.26	-15.04	-8.53%	(1.53)
2017Q2	155.12	159.86	-4.75	-3.06%	(0.48)
2017Q3	127.35	123.38	3.97	3.12%	0.41
2017Q4	162.61	149.83	12.78	7.86%	1.31
2018Q1	202.35	196.15	6.20	3.07%	0.63
2018Q2	178.93	160.65	18.28	10.22%	1.87
2018Q3	155.77	155.77	0.00	0.00%	(0.00)
2018Q4	162.53	154.61	7.92	4.87%	0.81
2019Q1	188.56	191.85	-3.29	-1.74%	(0.34)
2019Q2	145.64	153.94	-8.30	-5.70%	(0.85)
2019Q3	131.54	122.51	9.03	6.86%	0.92
2019Q4	165.01	154.13	10.88	6.59%	1.11
2020Q1	198.77	187.59	11.19	5.63%	1.14
2020Q2	123.22	123.22	0.00	0.00%	(0.00)
2020Q3	105.10	123.46	-18.36	-17.47%	(1.87)

Ex Post

Actual Results vs. Ex Post Forecast

	Actuals	Ex Post Forecast	Difference	% Difference
Q4 2019	165.01	152.16	12.85	7.8%
Q1 2020	198.77	186.32	12.45	6.3%
Q2 2020	123.22	161.03	-37.81	-30.7%
Q3 2020	105.10	124.36	-19.26	-18.3%
Total	592.10	623.87	-31.77	-5.4%

Comparison of Original and Ex Post Parameter Estimates

Variable	Estimate	Ex-Post Estimate	Difference	% Difference
C	125.36	127.93	-2.57	-2%
S_HLFNGP_S(-3)	-3.11	-3.18	0.07	-2%
S_Q1_EDD	0.02	0.02	0.00	3%
S_Q4_EDD	0.02	0.02	0.00	9%
S_Q2_EDD	0.03	0.03	0.00	5%
D_AFTER15Q4*S_HLFNGP_S(-4	2.86	2.74	0.12	4%
S_D18Q3	32.24	30.99	1.25	4%
S_D16Q1	-43.62	-41.90	-1.73	4%
S_D20Q2	-38.78			
S_D16Q2	-42.18	-41.20	-0.98	2%
S_D16Q4	-32.32	-30.58	-1.74	5%
S_D15Q4	-30.16	-28.12	-2.05	7%

Appendix 5: Billing Cycle Effective Degree Days (EDD)

In any given billing month, billed usage will include usage for customers whose bills were sent out at the beginning of the month, during the month, and at the end of the month. But bills sent out at the beginning of the month represent usage that mostly occurred in the prior month. Bills sent at the end of the month represent usage that mostly occurred within the current month. Analogously, EDD's that occur at the beginning of the month are more likely to affect the current billing month; EDD's at the end of the month are more likely to affect future billing months.

For its forecasting, the Company needs to align its billing month usage with the effective degree days ("EDDs") related to that usage: billing period EDDs. The Company makes this calculation using 2 data sources. The first is meter reading schedules, and the second daily NOAA weather data purchased for each of the Company's three divisions from a weather consulting firm. The main tool is a program that allocates actual daily EDD's into the billing months in which those EDD's were most represented.

For example, consider January 1st, 2007. We examine all the bills that covered a billing period that included 01/01/07. It turns out that about 95% of those bills were sent out in January. The other 5% of bills were sent out in February. We use these percentages to allocate the EDD's that occurred on 01/01/07 into the 2 billing months: 95% of that day's EDD's will be grouped into January billed EDD's, while 5% will be grouped with February. The intuition is clear: the EDD's on 01/01/07 had a 95% chance of affecting January 2007 billed volumes and a 5% chance of affecting February 2007 billed volumes.

We repeat this process for every day in the history and carry the historical billing patterns into the forecast in order to produce our history and forecast of billing period EDD's.

APPENDIX 6: CALCULATION OF NATURAL GAS PRICES

Because economic theory suggests that price is likely to influence demand, an appropriate natural gas price variable that reflects the price that EGMA Gas customers pay for natural gas was developed to be tested in the use per customer models. Historical natural gas prices were developed from Company data by dividing quarterly revenues by quarterly volumes for firm sales customers for each Customer Segment (residential heating, residential non-heating, low load factor, and high load factor) and for each division (Brockton, Lawrence, and Springfield). The calculated prices represent the full delivered cost to customers for gas service "at the burnertip," i.e., delivery and fuel charge. All nominal historical prices were converted to real 2020 dollars using the relevant consumer price indexes ("CPIs") from Moody's Analytics.

Forecasted natural gas prices were developed using a combination of: (1) the Department of Energy, Energy Information Administration's ("DOE-EIA") Short Term Energy Outlook ("STEO"),[1] which provides approximately one year of quarterly forecasts and (2) DOE-EIA's Annual Energy Outlook 2021 with Projections to 2050 ("AEO").[2] The STEO and AEO both provide region-specific natural gas price forecasts for residential, commercial, and industrial customer classes. To develop forecasted customer class gas prices, data for the New England region were used. For each division, a weighted average annual growth rate based on the New England residential, commercial and industrial long-term price forecasts from the AEO were applied to all customer segments; New England class-specific shapes were developed from the STEO (residential STEO data was used to develop price shapes for the residential heating and residential non-heating customer segments, commercial and industrial STEO data was used to develop price shapes for the C&I LLF and C&I HLF Customer Segments, respectively).

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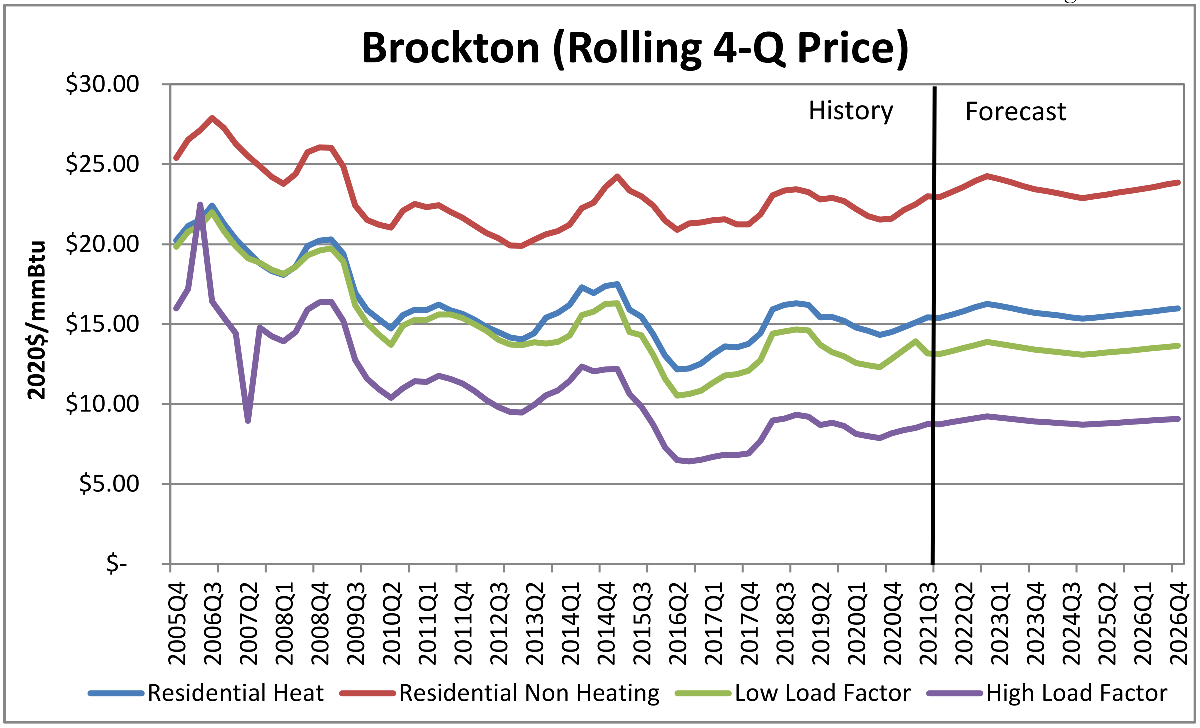
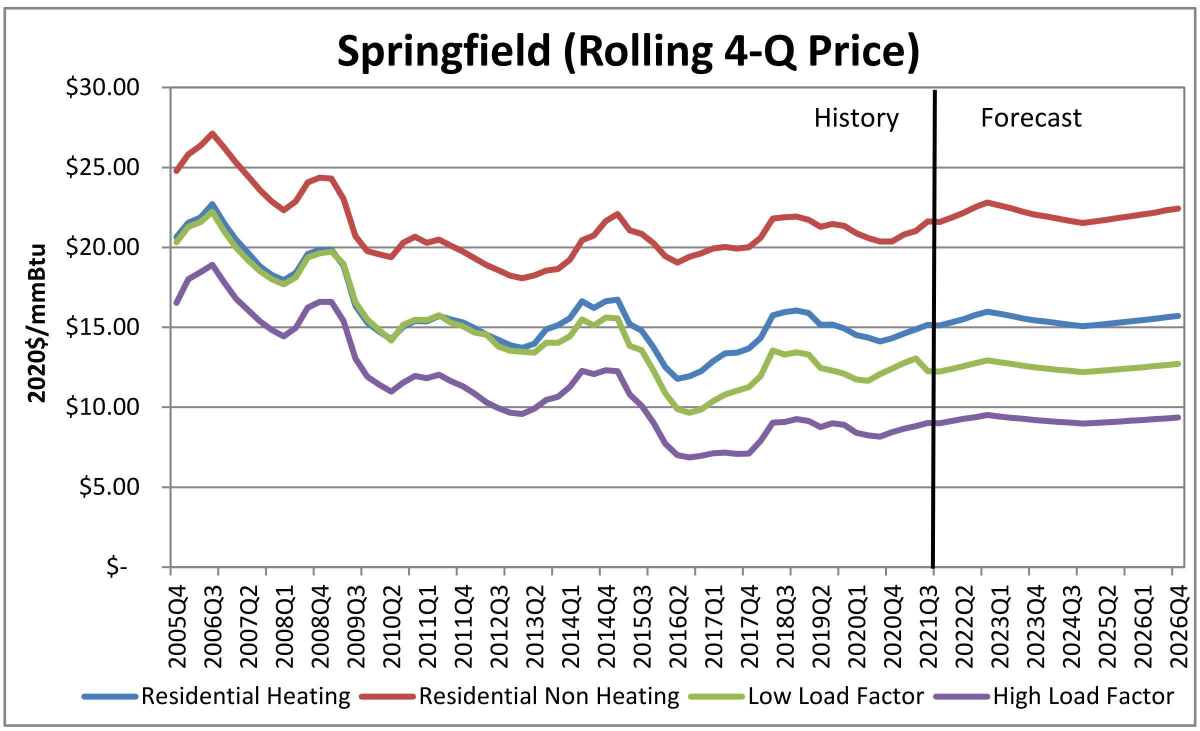
1 Dated April 2021.
2 Dated February 2021.

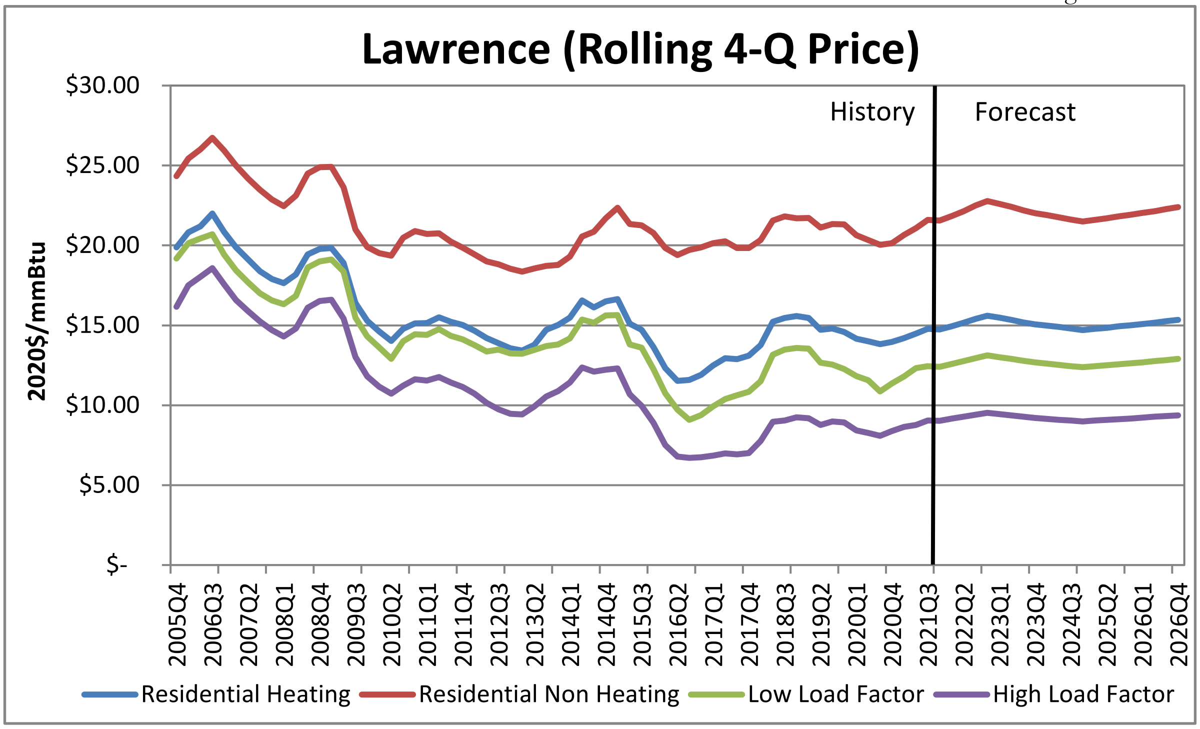
To develop forecasted gas prices that were calibrated to the EGMA Gas service territories, percent changes in the STEO and AEO prices throughout the forecast period were applied to the base period or forecast period Company prices. Specifically, the AEO weighted average annual percent change was applied to the Company-specific historical gas prices to develop the forecast annual natural gas price levels through 2026. A quarterly shape for the forecast period was developed by Customer Segment and division using the STEO quarterly price forecast and applied to the forecast annual natural gas prices to develop a quarterly shape for the 2020 Q4 through 2026 price forecast.

The price variable that was used in the use per customer models was determined by calculating volume-weighted, rolling four quarter averages from the actual and forecasted quarterly natural gas price data. The price variable reflects the concept that gas equipment purchases and changes in gas usage behavior are customer decisions that occur over an extended twelve month period.[3] The following graphs illustrate the historical and forecast data for the rolling four quarters price variables that were used in the use per customer models.

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


Brockton (Rolling 4-Q Price)
History
Forecast
2020$/mmBtu
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$-
2005Q4
2006Q3
2007Q2
2008Q1
2008Q4
2009Q3
2010Q2
2011Q1
2011Q4
2012Q3
2013Q2
2014Q1
2014Q4
2015Q3
2016Q2
2017Q1
2017Q4
2018Q3
2019Q2
2020Q1
2020Q4
2021Q3
2022Q2
2023Q1
2023Q4
2024Q3
2025Q2
2026Q1
2026Q4
Residential Heat
Residential Non Heating
Low Load Factor
High Load Factor


Springfield (Rolling 4-Q Price)
History
Forecast
2020$/mmBtu
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$-
2005Q4
2006Q3
2007Q2
2008Q1
2008Q4
2009Q3
2010Q2
2011Q1
2011Q4
2012Q3
2013Q2
2014Q1
2014Q4
2015Q3
2016Q2
2017Q1
2017Q4
2018Q3
2019Q2
2020Q1
2020Q4
2021Q3
2022Q2
2023Q1
2023Q4
2024Q3
2025Q2
2026Q1
2026Q4
Residential Heating
Residential Non Heating
Low Load Factor
High Load Factor



Additional variables based on natural gas prices were developed for testing in the customer count models. Economic theory suggests that fuel switching from oil to natural gas depends on the relative prices of the two fuels and the savings to be realized from fuel switching. Two variables were developed to measure those economic factors. A natural gas to oil price ratio variable was developed for each division and Customer Segment. This variable was calculated as the ratio of the rolling eight quarter average natural gas price to the rolling eight quarter national average retail price for No. 2 diesel fuel on an energy-equivalent basis.[4] In addition, a variable was developed to estimate the cumulative savings from fuel switching from oil to natural gas. Savings from fuel switching for a given quarter was calculated as the difference between the aforementioned oil and natural gas prices used for the price ratio variable multiplied by the most recent historical quarterly use per customer values by division and Customer Segment.

4 Moody's Analytics does not forecast heating oil prices specific to the EGMA Gas service territories, so a national average price was used.

Appendix 7: Customer Segment Variable Descriptions[1]

	Variable Name	Description	Geography	Source
1	B_RH_CUST_S_T	Residential Heating Customers	Brockton Division	EGMA Billing System
2	L_RH_CUST_S_T	Residential Heating Customers	Lawrence Division	EGMA Billing System
3	S_RH_CUST_S_T	Residential Heating Customers	Springfield Division	EGMA Billing System
4	B_RNH_CUST_S_T	Residential Non-Heating Customers	Brockton Division	EGMA Billing System
5	L_RNH_CUST_S_T	Residential Non-Heating Customers	Lawrence Division	EGMA Billing System
6	S_RNH_CUST_S_T	Residential Non-Heating Customers	Springfield Division	EGMA Billing System
7	B_LLF_CUST_SALES	Low Load Factor Customers Sales Only	Brockton Division	EGMA Billing System
8	L_LLF_CUST_SALES	Low Load Factor Customers Sales Only	Lawrence Division	EGMA Billing System
9	S_LLF_CUST_SALES	Low Load Factor Customers Sales Only	Springfield Division	EGMA Billing System
10	B_LLF_CUST_S_T	Low Load Factor Customers Sales and Transportation	Brockton Division	EGMA Billing System
11	L_LLF_CUST_S_T	Low Load Factor Customers Sales and Transportation	Lawrence Division	EGMA Billing System
12	S_LLF_CUST_S_T	Low Load Factor Customers Sales and Transportation	Springfield Division	EGMA Billing System
13	B_HLF_CUST_SALES	High Load Factor Customers Sales Only	Brockton Division	EGMA Billing System
14	L_HLF_CUST_SALES	High Load Factor Customers Sales Only	Lawrence Division	EGMA Billing System
15	S_HLF_CUST_SALES	High Load Factor Customers Sales Only	Springfield Division	EGMA Billing System
16	B_HLF_CUST_S_T	High Load Factor Customers Sales and Transportation	Brockton Division	EGMA Billing System
17	L_HLF_CUST_S_T	High Load Factor Customers Sales and Transportation	Lawrence Division	EGMA Billing System
18	S_HLF_CUST_S_T	High Load Factor Customers Sales and Transportation	Springfield Division	EGMA Billing System
19	B_RH_UPC_S_T	Residential Heating Use Per Customer	Brockton Division	EGMA Billing System
20	L_RH_UPC_S_T	Residential Heating Use Per Customer	Lawrence Division	EGMA Billing System
21	S_RH_UPC_S_T	Residential Heating Use Per Customer	Springfield Division	EGMA Billing System
22	B_RNH_UPC_S_T	Residential Non-Heating Use Per Customer	Brockton Division	EGMA Billing System
23	L_RNH_UPC_S_T	Residential Non-Heating Use Per Customer	Lawrence Division	EGMA Billing System
24	S_RNH_UPC_S_T	Residential Non-Heating Use Per Customer	Springfield Division	EGMA Billing System

[1] This appendix shows all of the variables available for testing in the customer and use per customer regression models. It does not list all binary variables and interactive variables developed for specific models; rather those variables are presented in the models' statistical summaries. Some models employed natural log specifications of the variables in this appendix.

	Variable Name	Description	Geography	Source
25	B_LLF_UPC_SALES	Low Load Factor Use Per Customer Sales Only	Brockton Division	EGMA Billing System
26	L_LLF_UPC_SALES	Low Load Factor Use Per Customer Sales Only	Lawrence Division	EGMA Billing System
27	S_LLF_UPC_SALES	Low Load Factor Use Per Customer Sales Only	Springfield Division	EGMA Billing System
28	B_LLF_UPC_S_T	Low Load Factor Use Per Customer Sales and Transportation	Brockton Division	EGMA Billing System
29	L_LLF_UPC_S_T	Low Load Factor Use Per Customer Sales and Transportation	Lawrence Division	EGMA Billing System
30	S_LLF_UPC_S_T	Low Load Factor Use Per Customer Sales and Transportation	Springfield Division	EGMA Billing System
31	B_HLF_UPC_SALES	High Load Factor Use Per Customer Sales Only	Brockton Division	EGMA Billing System
32	L_HLF_UPC_SALES	High Load Factor Use Per Customer Sales Only	Lawrence Division	EGMA Billing System
33	S_HLF_UPC_SALES	High Load Factor Use Per Customer Sales Only	Springfield Division	EGMA Billing System
34	B_HLF_UPC_S_T	High Load Factor Use Per Customer Sales and Transportation	Brockton Division	EGMA Billing System
35	L_HLF_UPC_S_T	High Load Factor Use Per Customer Sales and Transportation	Lawrence Division	EGMA Billing System
36	S_HLF_UPC_S_T	High Load Factor Use Per Customer Sales and Transportation	Springfield Division	EGMA Billing System
37	TREND	Quarterly Trend	NA	NA
38	Q1	Quarter 1 Binary Variable	NA	NA
39	Q2	Quarter 2 Binary Variable	NA	NA
40	Q3	Quarter 3 Binary Variable	NA	NA
41	Q4	Quarter 4 Binary Variable	NA	NA
42	B_RHNGP	Residential Heating Natural Gas Price	Brockton Division	EGMA Billing System; U.S. DOE-EIA
43	L_RHNGP	Residential Heating Natural Gas Price	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
44	S_RHNGP	Residential Heating Natural Gas Price	Springfield Division	EGMA Billing System; U.S. DOE-EIA
45	B_RRNGP	Residential Non-Heating Natural Gas Price	Brockton Division	EGMA Billing System; U.S. DOE-EIA
46	L_RRNGP	Residential Non-Heating Natural Gas Price	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
47	S_RRNGP	Residential Non-Heating Natural Gas Price	Springfield Division	EGMA Billing System; U.S. DOE-EIA
48	B_LLFNGP_S	Low Load Factor Natural Gas Price Sales Only	Brockton Division	EGMA Billing System; U.S. DOE-EIA
49	L_LLFNGP_S	Low Load Factor Natural Gas Price Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA

	Variable Name	Description	Geography	Source
50	S_LLFNGP_S	Low Load Factor Natural Gas Price Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA
51	B_LLFNGP_ST	Low Load Factor Natural Gas Price Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA
52	L_LLFNGP_ST	Low Load Factor Natural Gas Price Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
53	S_LLFNGP_ST	Low Load Factor Natural Gas Price Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA
54	B_HLFNGP_S	High Load Factor Natural Gas Price Sales Only	Brockton Division	EGMA Billing System; U.S. DOE-EIA
55	L_HLFNGP_S	High Load Factor Natural Gas Price Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
56	S_HLFNGP_S	High Load Factor Natural Gas Price Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA
57	B_HLFNGP_ST	High Load Factor Natural Gas Price Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA
58	L_HLFNGP_ST	High Load Factor Natural Gas Price Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
59	S_HLFNGP_ST	High Load Factor Natural Gas Price Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA
60	B_RHNGP_ROLL12	Residential Heating Natural Gas Price Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
61	L_RHNGP_ROLL12	Residential Heating Natural Gas Price Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
62	S_RHNGP_ROLL12	Residential Heating Natural Gas Price Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
63	B_RRNGP_ROLL12	Residential Non-Heating Natural Gas Price Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
64	L_RRNGP_ROLL12	Residential Non-Heating Natural Gas Price Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
65	S_RRNGP_ROLL12	Residential Non-Heating Natural Gas Price Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
66	B_LLFNGP_S_ROLL12	Low Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
67	L_LLFNGP_S_ROLL12	Low Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
68	S_LLFNGP_S_ROLL12	Low Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
69	B_HLFNGP_S_ROLL12	High Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
70	L_HLFNGP_S_ROLL12	High Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
71	S_HLFNGP_S_ROLL12	High Load Factor Natural Gas Price Sales Only Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA

	Variable Name	Description	Geography	Source
72	B_LLFNGP_ST_ROLL12	Low Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
73	L_LLFNGP_ST_ROLL12	Low Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
74	S_LLFNGP_ST_ROLL12	Low Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
75	B_HLFNGP_ST_ROLL12	High Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA
76	L_HLFNGP_ST_ROLL12	High Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Lawrence Division	EGMA Billing System; U.S. DOE-EIA
77	S_HLFNGP_ST_ROLL12	High Load Factor Natural Gas Price Sales and Transportation Rolling 12 Quarter	Springfield Division	EGMA Billing System; U.S. DOE-EIA
78	B_RHNGOIL	Residential Heating Natural Gas to Oil Price Ratio	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
79	L_RHNGOIL	Residential Heating Natural Gas to Oil Price Ratio	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
80	S_RHNGOIL	Residential Heating Natural Gas to Oil Price Ratio	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
81	B_RRNGOIL	Residential Non-Heating Natural Gas to Oil Price Ratio	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
82	L_RRNGOIL	Residential Non-Heating Natural Gas to Oil Price Ratio	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
83	S_RRNGOIL	Residential Non-Heating Natural Gas to Oil Price Ratio	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
84	B_LLFNGOIL	Low Load Factor Natural Gas to Oil Price Ratio Rolling 8 Quarter	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
85	L_LLFNGOIL_S	Low Load Factor Natural Gas to Oil Price Ratio Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
86	S_LLFNGOIL_S	Low Load Factor Natural Gas to Oil Price Ratio Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
87	B_LLFNGOIL_ST	Low Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
88	L_LLFNGOIL_ST	Low Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's

	Variable Name	Description	Geography	Source
89	S_LLFNGOIL_ST	Low Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
90	B_HLFNGOIL_S	High Load Factor Natural Gas to Oil Price Ratio Sales Only	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
91	L_HLFNGOIL_S	High Load Factor Natural Gas to Oil Price Ratio Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
92	S_HLFNGOIL_S	High Load Factor Natural Gas to Oil Price Ratio Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
93	B_HLFNGOIL_ST	High Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
94	L_HLFNGOIL_ST	High Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
95	S_HLFNGOIL_ST	High Load Factor Natural Gas to Oil Price Ratio Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
96	B_RHOIL_NG_SAVE	Residential Heating Cumulative Savings from Fuel Switching	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
97	L_RHOIL_NG_SAVE	Residential Heating Cumulative Savings from Fuel Switching	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
98	S_RHOIL_NG_SAVE	Residential Heating Cumulative Savings from Fuel Switching	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
99	B_RROIL_NG_SAVE	Residential Non-Heating Cumulative Savings from Fuel Switching	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
100	L_RROIL_NG_SAVE	Residential Non-Heating Cumulative Savings from Fuel Switching	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
101	S_RROIL_NG_SAVE	Residential Non-Heating Cumulative Savings from Fuel Switching	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
102	B_LLFOIL_NG_SAVE_S	Low Load Factor Cumulative Savings from Fuel Switching Sales Only	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
103	L_LLFOIL_NG_SAVE_S	Low Load Factor Cumulative Savings from Fuel Switching Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
104	S_LLFOIL_NG_SAVE_S	Low Load Factor Cumulative Savings from Fuel Switching Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
105	B_LLFOIL_NG_SAVE_ST	Low Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's

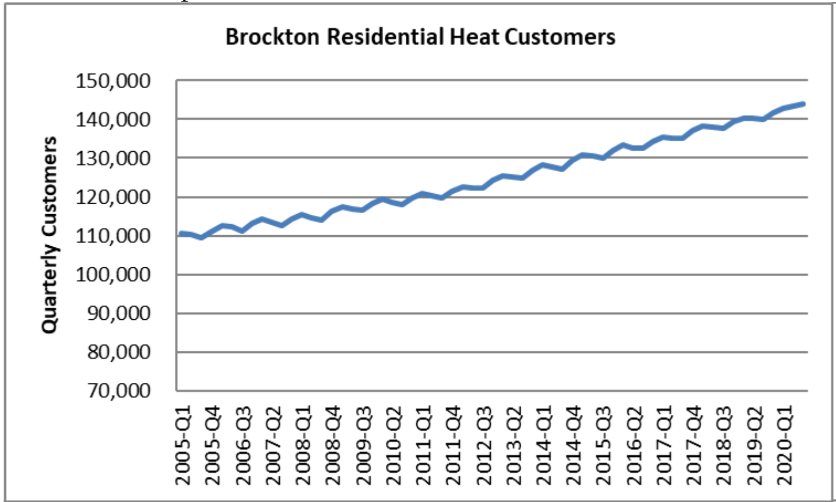
	Variable Name	Description	Geography	Source
106	L_LLFOIL_NG_SAVE_ST	Low Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
107	S_LLFOIL_NG_SAVE_ST	Low Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
108	B_HLFOIL_NG_SAVE_S	High Load Factor Cumulative Savings from Fuel Switching Sales Only	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
109	L_HLFOIL_NG_SAVE_S	High Load Factor Cumulative Savings from Fuel Switching Sales Only	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
110	S_HLFOIL_NG_SAVE_S	High Load Factor Cumulative Savings from Fuel Switching Sales Only	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
112	B_HLFOIL_NG_SAVE_ST	High Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Brockton Division	EGMA Billing System; U.S. DOE-EIA; Moody's
113	L_HLFOIL_NG_SAVE_ST	High Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Lawrence Division	EGMA Billing System; U.S. DOE-EIA; Moody's
114	S_HLFOIL_NG_SAVE_ST	High Load Factor Cumulative Savings from Fuel Switching Sales and Transportation	Springfield Division	EGMA Billing System; U.S. DOE-EIA; Moody's
115	B_EDD	Billing Cycle Effective Degree Days	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
116	L_EDD	Billing Cycle Effective Degree Days	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
117	S_EDD	Billing Cycle Effective Degree Days	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
118	B_Q1_EDD	Billing Cycle Effective Degree Days in Quarter 1	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
119	B_Q2_EDD	Billing Cycle Effective Degree Days in Quarter 2	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
120	B_Q3_EDD	Billing Cycle Effective Degree Days in Quarter 3	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
121	B_Q4_EDD	Billing Cycle Effective Degree Days in Quarter 4	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
122	B_Q2_4_EDD	Billing Cycle Effective Degree Days in Quarters 2 and 4	Brockton Division	U.S Weather Bureau (Bedford, MA-Providence RI)
123	L_Q1_EDD	Billing Cycle Effective Degree Days in Quarter 1	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
124	L_Q2_EDD	Billing Cycle Effective Degree Days in Quarter 2	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)

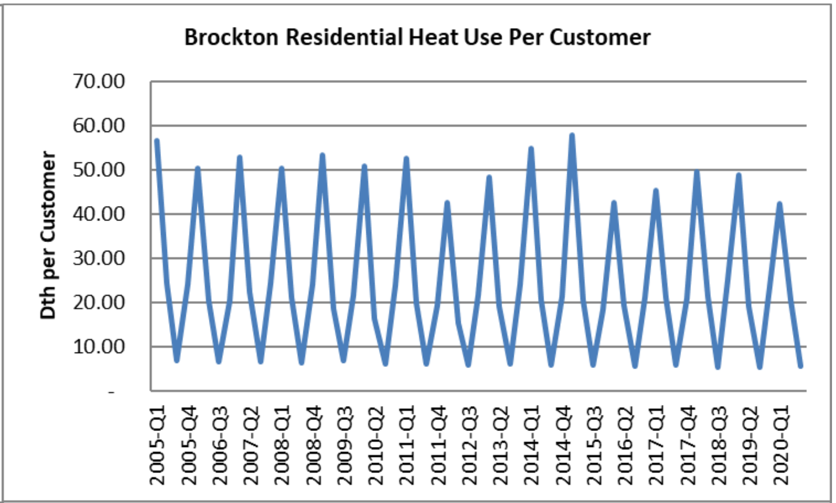
	Variable Name	Description	Geography	Source
125	L_Q3_EDD	Billing Cycle Effective Degree Days in Quarter 3	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
126	L_Q4_EDD	Billing Cycle Effective Degree Days in Quarter 4	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
127	L_Q2_4_EDD	Billing Cycle Effective Degree Days in Quarters 2 and 4	Lawrence Division	U.S Weather Bureau (Bedford, MA – Portsmouth, NH)
128	S_Q1_EDD	Billing Cycle Effective Degree Days in Quarter 1	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
129	S_Q2_EDD	Billing Cycle Effective Degree Days in Quarter 2	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
130	S_Q3_EDD	Billing Cycle Effective Degree Days in Quarter 3	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
131	S_Q4_EDD	Billing Cycle Effective Degree Days in Quarter 4	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
132	S_Q2_4_EDD	Billing Cycle Effective Degree Days in Quarters 2 and 4	Springfield Division	U.S. Weather Bureau (Windsor Locks, CT)
133	B_POP	Population (thousands)	Brockton Division	Moody's Economy.com
134	L_POP	Population (thousands)	Lawrence Division	Moody's Economy.com
135	S_POP	Population (thousands)	Springfield Division	Moody's Economy.com
136	B_HH	Households (thousands)	Brockton Division	Moody's Economy.com
137	L_HH	Households (thousands)	Lawrence Division	Moody's Economy.com
138	S_HH	Households (thousands)	Springfield Division	Moody's Economy.com
139	B_HC_MULTI	Multi-Family Housing Completions (# of units)	Brockton Division	Moody's Economy.com
140	L_HC_MULTI	Multi-Family Housing Completions (# of units)	Lawrence Division	Moody's Economy.com
141	S_HC_MULTI	Multi-Family Housing Completions (# of units)	Springfield Division	Moody's Economy.com
142	B_HC_SINGLE	Single-Family Housing Completions (# of units)	Brockton Division	Moody's Economy.com
143	L_HC_SINGLE	Single-Family Housing Completions (# of units)	Lawrence Division	Moody's Economy.com
144	S_HC_SINGLE	Single-Family Housing Completions (# of units)	Springfield Division	Moody's Economy.com
145	B_CUMULATIVE_HC	Cumulative Housing Completions (# of units)	Brockton Division	Moody's Economy.com
146	L_CUMULATIVE_HC	Cumulative Housing Completions (# of units)	Lawrence Division	Moody's Economy.com
147	S_CUMULATIVE_HC	Cumulative Housing Completions (# of units)	Springfield Division	Moody's Economy.com
148	B_MEAN_HH_INC	Average Household Income ($)	Brockton Division	Moody's Economy.com
149	L_MEAN_HH_INC	Average Household Income ($)	Lawrence Division	Moody's Economy.com
150	S_MEAN_HH_INC	Average Household Income ($)	Springfield Division	Moody's Economy.com
151	B_PINC	Total Personal Income (million $2012)	Brockton Division	Moody's Economy.com
152	L_PINC	Total Personal Income (million $2012)	Lawrence Division	Moody's Economy.com
153	S_PINC	Total Personal Income (million $2012)	Springfield Division	Moody's Economy.com

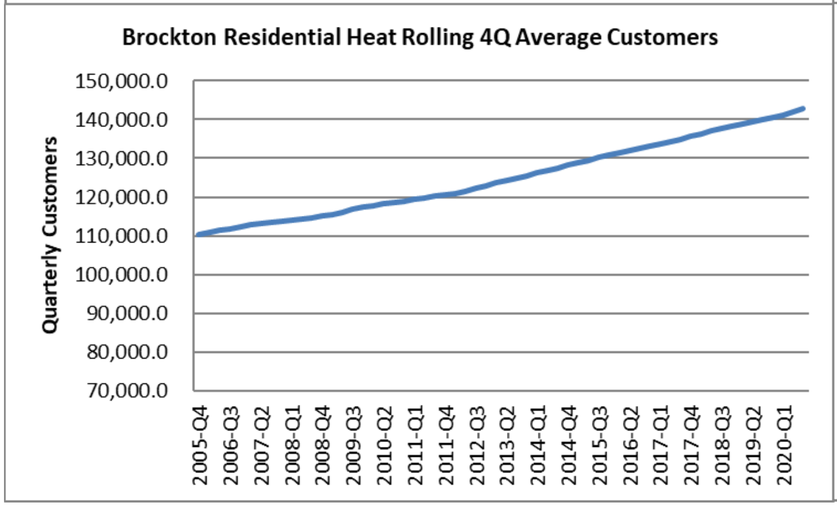
	Variable Name	Description	Geography	Source
154	B_GMP	Gross Metro Product (billion $)	Brockton Division	Moody's Economy.com
155	L_GMP	Gross Metro Product (billion $)	Lawrence Division	Moody's Economy.com
156	S_GMP	Gross Metro Product (billion $)	Springfield Division	Moody's Economy.com
157	B_GMP_CHAIN	Gross Metro Product (billion $)	Brockton Division	Moody's Economy.com
158	L_GMP_CHAIN	Gross Metro Product (billion chained 2012 $)	Lawrence Division	Moody's Economy.com
159	S_GMP_CHAIN	Gross Metro Product (billion chained 2012 $)	Springfield Division	Moody's Economy.com
160	B_EMPLOY	Non-Farm Employment (thousands)	Brockton Division	Moody's Economy.com
161	L_EMPLOY	Non-Farm Employment (thousands)	Lawrence Division	Moody's Economy.com
162	S_EMPLOY	Non-Farm Employment (thousands)	Springfield Division	Moody's Economy.com
163	B_MFG_EMPLOY	Manufacturing Employment (thousands)	Brockton Division	Moody's Economy.com
164	L_MFG_EMOLOY	Manufacturing Employment (thousands)	Lawrence Division	Moody's Economy.com
165	S_MFG_EMPLOY	Manufacturing Employment (thousands)	Springfield Division	Moody's Economy.com
166	B_NON_MFG_EMPLOY	Non-Manufacturing Employment (thousands)	Brockton Division	Moody's Economy.com
167	L_NON_MFG_EMPLOY	Non-Manufacturing Employment (thousands)	Lawrence Division	Moody's Economy.com
168	S_NON_MFG_EMPLOY	Non-Manufacturing Employment (thousands)	Springfield Division	Moody's Economy.com

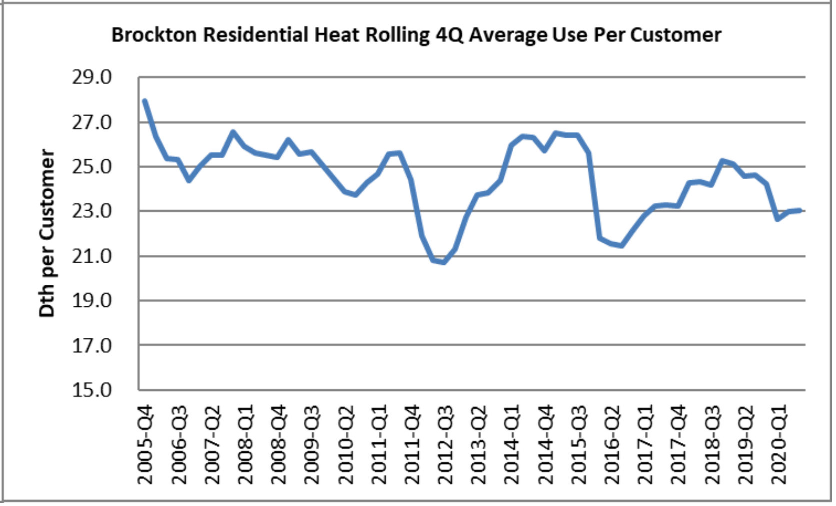
Appendix 8: Dependent Variable Graphs

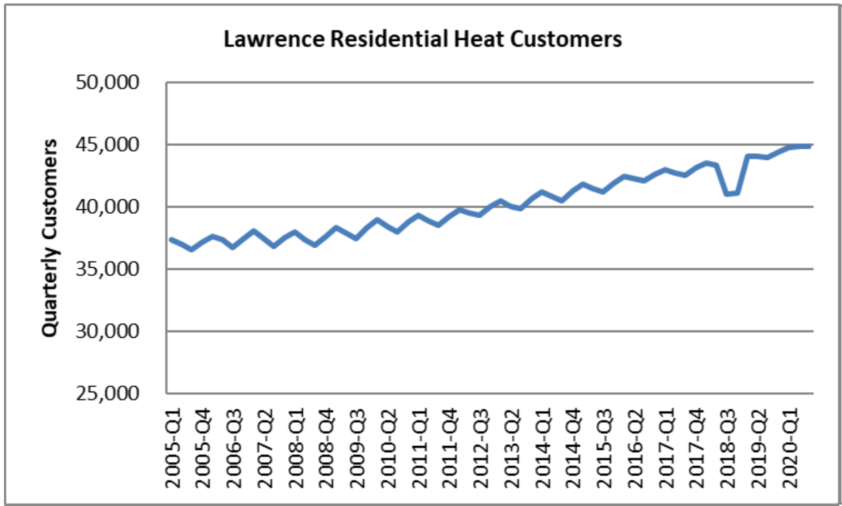
Sales and Transportation Combined:

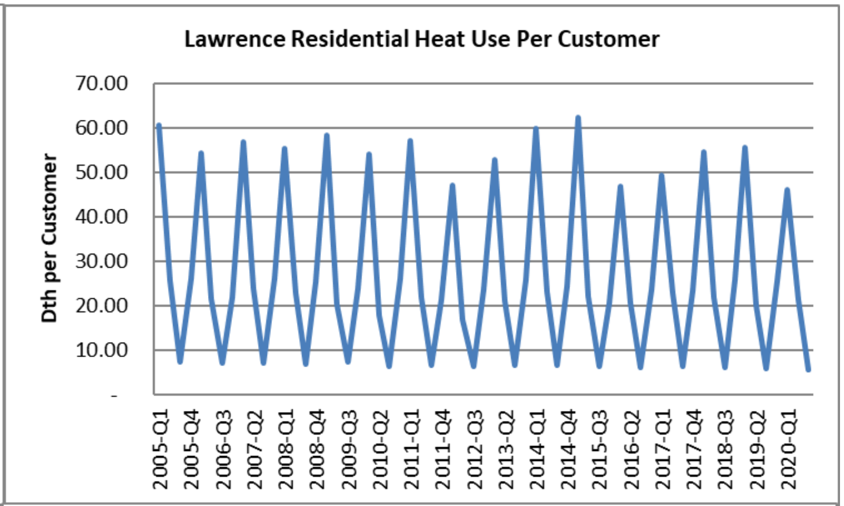


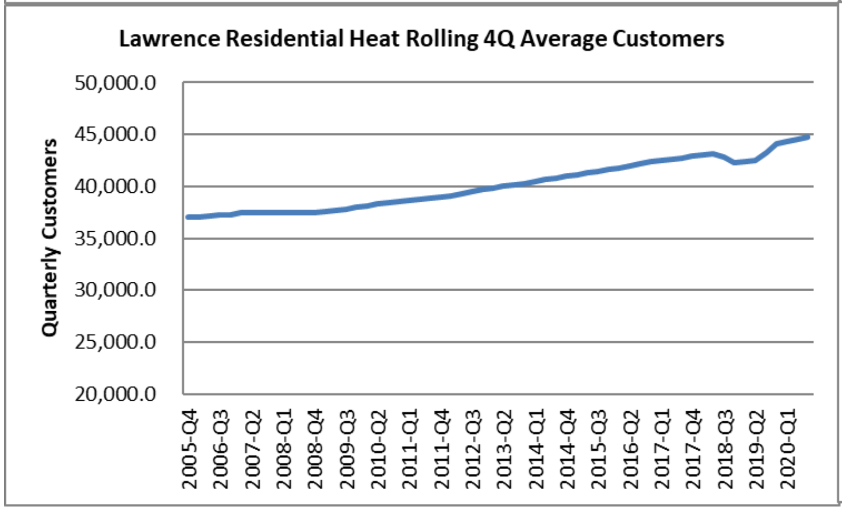


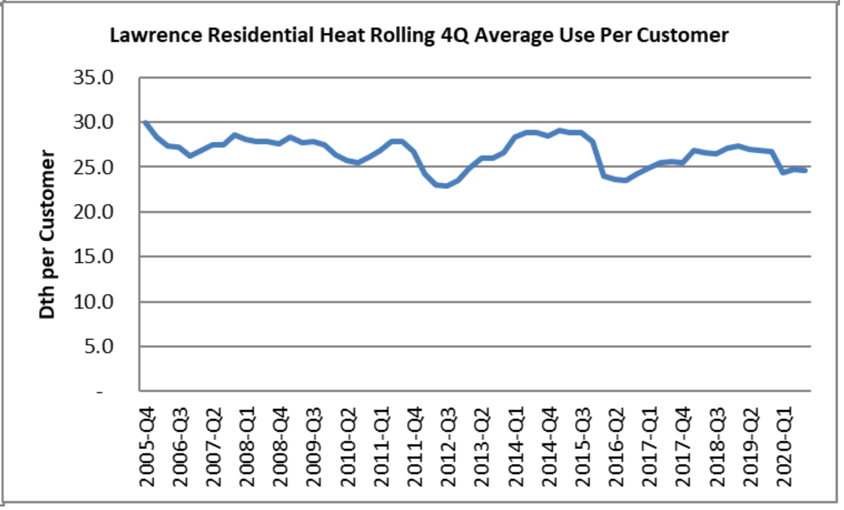


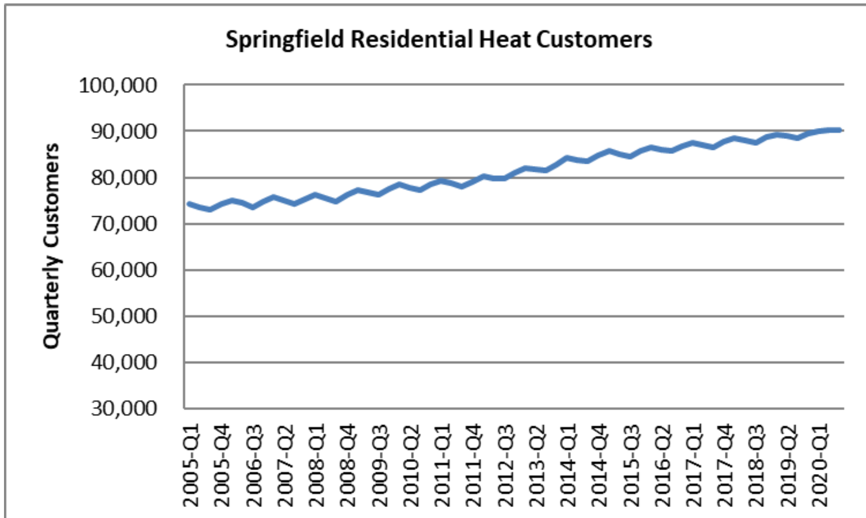


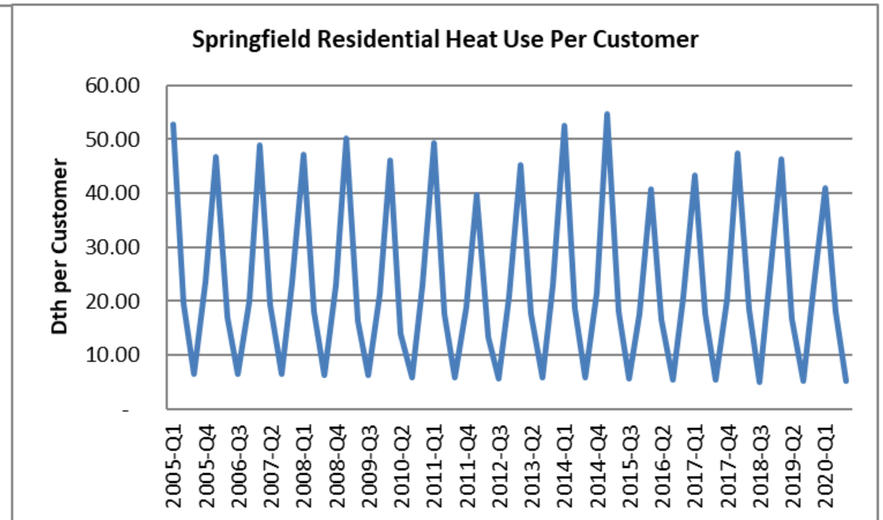

Lawrence Residential Heat Customers
Quarterly Customers
50,000
45,000
40,000
35,000
30,000
25,000
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

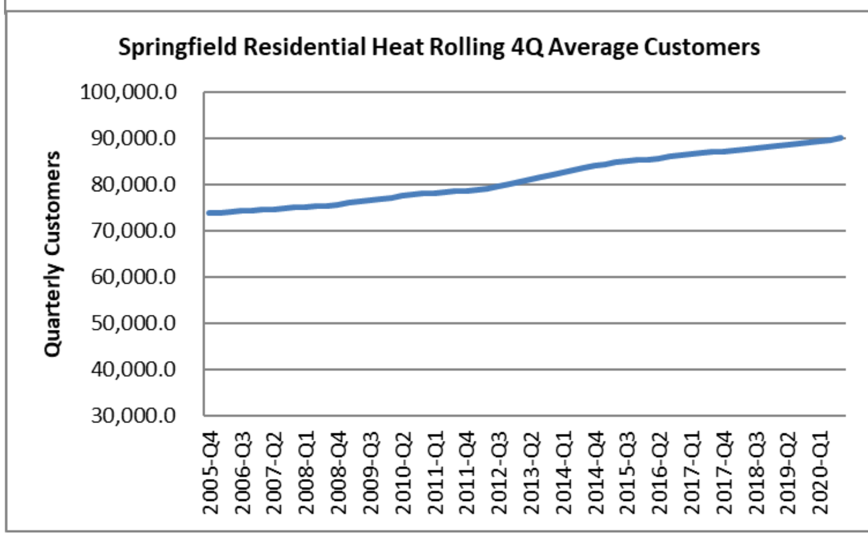

Lawrence Residential Heat Use Per Customer
Dth per Customer
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

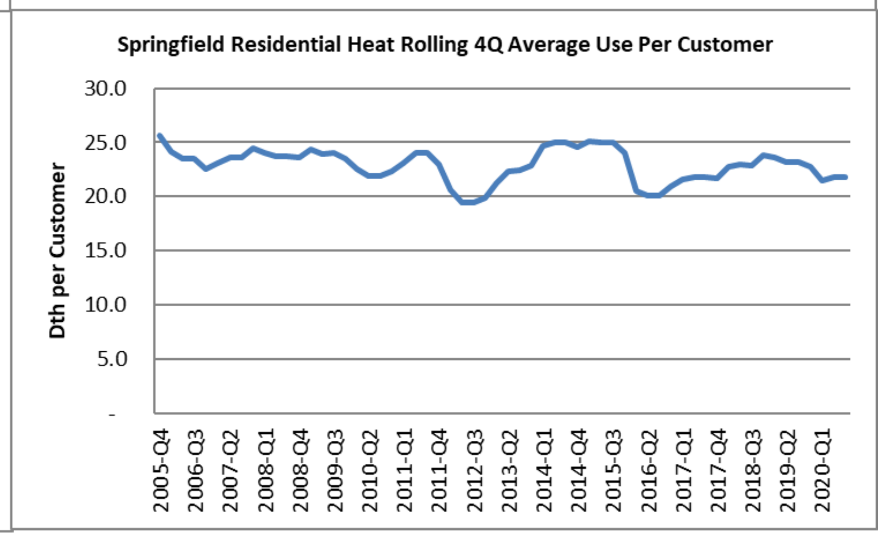

Lawrence Residential Heat Rolling 4Q Average Customers
Quarterly Customers
50,000.0
45,000.0
40,000.0
35,000.0
30,000.0
25,000.0
20,000.0
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

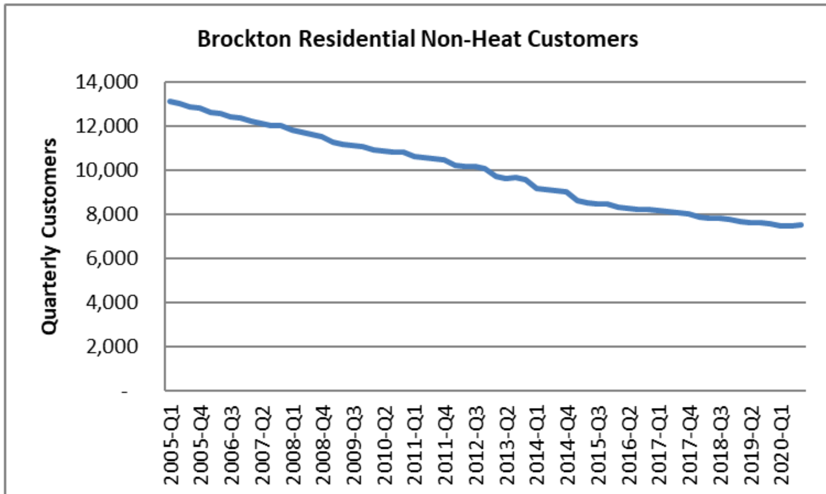

Lawrence Residential Heat Rolling 4Q Average Use Per Customer
Dth per Customer
35.0
30.0
25.0
20.0
15.0
10.0
5.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Springfield Residential Heat Customers
Quarterly Customers
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
2005-Q1 2005-Q4 2006-Q3 2007-Q2 2008-Q1 2008-Q4 2009-Q3 2010-Q2 2011-Q1 2011-Q4 2012-Q3 2013-Q2 2014-Q1 2014-Q4 2015-Q3 2016-Q2 2017-Q1 2017-Q4 2018-Q3 2019-Q2 2020-Q1


Springfield Residential Heat Use Per Customer
Dth per Customer
60.00
50.00
40.00
30.00
20.00
10.00
-
2005-Q1 2005-Q4 2006-Q3 2007-Q2 2008-Q1 2008-Q4 2009-Q3 2010-Q2 2011-Q1 2011-Q4 2012-Q3 2013-Q2 2014-Q1 2014-Q4 2015-Q3 2016-Q2 2017-Q1 2017-Q4 2018-Q3 2019-Q2 2020-Q1


Springfield Residential Heat Rolling 4Q Average Customers
Quarterly Customers
100,000.0
90,000.0
80,000.0
70,000.0
60,000.0
50,000.0
40,000.0
30,000.0
2005-Q4 2006-Q3 2007-Q2 2008-Q1 2008-Q4 2009-Q3 2010-Q2 2011-Q1 2011-Q4 2012-Q3 2013-Q2 2014-Q1 2014-Q4 2015-Q3 2016-Q2 2017-Q1 2017-Q4 2018-Q3 2019-Q2 2020-Q1


Springfield Residential Heat Rolling 4Q Average Use Per Customer
Dth per Customer
30.0
25.0
20.0
15.0
10.0
5.0
-
2005-Q4 2006-Q3 2007-Q2 2008-Q1 2008-Q4 2009-Q3 2010-Q2 2011-Q1 2011-Q4 2012-Q3 2013-Q2 2014-Q1 2014-Q4 2015-Q3 2016-Q2 2017-Q1 2017-Q4 2018-Q3 2019-Q2 2020-Q1


Brockton Residential Non-Heat Customers
Quarterly Customers
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
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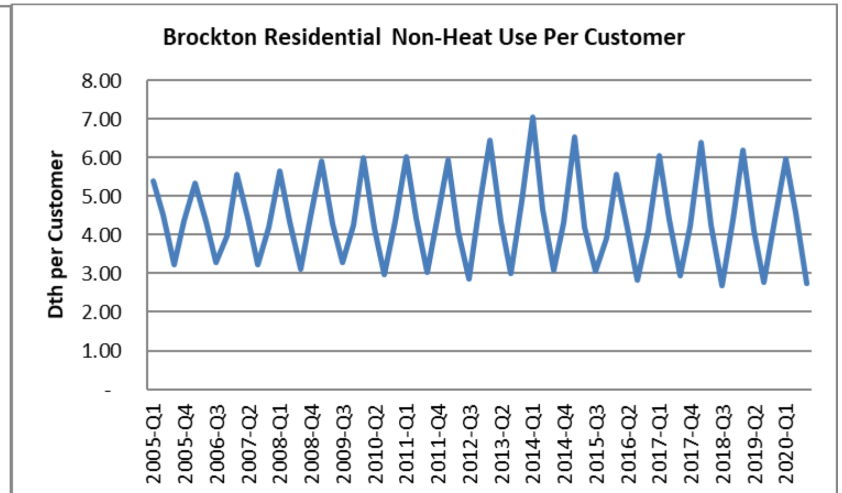
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Brockton Residential Non-Heat Use Per Customer
Dth per Customer
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
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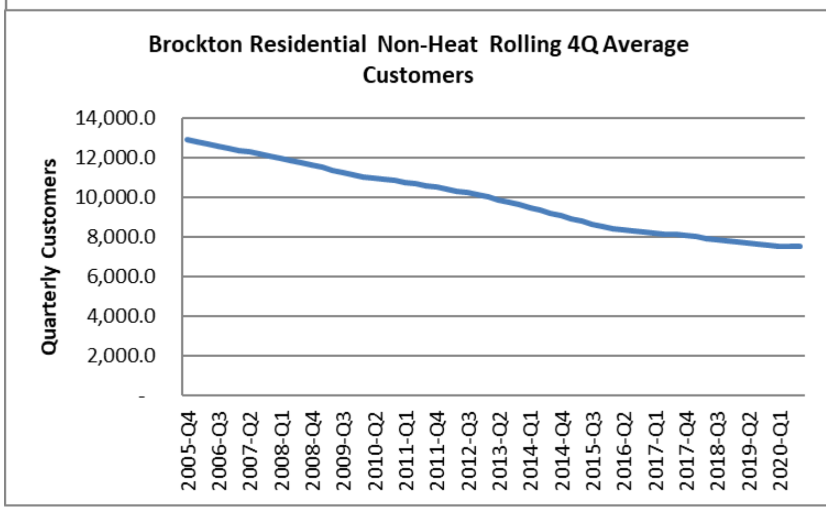
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Brockton Residential Non-Heat Rolling 4Q Average Customers
Quarterly Customers
14,000.0
12,000.0
10,000.0
8,000.0
6,000.0
4,000.0
2,000.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
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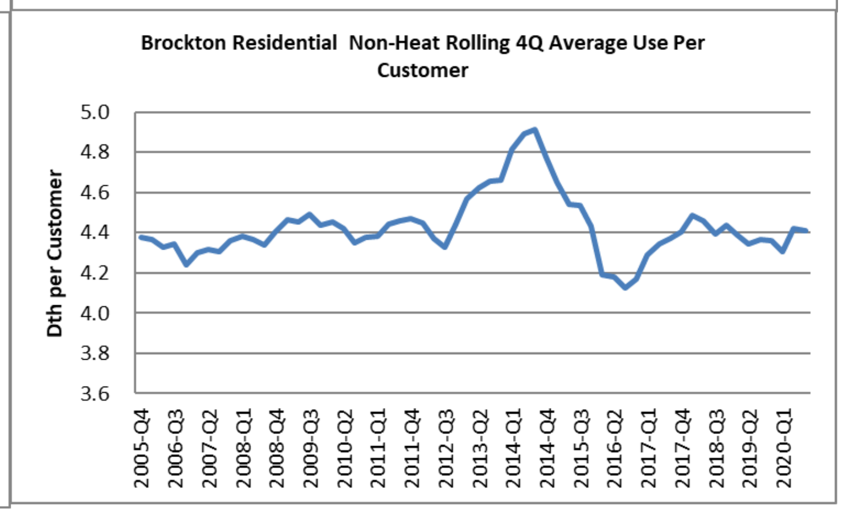
2018-Q3
2019-Q2
2020-Q1


Brockton Residential Non-Heat Rolling 4Q Average Use Per Customer
Dth per Customer
5.0
4.8
4.6
4.4
4.2
4.0
3.8
3.6
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
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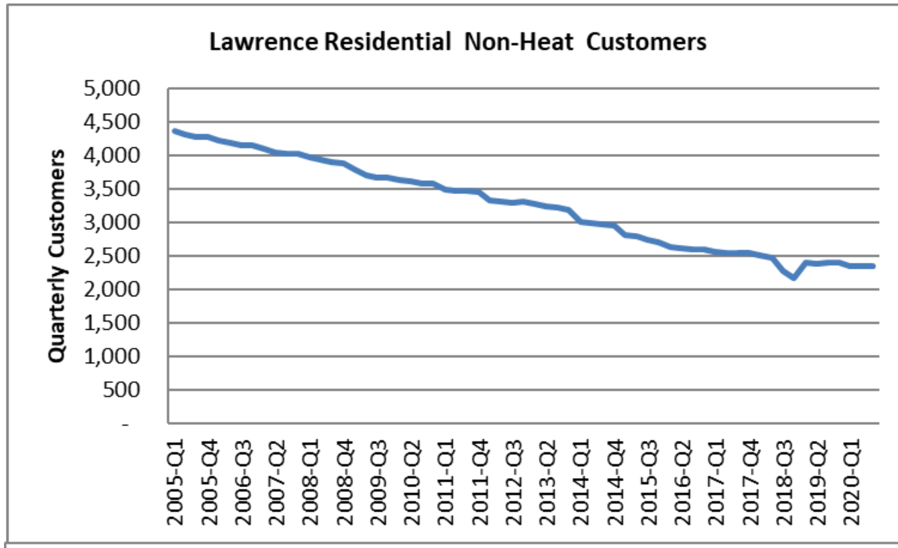
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Lawrence Residential Non-Heat Customers
Quarterly Customers
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
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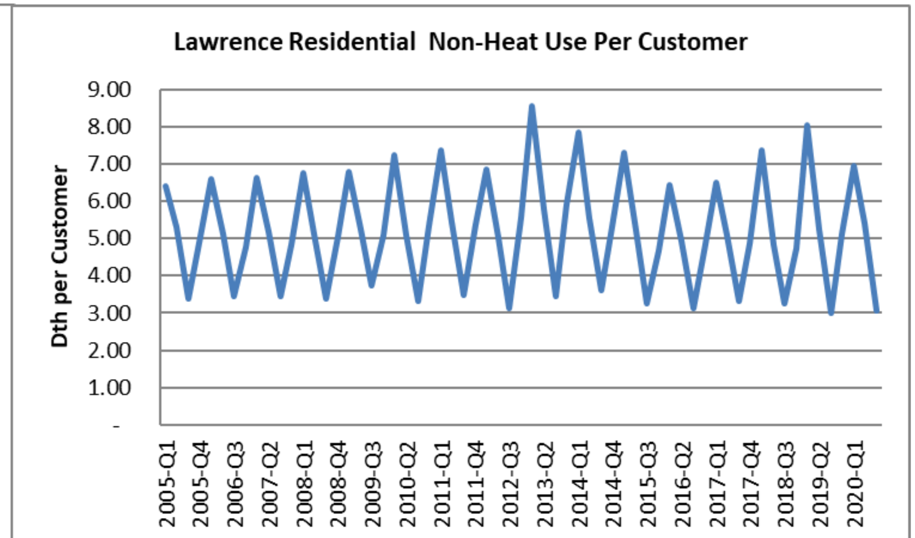
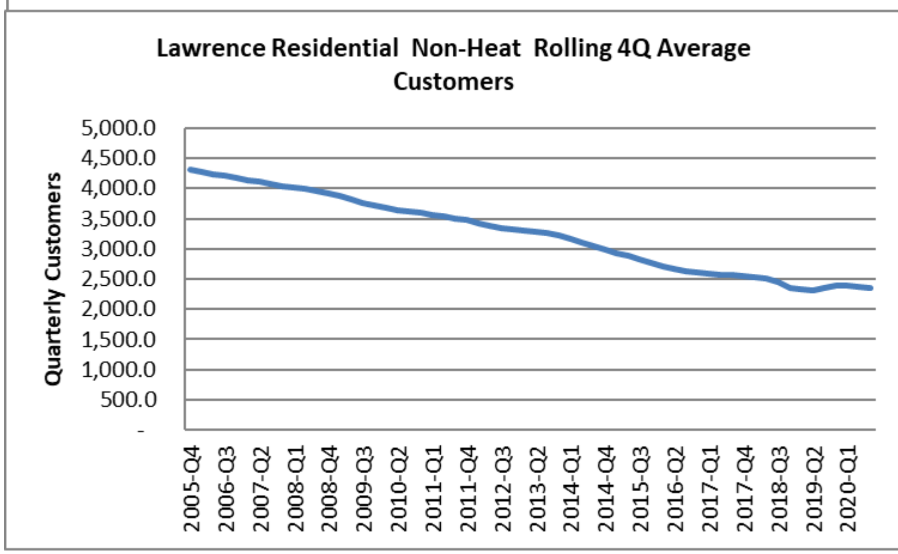
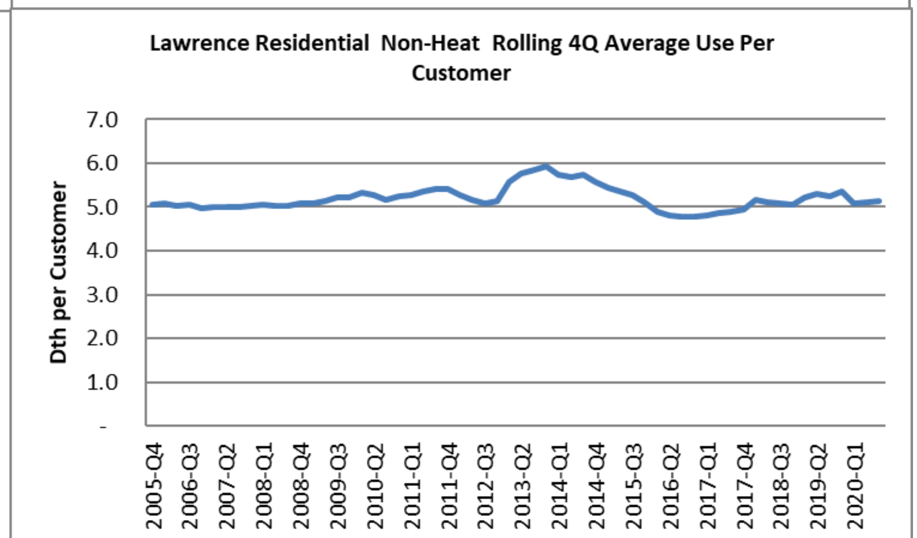
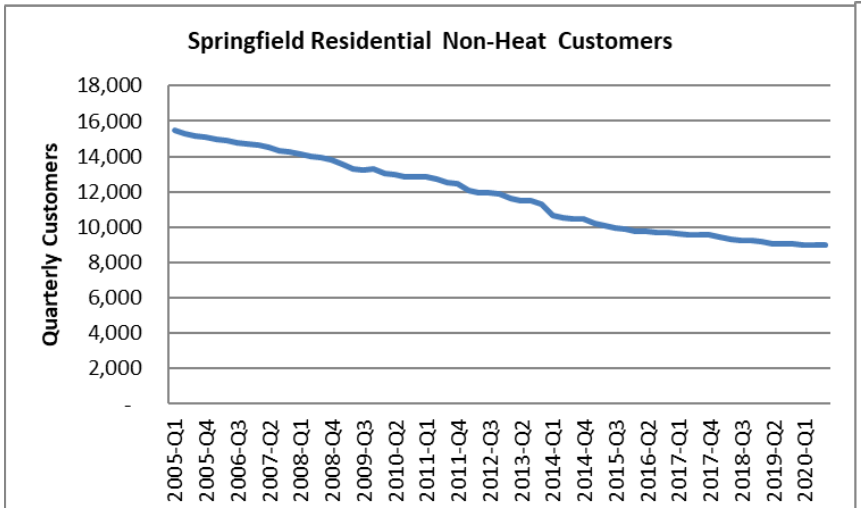
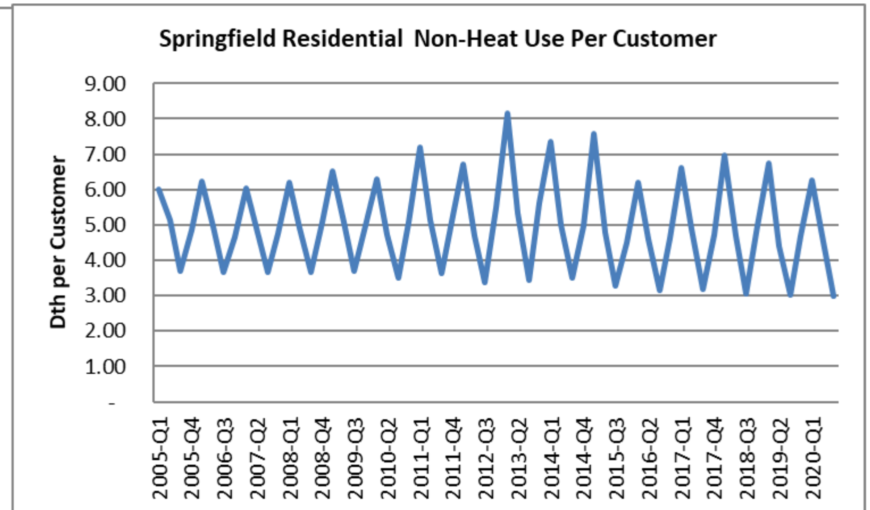
2019-Q2
2020-Q1

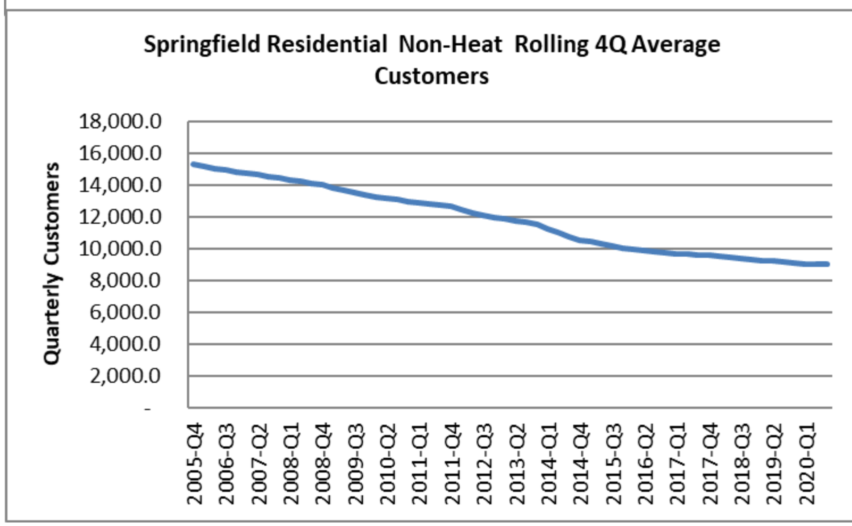

Lawrence Residential Non-Heat Use Per Customer
Dth per Customer
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

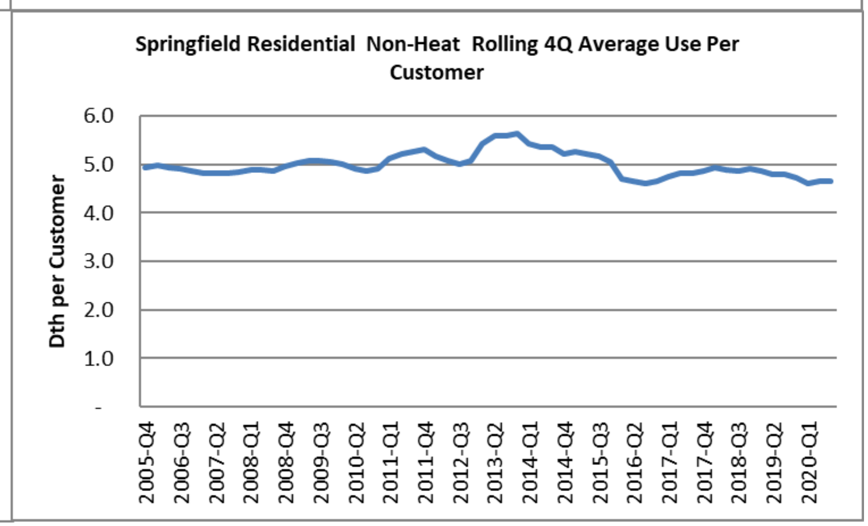

Lawrence Residential Non-Heat Rolling 4Q Average Customers
Quarterly Customers
5,000.0
4,500.0
4,000.0
3,500.0
3,000.0
2,500.0
2,000.0
1,500.0
1,000.0
500.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

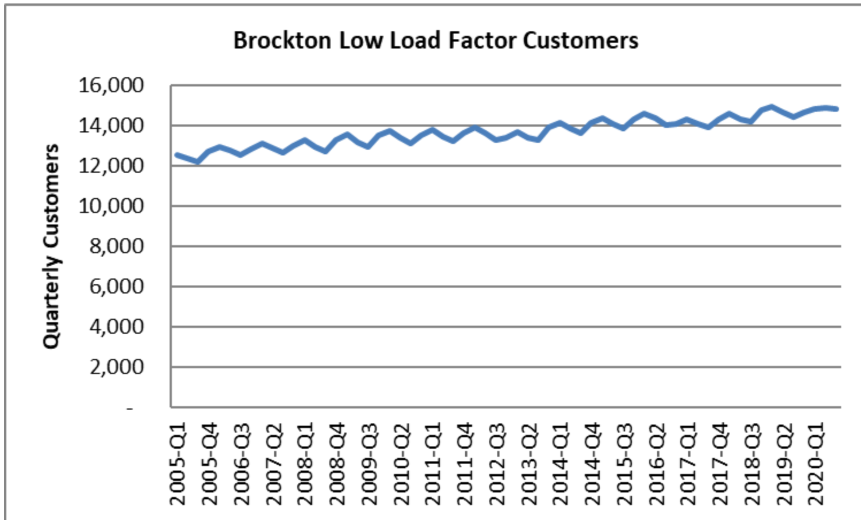

Lawrence Residential Non-Heat Rolling 4Q Average Use Per Customer
Dth per Customer
7.0
6.0
5.0
4.0
3.0
2.0
1.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

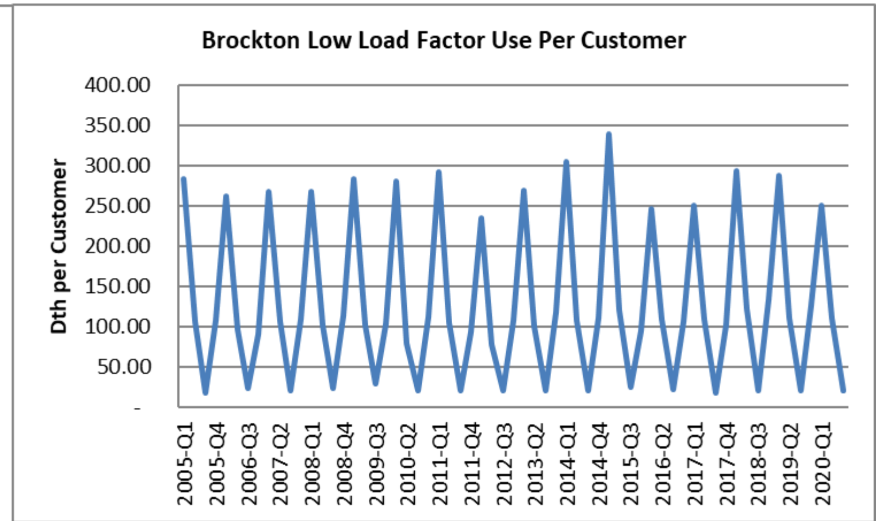

Springfield Residential Non-Heat Customers
Quarterly Customers
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

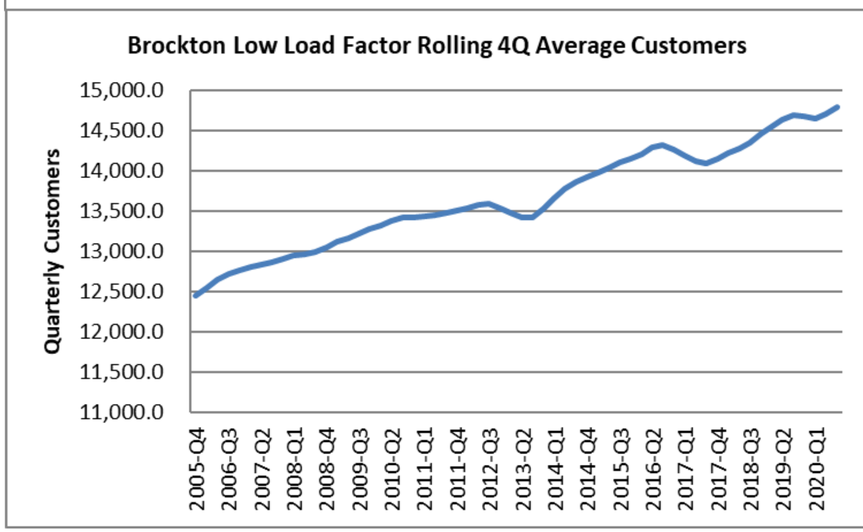

Springfield Residential Non-Heat Use Per Customer
Dth per Customer
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

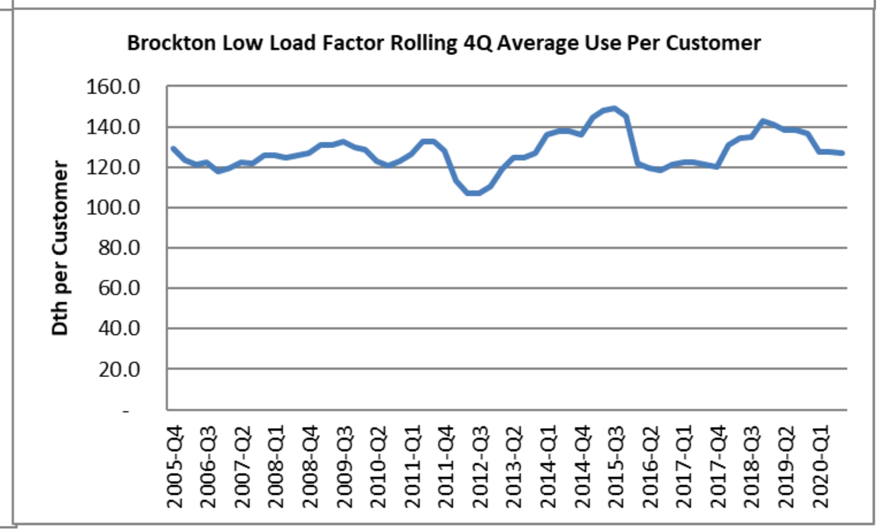

Springfield Residential Non-Heat Rolling 4Q Average Customers
Quarterly Customers
18,000.0
16,000.0
14,000.0
12,000.0
10,000.0
8,000.0
6,000.0
4,000.0
2,000.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

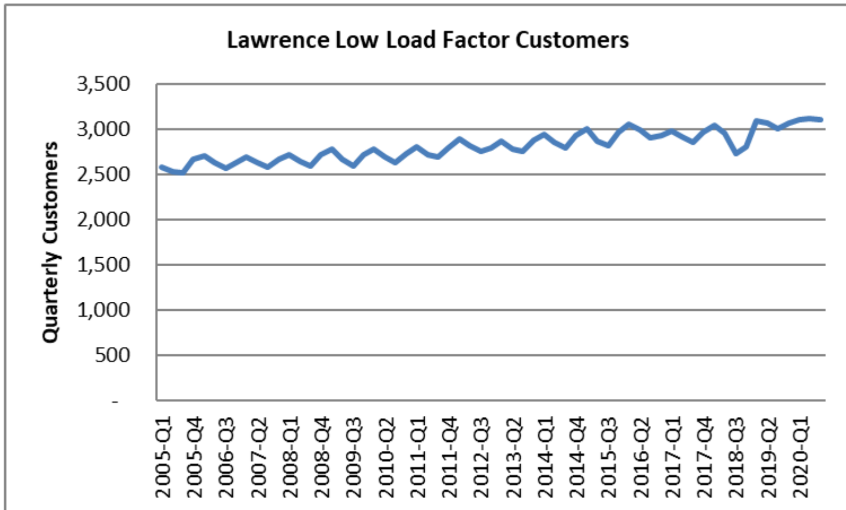

Springfield Residential Non-Heat Rolling 4Q Average Use Per Customer
Dth per Customer
6.0
5.0
4.0
3.0
2.0
1.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

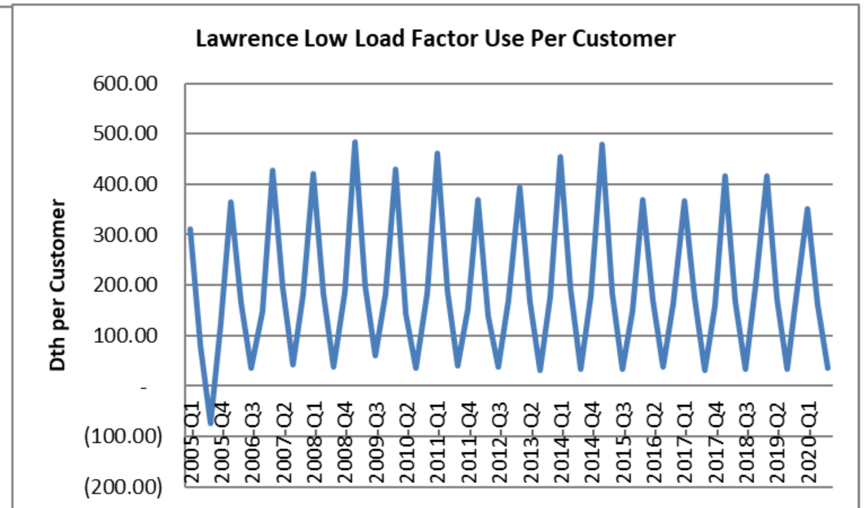

Brockton Low Load Factor Customers
Quarterly Customers
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2005-Q1 2005-Q4 2006-Q3 2007-Q2 2008-Q1 2008-Q4 2009-Q3 2010-Q2 2011-Q1 2011-Q4 2012-Q3 2013-Q2 2014-Q1 2014-Q4 2015-Q3 2016-Q2 2017-Q1 2017-Q4 2018-Q3 2019-Q2 2020-Q1

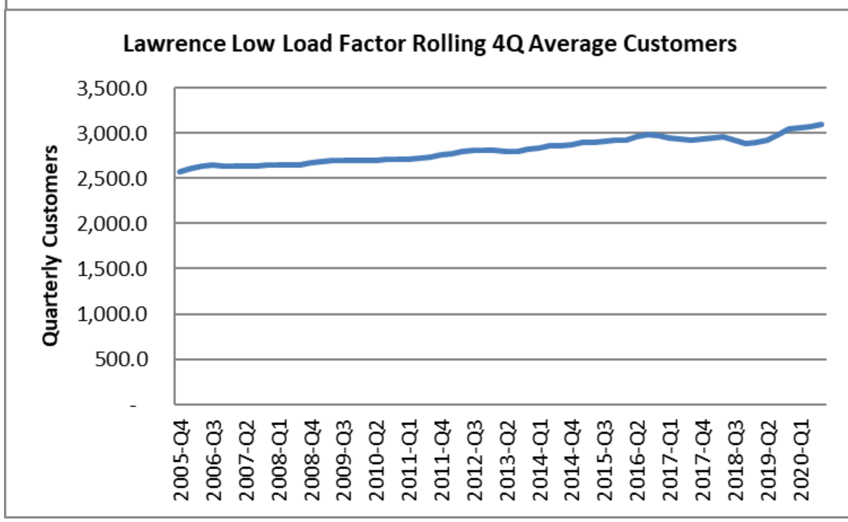

Brockton Low Load Factor Use Per Customer
Dth per Customer
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
-
2005-Q1 2005-Q4 2006-Q3 2007-Q2 2008-Q1 2008-Q4 2009-Q3 2010-Q2 2011-Q1 2011-Q4 2012-Q3 2013-Q2 2014-Q1 2014-Q4 2015-Q3 2016-Q2 2017-Q1 2017-Q4 2018-Q3 2019-Q2 2020-Q1

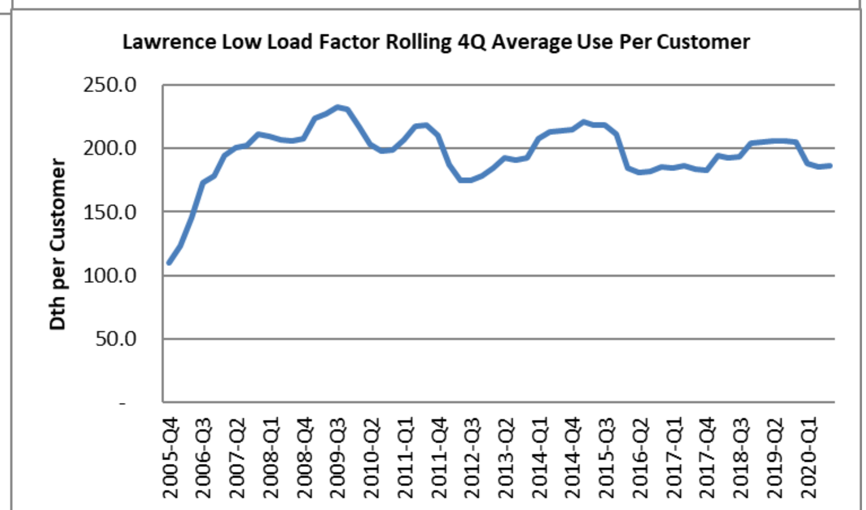

Brockton Low Load Factor Rolling 4Q Average Customers
Quarterly Customers
15,000.0
14,500.0
14,000.0
13,500.0
13,000.0
12,500.0
12,000.0
11,500.0
11,000.0
2005-Q4 2006-Q3 2007-Q2 2008-Q1 2008-Q4 2009-Q3 2010-Q2 2011-Q1 2011-Q4 2012-Q3 2013-Q2 2014-Q1 2014-Q4 2015-Q3 2016-Q2 2017-Q1 2017-Q4 2018-Q3 2019-Q2 2020-Q1

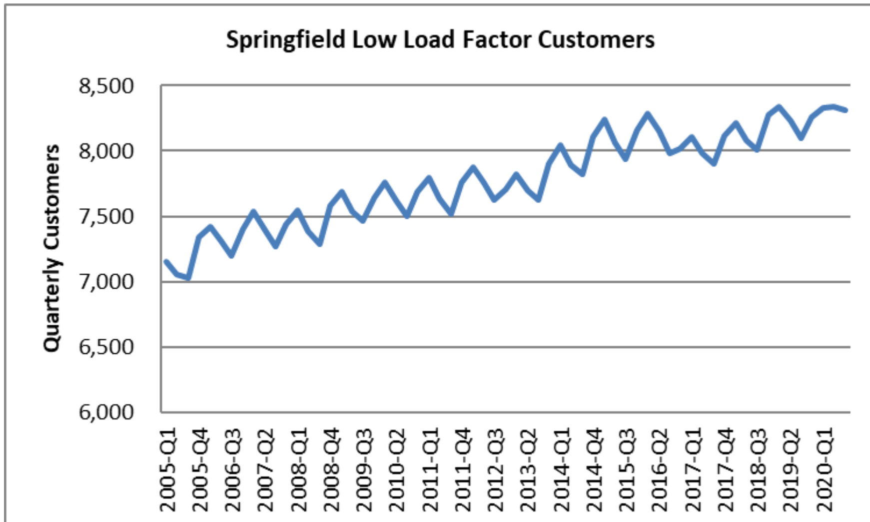

Brockton Low Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
160.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4 2006-Q3 2007-Q2 2008-Q1 2008-Q4 2009-Q3 2010-Q2 2011-Q1 2011-Q4 2012-Q3 2013-Q2 2014-Q1 2014-Q4 2015-Q3 2016-Q2 2017-Q1 2017-Q4 2018-Q3 2019-Q2 2020-Q1

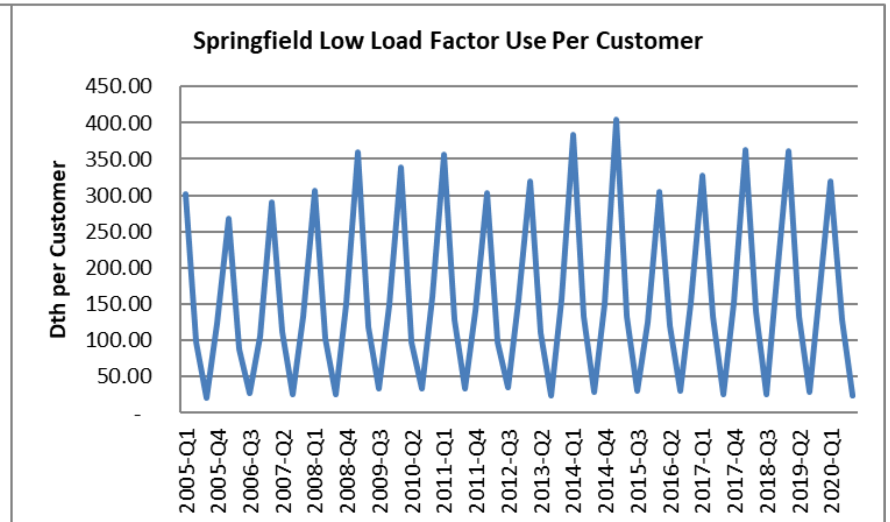

Lawrence Low Load Factor Customers
Quarterly Customers
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

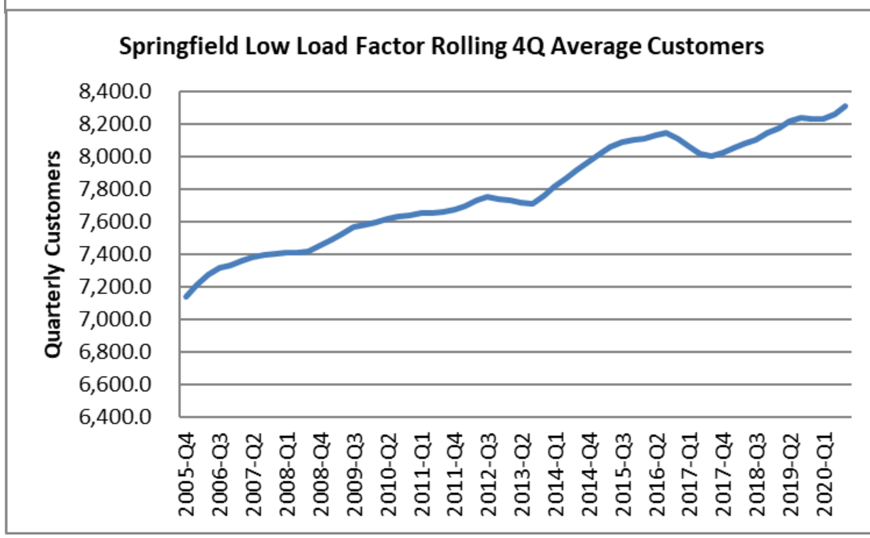

Lawrence Low Load Factor Use Per Customer
Dth per Customer
600.00
500.00
400.00
300.00
200.00
100.00
-
(100.00)
(200.00)
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

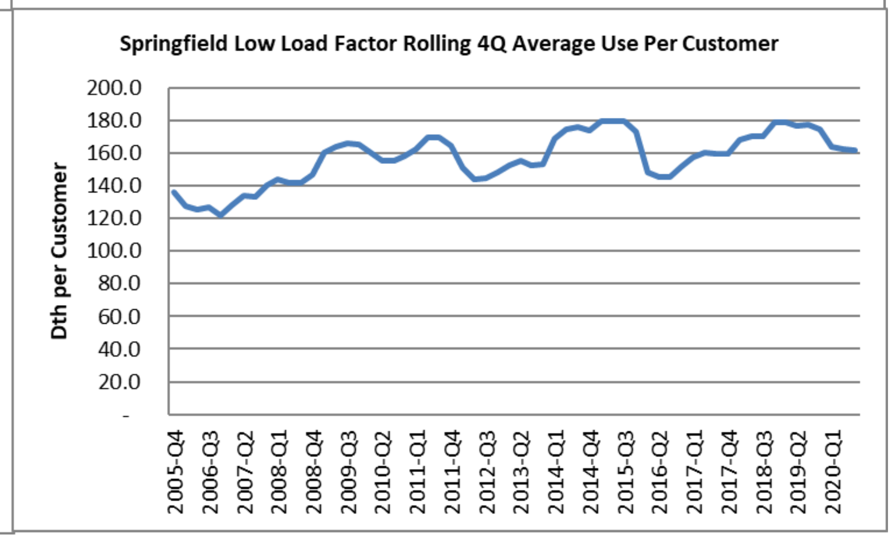

Lawrence Low Load Factor Rolling 4Q Average Customers
Quarterly Customers
3,500.0
3,000.0
2,500.0
2,000.0
1,500.0
1,000.0
500.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

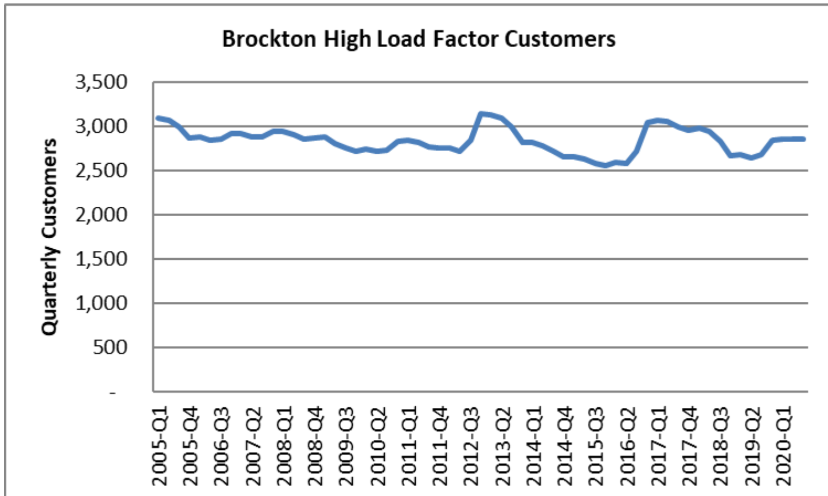

Lawrence Low Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
250.0
200.0
150.0
100.0
50.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

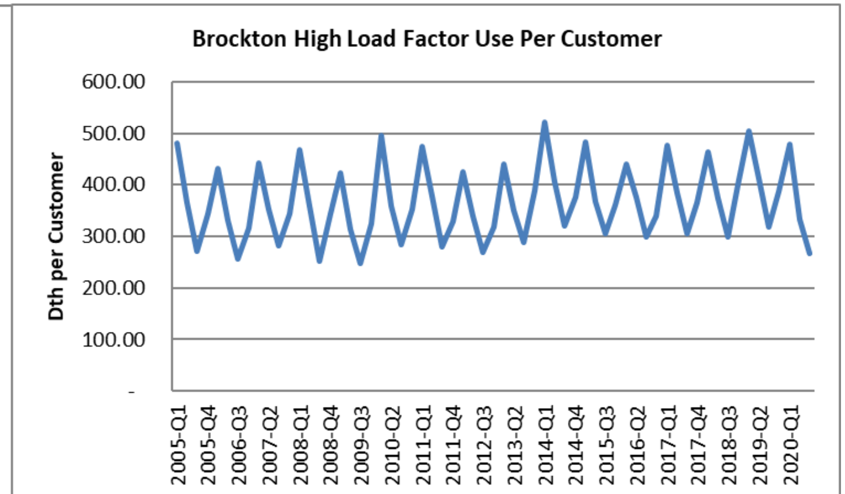

Springfield Low Load Factor Customers
Quarterly Customers
8,500
8,000
7,500
7,000
6,500
6,000
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

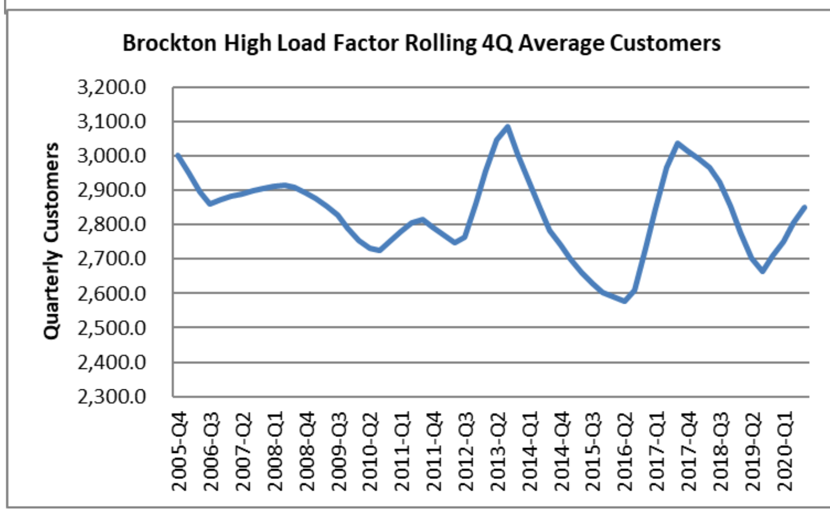

Springfield Low Load Factor Use Per Customer
Dth per Customer
450.00
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

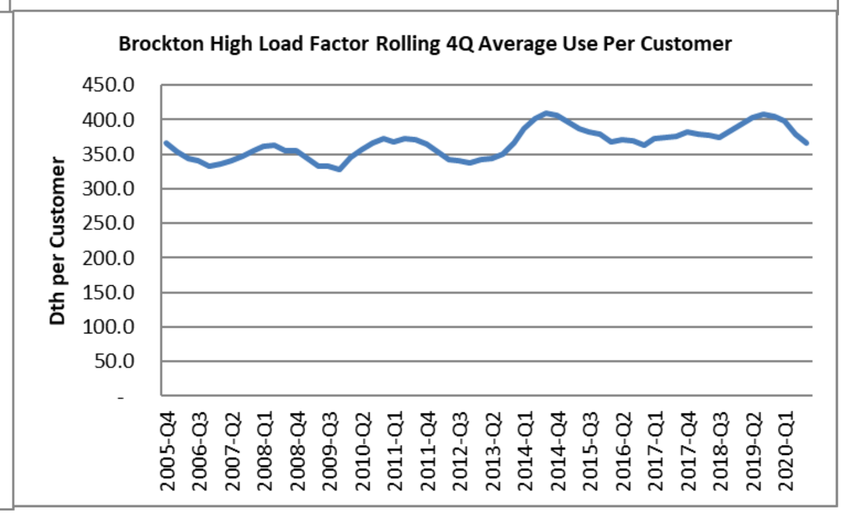

Springfield Low Load Factor Rolling 4Q Average Customers
Quarterly Customers
8,400.0
8,200.0
8,000.0
7,800.0
7,600.0
7,400.0
7,200.0
7,000.0
6,800.0
6,600.0
6,400.0
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

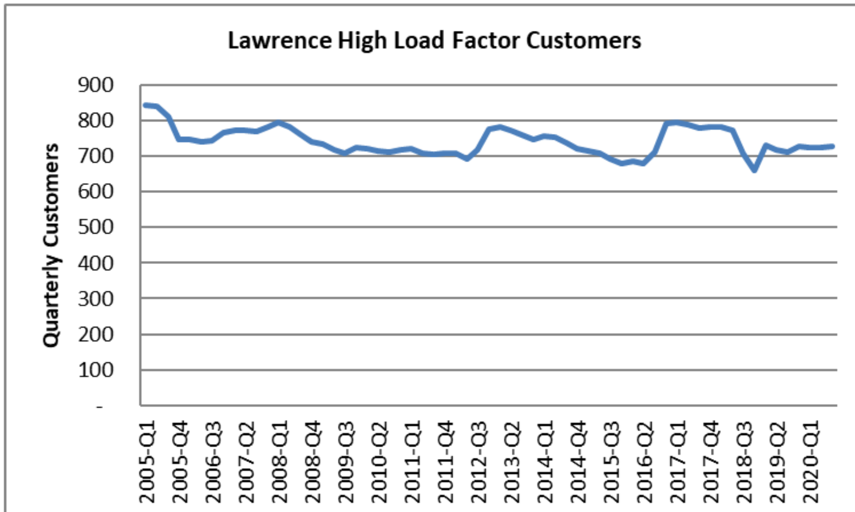

Springfield Low Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
200.0
180.0
160.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

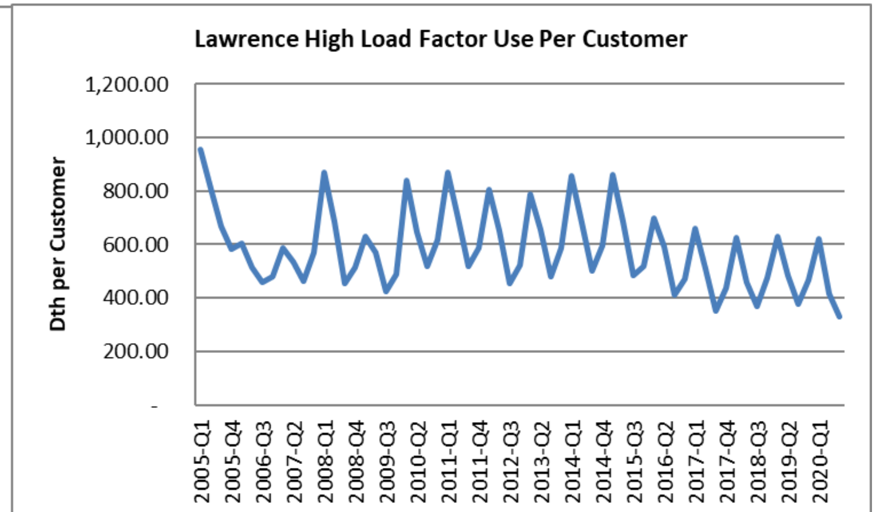

Brockton High Load Factor Customers
Quarterly Customers
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

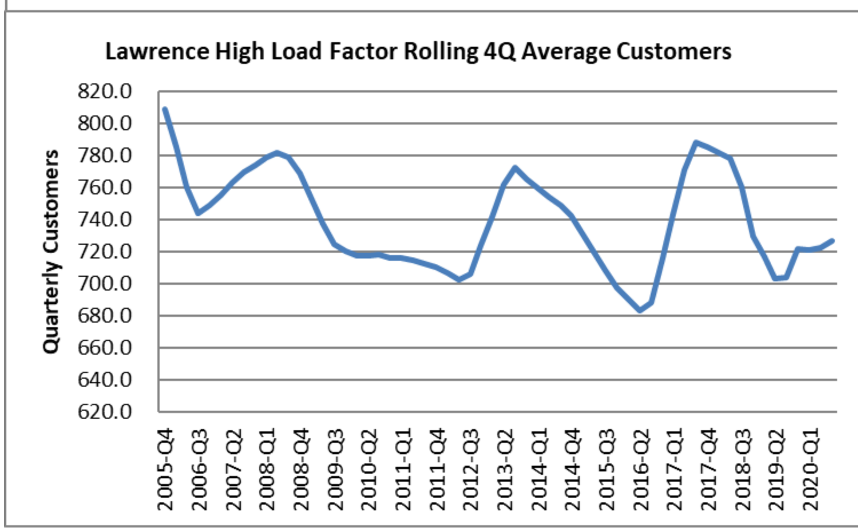

Brockton High Load Factor Use Per Customer
Dth per Customer
600.00
500.00
400.00
300.00
200.00
100.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

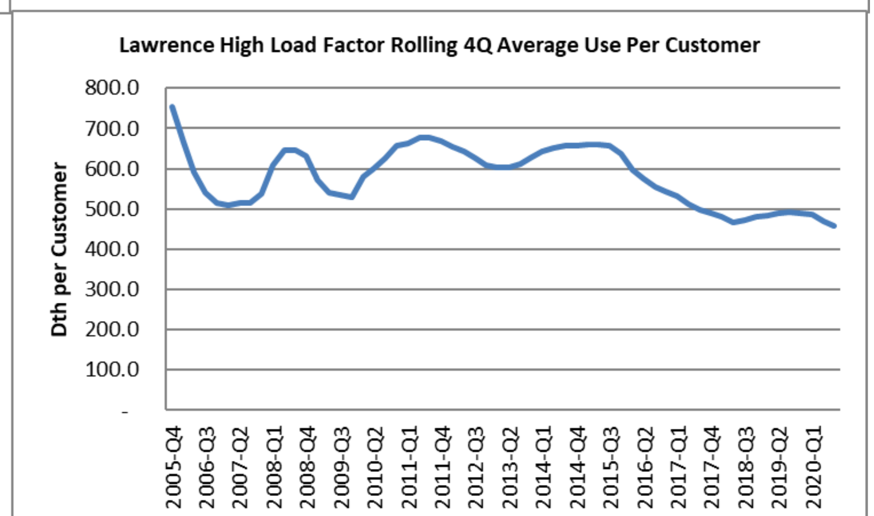

Brockton High Load Factor Rolling 4Q Average Customers
Quarterly Customers
3,200.0
3,100.0
3,000.0
2,900.0
2,800.0
2,700.0
2,600.0
2,500.0
2,400.0
2,300.0
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

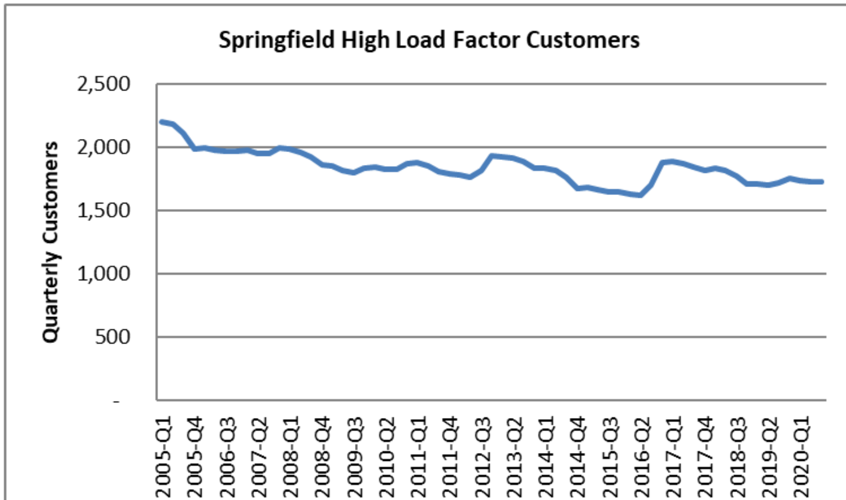

Brockton High Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
450.0
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

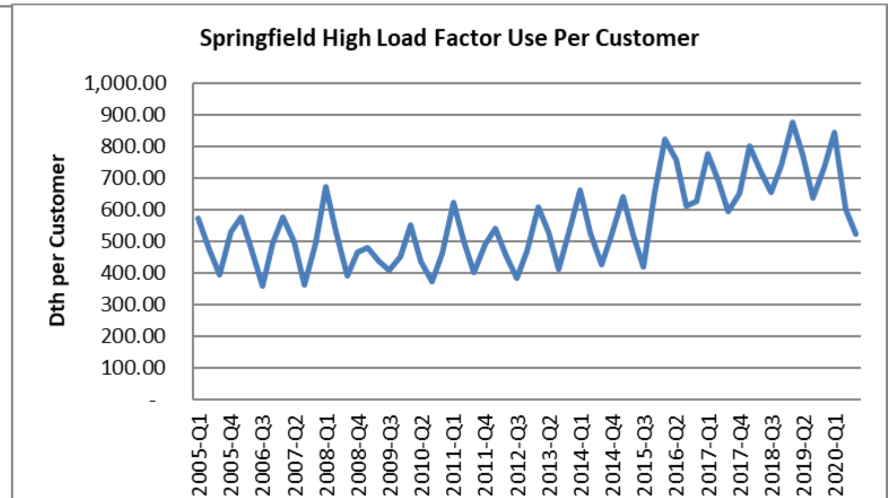

Lawrence High Load Factor Customers
Quarterly Customers
900
800
700
600
500
400
300
200
100
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

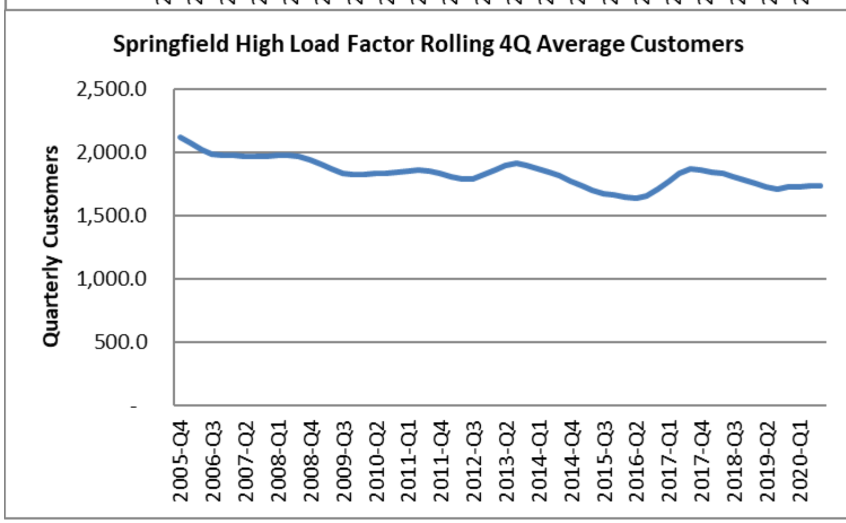

Lawrence High Load Factor Use Per Customer
Dth per Customer
1,200.00
1,000.00
800.00
600.00
400.00
200.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

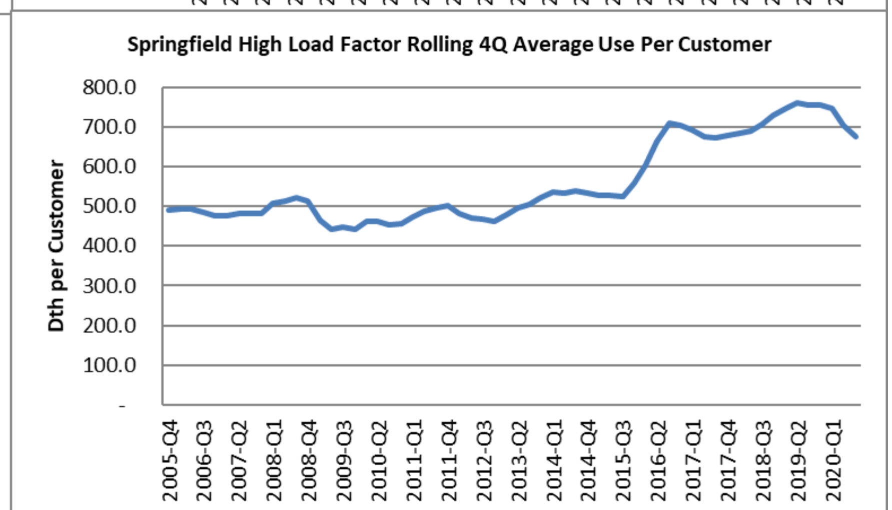

Lawrence High Load Factor Rolling 4Q Average Customers
Quarterly Customers
820.0
800.0
780.0
760.0
740.0
720.0
700.0
680.0
660.0
640.0
620.0
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Lawrence High Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

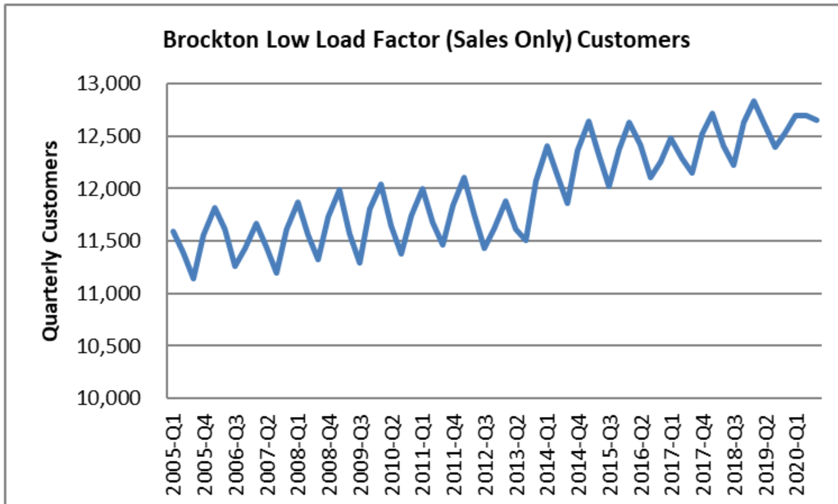

Springfield High Load Factor Customers
Quarterly Customers
2,500
2,000
1,500
1,000
500
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

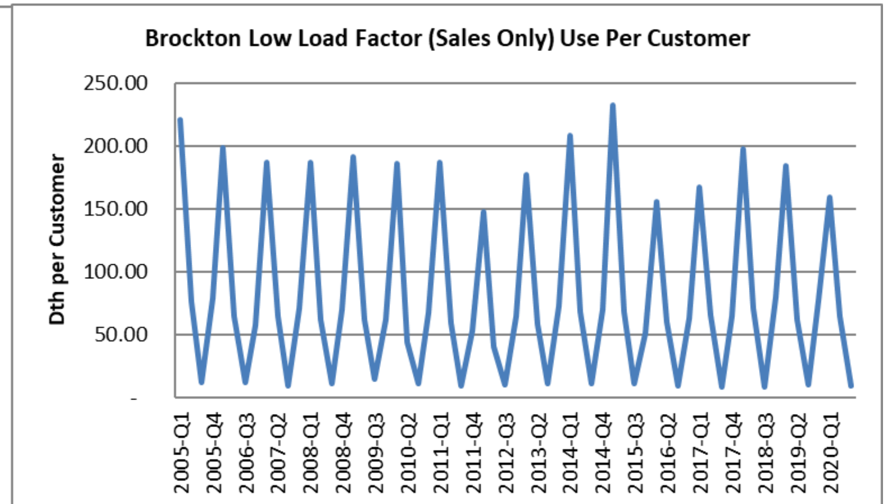

Springfield High Load Factor Use Per Customer
Dth per Customer
1,000.00
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

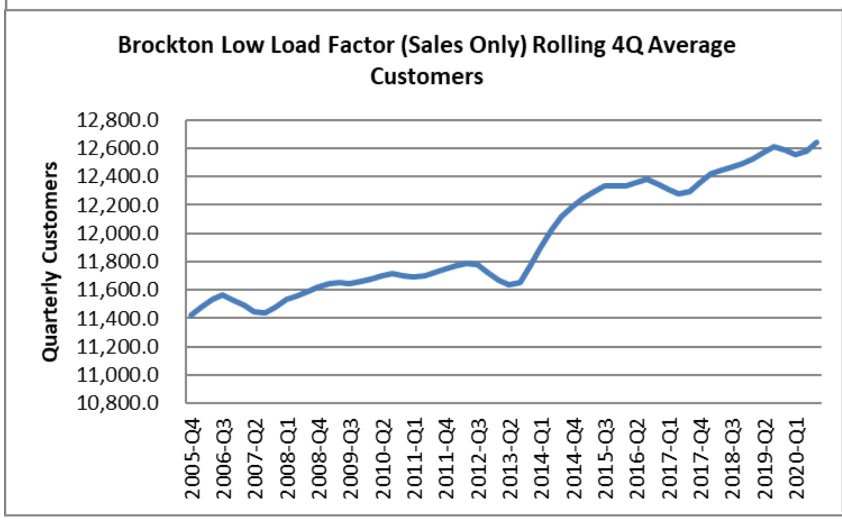

Springfield High Load Factor Rolling 4Q Average Customers
Quarterly Customers
2,500.0
2,000.0
1,500.0
1,000.0
500.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Springfield High Load Factor Rolling 4Q Average Use Per Customer
Dth per Customer
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

Sales Only:


Brockton Low Load Factor (Sales Only) Customers
Quarterly Customers
13,000
12,500
12,000
11,500
11,000
10,500
10,000
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Brockton Low Load Factor (Sales Only) Use Per Customer
Dth per Customer
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Brockton Low Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
12,800.0
12,600.0
12,400.0
12,200.0
12,000.0
11,800.0
11,600.0
11,400.0
11,200.0
11,000.0
10,800.0
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
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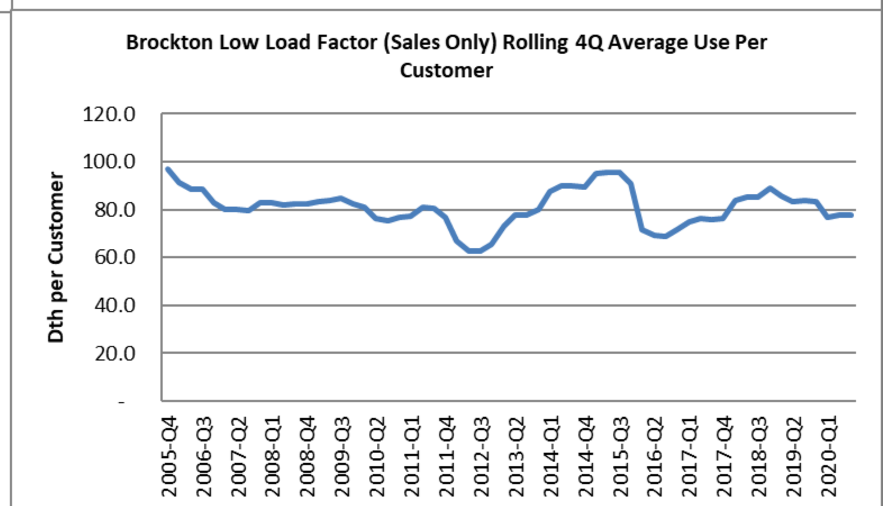
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Brockton Low Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
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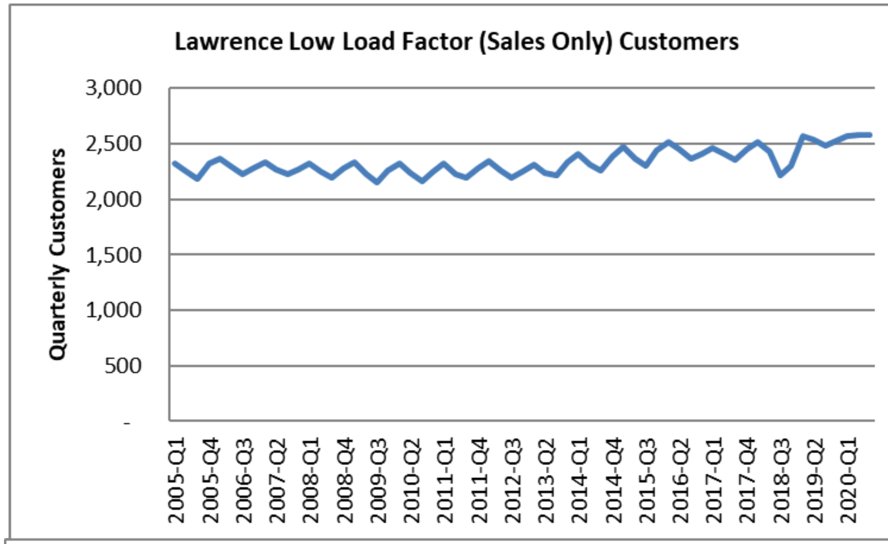
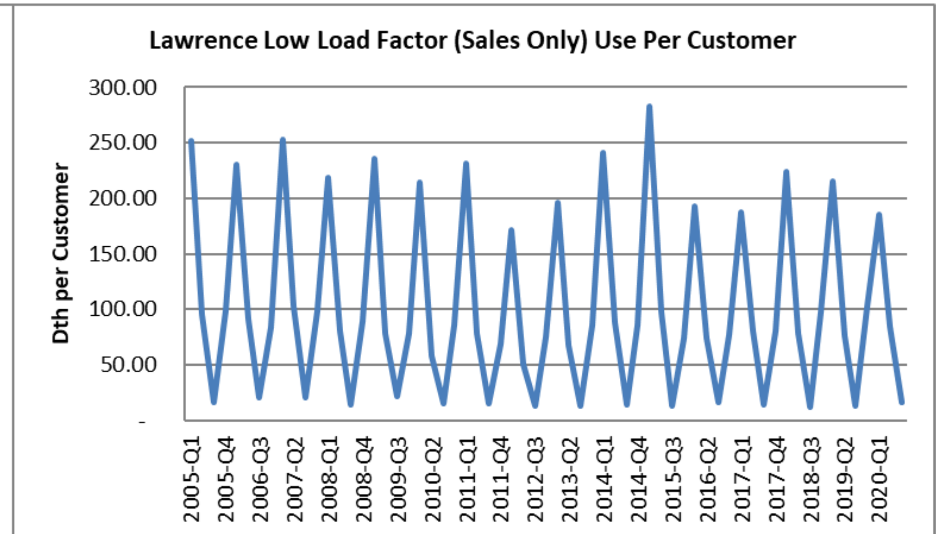
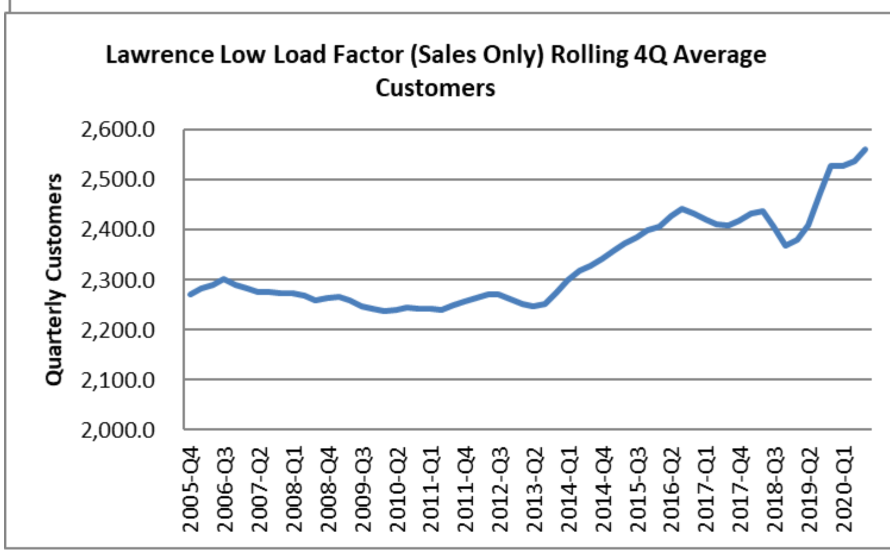
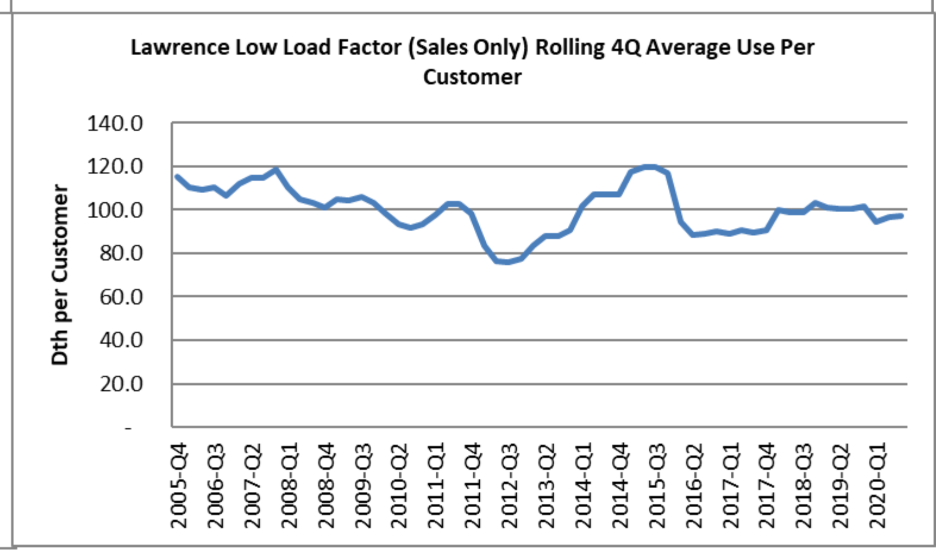
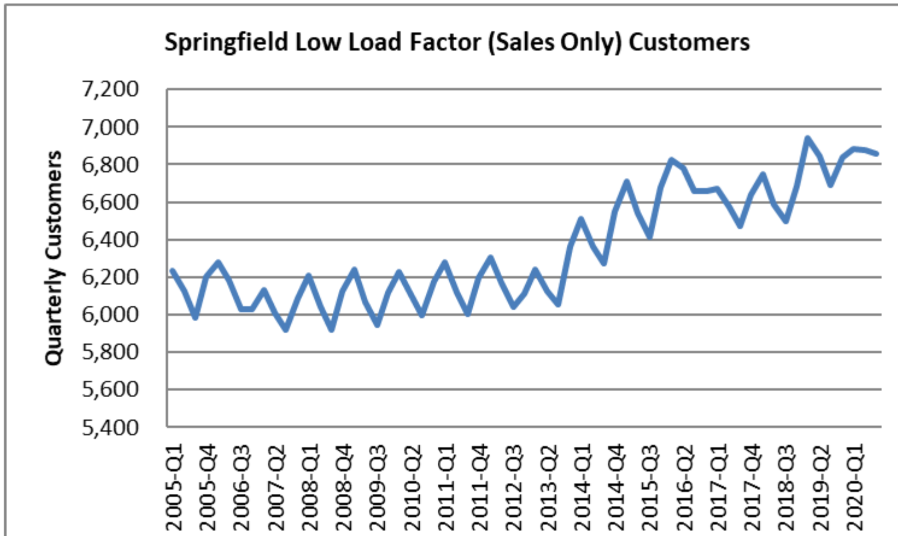
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Lawrence Low Load Factor (Sales Only) Customers
Quarterly Customers
3,000
2,500
2,000
1,500
1,000
500
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Lawrence Low Load Factor (Sales Only) Use Per Customer
Dth per Customer
300.00
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Lawrence Low Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
2,600.0
2,500.0
2,400.0
2,300.0
2,200.0
2,100.0
2,000.0
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Lawrence Low Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
140.0
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Springfield Low Load Factor (Sales Only) Customers
Quarterly Customers
7,200
7,000
6,800
6,600
6,400
6,200
6,000
5,800
5,600
5,400
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
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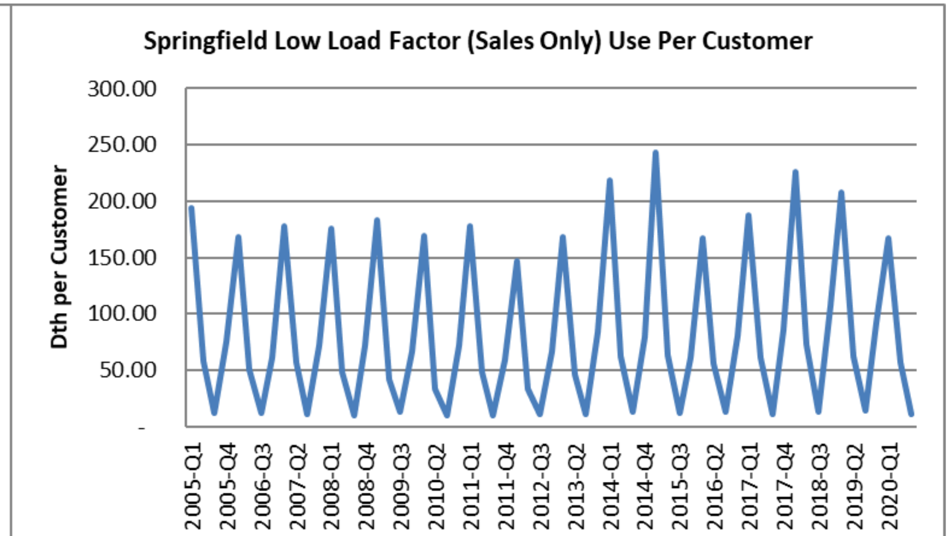
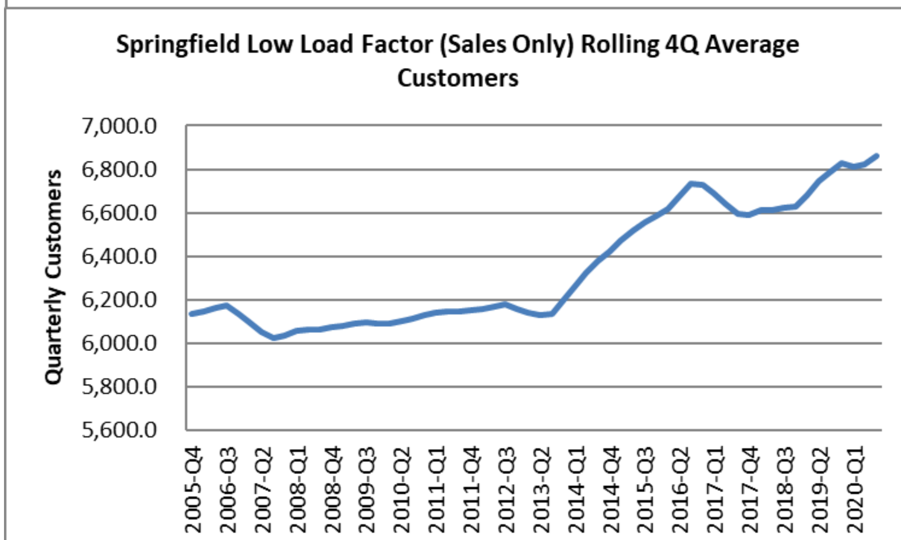
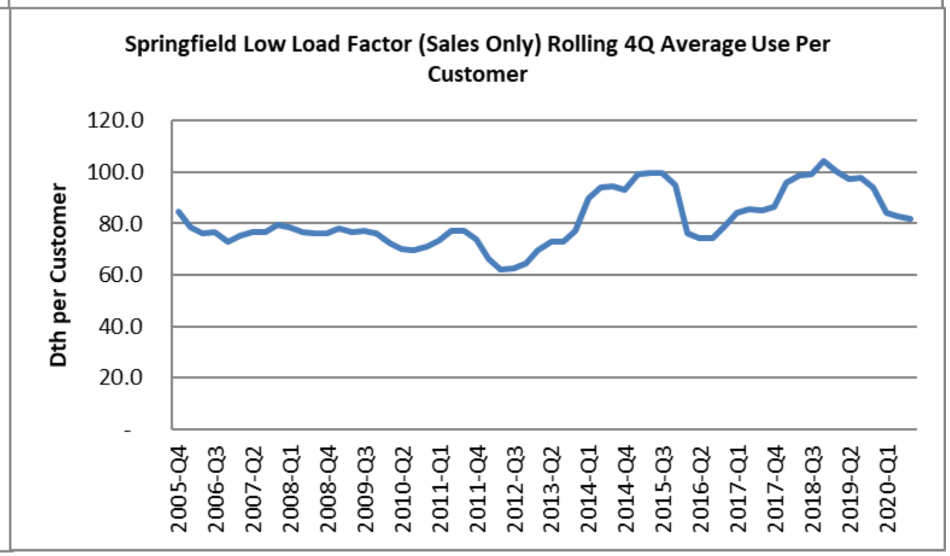
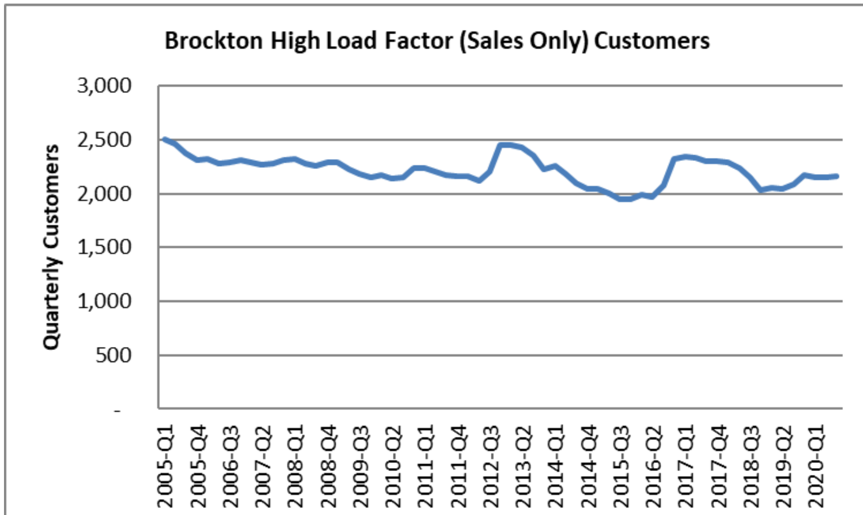
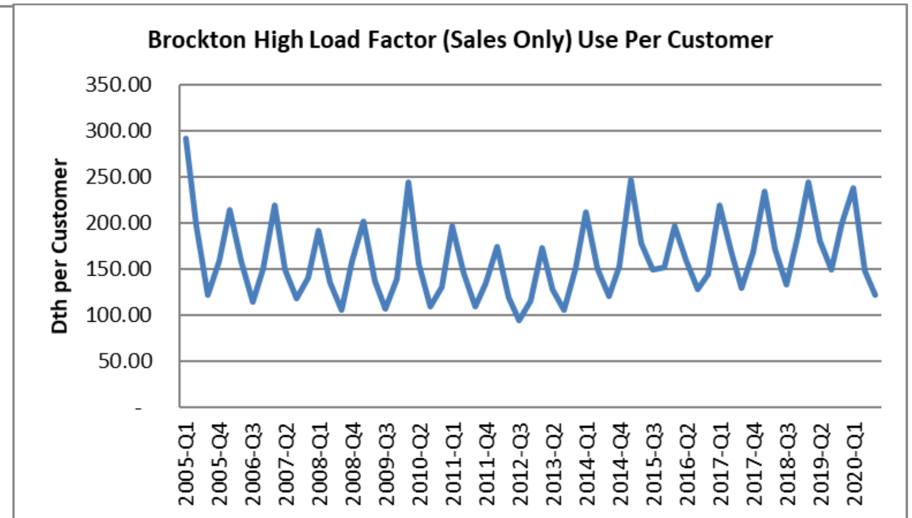
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

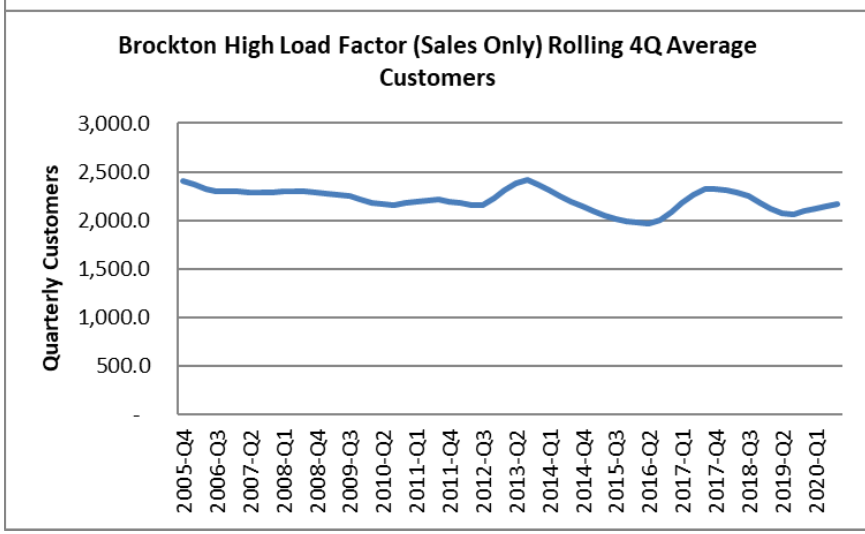

Springfield Low Load Factor (Sales Only) Use Per Customer
Dth per Customer
300.00
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

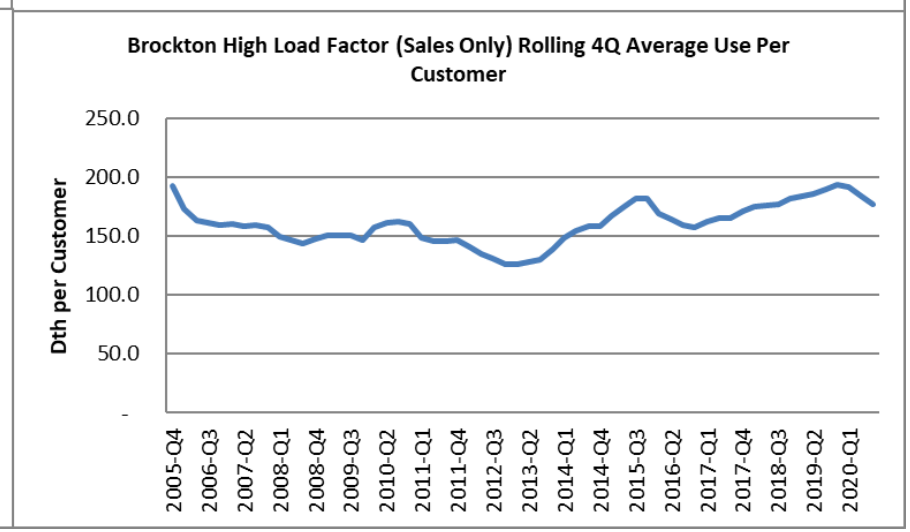

Springfield Low Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
7,000.0
6,800.0
6,600.0
6,400.0
6,200.0
6,000.0
5,800.0
5,600.0
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

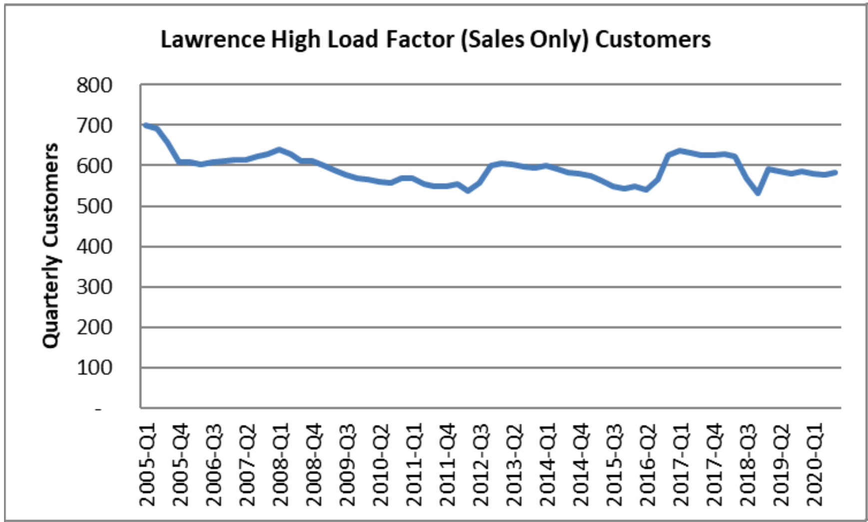

Springfield Low Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

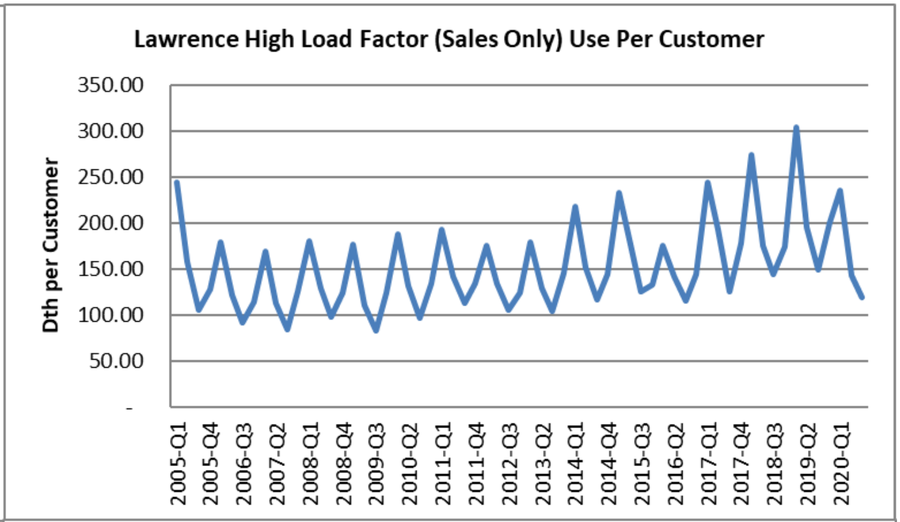

Brockton High Load Factor (Sales Only) Customers
Quarterly Customers
3,000
2,500
2,000
1,500
1,000
500
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

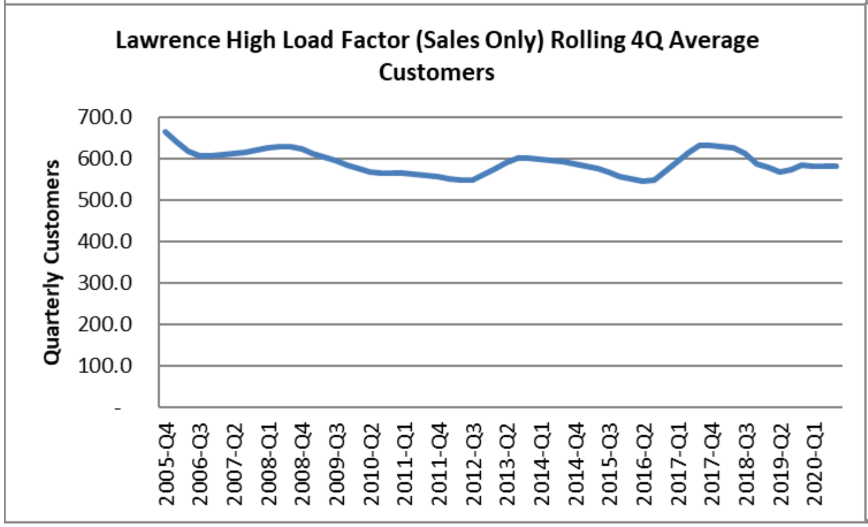

Brockton High Load Factor (Sales Only) Use Per Customer
Dth per Customer
350.00
300.00
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

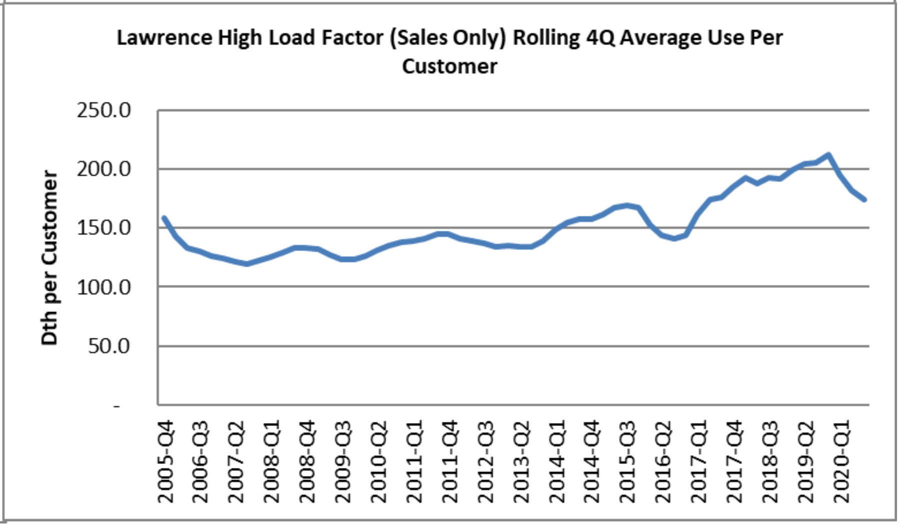

Brockton High Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
3,000.0
2,500.0
2,000.0
1,500.0
1,000.0
500.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

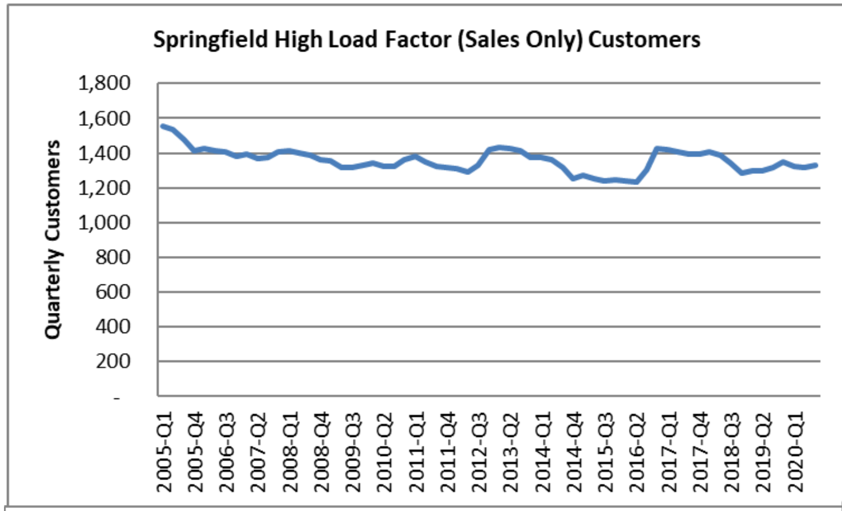

Brockton High Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
250.0
200.0
150.0
100.0
50.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

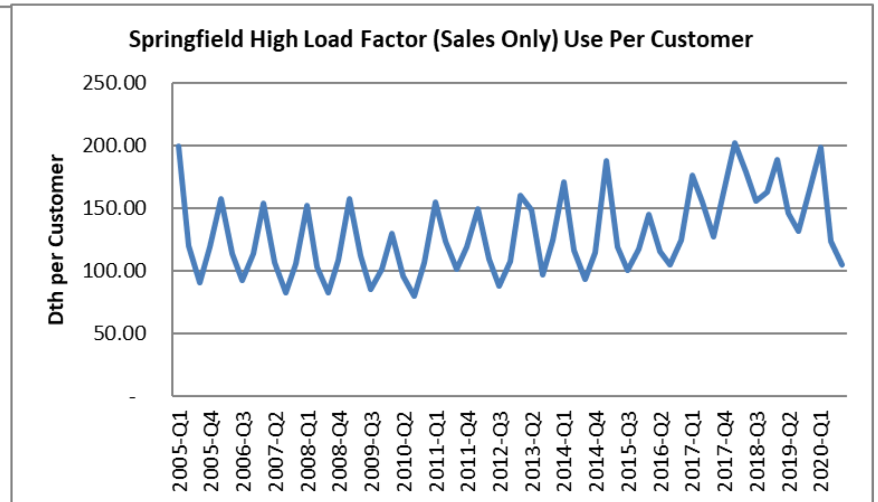

Lawrence High Load Factor (Sales Only) Customers
Quarterly Customers
800
700
600
500
400
300
200
100
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

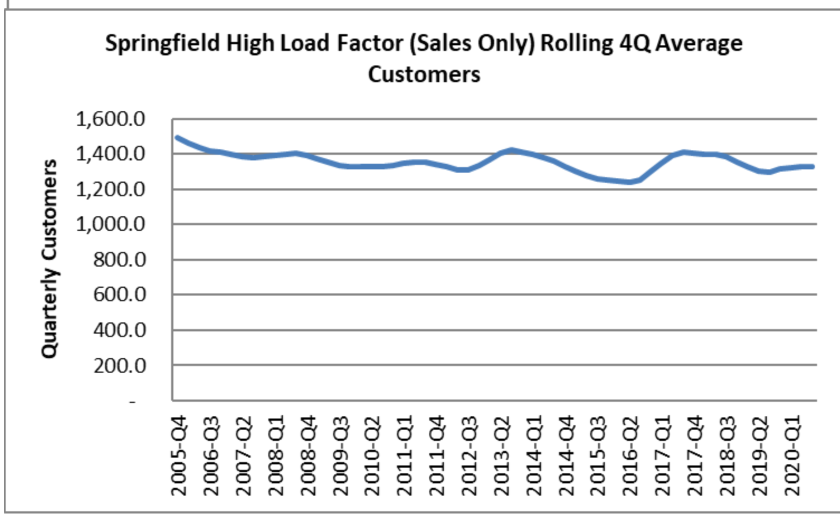

Lawrence High Load Factor (Sales Only) Use Per Customer
Dth per Customer
350.00
300.00
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

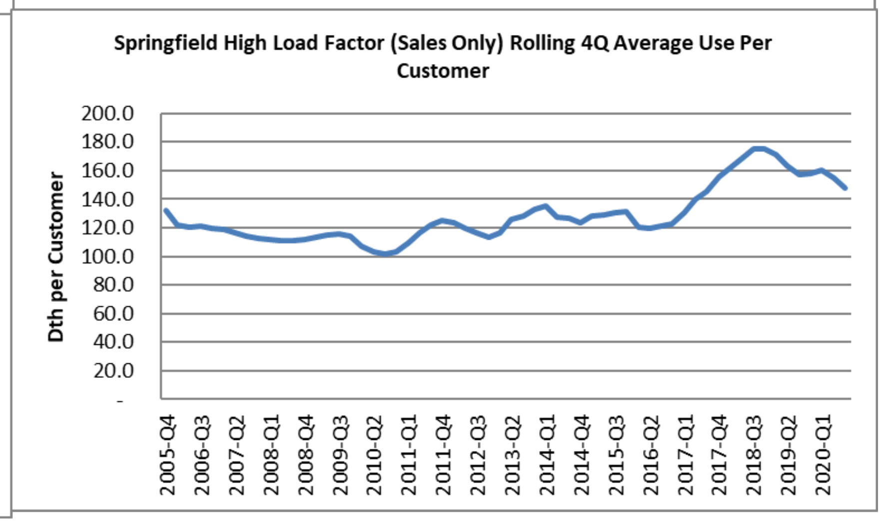

Lawrence High Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
700.0
600.0
500.0
400.0
300.0
200.0
100.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1

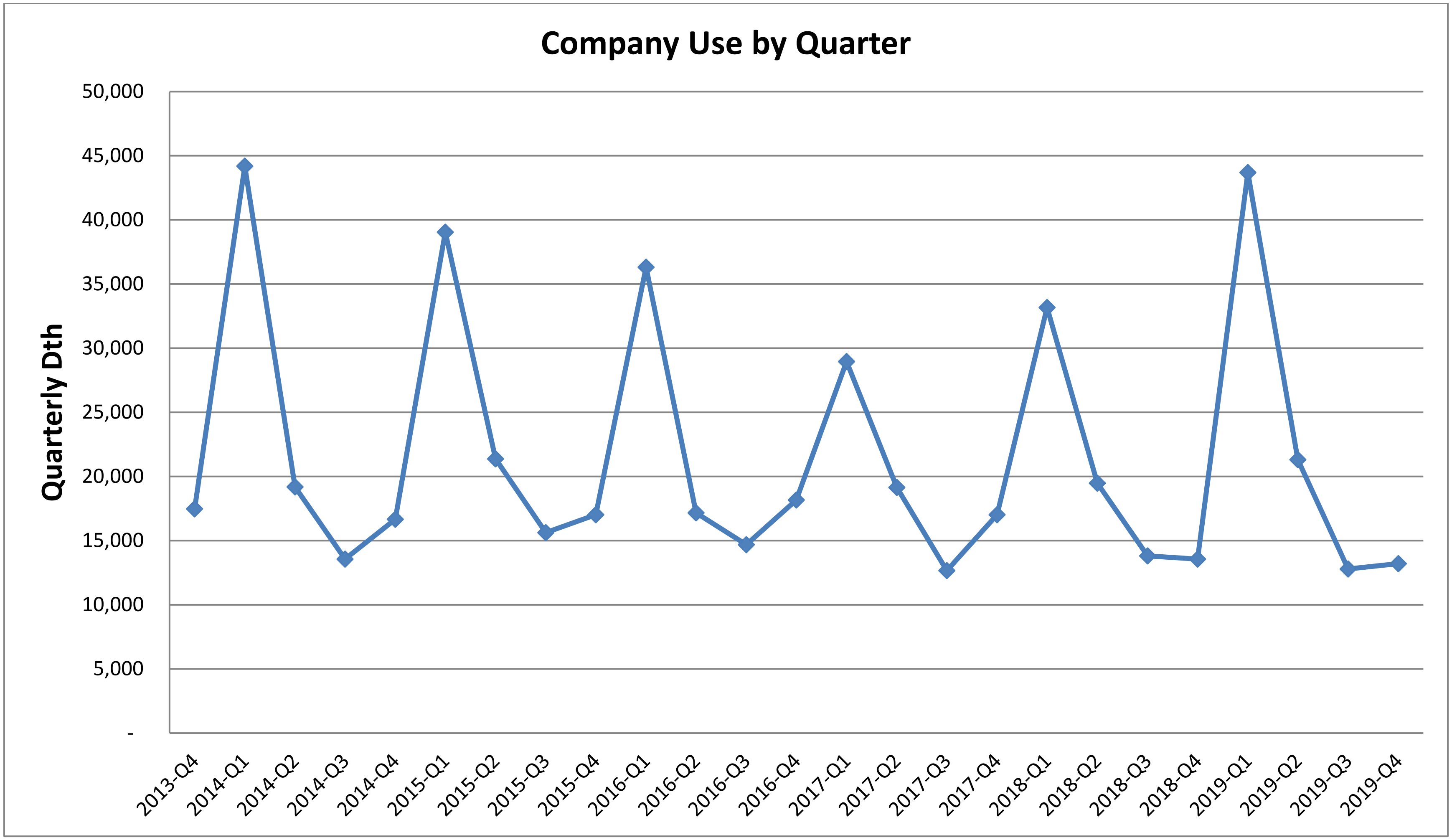

Lawrence High Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
250.0
200.0
150.0
100.0
50.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Springfield High Load Factor (Sales Only) Customers
Quarterly Customers
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Springfield High Load Factor (Sales Only) Use Per Customer
Dth per Customer
250.00
200.00
150.00
100.00
50.00
-
2005-Q1
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Springfield High Load Factor (Sales Only) Rolling 4Q Average Customers
Quarterly Customers
1,600.0
1,400.0
1,200.0
1,000.0
800.0
600.0
400.0
200.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Springfield High Load Factor (Sales Only) Rolling 4Q Average Use Per Customer
Dth per Customer
200.0
180.0
160.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
-
2005-Q4
2006-Q3
2007-Q2
2008-Q1
2008-Q4
2009-Q3
2010-Q2
2011-Q1
2011-Q4
2012-Q3
2013-Q2
2014-Q1
2014-Q4
2015-Q3
2016-Q2
2017-Q1
2017-Q4
2018-Q3
2019-Q2
2020-Q1


Company Use by Quarter
Quarterly Dth
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
2013-Q4
2014-Q1
2014-Q2
2014-Q3
2014-Q4
2015-Q1
2015-Q2
2015-Q3
2015-Q4
2016-Q1
2016-Q2
2016-Q3
2016-Q4
2017-Q1
2017-Q2
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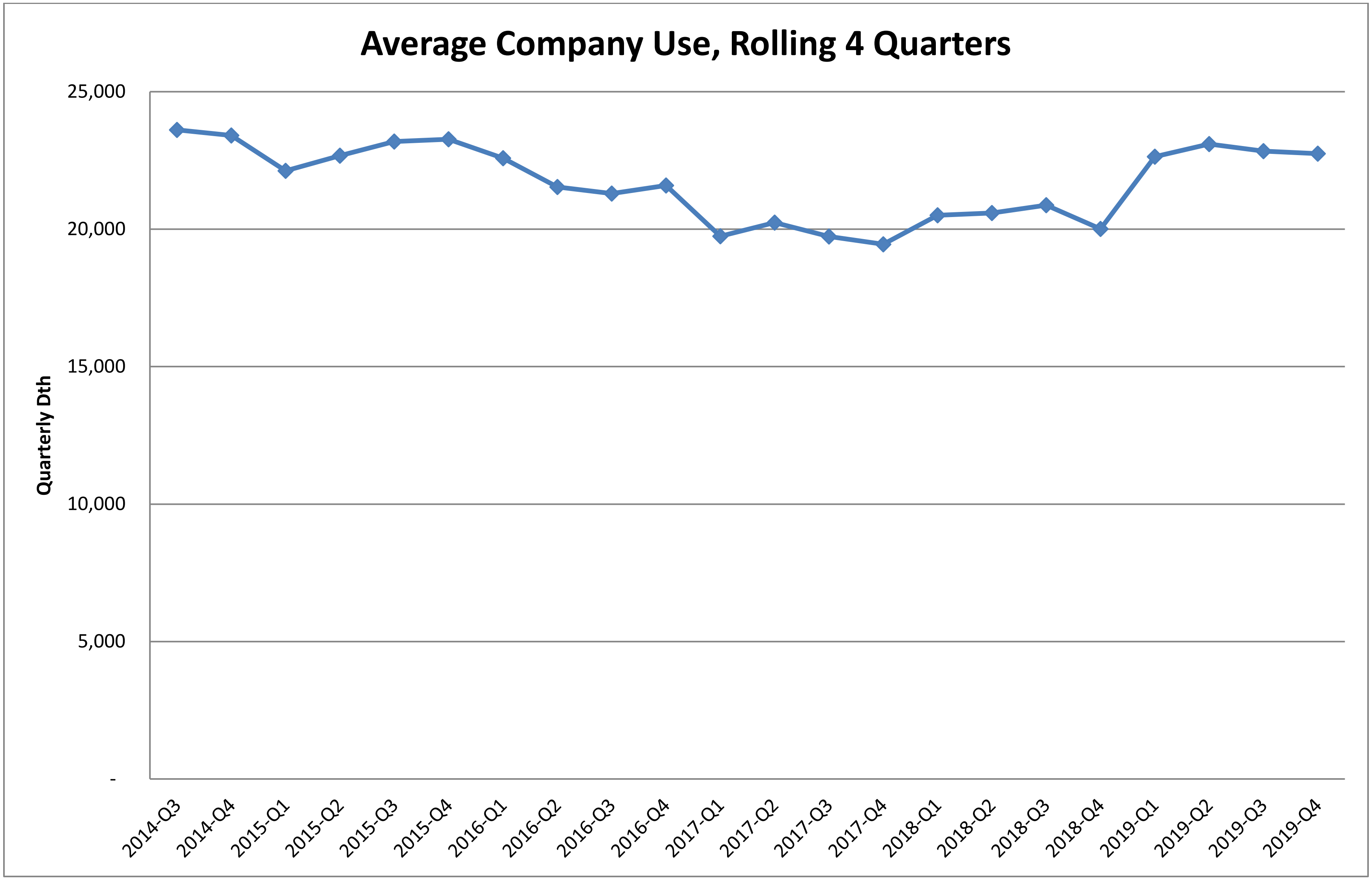
2019-Q1
2019-Q2
2019-Q3
2019-Q4


Average Company Use, Rolling 4 Quarters
Quarterly Dth
25,000
20,000
15,000
10,000
5,000
-
2014-Q3
2014-Q4
2015-Q1
2015-Q2
2015-Q3
2015-Q4
2016-Q1
2016-Q2
2016-Q3
2016-Q4
2017-Q1
2017-Q2
2017-Q3
2017-Q4
2018-Q1
2018-Q2
2018-Q3
2018-Q4
2019-Q1
2019-Q2
2019-Q3
2019-Q4

Appendix 10: Unbilled Calculation

To account for unbilled volumes, the Company used net unbilled history back to 2015. For each month from January 2015 through December 2020, the Company calculated historical average net unbilled. The monthly historical averages are shown in the table below. Those monthly historical averages became the forecast for net unbilled that the Company used in the forecast.

	Average Historical Net Unbilled
January	342,092
February	(580,469)
March	(371,239)
April	(1,376,464)
May	(1,268,890)
June	(546,338)
July	4,409
August	110,603
September	173,911
October	767,634
November	1,292,234
December	1,349,892

Calculation of Residential Energy Efficiency Forecast (Dth)

	Residential (including Low Income)			
	Incremental History	Incremental Forecast	Forecasted Incremental Less Trend	Forecasted Cumulative Less Trend (Impacts Forecast)
2010	87,135			
2011	93,898			
2012	125,406			
2013	174,692			
2014	200,542			
2015	245,794			
2016	255,246			
2017	233,048			
2018	282,899			
2019	292,734			
2020		342,325	101,617	101,617
2021		339,671	98,963	200,580
2022		258,316	17,608	218,188
2023		270,783	30,075	248,264
2024		287,316	46,608	294,872
2025		287,316	46,608	341,480
2026		287,316	46,608	388,088
2027		287,316	46,608	434,697
2028		287,316	46,608	481,305
2029		287,316	46,608	527,913
2030		287,316	46,608	574,521
('13 to '19) Historical Trend	240,708			

The same calculations were performed for C&I customers, and are demonstrated below.

Calculation of C&I Energy Efficiency Forecast (Dth)

	Commercial & Industrial			
	Incremental History	Incremental Forecast	Forecasted Incremental Less Trend	Forecasted Cumulative Less Trend (Impacts Forecast)
2010	162,964			
2011	132,556			
2012	149,369			
2013	196,014			
2014	208,141			
2015	120,748			
2016	125,893			
2017	91,354			
2018	188,863			
2019	124,101			
2020		347,029	196,298	196,298
2021		352,575	201,844	398,142
2022		124,003	-	398,142
2023		124,030	-	398,142
2024		124,215	-	398,142
2025		124,215	-	398,142
2026		124,215	-	398,142
2027		124,215	-	398,142
2028		124,215	-	398,142
2029		124,215	-	398,142
2030		124,215	-	398,142
('13 to '19) Historical Trend	150,731			

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NOV 2021 thru OCT 2022 Cost and Flow Summary Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	197516.	Injection Cost	204.41	Transportation Cost	3451.55	JAN 15, 2022	
Penalty Cost	0.00	Withdrawal Cost	237.15	Other Variable Cost	78.68	System Served	437.817
Other Variable Cost	0.00	Carrying Cost	0.00			System Unserved	0.000
		Other Variable Cost	0.00			Total	437.817
Total Variable	197516.	Total Variable	441.56	Total Variable	3530.23		
Demand/Reservation Co	9856450	Demand Cost	2780.79	Demand Cost	109530.		
Other Fixed Cost	0.00	Other Fixed Cost	3899.28	Other Fixed Cost	0.00		
Total Fixed	9856450	Total Fixed	6680.07	Total Fixed	109530.		
Sup Release Revenue	0.00	Sto Release Revenue	0.00	Cap Release Revenue	0.00		
Net Supply Cost	1.005e7	Net Storage Cost	7121.63	Net Trans Cost	113060.	Total Gas Cost	10174148.9
						Total Revenue	0.00
						Net Cost	10174148.9

Avg Cost of Served Demand 213.1 USD/DT Avg Cost of Gas Purchased 206.0 USD/DT
(System Cost/Served Dem.) (Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	47729.668	0.000	47729.668	0.000	47729.668	47729.668	0.000	0.00	437.817	0.000
Total	47729.668	0.000	47729.668	0.000	47729.668	47729.668	0.000	0.00	437.817	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	18.593	364635.000	364616.407			12.1260	225.46	0.00	225.46	12.1260
Centerville	4823.595	364635.000	359811.405			5.3982	26038.53	0.00	26038.53	5.3982
Dawn	10657.812	364635.000	353977.188			4.4563	47494.82	0.00	47494.82	4.4563
Dracut	729.328	364635.000	363905.672			3.0495	2224.11	0.00	2224.11	3.0495
Ellisburg	7163.484	364635.000	357471.516			3.7994	27217.02	0.00	27217.02	3.7994
Hereford	1575.408	364635.000	363059.592			3.0376	4785.50	0.00	4785.50	3.0376
LNG Inject	810.439	364635.000	363824.561			5.6564	4584.14	0.00	4584.14	5.6564
LPG Inject	0.000	364635.000	364635.000			0.0000	0.00	0.00	0.00	0.0000
Millennium	5499.196	364635.000	359135.804			3.3547	18448.07	0.00	18448.07	3.3547

Scenario 2246 Ventyx
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NOV 2021 thru OCT 2022 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Niagara	3380.309	364635.000	361254.691			3.8066	12867.48	0.00	12867.48	3.8066
Ramapo	886.895	364635.000	363748.105			4.0706	3610.16	0.00	3610.16	4.0706
Repsol 30	987.000	987.000	0.000			4.9356	4871.48	12993.53	17865.00	18.1003
Repsol 40	564.000	564.000	0.000			4.9147	2771.91	5568.65	8340.56	14.7882
TETCO M2	11077.132	364635.000	353557.868			3.5290	39091.21	0.00	39091.21	3.5290
TETCO M3	597.436	364635.000	364037.564			4.8441	2894.05	0.00	2894.05	4.8441
Waddington	28.258	364635.000	364606.742			13.8782	392.17	0.00	392.17	13.8782
Freepoint	0.000	50.000	50.000			0.0000	0.00	693600.00	693600.00	0.0000
CLNG	0.000	360.000	360.000			0.0000	0.00	5242788.00	5242788.00	0.0000
Direct	0.000	450.000	450.000			0.0000	0.00	3901500.00	3901500.00	0.0000
Total	48798.884						197516.11	9856450.18	10053966.2	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	323.007	344.958	0.000	0.000	709.753	97	0.000	-21.951	4285.22	4098.81	-186.42
LNG Lawrence	11.628	100	24.820	24.820	0.000	0.000	11.628	100	0.000	0.000	68.10	66.44	-1.66
LNG Marshfld	7.622	100	14.301	14.301	0.000	0.000	7.622	100	0.000	0.000	44.64	43.40	-1.23
LNG Spring	948.413	100	448.310	476.762	0.000	0.000	919.961	97	0.000	-28.452	5554.38	5311.07	-243.31
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	158.62	158.62	0.00
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	861.04	861.04	0.00
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	264.37	264.37	0.00
DTI GSS TET	1441.753	100	1470.426	1441.753	0.000	28.673	1441.753	100	0.000	0.000	3624.13	4110.38	486.25
Enbridge 16	1600.000	100	1597.425	1587.840	0.000	9.585	1600.000	100	9.527	0.000	3245.28	5646.63	2401.35
Enbridge 18	1820.000	100	1830.986	1820.000	0.000	10.986	1820.000	100	10.920	0.000	3642.37	6412.55	2770.19
Nat Fuel FSS	1100.000	100	1111.785	1100.000	0.000	11.785	1100.000	100	11.660	0.000	3161.73	3626.22	464.49
TETCO FSS-1	63.360	100	63.787	63.360	0.000	0.427	63.360	100	0.425	0.000	168.49	181.64	13.15
TETCO SS-1	1588.950	100	1502.912	1492.842	0.000	10.070	1588.950	100	26.423	0.000	3470.90	4454.46	983.55
TGP FSMA	1222.594	100	1242.726	1222.594	0.000	20.132	1222.594	100	0.000	0.000	3359.93	3791.06	431.13
Total	10641.528	100	9630.486	9589.232	0.000	91.658	10591.124	100	58.955	-50.404	31909.20	39026.7	7117.50

NOV 2021 thru OCT 2022 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2630.442	32.617	2597.825	5840.000	3242.175	4.42	4290.74	0.00	4295.16	1.6329
TCPL 63398	1896.515	12.327	1884.188	9512.630	7628.442	3.20	3389.68	0.00	3392.88	1.7890
TCPL 64198	6037.926	74.870	5963.055	21836.855	15873.800	10.14	12995.00	0.00	13005.14	2.1539
Union 12292	6099.533	39.647	6059.886	21735.750	15675.864	10.30	2254.21	0.00	2264.51	0.3713
Union 12204	1886.819	12.264	1874.554	9618.480	7743.926	3.19	997.53	0.00	1000.72	0.5304
PNG 233301 D	128.751	0.361	128.391	3407.500	3279.109	0.14	2594.70	0.00	2594.84	20.1539
PNG 233301 U	1451.548	4.064	1447.484	1812.000	364.516	1.59	1395.00	0.00	1396.59	0.9621
PNG 208535 D	3567.497	0.000	3567.497	8577.500	5010.003	3.92	6556.50	0.00	6560.42	1.8389
PNG 208535 H	3140.672	0.000	3140.672	8030.000	4889.328	3.45	6138.00	0.00	6141.45	1.9555
PNG 208540	1847.820	0.000	1847.820	5840.000	3992.180	2.03	3504.00	0.00	3506.03	1.8974
IGT RTS	1912.446	1.912	1910.533	10526.600	8616.067	8.60	1811.97	0.00	1820.57	0.9520
N Fuel FST I	1127.228	15.443	1111.785	3650.000	2538.215	18.01	543.29	0.00	561.30	0.4979
N Fuel FST W	1088.340	14.910	1073.430	3650.000	2576.570	17.39	0.00	0.00	17.39	0.0160
MLP 217524	5499.196	24.196	5475.000	5475.000	0.000	22.45	3558.20	0.00	3580.65	0.6511
TGP 95349	354.364	3.048	351.317	3567.510	3216.193	27.09	738.41	0.00	765.50	2.1602
TGP 5173	3351.890	40.893	3310.997	4653.020	1342.023	335.40	2883.03	0.00	3218.44	0.9602
TGP 5293	2725.465	33.251	2692.215	4579.655	1887.440	272.72	1078.72	0.00	1351.44	0.4959
TGP 5196	2139.426	26.101	2113.325	5611.875	3498.550	214.08	1321.85	0.00	1535.93	0.7179
TGP 5196 Wth	1065.996	0.000	1065.996	2007.500	941.504	1.17	0.00	0.00	1.17	0.0011
TGP 5291 Sup	2252.415	0.000	2252.415	2252.415	0.000	2.48	0.00	0.00	2.48	0.0011
TGP 5291 5-6	1117.812	9.613	1108.199	2252.415	1144.216	85.44	466.21	0.00	551.65	0.4935
TGP 5291 NF	1134.603	7.375	1127.228	2252.415	1125.187	70.56	0.00	0.00	70.56	0.0622
TGP Pool Law	3785.232	0.000	3785.232	13726.920	9941.688	0.00	0.00	0.00	0.00	0.0000
TGP Pool Spr	5790.820	0.000	5790.820	16214.760	10423.940	0.00	0.00	0.00	0.00	0.0000
TGP 39741	1127.894	9.700	1118.194	1489.565	371.371	86.21	308.31	0.00	394.53	0.3498
TGP 41098	1556.169	13.383	1542.786	6837.545	5294.759	118.95	1415.25	0.00	1534.20	0.9859
TGP 98775	1339.581	2.679	1336.902	2226.500	889.598	44.25	2008.20	0.00	2052.45	1.5322
TGP 330904 L	3140.672	6.281	3134.390	8030.000	4895.610	103.75	3463.81	0.00	3567.56	1.1359
TGP 330904 S	6395.891	12.792	6383.100	27156.000	20772.900	211.28	0.00	0.00	211.28	0.0330
TGP 48427	88.563	0.177	88.386	6205.000	6116.614	2.93	5596.62	0.00	5599.54	63.2269
TGP 362252	88.386	0.177	88.209	5110.000	5021.791	2.92	364.64	0.00	367.56	4.1586
TGP to AGT	526.598	0.000	526.598	2190.000	1663.402	0.00	0.00	0.00	0.00	0.0000
Unitil X Bro	491.029	0.000	491.029	1999.105	1508.076	0.00	0.00	0.00	0.00	0.0000
Unitil X Law	752.181	0.000	752.181	1861.135	1108.954	0.00	0.00	0.00	0.00	0.0000
Unitil X Spr	204.274	0.000	204.274	504.430	300.156	0.00	0.00	0.00	0.00	0.0000
AGT AIM	6361.895	189.108	6172.787	10950.000	4777.213	344.44	15043.03	0.00	15387.47	2.4187
AGT 93001EC	9149.466	87.436	9062.030	15467.350	6405.320	317.17	5296.06	0.00	5613.23	0.6135
AGT 93401	550.938	5.294	545.644	2076.850	1531.206	19.10	586.71	0.00	605.81	1.0996

NOV 2021 thru OCT 2022 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001F	1542.786	14.965	1527.821	6748.850	5221.029	53.47	1906.55	0.00	1960.02	1.2704
AGT Hubline	18.593	0.180	18.413	7300.000	7281.587	0.64	1679.02	0.00	1679.66	90.3383
AGT 510352	4926.911	47.202	4879.708	17520.000	12640.292	170.79	4949.40	0.00	5120.18	1.0392
AGT 93201 Ce	79.769	0.767	79.002	457.710	378.708	2.77	129.30	0.00	132.07	1.6556
AGT 93201 La	363.125	3.496	359.629	1545.775	1186.146	12.59	436.68	0.00	449.27	1.2372
AGT 94501	1150.517	11.055	1139.462	5386.670	4247.208	39.88	1521.73	0.00	1561.61	1.3573
TET 800414	62.935	0.906	62.029	385.440	323.411	3.70	92.37	0.00	96.07	1.5265
TET 800462	8002.185	153.642	7848.543	13274.685	5426.142	673.40	7787.10	0.00	8460.50	1.0573
TET 800382	513.204	7.390	505.814	1545.775	1039.961	30.20	370.43	0.00	400.62	0.7806
TET Stor Inj	1586.210	19.510	1566.699	364635.000	363068.301	65.49	0.00	0.00	65.49	0.0413
GSS Stor Inj	1488.738	18.311	1470.426	364635.000	363164.574	61.46	0.00	0.00	61.46	0.0413
GSS AMA Tran	744.526	10.721	733.805	2376.515	1642.710	43.81	0.00	0.00	43.81	0.0588
TRANSCO FT	184.023	0.939	183.084	457.710	274.626	3.25	58.53	0.00	61.78	0.3357
Total		969.007				3530.23	109530.76		113060.99	0.9877

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NOV 2022 thru OCT 2023 Cost and Flow Summary Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	198845.	Injection Cost	204.41	Transportation Cost	3457.82	JAN 15, 2023	
Penalty Cost	0.00	Withdrawal Cost	237.15	Other Variable Cost	78.88	System Served	440.758
Other Variable Cost	0.00	Carrying Cost	0.00			System Unserved	0.000
		Other Variable Cost	0.00			Total	440.758
Total Variable	198845.	Total Variable	441.56	Total Variable	3536.70		
Demand/Reservation Co	9856450	Demand Cost	2780.79	Demand Cost	109530.		
Other Fixed Cost	0.00	Other Fixed Cost	3899.28	Other Fixed Cost	0.00		
Total Fixed	9856450	Total Fixed	6680.07	Total Fixed	109530.		
Sup Release Revenue	0.00	Sto Release Revenue	0.00	Cap Release Revenue	0.00		
Net Supply Cost	1.005e7	Net Storage Cost	7121.63	Net Trans Cost	113067.	Total Gas Cost	10175484.3
						Total Revenue	0.00
						Net Cost	10175484.3

Avg Cost of Served Demand 212.3 USD/DT Avg Cost of Gas Purchased 205.0 USD/DT
(System Cost/Served Dem.) (Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	47925.011	0.000	47925.011	0.000	47925.011	47925.011	0.000	0.00	440.758	0.000
Total	47925.011	0.000	47925.011	0.000	47925.011	47925.011	0.000	0.00	440.758	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	20.196	364635.000	364614.804			12.1260	244.90	0.00	244.90	12.1260
Centerville	4878.980	364635.000	359756.020			5.3987	26340.04	0.00	26340.04	5.3987
Dawn	10746.159	364635.000	353888.841			4.4590	47916.84	0.00	47916.84	4.4590
Dracut	725.481	364635.000	363909.519			3.0498	2212.59	0.00	2212.59	3.0498
Ellisburg	7159.473	364635.000	357475.527			3.7998	27204.43	0.00	27204.43	3.7998
Hereford	1584.508	364635.000	363050.492			3.0379	4813.56	0.00	4813.56	3.0379
LNG Inject	879.037	364635.000	363755.963			5.6609	4976.18	0.00	4976.18	5.6609
LPG Inject	0.000	364635.000	364635.000			0.0000	0.00	0.00	0.00	0.0000
Millennium	5499.196	364635.000	359135.804			3.3547	18448.07	0.00	18448.07	3.3547

NOV 2022 thru OCT 2023 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Niagara	3380.309	364635.000	361254.691			3.8066	12867.48	0.00	12867.48	3.8066
Ramapo	900.373	364635.000	363734.627			4.0983	3690.04	0.00	3690.04	4.0983
Repsol 30	987.000	987.000	0.000			4.9623	4897.79	12993.53	17891.31	18.1270
Repsol 40	564.000	564.000	0.000			4.8919	2759.02	5568.65	8327.67	14.7654
TETCO M2	11071.524	364635.000	353563.476			3.5294	39076.03	0.00	39076.03	3.5294
TETCO M3	623.042	364635.000	364011.958			4.8247	3005.97	0.00	3005.97	4.8247
Waddington	28.258	364635.000	364606.742			13.8782	392.17	0.00	392.17	13.8782
Freepoint	0.000	50.000	50.000			0.0000	0.00	693600.00	693600.00	0.0000
CLNG	0.000	360.000	360.000			0.0000	0.00	5242788.00	5242788.00	0.0000
Direct	0.000	450.000	450.000			0.0000	0.00	3901500.00	3901500.00	0.0000
Total	49047.536						198845.10	9856450.18	10055295.2	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	709.753	97	351.783	351.783	0.000	0.000	709.753	97	0.000	0.000	4098.81	4062.02	-36.79
LNG Lawrence	11.628	100	24.820	24.820	0.000	0.000	11.628	100	0.000	0.000	66.44	66.44	-0.00
LNG Marshfld	7.622	100	17.304	17.304	0.000	0.000	7.622	100	0.000	0.000	43.40	43.40	0.00
LNG Spring	919.961	97	485.130	485.130	0.000	0.000	919.961	97	0.000	0.000	5311.07	5263.05	-48.02
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	158.62	158.62	0.00
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	861.04	861.04	0.00
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	264.37	264.37	0.00
DTI GSS TET	1441.753	100	1470.426	1441.753	0.000	28.673	1441.753	100	0.000	0.000	4110.38	4110.38	0.00
Enbridge 16	1600.000	100	1597.425	1587.840	0.000	9.585	1600.000	100	9.527	0.000	5646.63	5664.88	18.25
Enbridge 18	1820.000	100	1830.986	1820.000	0.000	10.986	1820.000	100	10.920	0.000	6412.55	6412.55	0.00
Nat Fuel FSS	1100.000	100	1111.785	1100.000	0.000	11.785	1100.000	100	11.660	0.000	3626.22	3626.22	0.00
TETCO FSS-1	63.360	100	63.787	63.360	0.000	0.427	63.360	100	0.425	0.000	181.64	181.64	0.00
TETCO SS-1	1588.950	100	1502.912	1492.842	0.000	10.070	1588.950	100	26.423	0.000	4454.46	4513.95	59.49
TGP FSMA	1222.594	100	1242.726	1222.594	0.000	20.132	1222.594	100	0.000	0.000	3791.06	3791.06	0.00
Total	10591.124	100	9699.084	9607.427	0.000	91.658	10591.124	100	58.955	0.000	39026.70	39019.6	-7.07

Scenario 2246
EGMA 2021 F&SP - Base Case - Normal Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0 REP 1 29-Oct-2021
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NOV 2022 thru OCT 2023 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2632.965	32.649	2600.316	5840.000	3239.684	4.42	4290.74	0.00	4295.16	1.6313
TCPL 63398	1901.092	12.357	1888.735	9512.630	7623.895	3.21	3389.68	0.00	3392.89	1.7847
TCPL 64198	6118.616	75.871	6042.745	21836.855	15794.110	10.27	12995.00	0.00	13005.27	2.1255
Union 12292	5989.213	38.930	5950.283	21735.750	15785.467	10.12	2254.21	0.00	2264.32	0.3781
Union 12204	2082.964	13.539	2069.424	9618.480	7549.056	3.52	997.53	0.00	1001.05	0.4806
PNG 233301 D	128.088	0.359	127.730	3407.500	3279.770	0.14	2594.70	0.00	2594.84	20.2582
PNG 233301 U	1452.144	4.066	1448.078	1812.000	363.922	1.59	1395.00	0.00	1396.59	0.9617
PNG 208535 D	3512.140	0.000	3512.140	8577.500	5065.360	3.86	6556.50	0.00	6560.36	1.8679
PNG 208535 H	3221.735	0.000	3221.735	8030.000	4808.265	3.54	6138.00	0.00	6141.54	1.9063
PNG 208540	1913.462	0.000	1913.462	5840.000	3926.538	2.10	3504.00	0.00	3506.10	1.8323
IGT RTS	1916.992	1.917	1915.075	10526.600	8611.525	8.62	1811.97	0.00	1820.59	0.9497
N Fuel FST I	1127.228	15.443	1111.785	3650.000	2538.215	18.01	543.29	0.00	561.30	0.4979
N Fuel FST W	1088.340	14.910	1073.430	3650.000	2576.570	17.39	0.00	0.00	17.39	0.0160
MLP 217524	5499.196	24.196	5475.000	5475.000	0.000	22.45	3558.20	0.00	3580.65	0.6511
TGP 95349	355.469	3.057	352.412	3567.510	3215.098	27.17	738.41	0.00	765.58	2.1537
TGP 5173	3347.061	40.834	3306.227	4653.020	1346.793	334.92	2883.03	0.00	3217.95	0.9614
TGP 5293	2725.612	33.252	2692.359	4579.655	1887.296	272.74	1078.72	0.00	1351.45	0.4958
TGP 5196	2140.098	26.109	2113.989	5611.875	3497.886	214.15	1321.85	0.00	1536.00	0.7177
TGP 5196 Wth	1066.668	0.000	1066.668	2007.500	940.832	1.17	0.00	0.00	1.17	0.0011
TGP 5291 Sup	2252.415	0.000	2252.415	2252.415	0.000	2.48	0.00	0.00	2.48	0.0011
TGP 5291 5-6	1117.812	9.613	1108.199	2252.415	1144.216	85.44	466.21	0.00	551.65	0.4935
TGP 5291 NF	1134.603	7.375	1127.228	2252.415	1125.187	70.56	0.00	0.00	70.56	0.0622
TGP Pool Law	3764.090	0.000	3764.090	13726.920	9962.830	0.00	0.00	0.00	0.00	0.0000
TGP Pool Spr	5809.095	0.000	5809.095	16214.760	10405.665	0.00	0.00	0.00	0.00	0.0000
TGP 39741	1127.894	9.700	1118.194	1489.565	371.371	86.21	308.31	0.00	394.53	0.3498
TGP 41098	1559.607	13.413	1546.194	6837.545	5291.351	119.21	1415.25	0.00	1534.46	0.9839
TGP 98775	1343.563	2.687	1340.876	2226.500	885.624	44.38	2008.20	0.00	2052.58	1.5277
TGP 330904 L	3221.735	6.443	3215.292	8030.000	4814.708	106.43	3463.81	0.00	3570.24	1.1082
TGP 330904 S	6391.729	12.783	6378.946	27156.000	20777.054	211.14	0.00	0.00	211.14	0.0330
TGP 48427	94.520	0.189	94.331	6205.000	6110.669	3.12	5596.62	0.00	5599.74	59.2440
TGP 362252	94.331	0.189	94.142	5110.000	5015.858	3.12	364.64	0.00	367.76	3.8986
TGP to AGT	526.240	0.000	526.240	2190.000	1663.760	0.00	0.00	0.00	0.00	0.0000
Unitil X Bro	491.353	0.000	491.353	1999.105	1507.752	0.00	0.00	0.00	0.00	0.0000
Unitil X Law	752.189	0.000	752.189	1861.135	1108.946	0.00	0.00	0.00	0.00	0.0000
Unitil X Spr	204.536	0.000	204.536	504.430	299.894	0.00	0.00	0.00	0.00	0.0000
AGT AIM	6375.373	189.552	6185.821	10950.000	4764.179	345.17	15043.03	0.00	15388.20	2.4137
AGT 93001EC	8991.384	85.925	8905.459	15467.350	6561.891	311.69	5296.06	0.00	5607.75	0.6237
AGT 93401	638.442	6.129	632.313	2076.850	1444.537	22.13	586.71	0.00	608.84	0.9536

NOV 2022 thru OCT 2023 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001F	1546.194	14.998	1531.196	6748.850	5217.654	53.59	1906.55	0.00	1960.14	1.2677
AGT Hubline	20.196	0.196	20.000	7300.000	7280.000	0.70	1679.02	0.00	1679.72	83.1711
AGT 510352	4985.509	47.762	4937.747	17520.000	12582.253	172.82	4949.40	0.00	5122.22	1.0274
AGT 93201 Ce	76.554	0.737	75.817	457.710	381.893	2.65	129.30	0.00	131.96	1.7237
AGT 93201 La	432.892	4.161	428.730	1545.775	1117.045	15.01	436.68	0.00	451.69	1.0434
AGT 94501	1171.434	11.257	1160.177	5386.670	4226.493	40.61	1521.73	0.00	1562.34	1.3337
TET 800414	62.935	0.906	62.029	385.440	323.411	3.70	92.37	0.00	96.07	1.5265
TET 800462	7996.576	153.534	7843.042	13274.685	5431.643	672.93	7787.10	0.00	8460.03	1.0580
TET 800382	518.046	7.460	510.587	1545.775	1035.188	30.48	370.43	0.00	400.91	0.7739
TET Stor Inj	1586.210	19.510	1566.699	364635.000	363068.301	65.49	0.00	0.00	65.49	0.0413
GSS Stor Inj	1488.738	18.311	1470.426	364635.000	363164.574	61.46	0.00	0.00	61.46	0.0413
GSS AMA Tran	739.684	10.651	729.033	2376.515	1647.482	43.52	0.00	0.00	43.52	0.0588
TRANSCO FT	184.023	0.939	183.084	457.710	274.626	3.25	58.53	0.00	61.78	0.3357
Total		971.912				3536.70	109530.76		113067.47	0.9839

NOV 2023 thru OCT 2024 — Cost and Flow Summary — Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	200952.	Injection Cost	204.41	Transportation Cost	3483.88	JAN 15, 2024	
Penalty Cost	0.00	Withdrawal Cost	237.15	Other Variable Cost	79.48	System Served	443.871
Other Variable Cost	0.00	Carrying Cost	0.00			System Unserved	0.000
		Other Variable Cost	0.00			Total	443.871
Total Variable	200952.	Total Variable	441.56	Total Variable	3563.35		
Demand/Reservation Co	9856450	Demand Cost	2780.79	Demand Cost	109530.		
Other Fixed Cost	0.00	Other Fixed Cost	3899.28	Other Fixed Cost	0.00		
Total Fixed	9856450	Total Fixed	6680.07	Total Fixed	109530.		
Sup Release Revenue	0.00	Sto Release Revenue	0.00	Cap Release Revenue	0.00		
Net Supply Cost	1.005e7	Net Storage Cost	7121.63	Net Trans Cost	113094.	Total Gas Cost	10177618.0
						Total Revenue	0.00
						Net Cost	10177618.0

Avg Cost of Served Demand 210.4 USD/DT (System Cost/Served Dem.)
Avg Cost of Gas Purchased 203.1 USD/DT (Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	48370.092	0.000	48370.092	0.000	48370.092	48370.092	0.000	0.00	443.871	0.000
Total	48370.092	0.000	48370.092	0.000	48370.092	48370.092	0.000	0.00	443.871	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	20.196	365634.000	365613.804			12.1260	244.90	0.00	244.90	12.1260
Centerville	4989.869	365634.000	360644.131			5.3976	26933.45	0.00	26933.45	5.3976
Dawn	10861.385	365634.000	354772.615			4.4633	48477.98	0.00	48477.98	4.4633
Dracut	729.344	365634.000	364904.656			3.0494	2224.08	0.00	2224.08	3.0494
Ellisburg	7199.333	365634.000	358434.667			3.8027	27377.26	0.00	27377.26	3.8027
Hereford	1609.236	365634.000	364024.764			3.0385	4889.63	0.00	4889.63	3.0385
LNG Inject	901.741	365634.000	364732.259			5.6669	5110.07	0.00	5110.07	5.6669
LPG Inject	0.000	365634.000	365634.000			0.0000	0.00	0.00	0.00	0.0000
Millennium	5514.263	365634.000	360119.737			3.3574	18513.42	0.00	18513.42	3.3574

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Niagara	3390.596	365634.000	362243.404			3.8093	12915.83	0.00	12915.83	3.8093
Ramapo	917.975	365634.000	364716.025			4.1125	3775.13	0.00	3775.13	4.1125
Repsol 30	987.000	987.000	0.000			4.9595	4895.00	12993.53	17888.52	18.1241
Repsol 40	564.000	564.000	0.000			4.9034	2765.52	5568.65	8334.17	14.7769
TETCO M2	11145.104	365634.000	354488.896			3.5300	39341.90	0.00	39341.90	3.5300
TETCO M3	648.013	365634.000	364985.987			4.7752	3094.37	0.00	3094.37	4.7752
Waddington	28.351	365634.000	365605.649			13.8812	393.54	0.00	393.54	13.8812
Freepoint	0.000	50.000	50.000			0.0000	0.00	693600.00	693600.00	0.0000
CLNG	0.000	360.000	360.000			0.0000	0.00	5242788.00	5242788.00	0.0000
Direct	0.000	450.000	450.000			0.0000	0.00	3901500.00	3901500.00	0.0000
Total	49506.405						200952.09	9856450.18	10057402.2	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	709.753	97	364.791	358.681	0.000	0.000	715.863	98	0.000	6.110	4062.02	4076.28	14.27
LNG Lawrence	11.628	100	24.884	24.884	0.000	0.000	11.628	100	0.000	0.000	66.44	66.44	0.00
LNG Marshfld	7.622	100	20.749	20.749	0.000	0.000	7.622	100	0.000	0.000	43.40	43.40	0.00
LNG Spring	919.961	97	491.316	491.316	0.000	0.000	919.961	97	0.000	0.000	5263.05	5236.35	-26.70
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	158.62	158.62	0.00
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	861.04	861.04	0.00
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	264.37	264.37	0.00
DTI GSS TET	1441.753	100	1470.426	1441.753	0.000	28.673	1441.753	100	0.000	0.000	4110.38	4110.38	0.00
Enbridge 16	1600.000	100	1597.425	1587.840	0.000	9.585	1600.000	100	9.527	0.000	5664.88	5665.02	0.14
Enbridge 18	1820.000	100	1830.986	1820.000	0.000	10.986	1820.000	100	10.920	0.000	6412.55	6412.55	0.00
Nat Fuel FSS	1100.000	100	1111.785	1100.000	0.000	11.785	1100.000	100	11.660	0.000	3626.22	3626.22	0.00
TETCO FSS-1	63.360	100	63.787	63.360	0.000	0.427	63.360	100	0.425	0.000	181.64	181.64	0.00
TETCO SS-1	1588.950	100	1502.912	1492.842	0.000	10.070	1588.950	100	26.423	0.000	4513.95	4517.54	3.60
TGP FSMA	1222.594	100	1242.726	1222.594	0.000	20.132	1222.594	100	0.000	0.000	3791.06	3791.06	0.00
Total	10591.124	100	9721.788	9624.020	0.000	91.658	10597.235	100	58.955	6.110	39019.63	39010.9	-8.70

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2653.078	32.898	2620.180	5856.000	3235.820	4.45	4290.74	0.00	4295.19	1.6189
TCPL 63398	1923.963	12.506	1911.458	9538.692	7627.234	3.25	3389.68	0.00	3392.93	1.7635
TCPL 64198	6190.239	76.759	6113.480	21896.682	15783.202	10.39	12995.00	0.00	13005.39	2.1010
Union 12292	6316.364	41.056	6275.308	21795.300	15519.992	10.67	2254.21	0.00	2264.87	0.3586
Union 12204	1850.925	12.031	1838.894	9644.832	7805.938	3.13	997.53	0.00	1000.65	0.5406
PNG 233301 D	129.872	0.364	129.508	3409.800	3280.292	0.14	2594.70	0.00	2594.84	19.9800
PNG 233301 U	1464.546	4.101	1460.445	1824.000	363.555	1.61	1395.00	0.00	1396.61	0.9536
PNG 208535 D	3611.380	0.000	3611.380	8601.000	4989.620	3.97	6556.50	0.00	6560.47	1.8166
PNG 208535 H	3280.261	0.000	3280.261	8052.000	4771.739	3.61	6138.00	0.00	6141.61	1.8723
PNG 208540	1856.837	0.000	1856.837	5856.000	3999.163	2.04	3504.00	0.00	3506.04	1.8882
IGT RTS	1939.808	1.940	1937.869	10555.440	8617.571	8.72	1811.97	0.00	1820.69	0.9386
N Fuel FST I	1127.228	15.443	1111.785	3660.000	2548.215	18.01	543.29	0.00	561.30	0.4979
N Fuel FST W	1088.340	14.910	1073.430	3660.000	2586.570	17.39	0.00	0.00	17.39	0.0160
MLP 217524	5514.263	24.263	5490.000	5490.000	0.000	22.51	3558.20	0.00	3580.71	0.6494
TGP 95349	355.237	3.055	352.182	3577.284	3225.102	27.15	738.41	0.00	765.56	2.1551
TGP 5173	3362.666	41.025	3321.641	4665.768	1344.127	336.48	2883.03	0.00	3219.51	0.9574
TGP 5293	2742.723	33.461	2709.261	4592.202	1882.941	274.45	1078.72	0.00	1353.16	0.4934
TGP 5196	2147.242	26.196	2121.046	5627.250	3506.204	214.86	1321.85	0.00	1536.71	0.7157
TGP 5196 Wth	1073.812	0.000	1073.812	2013.000	939.188	1.18	0.00	0.00	1.18	0.0011
TGP 5291 Sup	2258.586	0.000	2258.586	2258.586	0.000	2.48	0.00	0.00	2.48	0.0011
TGP 5291 5-6	1123.983	9.666	1114.317	2258.586	1144.269	85.91	466.21	0.00	552.12	0.4912
TGP 5291 NF	1134.603	7.375	1127.228	2258.586	1131.358	70.56	0.00	0.00	70.56	0.0622
TGP Pool Law	3769.957	0.000	3769.957	13764.528	9994.571	0.00	0.00	0.00	0.00	0.0000
TGP Pool Spr	5848.491	0.000	5848.491	16259.184	10410.693	0.00	0.00	0.00	0.00	0.0000
TGP 39741	1132.010	9.735	1122.275	1493.646	371.371	86.53	308.31	0.00	394.84	0.3488
TGP 41098	1582.631	13.611	1569.021	6856.278	5287.257	120.97	1415.25	0.00	1536.22	0.9707
TGP 98775	1324.965	2.650	1322.315	2232.600	910.285	43.77	2008.20	0.00	2051.97	1.5487
TGP 330904 L	3280.261	6.561	3273.700	8052.000	4778.300	108.36	3463.81	0.00	3572.17	1.0890
TGP 330904 S	6457.311	12.915	6444.396	27230.400	20786.004	213.31	0.00	0.00	213.31	0.0330
TGP 48427	95.793	0.192	95.602	6222.000	6126.398	3.16	5596.62	0.00	5599.78	58.4570
TGP 362252	95.602	0.191	95.410	5124.000	5028.590	3.16	364.64	0.00	367.80	3.8472
TGP to AGT	533.635	0.000	533.635	2196.000	1662.365	0.00	0.00	0.00	0.00	0.0000
Unitil X Bro	497.363	0.000	497.363	2004.582	1507.219	0.00	0.00	0.00	0.00	0.0000
Unitil X Law	757.396	0.000	757.396	1866.234	1108.838	0.00	0.00	0.00	0.00	0.0000
Unitil X Spr	205.686	0.000	205.686	505.812	300.126	0.00	0.00	0.00	0.00	0.0000
AGT AIM	6407.975	190.603	6217.372	10980.000	4762.628	346.93	15043.03	0.00	15389.96	2.4017
AGT 93001EC	9253.349	88.422	9164.927	15518.982	6354.055	320.77	5296.06	0.00	5616.83	0.6070
AGT 93401	541.375	5.194	536.181	2082.540	1546.359	18.77	586.71	0.00	605.48	1.1184

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001F	1569.021	15.220	1553.801	6767.340	5213.539	54.38	1906.55	0.00	1960.93	1.2498
AGT Hubline	20.196	0.196	20.000	7320.000	7300.000	0.70	1679.02	0.00	1679.72	83.1711
AGT 510352	5092.672	48.788	5043.884	17568.000	12524.116	176.54	4949.40	0.00	5125.93	1.0065
AGT 93201 Ce	81.534	0.785	80.749	458.964	378.215	2.83	129.30	0.00	132.13	1.6205
AGT 93201 La	412.343	3.967	408.376	1550.010	1141.634	14.29	436.68	0.00	450.97	1.0937
AGT 94501	1122.980	10.801	1112.180	5401.428	4289.248	38.93	1521.73	0.00	1560.66	1.3897
TET 800414	62.935	0.906	62.029	386.496	324.467	3.70	92.37	0.00	96.07	1.5265
TET 800462	8070.156	154.947	7915.209	13311.054	5395.845	679.12	7787.10	0.00	8466.22	1.0491
TET 800382	508.571	7.323	501.247	1550.010	1048.763	29.92	370.43	0.00	400.35	0.7872
TET Stor Inj	1586.210	19.510	1566.699	365634.000	364067.301	65.49	0.00	0.00	65.49	0.0413
GSS Stor Inj	1488.738	18.311	1470.426	365634.000	364163.574	61.46	0.00	0.00	61.46	0.0413
GSS AMA Tran	747.899	10.770	737.130	2383.026	1645.896	44.01	0.00	0.00	44.01	0.0588
TRANSCO FT	185.283	0.945	184.338	458.964	274.626	3.27	58.53	0.00	61.80	0.3335
Total		979.590				3563.35	109530.76		113094.11	0.9760

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	203131.	Injection Cost	204.41	Transportation Cost	3496.98	JAN 15, 2025	
Penalty Cost	0.00	Withdrawal Cost	237.15	Other Variable Cost	79.89	System Served	448.374
Other Variable Cost	0.00	Carrying Cost	0.00			System Unserved	0.000
		Other Variable Cost	0.00			Total	448.374
Total Variable	203131.	Total Variable	441.56	Total Variable	3576.87		
Demand/Reservation Co	9856450	Demand Cost	2780.79	Demand Cost	109530.		
Other Fixed Cost	0.00	Other Fixed Cost	3899.28	Other Fixed Cost	0.00		
Total Fixed	9856450	Total Fixed	6680.07	Total Fixed	109530.		
Sup Release Revenue	0.00	Sto Release Revenue	0.00	Cap Release Revenue	0.00		
Net Supply Cost	1.005e7	Net Storage Cost	7121.63	Net Trans Cost	113107.	Total Gas Cost	10179811.2
						Total Revenue	0.00
						Net Cost	10179811.2

Avg Cost of Served Demand 208.5 USD/DT Avg Cost of Gas Purchased 201.4 USD/DT
(System Cost/Served Dem.) (Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	48809.625	0.000	48809.625	0.000	48809.625	48809.625	0.000	0.00	448.374	0.000
Total	48809.625	0.000	48809.625	0.000	48809.625	48809.625	0.000	0.00	448.374	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	21.274	364635.000	364613.726			12.4012	263.83	0.00	263.83	12.4012
Centerville	5168.547	364635.000	359466.453			5.3946	27882.18	0.00	27882.18	5.3946
Dawn	11015.366	364635.000	353619.634			4.4667	49201.82	0.00	49201.82	4.4667
Dracut	735.699	364635.000	363899.301			3.0487	2242.96	0.00	2242.96	3.0487
Ellisburg	7183.239	364635.000	357451.761			3.7979	27281.12	0.00	27281.12	3.7979
Hereford	1633.951	364635.000	363001.049			3.0389	4965.40	0.00	4965.40	3.0389
LNG Inject	939.128	364635.000	363695.872			5.6736	5328.23	0.00	5328.23	5.6736
LPG Inject	0.000	364635.000	364635.000			0.0000	0.00	0.00	0.00	0.0000
Millennium	5499.196	364635.000	359135.804			3.3547	18448.07	0.00	18448.07	3.3547

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Niagara	3380.309	364635.000	361254.691			3.8066	12867.48	0.00	12867.48	3.8066
Ramapo	953.180	364635.000	363681.820			4.1704	3975.14	0.00	3975.14	4.1704
Repsol 30	987.000	987.000	0.000			4.9777	4913.04	12993.53	17906.56	18.1424
Repsol 40	564.000	564.000	0.000			4.9356	2783.67	5568.65	8352.32	14.8091
TETCO M2	11135.471	364635.000	353499.529			3.5245	39246.99	0.00	39246.99	3.5245
TETCO M3	693.027	364635.000	363941.973			4.7850	3316.16	0.00	3316.16	4.7850
Waddington	29.853	364635.000	364605.147			13.9255	415.72	0.00	415.72	13.9255
Freepoint	0.000	50.000	50.000			0.0000	0.00	693600.00	693600.00	0.0000
CLNG	0.000	360.000	360.000			0.0000	0.00	5242788.00	5242788.00	0.0000
Direct	0.000	450.000	450.000			0.0000	0.00	3901500.00	3901500.00	0.0000
Total	49939.241						203131.81	9856450.18	10059581.9	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	715.863	98	377.224	383.334	0.000	0.000	709.753	97	0.000	-6.110	4076.28	4030.33	-45.95
LNG Lawrence	11.628	100	24.820	24.820	0.000	0.000	11.628	100	0.000	0.000	66.44	66.44	0.00
LNG Marshfld	7.622	100	24.925	24.925	0.000	0.000	7.622	100	0.000	0.000	43.40	74.80	31.40
LNG Spring	919.961	97	512.159	512.159	0.000	0.000	919.961	97	0.000	0.000	5236.35	5221.36	-14.99
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	158.62	158.62	0.00
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	861.04	861.04	0.00
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	264.37	264.37	0.00
DTI GSS TET	1441.753	100	1470.426	1441.753	0.000	28.673	1441.753	100	0.000	0.000	4110.38	4110.38	0.00
Enbridge 16	1600.000	100	1597.425	1587.840	0.000	9.585	1600.000	100	9.527	0.000	5665.02	5665.02	0.00
Enbridge 18	1820.000	100	1830.986	1820.000	0.000	10.986	1820.000	100	10.920	0.000	6412.55	6412.55	0.00
Nat Fuel FSS	1100.000	100	1111.785	1100.000	0.000	11.785	1100.000	100	11.660	0.000	3626.22	3626.22	0.00
TETCO FSS-1	63.360	100	63.787	63.360	0.000	0.427	63.360	100	0.425	0.000	181.64	181.64	0.00
TETCO SS-1	1588.950	100	1502.912	1492.842	0.000	10.070	1588.950	100	26.423	0.000	4517.54	4517.76	0.22
TGP FSMA	1222.594	100	1242.726	1222.594	0.000	20.132	1222.594	100	0.000	0.000	3791.06	3791.06	0.00
Total	10597.235	100	9759.176	9673.628	0.000	91.658	10591.124	100	58.955	-6.110	39010.93	38981.6	-29.32

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2643.798	32.783	2611.015	5840.000	3228.985	4.44	4290.74	0.00	4295.18	1.6246
TCPL 63398	1941.841	12.622	1929.219	9512.630	7583.411	3.28	3389.68	0.00	3392.96	1.7473
TCPL 64198	6334.561	78.549	6256.012	21836.855	15580.843	10.64	12995.00	0.00	13005.63	2.0531
Union 12292	6278.035	40.807	6237.227	21735.750	15498.523	10.60	2254.21	0.00	2264.81	0.3608
Union 12204	2052.516	13.341	2039.175	9618.480	7579.305	3.47	997.53	0.00	1001.00	0.4877
PNG 233301 D	135.636	0.380	135.257	3407.500	3272.243	0.15	2594.70	0.00	2594.85	19.1309
PNG 233301 U	1458.341	4.083	1454.258	1812.000	357.742	1.60	1395.00	0.00	1396.60	0.9577
PNG 208535 D	3599.765	0.000	3599.765	8577.500	4977.735	3.96	6556.50	0.00	6560.46	1.8225
PNG 208535 H	3366.274	0.000	3366.274	8030.000	4663.726	3.70	6138.00	0.00	6141.70	1.8245
PNG 208540	1940.962	0.000	1940.962	5840.000	3899.038	2.14	3504.00	0.00	3506.14	1.8064
IGT RTS	1959.072	1.959	1957.113	10526.600	8569.487	8.81	1811.97	0.00	1820.78	0.9294
N Fuel FST I	1127.228	15.443	1111.785	3650.000	2538.215	18.01	543.29	0.00	561.30	0.4979
N Fuel FST W	1088.340	14.910	1073.430	3650.000	2576.570	17.39	0.00	0.00	17.39	0.0160
MLP 217524	5499.196	24.196	5475.000	5475.000	0.000	22.45	3558.20	0.00	3580.65	0.6511
TGP 95349	377.141	3.243	373.897	3567.510	3193.613	28.83	738.41	0.00	767.24	2.0344
TGP 5173	3372.320	41.142	3331.177	4653.020	1321.843	337.45	2883.03	0.00	3220.48	0.9550
TGP 5293	2719.714	33.181	2686.534	4579.655	1893.121	272.15	1078.72	0.00	1350.86	0.4967
TGP 5196	2144.503	26.163	2118.340	5611.875	3493.535	214.59	1321.85	0.00	1536.44	0.7165
TGP 5196 Wth	1071.073	0.000	1071.073	2007.500	936.427	1.18	0.00	0.00	1.18	0.0011
TGP 5291 Sup	2252.415	0.000	2252.415	2252.415	0.000	2.48	0.00	0.00	2.48	0.0011
TGP 5291 5-6	1117.812	9.613	1108.199	2252.415	1144.216	85.44	466.21	0.00	551.65	0.4935
TGP 5291 NF	1134.603	7.375	1127.228	2252.415	1125.187	70.56	0.00	0.00	70.56	0.0622
TGP Pool Law	3758.270	0.000	3758.270	13726.920	9968.650	0.00	0.00	0.00	0.00	0.0000
TGP Pool Spr	5859.877	0.000	5859.877	16214.760	10354.883	0.00	0.00	0.00	0.00	0.0000
TGP 39741	1127.894	9.700	1118.194	1489.565	371.371	86.21	308.31	0.00	394.53	0.3498
TGP 41098	1579.972	13.588	1566.384	6837.545	5271.161	120.77	1415.25	0.00	1536.02	0.9722
TGP 98775	1394.562	2.789	1391.772	2226.500	834.728	46.07	2008.20	0.00	2054.27	1.4731
TGP 330904 L	3366.274	6.733	3359.541	8030.000	4670.459	111.20	3463.81	0.00	3575.01	1.0620
TGP 330904 S	6459.414	12.919	6446.495	27156.000	20709.505	213.38	0.00	0.00	213.38	0.0330
TGP 48427	108.707	0.217	108.489	6205.000	6096.511	3.59	5596.62	0.00	5600.21	51.5167
TGP 362252	108.489	0.217	108.272	5110.000	5001.728	3.58	364.64	0.00	368.23	3.3941
TGP to AGT	530.651	0.000	530.651	2190.000	1659.349	0.00	0.00	0.00	0.00	0.0000
Unitil X Bro	497.165	0.000	497.165	1999.105	1501.940	0.00	0.00	0.00	0.00	0.0000
Unitil X Law	752.557	0.000	752.557	1861.135	1108.578	0.00	0.00	0.00	0.00	0.0000
Unitil X Spr	204.536	0.000	204.536	504.430	299.894	0.00	0.00	0.00	0.00	0.0000
AGT AIM	6428.180	191.242	6236.938	10950.000	4713.062	348.02	15043.03	0.00	15391.05	2.3943
AGT 93001EC	9212.675	88.013	9124.663	15467.350	6342.687	319.36	5296.06	0.00	5615.42	0.6095
AGT 93401	583.752	5.608	578.145	2076.850	1498.705	20.24	586.71	0.00	606.94	1.0397

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001F	1566.384	15.194	1551.191	6748.850	5197.659	54.29	1906.55	0.00	1960.84	1.2518
AGT Hubline	21.274	0.206	21.068	7300.000	7278.932	0.74	1679.02	0.00	1679.75	78.9567
AGT 510352	5266.576	50.458	5216.118	17520.000	12303.882	182.56	4949.40	0.00	5131.96	0.9744
AGT 93201 Ce	86.309	0.827	85.482	457.710	372.228	2.99	129.30	0.00	132.29	1.5328
AGT 93201 La	410.784	3.946	406.838	1545.775	1138.937	14.24	436.68	0.00	450.92	1.0977
AGT 94501	1158.402	11.138	1147.264	5386.670	4239.406	40.15	1521.73	0.00	1561.89	1.3483
TET 800414	62.935	0.906	62.029	385.440	323.411	3.70	92.37	0.00	96.07	1.5265
TET 800462	8060.523	154.762	7905.761	13274.685	5368.924	678.31	7787.10	0.00	8465.41	1.0502
TET 800382	502.955	7.243	495.713	1545.775	1050.062	29.59	370.43	0.00	400.02	0.7953
TET Stor Inj	1586.210	19.510	1566.699	364635.000	363068.301	65.49	0.00	0.00	65.49	0.0413
GSS Stor Inj	1488.738	18.311	1470.426	364635.000	363164.574	61.46	0.00	0.00	61.46	0.0413
GSS AMA Tran	753.515	10.851	742.664	2376.515	1633.851	44.34	0.00	0.00	44.34	0.0588
TRANSCO FT	185.283	0.945	184.338	457.710	273.372	3.27	58.53	0.00	61.80	0.3335
Total		985.114				3576.87	109530.76		113107.63	0.9689

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	205353.	Injection Cost	204.41	Transportation Cost	3514.78	JAN 15, 2026	
Penalty Cost	0.00	Withdrawal Cost	237.15	Other Variable Cost	80.35	System Served	452.888
Other Variable Cost	0.00	Carrying Cost	0.00			System Unserved	0.000
		Other Variable Cost	0.00			Total	452.888
Total Variable	205353.	Total Variable	441.56	Total Variable	3595.12		
Demand/Reservation Co	9856450	Demand Cost	2780.79	Demand Cost	109530.		
Other Fixed Cost	0.00	Other Fixed Cost	3899.28	Other Fixed Cost	0.00		
Total Fixed	9856450	Total Fixed	6680.07	Total Fixed	109530.		
Sup Release Revenue	0.00	Sto Release Revenue	0.00	Cap Release Revenue	0.00		
Net Supply Cost	1.006e7	Net Storage Cost	7121.63	Net Trans Cost	113125.	Total Gas Cost	10182051.3
						Total Revenue	0.00
						Net Cost	10182051.3

Avg Cost of Served Demand 206.8 USD/DT Avg Cost of Gas Purchased 199.7 USD/DT
(System Cost/Served Dem.) (Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	49229.787	0.000	49229.787	0.000	49229.787	49229.787	0.000	0.00	452.888	0.000
Total	49229.787	0.000	49229.787	0.000	49229.787	49229.787	0.000	0.00	452.888	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	25.609	364635.000	364609.391			12.9785	332.37	0.00	332.37	12.9785
Centerville	5293.871	364635.000	359341.129			5.3948	28559.50	0.00	28559.50	5.3948
Dawn	11154.085	364635.000	353480.915			4.4706	49865.85	0.00	49865.85	4.4706
Dracut	737.976	364635.000	363897.024			3.0484	2249.64	0.00	2249.64	3.0484
Ellisburg	7190.483	364635.000	357444.517			3.7974	27304.97	0.00	27304.97	3.7974
Hereford	1658.209	364635.000	362976.791			3.0388	5039.03	0.00	5039.03	3.0388
LNG Inject	980.911	364635.000	363654.089			5.6773	5568.92	0.00	5568.92	5.6773
LPG Inject	0.000	364635.000	364635.000			0.0000	0.00	0.00	0.00	0.0000
Millennium	5499.196	364635.000	359135.804			3.3547	18448.07	0.00	18448.07	3.3547

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Niagara	3380.309	364635.000	361254.691			3.8066	12867.48	0.00	12867.48	3.8066
Ramapo	978.297	364635.000	363656.703			4.2198	4128.20	0.00	4128.20	4.2198
Repsol 30	987.000	987.000	0.000			4.9913	4926.44	12993.53	17919.97	18.1560
Repsol 40	564.000	564.000	0.000			4.9469	2790.04	5568.65	8358.70	14.8204
TETCO M2	11156.857	364635.000	353478.143			3.5231	39306.19	0.00	39306.19	3.5231
TETCO M3	731.181	364635.000	363903.819			4.7789	3494.24	0.00	3494.24	4.7789
Waddington	33.783	364635.000	364601.217			13.9914	472.67	0.00	472.67	13.9914
Freepoint	0.000	50.000	50.000			0.0000	0.00	693600.00	693600.00	0.0000
CLNG	0.000	360.000	360.000			0.0000	0.00	5242788.00	5242788.00	0.0000
Direct	0.000	450.000	450.000			0.0000	0.00	3901500.00	3901500.00	0.0000
Total	50371.767						205353.62	9856450.18	10061803.8	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	709.753	97	403.251	403.251	0.000	0.000	709.753	97	0.000	0.000	4030.33	4024.89	-5.44
LNG Lawrence	11.628	100	24.820	24.820	0.000	0.000	11.628	100	0.000	0.000	66.44	66.44	0.00
LNG Marshfld	7.622	100	27.210	27.210	0.000	0.000	7.622	100	0.000	0.000	74.80	74.19	-0.61
LNG Spring	919.961	97	525.629	525.629	0.000	0.000	919.961	97	0.000	0.000	5221.36	5213.42	-7.95
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	158.62	158.62	0.00
LPG Meadow	70.749	100	0.000	0.000	0.000	0.000	70.749	100	0.000	0.000	861.04	861.04	0.00
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	264.37	264.37	0.00
DTI GSS TET	1441.753	100	1470.426	1441.753	0.000	28.673	1441.753	100	0.000	0.000	4110.38	4110.38	0.00
Enbridge 16	1600.000	100	1597.425	1587.840	0.000	9.585	1600.000	100	9.527	0.000	5665.02	5665.02	0.00
Enbridge 18	1820.000	100	1830.986	1820.000	0.000	10.986	1820.000	100	10.920	0.000	6412.55	6412.55	0.00
Nat Fuel FSS	1100.000	100	1111.785	1100.000	0.000	11.785	1100.000	100	11.660	0.000	3626.22	3626.22	0.00
TETCO FSS-1	63.360	100	63.787	63.360	0.000	0.427	63.360	100	0.425	0.000	181.64	181.64	0.00
TETCO SS-1	1588.950	100	1502.912	1492.842	0.000	10.070	1588.950	100	26.423	0.000	4517.76	4517.78	0.01
TGP FSMA	1222.594	100	1242.726	1222.594	0.000	20.132	1222.594	100	0.000	0.000	3791.06	3791.06	0.00
Total	10591.124	100	9800.958	9709.301	0.000	91.658	10591.124	100	58.955	0.000	38981.61	38967.6	-13.99

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2642.603	32.768	2609.835	5840.000	3230.165	4.44	4290.74	0.00	4295.18	1.6254
TCPL 63398	1965.140	12.773	1952.367	9512.630	7560.263	3.32	3389.68	0.00	3392.99	1.7266
TCPL 64198	6450.266	79.983	6370.283	21836.855	15466.572	10.83	12995.00	0.00	13005.83	2.0163
Union 12292	6431.119	41.802	6389.316	21735.750	15346.434	10.86	2254.21	0.00	2265.07	0.3522
Union 12204	2039.346	13.256	2026.090	9618.480	7592.390	3.44	997.53	0.00	1000.97	0.4908
PNG 233301 D	138.531	0.388	138.143	3407.500	3269.357	0.15	2594.70	0.00	2594.85	18.7312
PNG 233301 U	1461.028	4.091	1456.937	1812.000	355.063	1.60	1395.00	0.00	1396.60	0.9559
PNG 208535 D	3655.612	0.000	3655.612	8577.500	4921.888	4.02	6556.50	0.00	6560.52	1.7946
PNG 208535 H	3459.977	0.000	3459.977	8030.000	4570.023	3.81	6138.00	0.00	6141.81	1.7751
PNG 208540	1923.179	0.000	1923.179	5840.000	3916.821	2.12	3504.00	0.00	3506.12	1.8231
IGT RTS	1986.150	1.986	1984.163	10526.600	8542.437	8.93	1811.97	0.00	1820.90	0.9168
N Fuel FST I	1127.228	15.443	1111.785	3650.000	2538.215	18.01	543.29	0.00	561.30	0.4979
N Fuel FST W	1088.340	14.910	1073.430	3650.000	2576.570	17.39	0.00	0.00	17.39	0.0160
MLP 217524	5499.196	24.196	5475.000	5475.000	0.000	22.45	3558.20	0.00	3580.65	0.6511
TGP 95349	395.487	3.401	392.086	3567.510	3175.424	30.23	738.41	0.00	768.64	1.9435
TGP 5173	3379.393	41.229	3338.165	4653.020	1314.855	338.16	2883.03	0.00	3221.19	0.9532
TGP 5293	2718.192	33.162	2685.030	4579.655	1894.625	271.99	1078.72	0.00	1350.71	0.4969
TGP 5196	2146.195	26.184	2120.012	5611.875	3491.863	214.76	1321.85	0.00	1536.61	0.7160
TGP 5196 Wth	1072.766	0.000	1072.766	2007.500	934.734	1.18	0.00	0.00	1.18	0.0011
TGP 5291 Sup	2252.415	0.000	2252.415	2252.415	0.000	2.48	0.00	0.00	2.48	0.0011
TGP 5291 5-6	1117.812	9.613	1108.199	2252.415	1144.216	85.44	466.21	0.00	551.65	0.4935
TGP 5291 NF	1134.603	7.375	1127.228	2252.415	1125.187	70.56	0.00	0.00	70.56	0.0622
TGP Pool Law	3740.165	0.000	3740.165	13726.920	9986.755	0.00	0.00	0.00	0.00	0.0000
TGP Pool Spr	5903.326	0.000	5903.326	16214.760	10311.434	0.00	0.00	0.00	0.00	0.0000
TGP 39741	1127.894	9.700	1118.194	1489.565	371.371	86.21	308.31	0.00	394.53	0.3498
TGP 41098	1588.677	13.663	1575.014	6837.545	5262.531	121.43	1415.25	0.00	1536.68	0.9673
TGP 98775	1382.696	2.765	1379.930	2226.500	846.570	45.68	2008.20	0.00	2053.87	1.4854
TGP 330904 L	3459.977	6.920	3453.057	8030.000	4576.943	114.30	3463.81	0.00	3578.11	1.0341
TGP 330904 S	6508.466	13.017	6495.449	27156.000	20660.551	215.00	0.00	0.00	215.00	0.0330
TGP 48427	114.747	0.229	114.518	6205.000	6090.482	3.79	5596.62	0.00	5600.41	48.8065
TGP 362252	114.518	0.229	114.289	5110.000	4995.711	3.78	364.64	0.00	368.43	3.2172
TGP to AGT	531.320	0.000	531.320	2190.000	1658.680	0.00	0.00	0.00	0.00	0.0000
Unitil X Bro	499.844	0.000	499.844	1999.105	1499.261	0.00	0.00	0.00	0.00	0.0000
Unitil X Law	752.557	0.000	752.557	1861.135	1108.578	0.00	0.00	0.00	0.00	0.0000
Unitil X Spr	204.536	0.000	204.536	504.430	299.894	0.00	0.00	0.00	0.00	0.0000
AGT AIM	6453.297	192.070	6261.227	10950.000	4688.773	349.38	15043.03	0.00	15392.41	2.3852
AGT 93001EC	9050.030	86.468	8963.562	15467.350	6503.788	313.72	5296.06	0.00	5609.78	0.6199
AGT 93401	661.166	6.341	654.825	2076.850	1422.025	22.92	586.71	0.00	609.63	0.9221

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001F	1575.014	15.278	1559.737	6748.850	5189.113	54.59	1906.55	0.00	1961.14	1.2452
AGT Hubline	25.609	0.248	25.361	7300.000	7274.639	0.89	1679.02	0.00	1679.90	65.5970
AGT 510352	5384.403	51.585	5332.818	17520.000	12187.182	186.65	4949.40	0.00	5136.04	0.9539
AGT 93201 Ce	93.806	0.900	92.906	457.710	364.804	3.25	129.30	0.00	132.55	1.4131
AGT 93201 La	441.979	4.245	437.734	1545.775	1108.041	15.32	436.68	0.00	452.00	1.0227
AGT 94501	1271.568	12.209	1259.359	5386.670	4127.311	44.08	1521.73	0.00	1565.81	1.2314
TET 800414	62.935	0.906	62.029	385.440	323.411	3.70	92.37	0.00	96.07	1.5265
TET 800462	8081.909	155.173	7926.737	13274.685	5347.948	680.11	7787.10	0.00	8467.21	1.0477
TET 800382	510.522	7.352	503.170	1545.775	1042.605	30.04	370.43	0.00	400.47	0.7844
TET Stor Inj	1586.210	19.510	1566.699	364635.000	363068.301	65.49	0.00	0.00	65.49	0.0413
GSS Stor Inj	1488.738	18.311	1470.426	364635.000	363164.574	61.46	0.00	0.00	61.46	0.0413
GSS AMA Tran	745.948	10.742	735.207	2376.515	1641.308	43.89	0.00	0.00	43.89	0.0588
TRANSCO FT	185.283	0.945	184.338	457.710	273.372	3.27	58.53	0.00	61.80	0.3335
Total		991.367				3595.12	109530.76		113125.88	0.9617

Scenario 2246
EGMA 2021 F&SP - Base Case - Normal Weather - Draw 0

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Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	OCT 2022	Total
Forecast Demand													
Demand	4779.198	7533.842	8762.467	7354.141	6205.312	3395.627	1898.069	1262.160	1176.512	1176.512	1326.174	2859.654	47729.668
Total Demand	4779.198	7533.842	8762.467	7354.141	6205.312	3395.627	1898.069	1262.160	1176.512	1176.512	1326.174	2859.654	47729.668
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	88.424	153.414	166.389	144.343	111.948	69.974	39.148	27.395	35.513	35.576	32.956	63.929	969.007
Injection	0.000	0.000	0.000	0.000	0.000	1.162	15.964	15.517	11.812	16.035	15.517	15.651	91.658
Withdrawal	1.053	16.278	21.360	15.548	4.715	0.000	0.000	0.000	0.000	0.000	0.000	0.000	58.955
Total Fuel	89.477	169.692	187.750	159.891	116.663	71.136	55.111	42.912	47.325	51.611	48.473	79.579	1119.620
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	155.000	127.105	0.000	0.000	40.902	0.000	323.007
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.128	13.829	2.130	0.000	0.000	6.532	2.201	24.820
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.607	8.645	0.990	0.000	0.000	3.036	1.023	14.301
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	34.537	0.000	0.000	98.900	4.873	448.310
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	243.468	235.614	240.121	243.468	235.614	243.468	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	188.288	246.512	238.560	246.512	246.512	238.560	182.896	1587.840
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	308.140	298.200	299.180	308.140	298.200	308.140	1820.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	185.467	179.484	184.632	185.467	179.484	185.467	1100.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.778	10.038	9.714	10.038	10.038	9.714	10.038	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.512	243.398	251.512	251.512	243.398	251.512	1492.842
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	244.282	240.569	0.000	248.588	240.569	248.588	1222.594
Total Inj	0.000	0.000	0.000	0.000	0.000	192.801	1976.892	1610.302	1231.995	1493.724	1594.909	1438.205	9538.828
Total Req	4868.675	7703.534	8950.217	7514.032	6321.975	3659.564	3930.073	2915.374	2455.832	2721.847	2969.556	4377.438	58388.116
Sources of Supply													
Beverly	0.000	18.593	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	18.593
Centerville	844.023	745.913	837.285	665.870	1117.597	13.416	180.115	223.690	0.000	0.000	0.000	195.687	4823.595
Dawn	926.987	1527.131	1693.069	1945.138	739.016	587.485	558.000	540.000	548.986	558.000	540.000	494.000	10657.812
Dracut	0.000	5.917	0.000	0.000	0.000	0.000	0.000	348.667	0.000	0.000	374.743	0.000	729.328
Ellisburg	918.752	564.523	377.093	635.457	955.010	835.141	248.304	244.530	386.746	640.291	244.530	1113.107	7163.484
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	833.616	204.619	0.000	0.000	203.788	333.385	1575.408

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	OCT 2022	Total
Sources of Supply													
LNG Inject	0.000	0.000	0.000	0.000	0.000	0.735	487.474	164.763	0.000	0.000	149.370	8.097	810.439
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	451.989	467.055	467.055	421.856	467.055	451.989	467.055	451.989	467.055	467.055	451.989	467.055	5499.196
Niagara	308.622	318.909	318.909	288.047	318.909	308.622	191.301	185.130	318.909	318.909	185.130	318.909	3380.309
Ramapo	0.000	27.142	111.237	60.101	41.021	253.572	393.822	0.000	0.000	0.000	0.000	0.000	886.895
Repsol 30	0.000	146.701	369.520	201.438	269.341	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	80.451	169.094	142.932	171.523	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1076.364	1149.510	1149.510	1038.267	1141.668	971.470	517.995	501.286	681.746	685.202	769.307	1394.808	11077.132
TETCO M3	76.139	20.291	61.792	45.445	207.335	186.434	0.000	0.000	0.000	0.000	0.000	0.000	597.436
Waddington	0.000	3.532	17.661	7.064	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	28.258
Freepoint	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CLNG	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Direct	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	4602.875	5075.669	5572.225	5451.616	5428.477	3608.864	3877.683	2864.674	2403.442	2669.457	2918.856	4325.048	48798.884
Storage Withdrawals													
LNG Easton	12.514	12.931	141.771	55.458	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	344.958
LNG Lawrence	1.912	1.976	1.976	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	24.820
LNG Marshfld	0.835	0.863	3.898	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	14.301
LNG Spring	27.072	27.974	114.527	49.164	27.974	32.250	33.325	32.250	33.325	33.325	32.250	33.325	476.762
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	50.895	377.066	377.066	340.576	296.150	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	168.800	496.000	496.000	288.160	138.880	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1587.840
Enbridge 18	0.000	654.790	721.235	286.465	157.510	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1820.000
Nat Fuel FSS	3.772	301.228	310.000	265.060	219.940	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1100.000
TETCO FSS-1	0.000	9.752	25.344	23.337	4.927	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	345.477	598.937	516.081	32.347	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1492.842
TGP FSMA	0.000	399.807	587.237	235.550	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	265.800	2627.865	3377.992	2062.416	893.498	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9589.232
Total Supply	4868.675	7703.534	8950.217	7514.032	6321.975	3659.564	3930.073	2915.374	2455.832	2721.847	2969.556	4377.438	58388.116
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Scenario 2246
EGMA 2021 F&SP - Base Case - Normal Weather - Draw 0

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Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	OCT 2022	Total
Net Storage Inv. Adj.													
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	731.704	719.190	706.260	564.489	509.030	496.100	480.770	619.929	731.704	715.863	700.022	725.594	731.704
LNG Lawrence	11.628	9.716	7.739	5.763	3.978	2.002	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	6.787	5.924	2.026	1.246	0.383	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	948.413	921.341	893.367	778.839	729.675	701.701	669.451	946.126	948.413	915.088	881.763	948.413	948.413
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1390.858	1013.792	636.726	296.150	0.000	0.000	243.468	479.082	719.203	962.671	1198.285	1441.753
Enbridge 16	1600.000	1431.200	935.200	439.200	151.040	12.160	200.448	446.960	685.520	932.032	1178.544	1417.104	1600.000
Enbridge 18	1820.000	1820.000	1165.210	443.975	157.510	0.000	0.000	308.140	606.340	905.520	1213.660	1511.860	1820.000
Nat Fuel FSS	1100.000	1096.228	795.000	485.000	219.940	0.000	0.000	185.467	364.951	549.583	735.049	914.533	1100.000
TETCO FSS-1	63.360	63.360	53.608	28.264	4.927	0.000	3.778	13.816	23.531	33.569	43.607	53.322	63.360
TETCO SS-1	1588.950	1588.950	1243.473	644.535	128.454	96.108	96.108	347.619	591.017	842.529	1094.040	1337.438	1588.950
TGP FSMA	1222.594	1222.594	822.787	235.550	0.000	0.000	0.000	244.282	484.850	484.850	733.438	974.006	1222.594
Total Inv	10641.52	10375.72	7747.863	4369.871	2307.455	1413.956	1556.058	3480.560	5040.162	6219.766	7661.101	9205.310	10641.528
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	OCT 2023	Total
Forecast Demand													
Demand	4799.450	7565.614	8815.488	7386.751	6236.426	3419.676	1900.204	1257.592	1170.250	1170.250	1322.896	2880.414	47925.011
Total Demand	4799.450	7565.614	8815.488	7386.751	6236.426	3419.676	1900.204	1257.592	1170.250	1170.250	1322.896	2880.414	47925.011
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	88.759	153.819	166.901	144.694	113.051	70.359	39.146	27.365	35.371	35.434	32.894	64.119	971.912
Injection	0.000	0.000	0.000	0.000	0.000	1.162	15.964	15.517	11.812	16.035	15.517	15.651	91.658
Withdrawal	1.147	16.237	21.406	15.547	4.618	0.000	0.000	0.000	0.000	0.000	0.000	0.000	58.955
Total Fuel	89.906	170.056	188.307	160.240	117.669	71.521	55.110	42.883	47.183	51.469	48.411	79.770	1122.525
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	155.000	150.000	0.000	0.000	46.783	0.000	351.783
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.128	13.829	2.130	0.000	0.000	6.532	2.201	24.820
LNG Marshfld	0.835	0.142	0.000	0.780	0.863	0.990	8.645	0.990	0.000	0.000	3.036	1.023	17.304
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	71.357	0.000	0.000	98.900	4.873	485.130
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	243.468	235.614	240.121	243.468	235.614	243.468	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	188.288	246.512	238.560	246.512	246.512	238.560	182.896	1587.840
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	308.140	298.200	299.180	308.140	298.200	308.140	1820.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	185.467	179.484	184.632	185.467	179.484	185.467	1100.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.778	10.038	9.714	10.038	10.038	9.714	10.038	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.512	243.398	251.512	251.512	243.398	251.512	1492.842
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	244.282	240.569	0.000	248.588	240.569	248.588	1222.594
Total Inj	0.835	0.142	0.000	0.780	0.863	193.184	1976.892	1670.016	1231.995	1493.724	1600.791	1438.205	9607.427
Total Req	4890.191	7735.812	9003.795	7547.771	6354.958	3684.381	3932.206	2970.491	2449.427	2715.443	2972.098	4398.389	58654.963
Sources of Supply													
Beverly	0.000	20.196	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	20.196
Centerville	850.286	758.569	849.613	673.056	1123.161	14.943	183.196	220.935	0.000	0.000	0.000	205.222	4878.980
Dawn	927.936	1536.701	1699.596	1954.290	795.256	593.394	558.000	540.000	548.986	558.000	540.000	494.000	10746.159
Dracut	0.000	5.917	0.000	0.000	0.000	0.000	0.000	346.475	0.000	0.000	373.088	0.000	725.481
Ellisburg	918.923	564.523	377.093	635.457	955.080	835.381	248.304	244.530	384.329	637.874	244.530	1113.448	7159.473
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	833.775	204.970	0.000	0.000	204.184	341.579	1584.508

Scenario 2246
EGMA 2021 F&SP - Base Case - Normal Weather - Draw 0

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SENDOUT® Version 14.3.0 REP 13 29-Oct-2021
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Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	OCT 2023	Total
Sources of Supply													
LNG Inject	0.835	0.142	0.000	0.780	0.863	1.118	487.474	224.477	0.000	0.000	155.251	8.097	879.037
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	451.989	467.055	467.055	421.856	467.055	451.989	467.055	451.989	467.055	467.055	451.989	467.055	5499.196
Niagara	308.622	318.909	318.909	288.047	318.909	308.622	191.301	185.130	318.909	318.909	185.130	318.909	3380.309
Ramapo	0.000	28.524	116.117	61.567	43.571	257.878	392.716	0.000	0.000	0.000	0.000	0.000	900.373
Repsol 30	0.000	175.605	386.482	215.541	209.371	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	59.996	164.640	138.276	201.089	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1076.550	1149.510	1149.510	1038.267	1141.721	972.801	517.995	501.286	677.758	681.214	767.226	1397.688	11071.524
TETCO M3	80.503	20.908	62.893	46.772	214.411	197.555	0.000	0.000	0.000	0.000	0.000	0.000	623.042
Waddington	0.000	3.532	17.661	7.064	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	28.258
Freepoint	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CLNG	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Direct	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	4615.644	5110.088	5609.568	5480.973	5470.487	3633.681	3879.816	2919.791	2397.037	2663.053	2921.398	4345.999	49047.536
Storage Withdrawals													
LNG Easton	12.514	12.931	146.081	57.973	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	351.783
LNG Lawrence	1.912	1.976	1.976	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	24.820
LNG Marshfld	0.835	0.863	6.901	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	17.304
LNG Spring	27.072	28.248	120.481	51.304	27.974	32.250	33.325	32.250	33.325	33.325	32.250	33.325	485.130
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	50.752	377.066	377.066	340.576	296.292	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	168.800	496.000	496.000	288.160	138.880	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1587.840
Enbridge 18	0.000	654.194	721.831	286.465	157.510	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1820.000
Nat Fuel FSS	12.661	302.339	310.000	264.230	210.770	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1100.000
TETCO FSS-1	0.000	9.504	25.344	23.585	4.927	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	342.796	601.310	516.389	32.347	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1492.842
TGP FSMA	0.000	399.807	587.237	235.550	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	274.547	2625.724	3394.227	2066.797	884.471	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9607.427
Total Supply	4890.191	7735.812	9003.795	7547.771	6354.958	3684.381	3932.206	2970.491	2449.427	2715.443	2972.098	4398.389	58654.963
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	OCT 2023	Total
Net Storage Inv. Adj.													
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	709.753	697.239	684.309	538.228	480.254	467.324	451.994	591.153	725.823	709.982	694.141	725.594	709.753
LNG Lawrence	11.628	9.715	7.739	5.763	3.978	2.002	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	7.622	6.901	0.000	0.000	0.000	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	919.961	892.889	864.641	744.160	692.855	664.881	632.631	909.306	948.413	915.088	881.763	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1391.001	1013.934	636.868	296.292	0.000	0.000	243.468	479.082	719.203	962.671	1198.285	1441.753
Enbridge 16	1600.000	1431.200	935.200	439.200	151.040	12.160	200.448	446.960	685.520	932.032	1178.544	1417.104	1600.000
Enbridge 18	1820.000	1820.000	1165.806	443.975	157.510	0.000	0.000	308.140	606.340	905.520	1213.660	1511.860	1820.000
Nat Fuel FSS	1100.000	1087.339	785.000	475.000	210.770	0.000	0.000	185.467	364.951	549.583	735.049	914.533	1100.000
TETCO FSS-1	63.360	63.360	53.856	28.512	4.927	0.000	3.778	13.816	23.531	33.569	43.607	53.322	63.360
TETCO SS-1	1588.950	1588.950	1246.154	644.844	128.454	96.108	96.108	347.619	591.017	842.529	1094.040	1337.438	1588.950
TGP FSMA	1222.594	1222.594	822.787	235.550	0.000	0.000	0.000	244.282	484.850	484.850	733.438	974.006	1222.594
Total Inv	10591.12	10317.41	7691.831	4297.604	2231.586	1347.978	1490.462	3414.964	5034.281	6213.885	7655.219	9205.310	10591.124
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Scenario 2246
EGMA 2021 F&SP - Base Case - Normal Weather - Draw 0

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Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Forecast Demand													
Demand	4792.333	7572.470	8877.907	7632.154	6232.863	3459.363	1918.637	1267.784	1179.488	1179.488	1333.698	2923.907	48370.092
Total Demand	4792.333	7572.470	8877.907	7632.154	6232.863	3459.363	1918.637	1267.784	1179.488	1179.488	1333.698	2923.907	48370.092
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	88.429	153.908	167.514	149.902	113.035	71.044	39.351	27.441	35.602	35.665	33.130	64.568	979.590
Injection	0.000	0.000	0.000	0.000	0.000	1.162	15.964	15.517	11.812	16.035	15.517	15.651	91.658
Withdrawal	1.048	15.598	21.544	16.240	4.526	0.000	0.000	0.000	0.000	0.000	0.000	0.000	58.955
Total Fuel	89.477	169.506	189.058	166.142	117.561	72.206	55.314	42.959	47.414	51.700	48.648	80.219	1130.202
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	155.000	150.000	0.000	0.000	59.791	0.000	364.791
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.192	13.829	2.130	0.000	0.000	6.532	2.201	24.884
LNG Marshfld	0.835	0.863	2.696	0.807	0.863	0.990	8.645	0.990	0.000	0.000	3.036	1.023	20.749
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	77.544	0.000	0.000	98.900	4.873	491.316
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	243.468	235.614	240.121	243.468	235.614	243.468	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	188.288	246.512	238.560	246.512	246.512	238.560	182.896	1587.840
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	308.140	298.200	299.180	308.140	298.200	308.140	1820.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	185.467	179.484	184.632	185.467	179.484	185.467	1100.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.778	10.038	9.714	10.038	10.038	9.714	10.038	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.512	243.398	251.512	251.512	243.398	251.512	1492.842
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	244.282	240.569	0.000	248.588	240.569	248.588	1222.594
Total Inj	0.835	0.863	2.696	0.807	0.863	193.248	1976.892	1676.203	1231.995	1493.724	1613.799	1438.205	9630.130
Total Req	4882.645	7742.839	9069.661	7799.103	6351.287	3724.817	3950.843	2986.946	2458.896	2724.912	2996.144	4442.330	59130.425
Sources of Supply													
Beverly	0.000	20.196	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	20.196
Centerville	851.137	794.885	864.802	696.401	1124.342	16.781	193.365	228.535	0.000	0.000	0.000	219.621	4989.869
Dawn	935.916	1562.571	1695.990	2019.237	804.945	603.740	558.000	540.000	548.986	558.000	540.000	494.000	10861.385
Dracut	0.000	5.917	0.000	0.000	0.000	0.000	0.000	348.311	0.000	0.000	375.116	0.000	729.344
Ellisburg	918.807	584.278	366.306	657.596	955.104	836.975	248.304	244.530	386.620	640.165	244.530	1116.118	7199.333
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	838.592	205.802	0.000	0.000	205.062	359.780	1609.236

Scenario 2246
EGMA 2021 F&SP - Base Case - Normal Weather - Draw 0

Ventyx
SENDOUT® Version 14.3.0 REP 13 29-Oct-2021
Report 13 (Continued) 10:55:38

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Sources of Supply													
LNG Inject	0.835	0.863	2.696	0.807	0.863	1.182	487.474	230.664	0.000	0.000	168.259	8.097	901.741
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	451.989	467.055	467.055	436.922	467.055	451.989	467.055	451.989	467.055	467.055	451.989	467.055	5514.263
Niagara	308.622	318.909	318.909	298.335	318.909	308.622	191.301	185.130	318.909	318.909	185.130	318.909	3390.596
Ramapo	0.000	29.503	121.144	62.541	43.496	264.925	396.366	0.000	0.000	0.000	0.000	0.000	917.975
Repsol 30	0.000	165.989	373.583	236.242	211.187	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	66.991	191.625	111.975	193.409	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1077.196	1149.510	1149.510	1075.348	1141.903	977.310	517.995	501.286	684.936	688.392	775.358	1406.361	11145.104
TETCO M3	92.193	21.367	64.165	43.782	213.912	212.593	0.000	0.000	0.000	0.000	0.000	0.000	648.013
Waddington	0.000	3.532	17.754	7.064	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	28.351
Freepoint	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CLNG	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Direct	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	4636.695	5191.566	5633.538	5646.250	5475.125	3674.117	3898.453	2936.246	2406.506	2672.522	2945.444	4389.940	49506.405
Storage Withdrawals													
LNG Easton	12.514	12.931	151.037	59.916	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	358.681
LNG Lawrence	1.912	1.976	1.976	1.849	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	24.884
LNG Marshfld	0.835	0.863	10.318	0.807	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	20.749
LNG Spring	27.072	28.424	126.877	50.919	27.974	32.250	33.325	32.250	33.325	33.325	32.250	33.325	491.316
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	38.432	377.066	377.066	352.740	296.449	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	152.800	496.000	496.000	304.160	138.880	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1587.840
Enbridge 18	0.000	626.664	734.786	301.040	157.510	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1820.000
Nat Fuel FSS	12.385	302.615	310.000	273.400	201.600	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1100.000
TETCO FSS-1	0.000	8.448	25.344	23.936	5.632	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	316.233	604.694	539.568	32.347	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1492.842
TGP FSMA	0.000	380.052	598.023	244.519	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	245.950	2551.272	3436.123	2152.853	876.162	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9624.020
Total Supply	4882.645	7742.839	9069.661	7799.103	6351.287	3724.817	3950.843	2986.946	2458.896	2724.912	2996.144	4442.330	59130.425
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Net Storage Inv. Adj.													
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	709.753	697.239	684.309	533.272	473.356	460.426	445.096	584.255	718.925	703.084	687.243	731.704	709.753
LNG Lawrence	11.628	9.715	7.739	5.763	3.914	1.938	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	919.961	892.889	864.465	737.587	686.669	658.694	626.444	903.119	948.413	915.088	881.763	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1403.321	1026.255	649.188	296.449	0.000	0.000	243.468	479.082	719.203	962.671	1198.285	1441.753
Enbridge 16	1600.000	1447.200	951.200	455.200	151.040	12.160	200.448	446.960	685.520	932.032	1178.544	1417.104	1600.000
Enbridge 18	1820.000	1820.000	1193.336	458.550	157.510	0.000	0.000	308.140	606.340	905.520	1213.660	1511.860	1820.000
Nat Fuel FSS	1100.000	1087.615	785.000	475.000	201.600	0.000	0.000	185.467	364.951	549.583	735.049	914.533	1100.000
TETCO FSS-1	63.360	63.360	54.912	29.568	5.632	0.000	3.778	13.816	23.531	33.569	43.607	53.322	63.360
TETCO SS-1	1588.950	1588.950	1272.717	668.023	128.454	96.108	96.108	347.619	591.017	842.529	1094.040	1337.438	1588.950
TGP FSMA	1222.594	1222.594	842.542	244.519	0.000	0.000	0.000	244.282	484.850	484.850	733.438	974.006	1222.594
Total Inv	10591.12	10346.00	7795.600	4362.174	2210.128	1334.829	1477.377	3401.879	5027.383	6206.987	7648.321	9211.420	10591.124
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Forecast Demand													
Demand	4867.917	7720.701	8966.764	7530.733	6332.808	3495.607	1936.640	1278.642	1189.439	1189.439	1345.350	2955.585	48809.625
Total Demand	4867.917	7720.701	8966.764	7530.733	6332.808	3495.607	1936.640	1278.642	1189.439	1189.439	1345.350	2955.585	48809.625
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	89.585	155.752	168.324	146.407	116.421	71.668	39.518	27.508	35.822	35.884	33.338	64.886	985.114
Injection	0.000	0.000	0.000	0.000	0.000	1.162	15.964	15.517	11.812	16.035	15.517	15.651	91.658
Withdrawal	1.120	15.493	21.637	15.767	4.937	0.000	0.000	0.000	0.000	0.000	0.000	0.000	58.955
Total Fuel	90.706	171.245	189.961	162.174	121.357	72.831	55.482	43.026	47.633	51.919	48.855	80.537	1135.726
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	155.000	150.000	0.000	0.000	72.224	0.000	377.224
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.128	13.829	2.130	0.000	0.000	6.532	2.201	24.820
LNG Marshfld	0.835	0.863	6.900	0.780	0.863	0.990	8.645	0.990	0.000	0.000	3.036	1.023	24.925
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	98.386	0.000	0.000	98.900	4.873	512.159
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	243.468	235.614	240.121	243.468	235.614	243.468	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	188.288	246.512	238.560	246.512	246.512	238.560	182.896	1587.840
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	308.140	298.200	299.180	308.140	298.200	308.140	1820.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	185.467	179.484	184.632	185.467	179.484	185.467	1100.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.778	10.038	9.714	10.038	10.038	9.714	10.038	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.512	243.398	251.512	251.512	243.398	251.512	1492.842
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	244.282	240.569	0.000	248.588	240.569	248.588	1222.594
Total Inj	0.835	0.863	6.900	0.780	0.863	193.184	1976.892	1697.046	1231.995	1493.724	1626.232	1438.205	9667.518
Total Req	4959.458	7892.809	9163.625	7693.687	6455.028	3761.622	3969.014	3018.714	2469.067	2735.082	3020.437	4474.326	59612.869
Sources of Supply													
Beverly	0.000	20.196	1.078	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.274
Centerville	879.801	857.769	885.616	715.470	1146.952	18.240	201.105	234.743	0.000	0.000	0.000	228.852	5168.547
Dawn	950.114	1602.242	1707.252	1979.248	921.678	615.846	558.000	540.000	548.986	558.000	540.000	494.000	11015.366
Dracut	0.000	5.917	0.000	0.000	0.000	0.000	0.000	351.214	0.000	0.000	378.567	0.000	735.699
Ellisburg	920.024	564.523	377.093	635.457	955.526	839.071	248.304	244.530	390.888	644.433	244.530	1118.859	7183.239
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	846.087	207.615	0.000	0.000	206.475	373.774	1633.951

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Sources of Supply													
LNG Inject	0.835	0.863	6.900	0.780	0.863	1.118	487.474	251.506	0.000	0.000	180.692	8.097	939.128
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	451.989	467.055	467.055	421.856	467.055	451.989	467.055	451.989	467.055	467.055	451.989	467.055	5499.196
Niagara	308.622	318.909	318.909	288.047	318.909	308.622	191.301	185.130	318.909	318.909	185.130	318.909	3380.309
Ramapo	0.000	36.859	126.308	71.105	49.286	270.318	399.302	0.000	0.000	0.000	0.000	0.000	953.180
Repsol 30	0.000	179.028	389.657	247.945	170.370	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	86.797	193.097	135.297	148.809	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1079.987	1149.510	1149.510	1038.267	1138.102	980.937	517.995	501.286	690.838	694.294	782.354	1412.391	11135.471
TETCO M3	103.432	26.670	66.625	49.227	222.293	224.781	0.000	0.000	0.000	0.000	0.000	0.000	693.027
Waddington	0.000	3.532	19.256	7.064	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	29.853
Freepoint	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CLNG	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Direct	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	4694.803	5319.871	5708.357	5589.764	5539.844	3710.922	3916.624	2968.014	2416.677	2682.692	2969.737	4421.936	49939.241
Storage Withdrawals													
LNG Easton	12.514	14.891	162.032	71.613	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	383.334
LNG Lawrence	1.912	1.976	1.976	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	24.820
LNG Marshfld	0.835	0.863	14.522	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	24.925
LNG Spring	27.072	34.287	135.388	57.387	27.974	32.250	33.325	32.250	33.325	33.325	32.250	33.325	512.159
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	43.383	377.066	377.066	340.576	303.661	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	168.800	496.000	496.000	288.160	138.880	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1587.840
Enbridge 18	0.000	625.265	736.185	293.620	164.930	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1820.000
Nat Fuel FSS	10.138	304.862	310.000	264.230	210.770	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1100.000
TETCO FSS-1	0.000	8.448	25.344	23.936	5.632	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	309.472	609.517	526.286	47.567	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1492.842
TGP FSMA	0.000	399.807	587.237	235.550	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	264.655	2572.938	3455.268	2103.923	915.184	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9673.628
Total Supply	4959.458	7892.809	9163.625	7693.687	6455.028	3761.622	3969.014	3018.714	2469.067	2735.082	3020.437	4474.326	59612.869
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Net Storage Inv. Adj.													
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	715.863	703.349	688.459	526.427	454.813	441.883	426.553	565.712	700.382	684.541	668.700	725.594	715.863
LNG Lawrence	11.628	9.715	7.739	5.763	3.978	2.002	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	919.961	892.889	858.602	723.213	665.826	637.852	605.602	882.277	948.413	915.088	881.763	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1398.370	1021.304	644.237	303.661	0.000	0.000	243.468	479.082	719.203	962.671	1198.285	1441.753
Enbridge 16	1600.000	1431.200	935.200	439.200	151.040	12.160	200.448	446.960	685.520	932.032	1178.544	1417.104	1600.000
Enbridge 18	1820.000	1820.000	1194.735	458.550	164.930	0.000	0.000	308.140	606.340	905.520	1213.660	1511.860	1820.000
Nat Fuel FSS	1100.000	1089.862	785.000	475.000	210.770	0.000	0.000	185.467	364.951	549.583	735.049	914.533	1100.000
TETCO FSS-1	63.360	63.360	54.912	29.568	5.632	0.000	3.778	13.816	23.531	33.569	43.607	53.322	63.360
TETCO SS-1	1588.950	1588.950	1279.478	669.960	143.675	96.108	96.108	347.619	591.017	842.529	1094.040	1337.438	1588.950
TGP FSMA	1222.594	1222.594	822.787	235.550	0.000	0.000	0.000	244.282	484.850	484.850	733.438	974.006	1222.594
Total Inv	10597.23	10333.41	7761.340	4312.973	2209.829	1295.508	1437.992	3362.494	5008.840	6188.444	7629.778	9205.310	10597.235
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Forecast Demand													
Demand	4906.353	7792.840	9053.722	7602.193	6378.989	3525.226	1953.728	1284.880	1193.748	1193.748	1356.688	2987.672	49229.787
Total Demand	4906.353	7792.840	9053.722	7602.193	6378.989	3525.226	1953.728	1284.880	1193.748	1193.748	1356.688	2987.672	49229.787
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	90.165	156.563	169.177	147.292	118.161	72.168	39.663	27.550	35.918	35.981	33.492	65.237	991.367
Injection	0.000	0.000	0.000	0.000	0.000	1.162	15.964	15.517	11.812	16.035	15.517	15.651	91.658
Withdrawal	1.083	15.338	21.705	15.795	5.034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	58.955
Total Fuel	91.248	171.901	190.882	163.087	123.195	73.330	55.626	43.068	47.730	52.016	49.009	80.888	1141.980
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	155.000	150.000	0.000	0.000	98.251	0.000	403.251
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.128	13.829	2.130	0.000	0.000	6.532	2.201	24.820
LNG Marshfld	0.835	0.863	9.185	0.780	0.863	0.990	8.645	0.990	0.000	0.000	3.036	1.023	27.210
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	111.857	0.000	0.000	98.900	4.873	525.629
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	243.468	235.614	240.121	243.468	235.614	243.468	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	188.288	246.512	238.560	246.512	246.512	238.560	182.896	1587.840
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	308.140	298.200	299.180	308.140	298.200	308.140	1820.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	185.467	179.484	184.632	185.467	179.484	185.467	1100.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.778	10.038	9.714	10.038	10.038	9.714	10.038	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.512	243.398	251.512	251.512	243.398	251.512	1492.842
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	244.282	240.569	0.000	248.588	240.569	248.588	1222.594
Total Inj	0.835	0.863	9.185	0.780	0.863	193.184	1976.892	1710.516	1231.995	1493.724	1652.259	1438.205	9709.301
Total Req	4998.436	7965.604	9253.790	7766.059	6503.047	3791.740	3986.246	3038.464	2473.473	2739.488	3057.956	4506.765	60081.068
Sources of Supply													
Beverly	0.000	21.588	4.021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	25.609
Centerville	890.876	893.510	903.608	738.738	1156.879	19.713	209.686	238.740	0.000	0.000	0.000	242.121	5293.871
Dawn	971.270	1626.961	1718.142	1992.867	979.048	626.811	558.000	540.000	548.986	558.000	540.000	494.000	11154.085
Dracut	0.000	5.917	0.000	0.000	0.000	0.000	0.000	351.864	0.000	0.000	380.194	0.000	737.976
Ellisburg	920.736	564.523	377.093	635.457	955.662	840.357	248.304	244.530	392.614	646.159	244.530	1120.518	7190.483
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	852.871	209.248	0.000	0.000	211.375	384.715	1658.209

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Sources of Supply													
LNG Inject	0.835	0.863	9.185	0.780	0.863	1.118	487.474	264.977	0.000	0.000	206.719	8.097	980.911
LPG Inject	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Millennium	451.989	467.055	467.055	421.856	467.055	451.989	467.055	451.989	467.055	467.055	451.989	467.055	5499.196
Niagara	308.622	318.909	318.909	288.047	318.909	308.622	191.301	185.130	318.909	318.909	185.130	318.909	3380.309
Ramapo	0.000	40.085	132.144	78.764	52.074	274.060	401.170	0.000	0.000	0.000	0.000	0.000	978.297
Repsol 30	0.000	154.848	417.578	275.019	139.555	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	125.104	181.614	122.815	134.467	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1081.207	1149.510	1149.510	1038.267	1138.872	983.438	517.995	501.286	693.518	696.974	787.319	1418.961	11156.857
TETCO M3	111.771	29.762	70.181	49.227	235.307	234.932	0.000	0.000	0.000	0.000	0.000	0.000	731.181
Waddington	0.000	3.532	21.956	8.294	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	33.783
Freepoint	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CLNG	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Direct	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	4737.307	5402.168	5770.996	5650.132	5578.692	3741.040	3933.856	2987.764	2421.083	2687.098	3007.256	4454.375	50371.767
Storage Withdrawals													
LNG Easton	12.514	17.179	172.787	78.488	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	403.251
LNG Lawrence	1.912	1.976	1.976	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	24.820
LNG Marshfld	0.835	0.863	16.807	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	27.210
LNG Spring	27.072	35.822	144.087	60.624	27.974	32.250	33.325	32.250	33.325	33.325	32.250	33.325	525.629
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	43.383	377.066	377.066	340.576	303.661	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	168.800	496.000	496.000	288.160	138.880	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1587.840
Enbridge 18	0.000	624.000	737.450	293.620	164.930	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1820.000
Nat Fuel FSS	6.613	298.387	310.000	265.060	219.940	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1100.000
TETCO FSS-1	0.000	6.641	27.151	23.936	5.632	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	305.696	612.231	527.349	47.567	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1492.842
TGP FSMA	0.000	399.807	587.237	235.550	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	261.129	2563.436	3482.793	2115.927	924.354	50.700	52.390	50.700	52.390	52.390	50.700	52.390	9709.301
Total Supply	4998.436	7965.604	9253.790	7766.059	6503.047	3791.740	3986.246	3038.464	2473.473	2739.488	3057.956	4506.765	60081.068
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Net Storage Inv. Adj.													
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	709.753	697.239	680.061	507.274	428.786	415.856	400.526	539.685	674.355	658.514	642.673	725.594	709.753
LNG Lawrence	11.628	9.715	7.739	5.763	3.978	2.002	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	919.961	892.889	857.067	712.980	652.356	624.381	592.131	868.806	948.413	915.088	881.763	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1398.370	1021.304	644.237	303.661	0.000	0.000	243.468	479.082	719.203	962.671	1198.285	1441.753
Enbridge 16	1600.000	1431.200	935.200	439.200	151.040	12.160	200.448	446.960	685.520	932.032	1178.544	1417.104	1600.000
Enbridge 18	1820.000	1820.000	1196.000	458.550	164.930	0.000	0.000	308.140	606.340	905.520	1213.660	1511.860	1820.000
Nat Fuel FSS	1100.000	1093.387	795.000	485.000	219.940	0.000	0.000	185.467	364.951	549.583	735.049	914.533	1100.000
TETCO FSS-1	63.360	63.360	56.719	29.568	5.632	0.000	3.778	13.816	23.531	33.569	43.607	53.322	63.360
TETCO SS-1	1588.950	1588.950	1283.254	671.023	143.675	96.108	96.108	347.619	591.017	842.529	1094.040	1337.438	1588.950
TGP FSMA	1222.594	1222.594	822.787	235.550	0.000	0.000	0.000	244.282	484.850	484.850	733.438	974.006	1222.594
Total Inv	10591.12	10330.83	7768.257	4294.649	2179.501	1256.010	1398.494	3322.996	4982.813	6162.417	7603.751	9205.310	10591.124
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Scenario 2247
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NOV 2021 thru OCT 2022 Cost and Flow Summary Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	230067.	Injection Cost	204.42	Transportation Cost	3632.45	JAN 15, 2022	
Penalty Cost	0.00	Withdrawal Cost	237.16	Other Variable Cost	83.53	System Served	516.002
Other Variable Cost	0.00	Carrying Cost	0.00			System Unserved	0.000
		Other Variable Cost	0.00			Total	516.002
Total Variable	230067.	Total Variable	441.58	Total Variable	3715.98		
Demand/Reservation Co	9856450	Demand Cost	2780.79	Demand Cost	109530.		
Other Fixed Cost	0.00	Other Fixed Cost	3899.28	Other Fixed Cost	0.00		
Total Fixed	9856450	Total Fixed	6680.07	Total Fixed	109530.		
Sup Release Revenue	0.00	Sto Release Revenue	0.00	Cap Release Revenue	0.00		
Net Supply Cost	1.008e7	Net Storage Cost	7121.66	Net Trans Cost	113246.	Total Gas Cost	10206885.7
						Total Revenue	0.00
						Net Cost	10206885.7

Avg Cost of Served Demand 193.1 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 186.8 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	52836.687	0.000	52836.687	0.000	52836.687	52836.687	0.000	0.00	516.002	0.000
Total	52836.687	0.000	52836.687	0.000	52836.687	52836.687	0.000	0.00	516.002	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	107.057	364635.000	364527.943			14.0598	1505.20	0.00	1505.20	14.0598
Centerville	6239.595	364635.000	358395.405			5.6320	35141.48	0.00	35141.48	5.6320
Dawn	12147.139	364635.000	352487.861			4.5102	54785.77	0.00	54785.77	4.5102
Dracut	971.935	364635.000	363663.065			4.6701	4539.08	0.00	4539.08	4.6701
Ellisburg	7192.550	364635.000	357442.450			3.7973	27312.28	0.00	27312.28	3.7973
Hereford	1597.163	364635.000	363037.837			3.0384	4852.87	0.00	4852.87	3.0384
LNG Inject	1622.887	364635.000	363012.113			5.7115	9269.15	0.00	9269.15	5.7115
LPG Inject	21.000	364635.000	364614.000			12.0000	252.00	0.00	252.00	12.0000
Millennium	5499.196	364635.000	359135.804			3.3547	18448.07	0.00	18448.07	3.3547

NOV 2021 thru OCT 2022 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Niagara	3380.309	364635.000	361254.691			3.8066	12867.48	0.00	12867.48	3.8066
Ramapo	1325.546	364635.000	363309.454			5.0662	6715.51	0.00	6715.51	5.0662
Repsol 30	987.000	987.000	0.000			5.0598	4994.04	12993.53	17987.57	18.2245
Repsol 40	564.000	564.000	0.000			5.0659	2857.18	5568.65	8425.83	14.9394
TETCO M2	11087.774	364635.000	353547.226			3.5295	39134.11	0.00	39134.11	3.5295
TETCO M3	1153.125	364635.000	363481.875			5.2834	6092.42	0.00	6092.42	5.2834
Waddington	91.000	364635.000	364544.000			13.2566	1206.36	0.00	1206.36	13.2566
Freepoint	5.000	50.000	45.000			18.5555	92.78	693600.00	693692.78	138738.555
CLNG	0.238	360.000	359.762			5.8685	1.40	5242788.00	5242789.40	22028526.8
Direct	0.000	450.000	450.000			0.0000	0.00	3901500.00	3901500.00	0.0000
Total	53992.514						230067.16	9856450.18	10086517.3	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	754.399	758.345	0.000	0.000	727.758	99	0.000	-3.946	4285.22	4143.75	-141.47
LNG Lawrence	11.628	100	41.168	41.168	0.000	0.000	11.628	100	0.000	0.000	68.10	70.98	2.88
LNG Marshfld	7.622	100	47.783	47.783	0.000	0.000	7.622	100	0.000	0.000	44.64	64.17	19.53
LNG Spring	948.413	100	779.538	807.990	0.000	0.000	919.961	97	0.000	-28.452	5554.38	5260.04	-294.35
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	158.62	158.62	0.00
LPG Meadow	70.749	100	21.000	21.000	0.000	0.000	70.749	100	0.000	0.000	861.04	857.47	-3.58
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	264.37	264.37	0.00
DTI GSS TET	1441.753	100	1470.426	1441.753	0.000	28.673	1441.753	100	0.000	0.000	3624.13	4110.38	486.25
Enbridge 16	1600.000	100	1600.322	1590.720	0.000	9.602	1600.000	100	9.544	0.000	3245.28	5651.36	2406.08
Enbridge 18	1820.000	100	1830.986	1820.000	0.000	10.986	1820.000	100	10.920	0.000	3642.37	6412.55	2770.19
Nat Fuel FSS	1100.000	100	1111.734	1099.950	0.000	11.784	1100.000	100	11.659	0.000	3161.73	3626.19	464.46
TETCO FSS-1	63.360	100	63.787	63.360	0.000	0.427	63.360	100	0.425	0.000	168.49	181.64	13.15
TETCO SS-1	1588.950	100	1502.912	1492.842	0.000	10.070	1588.950	100	26.423	0.000	3470.90	4454.46	983.55
TGP FSMA	1222.594	100	1242.726	1222.594	0.000	20.132	1222.594	100	0.000	0.000	3359.93	3791.06	431.13
Total	10641.528	100	10466.781	10407.50	0.000	91.675	10609.129	100	58.972	-32.399	31909.20	39047.0	7137.82

NOV 2021 thru OCT 2022 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2633.541	32.656	2600.885	5840.000	3239.115	4.42	4290.74	0.00	4295.16	1.6309
TCPL 63398	2205.717	14.337	2191.379	9512.630	7321.251	3.73	3389.68	0.00	3393.40	1.5385
TCPL 64198	7205.258	89.345	7115.913	21836.855	14720.942	12.10	12995.00	0.00	13007.10	1.8052
Union 12292	7122.476	46.296	7076.180	21735.750	14659.570	12.03	2254.21	0.00	2266.24	0.3182
Union 12204	2350.070	15.275	2334.795	9618.480	7283.685	3.97	997.53	0.00	1001.50	0.4262
PNG 233301 D	192.608	0.539	192.069	3407.500	3215.431	0.21	2594.70	0.00	2594.91	13.4725
PNG 233301 U	1473.360	4.125	1469.235	1812.000	342.765	1.62	1395.00	0.00	1396.62	0.9479
PNG 208535 D	3893.391	0.000	3893.391	8577.500	4684.109	4.28	6556.50	0.00	6560.78	1.6851
PNG 208535 H	3562.516	0.000	3562.516	8030.000	4467.484	3.92	6138.00	0.00	6141.92	1.7240
PNG 208540	2192.086	0.000	2192.086	5840.000	3647.914	2.41	3504.00	0.00	3506.41	1.5996
IGT RTS	2282.380	2.282	2280.097	10526.600	8246.503	10.26	1811.97	0.00	1822.23	0.7984
N Fuel FST I	1127.177	15.442	1111.734	3650.000	2538.266	18.01	543.29	0.00	561.30	0.4980
N Fuel FST W	1088.291	14.910	1073.381	3650.000	2576.619	17.39	0.00	0.00	17.39	0.0160
MLP 217524	5499.196	24.196	5475.000	5475.000	0.000	22.45	3558.20	0.00	3580.65	0.6511
TGP 95349	735.609	6.326	729.283	3567.510	2838.227	56.23	738.41	0.00	794.64	1.0802
TGP 5173	3361.579	41.011	3320.568	4653.020	1332.452	336.37	2883.03	0.00	3219.41	0.9577
TGP 5293	2738.558	33.410	2705.148	4579.655	1874.507	274.03	1078.72	0.00	1352.75	0.4940
TGP 5196	2145.661	26.177	2119.484	5611.875	3492.391	214.70	1321.85	0.00	1536.55	0.7161
TGP 5196 Wth	1072.280	0.000	1072.280	2007.500	935.220	1.18	0.00	0.00	1.18	0.0011
TGP 5291 Sup	2252.415	0.000	2252.415	2252.415	0.000	2.48	0.00	0.00	2.48	0.0011
TGP 5291 5-6	1117.864	9.614	1108.250	2252.415	1144.165	85.45	466.21	0.00	551.66	0.4935
TGP 5291 NF	1134.551	7.375	1127.177	2252.415	1125.238	70.56	0.00	0.00	70.56	0.0622
TGP Pool Law	4006.564	0.000	4006.564	13726.920	9720.356	0.00	0.00	0.00	0.00	0.0000
TGP Pool Spr	5976.169	0.000	5976.169	16214.760	10238.591	0.00	0.00	0.00	0.00	0.0000
TGP 39741	1127.894	9.700	1118.194	1489.565	371.371	86.21	308.31	0.00	394.53	0.3498
TGP 41098	1544.489	13.283	1531.206	6837.545	5306.339	118.06	1415.25	0.00	1533.30	0.9928
TGP 98775	1348.597	2.697	1345.900	2226.500	880.600	44.55	2008.20	0.00	2052.75	1.5221
TGP 330904 L	3562.516	7.125	3555.391	8030.000	4474.609	117.68	3463.81	0.00	3581.50	1.0053
TGP 330904 S	7223.930	14.448	7209.482	27156.000	19946.518	238.63	0.00	0.00	238.63	0.0330
TGP 48427	227.953	0.456	227.497	6205.000	5977.503	7.53	5596.62	0.00	5604.15	24.5847
TGP 362252	227.497	0.455	227.042	5110.000	4882.958	7.52	364.64	0.00	372.16	1.6359
TGP to AGT	350.275	0.000	350.275	2190.000	1839.725	0.00	0.00	0.00	0.00	0.0000
Unitil X Bro	511.433	0.000	511.433	1999.105	1487.672	0.00	0.00	0.00	0.00	0.0000
Unitil X Law	751.884	0.000	751.884	1861.135	1109.251	0.00	0.00	0.00	0.00	0.0000
Unitil X Spr	205.918	0.000	205.918	504.430	298.512	0.00	0.00	0.00	0.00	0.0000
AGT AIM	6800.546	204.216	6596.330	10950.000	4353.670	368.08	15043.03	0.00	15411.11	2.2662
AGT 93001EC	9266.523	88.566	9177.958	15467.350	6289.392	321.23	5296.06	0.00	5617.29	0.6062
AGT 93401	655.304	6.299	649.005	2076.850	1427.845	22.72	586.71	0.00	609.42	0.9300

NOV 2021 thru OCT 2022 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001F	1531.206	14.853	1516.353	6748.850	5232.497	53.07	1906.55	0.00	1959.62	1.2798
AGT Hubline	107.057	1.038	106.018	7300.000	7193.982	3.71	1679.02	0.00	1682.73	15.7181
AGT 510352	6302.379	60.491	6241.888	17520.000	11278.112	218.47	4949.40	0.00	5167.86	0.8200
AGT 93201 Ce	121.554	1.170	120.384	457.710	337.326	4.21	129.30	0.00	133.52	1.0984
AGT 93201 La	439.788	4.232	435.556	1545.775	1110.219	15.24	436.68	0.00	451.93	1.0276
AGT 94501	1417.315	13.620	1403.695	5386.670	3982.975	49.13	1521.73	0.00	1570.86	1.1083
TET 800414	62.935	0.906	62.029	385.440	323.411	3.70	92.37	0.00	96.07	1.5265
TET 800462	8012.827	153.846	7858.981	13274.685	5415.704	674.30	7787.10	0.00	8461.40	1.0560
TET 800382	512.355	7.378	504.977	1545.775	1040.798	30.15	370.43	0.00	400.57	0.7818
TET Stor Inj	1586.210	19.510	1566.699	364635.000	363068.301	65.49	0.00	0.00	65.49	0.0413
GSS Stor Inj	1488.738	18.311	1470.426	364635.000	363164.574	61.46	0.00	0.00	61.46	0.0413
GSS AMA Tran	744.115	10.715	733.400	2376.515	1643.115	43.78	0.00	0.00	43.78	0.0588
TRANSCO FT	185.283	0.945	184.338	457.710	273.372	3.27	58.53	0.00	61.80	0.3335
Total		1037.580				3715.98	109530.76		113246.74	0.9156

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NOV 2022 thru OCT 2023 Cost and Flow Summary Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	231856.	Injection Cost	204.42	Transportation Cost	3639.12	JAN 15, 2023	
Penalty Cost	0.00	Withdrawal Cost	237.16	Other Variable Cost	83.73	System Served	519.569
Other Variable Cost	0.00	Carrying Cost	0.00			System Unserved	0.000
		Other Variable Cost	0.00			Total	519.569
Total Variable	231856.	Total Variable	441.58	Total Variable	3722.85		
Demand/Reservation Co	9856450	Demand Cost	2780.79	Demand Cost	109530.		
Other Fixed Cost	0.00	Other Fixed Cost	3899.28	Other Fixed Cost	0.00		
Total Fixed	9856450	Total Fixed	6680.07	Total Fixed	109530.		
Sup Release Revenue	0.00	Sto Release Revenue	0.00	Cap Release Revenue	0.00		
Net Supply Cost	1.008e7	Net Storage Cost	7121.66	Net Trans Cost	113253.	Total Gas Cost	10208682.2
						Total Revenue	0.00
						Net Cost	10208682.2

Avg Cost of Served Demand 192.3 USD/DT (System Cost/Served Dem.)

Avg Cost of Gas Purchased 185.9 USD/DT (Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	53068.783	0.000	53068.783	0.000	53068.783	53068.783	0.000	0.00	519.569	0.000
Total	53068.783	0.000	53068.783	0.000	53068.783	53068.783	0.000	0.00	519.569	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	115.469	364635.000	364519.531			14.1206	1630.49	0.00	1630.49	14.1206
Centerville	6277.935	364635.000	358357.065			5.6293	35340.46	0.00	35340.46	5.6293
Dawn	12194.464	364635.000	352440.536			4.5111	55010.31	0.00	55010.31	4.5111
Dracut	1006.199	364635.000	363628.801			4.9420	4972.62	0.00	4972.62	4.9420
Ellisburg	7188.675	364635.000	357446.325			3.7977	27300.07	0.00	27300.07	3.7977
Hereford	1606.739	364635.000	363028.261			3.0387	4882.40	0.00	4882.40	3.0387
LNG Inject	1706.549	364635.000	362928.451			5.7170	9756.33	0.00	9756.33	5.7170
LPG Inject	21.000	364635.000	364614.000			12.0000	252.00	0.00	252.00	12.0000
Millennium	5499.196	364635.000	359135.804			3.3547	18448.07	0.00	18448.07	3.3547

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NOV 2022 thru OCT 2023 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Niagara	3380.309	364635.000	361254.691			3.8066	12867.48	0.00	12867.48	3.8066
Ramapo	1344.893	364635.000	363290.107			5.0805	6832.77	0.00	6832.77	5.0805
Repsol 30	987.000	987.000	0.000			5.0651	4999.25	12993.53	17992.78	18.2298
Repsol 40	564.000	564.000	0.000			5.0565	2851.89	5568.65	8420.54	14.9300
TETCO M2	11082.132	364635.000	353552.868			3.5299	39118.79	0.00	39118.79	3.5299
TETCO M3	1188.741	364635.000	363446.259			5.2634	6256.77	0.00	6256.77	5.2634
Waddington	92.715	364635.000	364542.285			13.2767	1230.95	0.00	1230.95	13.2767
Freepoint	5.000	50.000	45.000			18.5555	92.78	693600.00	693692.78	138738.555
CLNG	2.282	360.000	357.718			5.8685	13.39	5242788.00	5242801.39	2297458.97
Direct	0.000	450.000	450.000			0.0000	0.00	3901500.00	3901500.00	0.0000
Total	54263.298						231856.82	9856450.18	10088307.0	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	727.758	99	780.841	776.895	0.000	0.000	731.704	100	0.000	3.946	4143.75	4158.60	14.85
LNG Lawrence	11.628	100	44.005	44.005	0.000	0.000	11.628	100	0.000	0.000	70.98	70.98	-0.00
LNG Marshfld	7.622	100	52.470	52.470	0.000	0.000	7.622	100	0.000	0.000	64.17	74.68	10.51
LNG Spring	919.961	97	829.233	829.233	0.000	0.000	919.961	97	0.000	0.000	5260.04	5223.18	-36.85
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	158.62	158.62	0.00
LPG Meadow	70.749	100	21.000	21.000	0.000	0.000	70.749	100	0.000	0.000	857.47	854.95	-2.52
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	264.37	264.37	0.00
DTI GSS TET	1441.753	100	1470.426	1441.753	0.000	28.673	1441.753	100	0.000	0.000	4110.38	4110.38	0.00
Enbridge 16	1600.000	100	1600.322	1590.720	0.000	9.602	1600.000	100	9.544	0.000	5651.36	5665.31	13.96
Enbridge 18	1820.000	100	1830.986	1820.000	0.000	10.986	1820.000	100	10.920	0.000	6412.55	6412.55	0.00
Nat Fuel FSS	1100.000	100	1111.734	1099.950	0.000	11.784	1100.000	100	11.659	0.000	3626.19	3626.21	0.02
TETCO FSS-1	63.360	100	63.787	63.360	0.000	0.427	63.360	100	0.425	0.000	181.64	181.64	0.00
TETCO SS-1	1588.950	100	1502.912	1492.842	0.000	10.070	1588.950	100	26.423	0.000	4454.46	4513.95	59.49
TGP FSMA	1222.594	100	1242.726	1222.594	0.000	20.132	1222.594	100	0.000	0.000	3791.06	3791.06	0.00
Total	10609.129	100	10550.443	10454.82	0.000	91.675	10613.076	100	58.972	3.946	39047.02	39106.4	59.45

NOV 2022 thru OCT 2023 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2635.963	32.686	2603.277	5840.000	3236.723	4.43	4290.74	0.00	4295.16	1.6294
TCPL 63398	2215.272	14.399	2200.873	9512.630	7311.757	3.74	3389.68	0.00	3393.42	1.5318
TCPL 64198	7240.314	89.780	7150.534	21836.855	14686.321	12.16	12995.00	0.00	13007.15	1.7965
Union 12292	7064.494	45.919	7018.575	21735.750	14717.175	11.93	2254.21	0.00	2266.14	0.3208
Union 12204	2452.956	15.944	2437.011	9618.480	7181.469	4.14	997.53	0.00	1001.67	0.4084
PNG 233301 D	195.902	0.549	195.353	3407.500	3212.147	0.21	2594.70	0.00	2594.91	13.2460
PNG 233301 U	1474.658	4.129	1470.529	1812.000	341.471	1.62	1395.00	0.00	1396.62	0.9471
PNG 208535 D	3908.715	0.000	3908.715	8577.500	4668.785	4.30	6556.50	0.00	6560.80	1.6785
PNG 208535 H	3564.486	0.000	3564.486	8030.000	4465.514	3.92	6138.00	0.00	6141.92	1.7231
PNG 208540	2216.789	0.000	2216.789	5840.000	3623.211	2.44	3504.00	0.00	3506.44	1.5818
IGT RTS	2293.588	2.294	2291.294	10526.600	8235.306	10.31	1811.97	0.00	1822.28	0.7945
N Fuel FST I	1127.177	15.442	1111.734	3650.000	2538.266	18.01	543.29	0.00	561.30	0.4980
N Fuel FST W	1088.291	14.910	1073.381	3650.000	2576.619	17.39	0.00	0.00	17.39	0.0160
MLP 217524	5499.196	24.196	5475.000	5475.000	0.000	22.45	3558.20	0.00	3580.65	0.6511
TGP 95349	744.822	6.405	738.416	3567.510	2829.094	56.93	738.41	0.00	795.34	1.0678
TGP 5173	3363.802	41.038	3322.763	4653.020	1330.257	336.60	2883.03	0.00	3219.63	0.9571
TGP 5293	2731.805	33.328	2698.477	4579.655	1881.178	273.36	1078.72	0.00	1352.07	0.4949
TGP 5196	2146.317	26.185	2120.132	5611.875	3491.743	214.77	1321.85	0.00	1536.62	0.7159
TGP 5196 Wth	1072.936	0.000	1072.936	2007.500	934.564	1.18	0.00	0.00	1.18	0.0011
TGP 5291 Sup	2252.415	0.000	2252.415	2252.415	0.000	2.48	0.00	0.00	2.48	0.0011
TGP 5291 5-6	1117.864	9.614	1108.250	2252.415	1144.165	85.45	466.21	0.00	551.66	0.4935
TGP 5291 NF	1134.551	7.375	1127.177	2252.415	1125.238	70.56	0.00	0.00	70.56	0.0622
TGP Pool Law	4071.006	0.000	4071.006	13726.920	9655.914	0.00	0.00	0.00	0.00	0.0000
TGP Pool Spr	5917.032	0.000	5917.032	16214.760	10297.728	0.00	0.00	0.00	0.00	0.0000
TGP 39741	1127.894	9.700	1118.194	1489.565	371.371	86.21	308.31	0.00	394.53	0.3498
TGP 41098	1546.472	13.300	1533.173	6837.545	5304.372	118.21	1415.25	0.00	1533.46	0.9916
TGP 98775	1392.024	2.784	1389.240	2226.500	837.260	45.98	2008.20	0.00	2054.18	1.4757
TGP 330904 L	3564.486	7.129	3557.357	8030.000	4472.643	117.75	3463.81	0.00	3581.56	1.0048
TGP 330904 S	7251.550	14.503	7237.047	27156.000	19918.953	239.55	0.00	0.00	239.55	0.0330
TGP 48427	234.482	0.469	234.013	6205.000	5970.987	7.75	5596.62	0.00	5604.36	23.9010
TGP 362252	234.013	0.468	233.545	5110.000	4876.455	7.73	364.64	0.00	372.37	1.5913
TGP to AGT	349.709	0.000	349.709	2190.000	1840.291	0.00	0.00	0.00	0.00	0.0000
Unitil X Bro	512.364	0.000	512.364	1999.105	1486.741	0.00	0.00	0.00	0.00	0.0000
Unitil X Law	750.865	0.000	750.865	1861.135	1110.270	0.00	0.00	0.00	0.00	0.0000
Unitil X Spr	207.300	0.000	207.300	504.430	297.130	0.00	0.00	0.00	0.00	0.0000
AGT AIM	6819.893	204.850	6615.043	10950.000	4334.957	369.12	15043.03	0.00	15412.15	2.2599
AGT 93001EC	9167.025	87.588	9079.436	15467.350	6387.914	317.78	5296.06	0.00	5613.84	0.6124
AGT 93401	716.896	6.883	710.013	2076.850	1366.837	24.85	586.71	0.00	611.56	0.8531

NOV 2022 thru OCT 2023 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001F	1533.173	14.872	1518.301	6748.850	5230.549	53.14	1906.55	0.00	1959.69	1.2782
AGT Hubline	115.469	1.120	114.349	7300.000	7185.651	4.00	1679.02	0.00	1683.02	14.5755
AGT 510352	6333.292	60.784	6272.509	17520.000	11247.491	219.54	4949.40	0.00	5168.93	0.8162
AGT 93201 Ce	128.980	1.242	127.738	457.710	329.972	4.47	129.30	0.00	133.77	1.0372
AGT 93201 La	474.226	4.563	469.663	1545.775	1076.112	16.44	436.68	0.00	453.12	0.9555
AGT 94501	1450.867	13.970	1436.897	5386.670	3949.773	50.29	1521.73	0.00	1572.02	1.0835
TET 800414	62.935	0.906	62.029	385.440	323.411	3.70	92.37	0.00	96.07	1.5265
TET 800462	8007.185	153.738	7853.447	13274.685	5421.238	673.83	7787.10	0.00	8460.92	1.0567
TET 800382	515.222	7.419	507.803	1545.775	1037.972	30.32	370.43	0.00	400.74	0.7778
TET Stor Inj	1586.210	19.510	1566.699	364635.000	363068.301	65.49	0.00	0.00	65.49	0.0413
GSS Stor Inj	1488.738	18.311	1470.426	364635.000	363164.574	61.46	0.00	0.00	61.46	0.0413
GSS AMA Tran	741.248	10.674	730.574	2376.515	1645.941	43.62	0.00	0.00	43.62	0.0588
TRANSCO FT	185.283	0.945	184.338	457.710	273.372	3.27	58.53	0.00	61.80	0.3335
Total		1039.923				3722.85	109530.76		113253.61	0.9131

Scenario 2247 | Ventyx
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NOV 2023 thru OCT 2024 — Cost and Flow Summary — Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	234308.	Injection Cost	204.42	Transportation Cost	3665.94	JAN 15, 2024	
Penalty Cost	0.00	Withdrawal Cost	237.16	Other Variable Cost	84.34	System Served	523.237
Other Variable Cost	0.00	Carrying Cost	0.00			System Unserved	0.000
		Other Variable Cost	0.00			Total	523.237
Total Variable	234308.	Total Variable	441.58	Total Variable	3750.28		
Demand/Reservation Co	9856450	Demand Cost	2780.79	Demand Cost	109530.		
Other Fixed Cost	0.00	Other Fixed Cost	3899.28	Other Fixed Cost	0.00		
Total Fixed	9856450	Total Fixed	6680.07	Total Fixed	109530.		
Sup Release Revenue	0.00	Sto Release Revenue	0.00	Cap Release Revenue	0.00		
Net Supply Cost	1.009e7	Net Storage Cost	7121.66	Net Trans Cost	113281.	Total Gas Cost	10211161.1
						Total Revenue	0.00
						Net Cost	10211161.1

Avg Cost of Served Demand 190.6 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 184.3 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	53553.320	0.000	53553.320	0.000	53553.320	53553.320	0.000	0.00	523.237	0.000
Total	53553.320	0.000	53553.320	0.000	53553.320	53553.320	0.000	0.00	523.237	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	124.033	365634.000	365509.967			14.3477	1779.58	0.00	1779.58	14.3477
Centerville	6375.550	365634.000	359258.450			5.6283	35883.45	0.00	35883.45	5.6283
Dawn	12303.081	365634.000	353330.919			4.5144	55541.53	0.00	55541.53	4.5144
Dracut	1012.448	365634.000	364621.552			4.9691	5030.93	0.00	5030.93	4.9691
Ellisburg	7228.719	365634.000	358405.281			3.8006	27473.81	0.00	27473.81	3.8006
Hereford	1632.445	365634.000	364001.555			3.0393	4961.50	0.00	4961.50	3.0393
LNG Inject	1738.172	365634.000	363895.828			5.7206	9943.46	0.00	9943.46	5.7206
LPG Inject	21.000	365634.000	365613.000			12.0000	252.00	0.00	252.00	12.0000
Millennium	5514.263	365634.000	360119.737			3.3574	18513.42	0.00	18513.42	3.3574

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Niagara	3390.596	365634.000	362243.404			3.8093	12915.83	0.00	12915.83	3.8093
Ramapo	1366.803	365634.000	364267.197			5.0854	6950.78	0.00	6950.78	5.0854
Repsol 30	987.000	987.000	0.000			5.0642	4998.34	12993.53	17991.87	18.2288
Repsol 40	564.000	564.000	0.000			5.0597	2853.69	5568.65	8422.34	14.9332
TETCO M2	11155.548	365634.000	354478.452			3.5304	39384.00	0.00	39384.00	3.5304
TETCO M3	1235.301	365634.000	364398.699			5.2342	6465.85	0.00	6465.85	5.2342
Waddington	93.416	365634.000	365540.584			13.2918	1241.67	0.00	1241.67	13.2918
Freepoint	5.000	50.000	45.000			18.5555	92.78	693600.00	693692.78	138738.555
CLNG	4.365	360.000	355.635			5.8685	25.62	5242788.00	5242813.62	1201102.77
Direct	0.000	450.000	450.000			0.0000	0.00	3901500.00	3901500.00	0.0000
Total	54751.740						234308.24	9856450.18	10090758.4	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	795.456	795.456	0.000	0.000	731.704	100	0.000	0.000	4158.60	4158.82	0.23
LNG Lawrence	11.628	100	47.062	47.062	0.000	0.000	11.628	100	0.000	0.000	70.98	95.63	24.65
LNG Marshfld	7.622	100	54.225	54.225	0.000	0.000	7.622	100	0.000	0.000	74.68	74.58	-0.10
LNG Spring	919.961	97	841.429	841.429	0.000	0.000	919.961	97	0.000	0.000	5223.18	5214.66	-8.52
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	158.62	158.62	0.00
LPG Meadow	70.749	100	21.000	21.000	0.000	0.000	70.749	100	0.000	0.000	854.95	853.18	-1.77
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	264.37	264.37	0.00
DTI GSS TET	1441.753	100	1470.426	1441.753	0.000	28.673	1441.753	100	0.000	0.000	4110.38	4110.38	0.00
Enbridge 16	1600.000	100	1600.322	1590.720	0.000	9.602	1600.000	100	9.544	0.000	5665.31	5665.39	0.08
Enbridge 18	1820.000	100	1830.986	1820.000	0.000	10.986	1820.000	100	10.920	0.000	6412.55	6412.55	0.00
Nat Fuel FSS	1100.000	100	1111.734	1099.950	0.000	11.784	1100.000	100	11.659	0.000	3626.21	3626.21	0.00
TETCO FSS-1	63.360	100	63.787	63.360	0.000	0.427	63.360	100	0.425	0.000	181.64	181.64	0.00
TETCO SS-1	1588.950	100	1502.912	1492.842	0.000	10.070	1588.950	100	26.423	0.000	4513.95	4517.54	3.60
TGP FSMA	1222.594	100	1242.726	1222.594	0.000	20.132	1222.594	100	0.000	0.000	3791.06	3791.06	0.00
Total	10613.076	100	10582.066	10490.39	0.000	91.675	10613.076	100	58.972	0.000	39106.47	39124.6	18.17

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2655.242	32.925	2622.317	5856.000	3233.683	4.46	4290.74	0.00	4295.20	1.6176
TCPL 63398	2240.367	14.562	2225.805	9538.692	7312.887	3.78	3389.68	0.00	3393.46	1.5147
TCPL 64198	7303.976	90.569	7213.407	21896.682	14683.275	12.26	12995.00	0.00	13007.26	1.7808
Union 12292	7332.662	47.662	7285.000	21795.300	14510.300	12.38	2254.21	0.00	2266.59	0.3091
Union 12204	2274.125	14.782	2259.343	9644.832	7385.489	3.84	997.53	0.00	1001.37	0.4403
PNG 233301 D	196.875	0.551	196.324	3409.800	3213.476	0.22	2594.70	0.00	2594.92	13.1805
PNG 233301 U	1486.398	4.162	1482.236	1824.000	341.764	1.63	1395.00	0.00	1396.63	0.9396
PNG 208535 D	3954.091	0.000	3954.091	8601.000	4646.909	4.35	6556.50	0.00	6560.85	1.6593
PNG 208535 H	3662.774	0.000	3662.774	8052.000	4389.226	4.03	6138.00	0.00	6142.03	1.6769
PNG 208540	2168.031	0.000	2168.031	5856.000	3687.969	2.38	3504.00	0.00	3506.38	1.6173
IGT RTS	2319.221	2.319	2316.901	10555.440	8238.539	10.43	1811.97	0.00	1822.40	0.7858
N Fuel FST I	1127.177	15.442	1111.734	3660.000	2548.266	18.01	543.29	0.00	561.30	0.4980
N Fuel FST W	1088.291	14.910	1073.381	3660.000	2586.619	17.39	0.00	0.00	17.39	0.0160
MLP 217524	5514.263	24.263	5490.000	5490.000	0.000	22.51	3558.20	0.00	3580.71	0.6494
TGP 95349	752.539	6.472	746.067	3577.284	2831.217	57.52	738.41	0.00	795.93	1.0577
TGP 5173	3366.319	41.069	3325.250	4665.768	1340.518	336.85	2883.03	0.00	3219.88	0.9565
TGP 5293	2761.959	33.696	2728.263	4592.202	1863.939	276.37	1078.72	0.00	1355.09	0.4906
TGP 5196	2153.690	26.275	2127.415	5627.250	3499.835	215.51	1321.85	0.00	1537.36	0.7138
TGP 5196 Wth	1080.309	0.000	1080.309	2013.000	932.691	1.19	0.00	0.00	1.19	0.0011
TGP 5291 Sup	2258.586	0.000	2258.586	2258.586	0.000	2.48	0.00	0.00	2.48	0.0011
TGP 5291 5-6	1124.035	9.667	1114.368	2258.586	1144.218	85.92	466.21	0.00	552.13	0.4912
TGP 5291 NF	1134.551	7.375	1127.177	2258.586	1131.409	70.56	0.00	0.00	70.56	0.0622
TGP Pool Law	4040.377	0.000	4040.377	13764.528	9724.151	0.00	0.00	0.00	0.00	0.0000
TGP Pool Spr	6000.985	0.000	6000.985	16259.184	10258.199	0.00	0.00	0.00	0.00	0.0000
TGP 39741	1132.010	9.735	1122.275	1493.646	371.371	86.53	308.31	0.00	394.84	0.3488
TGP 41098	1564.363	13.454	1550.909	6856.278	5305.369	119.58	1415.25	0.00	1534.82	0.9811
TGP 98775	1366.494	2.733	1363.761	2232.600	868.839	45.14	2008.20	0.00	2053.34	1.5026
TGP 330904 L	3662.774	7.326	3655.449	8052.000	4396.551	121.00	3463.81	0.00	3584.81	0.9787
TGP 330904 S	7280.923	14.562	7266.361	27230.400	19964.039	240.52	0.00	0.00	240.52	0.0330
TGP 48427	234.477	0.469	234.008	6222.000	5987.992	7.75	5596.62	0.00	5604.36	23.9015
TGP 362252	234.008	0.468	233.540	5124.000	4890.460	7.73	364.64	0.00	372.37	1.5913
TGP to AGT	354.743	0.000	354.743	2196.000	1841.257	0.00	0.00	0.00	0.00	0.0000
Unitil X Bro	517.778	0.000	517.778	2004.582	1486.804	0.00	0.00	0.00	0.00	0.0000
Unitil X Law	757.158	0.000	757.158	1866.234	1109.076	0.00	0.00	0.00	0.00	0.0000
Unitil X Spr	207.300	0.000	207.300	505.812	298.512	0.00	0.00	0.00	0.00	0.0000
AGT AIM	6856.803	206.052	6650.750	10980.000	4329.250	371.11	15043.03	0.00	15414.14	2.2480
AGT 93001EC	9442.001	90.224	9351.776	15518.982	6167.206	327.31	5296.06	0.00	5623.37	0.5956
AGT 93401	632.153	6.071	626.082	2082.540	1456.458	21.91	586.71	0.00	608.62	0.9628

NOV 2023 thru OCT 2024 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001F	1550.909	15.044	1535.865	6767.340	5231.475	53.76	1906.55	0.00	1960.30	1.2640
AGT Hubline	124.033	1.203	122.829	7320.000	7197.171	4.30	1679.02	0.00	1683.32	13.5716
AGT 510352	6428.421	61.692	6366.729	17568.000	11201.271	222.84	4949.40	0.00	5172.23	0.8046
AGT 93201 Ce	129.393	1.247	128.146	458.964	330.818	4.49	129.30	0.00	133.79	1.0340
AGT 93201 La	464.774	4.472	460.302	1550.010	1089.708	16.11	436.68	0.00	452.79	0.9742
AGT 94501	1390.707	13.388	1377.319	5401.428	4024.109	48.21	1521.73	0.00	1569.94	1.1289
TET 800414	62.935	0.906	62.029	386.496	324.467	3.70	92.37	0.00	96.07	1.5265
TET 800462	8080.601	155.148	7925.453	13311.054	5385.601	680.00	7787.10	0.00	8467.10	1.0478
TET 800382	505.589	7.280	498.309	1550.010	1051.701	29.75	370.43	0.00	400.18	0.7915
TET Stor Inj	1586.210	19.510	1566.699	365634.000	364067.301	65.49	0.00	0.00	65.49	0.0413
GSS Stor Inj	1488.738	18.311	1470.426	365634.000	364163.574	61.46	0.00	0.00	61.46	0.0413
GSS AMA Tran	752.965	10.843	742.122	2383.026	1640.904	44.30	0.00	0.00	44.30	0.0588
TRANSCO FT	183.199	0.934	182.264	458.964	276.700	3.23	58.53	0.00	61.76	0.3371
Total		1047.773				3750.28	109530.76		113281.04	0.9063

NOV 2024 thru OCT 2025 — Cost and Flow Summary — Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	237867.	Injection Cost	204.42	Transportation Cost	3678.97	JAN 15, 2025	
Penalty Cost	0.00	Withdrawal Cost	237.16	Other Variable Cost	84.76	System Served	528.583
Other Variable Cost	0.00	Carrying Cost	0.00			System Unserved	0.000
		Other Variable Cost	0.00			Total	528.583
Total Variable	237867.	Total Variable	441.58	Total Variable	3763.73		
Demand/Reservation Co	9856450	Demand Cost	2780.79	Demand Cost	109530.		
Other Fixed Cost	0.00	Other Fixed Cost	3899.28	Other Fixed Cost	0.00		
Total Fixed	9856450	Total Fixed	6680.07	Total Fixed	109530.		
Sup Release Revenue	0.00	Sto Release Revenue	0.00	Cap Release Revenue	0.00		
Net Supply Cost	1.009e7	Net Storage Cost	7121.66	Net Trans Cost	113294.	Total Gas Cost	10214733.3
						Total Revenue	0.00
						Net Cost	10214733.3

Avg Cost of Served Demand 189.0 USD/DT (System Cost/Served Dem.)

Avg Cost of Gas Purchased 182.7 USD/DT (Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	54046.018	0.000	54046.018	0.000	54046.018	54046.018	0.000	0.00	528.583	0.000
Total	54046.018	0.000	54046.018	0.000	54046.018	54046.018	0.000	0.00	528.583	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	157.411	364635.000	364477.589			14.3862	2264.54	0.00	2264.54	14.3862
Centerville	6454.181	364635.000	358180.819			5.6106	36211.55	0.00	36211.55	5.6106
Dawn	12328.969	364635.000	352306.031			4.5132	55642.55	0.00	55642.55	4.5132
Dracut	1132.088	364635.000	363502.912			5.6394	6384.33	0.00	6384.33	5.6394
Ellisburg	7211.579	364635.000	357423.421			3.7958	27373.52	0.00	27373.52	3.7958
Hereford	1657.799	364635.000	362977.201			3.0397	5039.24	0.00	5039.24	3.0397
LNG Inject	1842.401	364635.000	362792.599			5.7266	10550.76	0.00	10550.76	5.7266
LPG Inject	21.000	364635.000	364614.000			12.0000	252.00	0.00	252.00	12.0000
Millennium	5499.196	364635.000	359135.804			3.3547	18448.07	0.00	18448.07	3.3547

NOV 2024 thru OCT 2025 | Cost and Flow Summary | Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Niagara	3380.309	364635.000	361254.691			3.8066	12867.48	0.00	12867.48	3.8066
Ramapo	1423.594	364635.000	363211.406			5.1118	7277.06	0.00	7277.06	5.1118
Repsol 30	987.000	987.000	0.000			5.0656	4999.75	12993.53	17993.27	18.2303
Repsol 40	564.000	564.000	0.000			5.0553	2851.16	5568.65	8419.82	14.9288
TETCO M2	11149.735	364635.000	353485.265			3.5252	39304.57	0.00	39304.57	3.5252
TETCO M3	1327.551	364635.000	363307.449			5.2421	6959.22	0.00	6959.22	5.2421
Waddington	98.686	364635.000	364536.314			13.2114	1303.78	0.00	1303.78	13.2114
Freepoint	5.000	50.000	45.000			18.5555	92.78	693600.00	693692.78	138738.555
CLNG	7.614	360.000	352.386			5.8685	44.68	5242788.00	5242832.68	688577.972
Direct	0.000	450.000	450.000			0.0000	0.00	3901500.00	3901500.00	0.0000
Total	55248.113						237867.03	9856450.18	10094317.2	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	844.419	844.419	0.000	0.000	731.704	100	0.000	0.000	4158.82	4163.00	4.17
LNG Lawrence	11.628	100	50.970	50.970	0.000	0.000	11.628	100	0.000	0.000	95.63	95.59	-0.03
LNG Marshfld	7.622	100	56.814	56.814	0.000	0.000	7.622	100	0.000	0.000	74.58	74.72	0.13
LNG Spring	919.961	97	890.198	890.198	0.000	0.000	919.961	97	0.000	0.000	5214.66	5213.90	-0.75
LPG Lawrence	13.033	100	0.000	0.000	0.000	0.000	13.033	100	0.000	0.000	158.62	158.62	0.00
LPG Meadow	70.749	100	21.000	21.000	0.000	0.000	70.749	100	0.000	0.000	853.18	851.94	-1.24
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	264.37	264.37	0.00
DTI GSS TET	1441.753	100	1470.426	1441.753	0.000	28.673	1441.753	100	0.000	0.000	4110.38	4110.38	0.00
Enbridge 16	1600.000	100	1600.322	1590.720	0.000	9.602	1600.000	100	9.544	0.000	5665.39	5665.39	0.00
Enbridge 18	1820.000	100	1830.986	1820.000	0.000	10.986	1820.000	100	10.920	0.000	6412.55	6412.55	0.00
Nat Fuel FSS	1100.000	100	1111.734	1099.950	0.000	11.784	1100.000	100	11.659	0.000	3626.21	3626.21	0.00
TETCO FSS-1	63.360	100	63.787	63.360	0.000	0.427	63.360	100	0.425	0.000	181.64	181.64	0.00
TETCO SS-1	1588.950	100	1502.912	1492.842	0.000	10.070	1588.950	100	26.423	0.000	4517.54	4517.76	0.22
TGP FSMA	1222.594	100	1242.726	1222.594	0.000	20.132	1222.594	100	0.000	0.000	3791.06	3791.06	0.00
Total	10613.076	100	10686.295	10594.62	0.000	91.675	10613.076	100	58.972	0.000	39124.64	39127.1	2.50

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2646.327	32.814	2613.513	5840.000	3226.487	4.44	4290.74	0.00	4295.18	1.6231
TCPL 63398	2250.293	14.627	2235.666	9512.630	7276.964	3.80	3389.68	0.00	3393.48	1.5080
TCPL 64198	7328.626	90.875	7237.751	21836.855	14599.104	12.30	12995.00	0.00	13007.30	1.7749
Union 12292	7139.509	46.407	7093.102	21735.750	14642.648	12.06	2254.21	0.00	2266.26	0.3174
Union 12204	2502.081	16.264	2485.817	9618.480	7132.663	4.23	997.53	0.00	1001.75	0.4004
PNG 233301 D	199.548	0.559	198.989	3407.500	3208.511	0.22	2594.70	0.00	2594.92	13.0040
PNG 233301 U	1478.566	4.140	1474.426	1812.000	337.574	1.62	1395.00	0.00	1396.62	0.9446
PNG 208535 D	3865.130	0.000	3865.130	8577.500	4712.370	4.25	6556.50	0.00	6560.75	1.6974
PNG 208535 H	3781.906	0.000	3781.906	8030.000	4248.094	4.16	6138.00	0.00	6142.16	1.6241
PNG 208540	2183.913	0.000	2183.913	5840.000	3656.087	2.40	3504.00	0.00	3506.40	1.6056
IGT RTS	2334.351	2.334	2332.017	10526.600	8194.583	10.49	1811.97	0.00	1822.47	0.7807
N Fuel FST I	1127.177	15.442	1111.734	3650.000	2538.266	18.01	543.29	0.00	561.30	0.4980
N Fuel FST W	1088.291	14.910	1073.381	3650.000	2576.619	17.39	0.00	0.00	17.39	0.0160
MLP 217524	5499.196	24.196	5475.000	5475.000	0.000	22.45	3558.20	0.00	3580.65	0.6511
TGP 95349	772.905	6.647	766.258	3567.510	2801.252	59.08	738.41	0.00	797.49	1.0318
TGP 5173	3389.235	41.349	3347.886	4653.020	1305.134	339.14	2883.03	0.00	3222.17	0.9507
TGP 5293	2725.706	33.254	2692.453	4579.655	1887.202	272.75	1078.72	0.00	1351.46	0.4958
TGP 5196	2149.886	26.229	2123.657	5611.875	3488.218	215.13	1321.85	0.00	1536.98	0.7149
TGP 5196 Wth	1076.505	0.000	1076.505	2007.500	930.995	1.18	0.00	0.00	1.18	0.0011
TGP 5291 Sup	2252.415	0.000	2252.415	2252.415	0.000	2.48	0.00	0.00	2.48	0.0011
TGP 5291 5-6	1117.864	9.614	1108.250	2252.415	1144.165	85.45	466.21	0.00	551.66	0.4935
TGP 5291 NF	1134.551	7.375	1127.177	2252.415	1125.238	70.56	0.00	0.00	70.56	0.0622
TGP Pool Law	3993.972	0.000	3993.972	13726.920	9732.948	0.00	0.00	0.00	0.00	0.0000
TGP Pool Spr	6044.532	0.000	6044.532	16214.760	10170.228	0.00	0.00	0.00	0.00	0.0000
TGP 39741	1127.894	9.700	1118.194	1489.565	371.371	86.21	308.31	0.00	394.53	0.3498
TGP 41098	1559.112	13.408	1545.704	6837.545	5291.841	119.17	1415.25	0.00	1534.42	0.9842
TGP 98775	1430.450	2.861	1427.589	2226.500	798.911	47.25	2008.20	0.00	2055.45	1.4369
TGP 330904 L	3781.906	7.564	3774.342	8030.000	4255.658	124.93	3463.81	0.00	3588.74	0.9489
TGP 330904 S	7244.602	14.489	7230.113	27156.000	19925.887	239.32	0.00	0.00	239.32	0.0330
TGP 48427	256.068	0.512	255.556	6205.000	5949.444	8.46	5596.62	0.00	5605.08	21.8890
TGP 362252	255.556	0.511	255.045	5110.000	4854.955	8.44	364.64	0.00	373.09	1.4599
TGP to AGT	358.236	0.000	358.236	2190.000	1831.764	0.00	0.00	0.00	0.00	0.0000
Unitil X Bro	514.838	0.000	514.838	1999.105	1484.267	0.00	0.00	0.00	0.00	0.0000
Unitil X Law	752.288	0.000	752.288	1861.135	1108.847	0.00	0.00	0.00	0.00	0.0000
Unitil X Spr	207.300	0.000	207.300	504.430	297.130	0.00	0.00	0.00	0.00	0.0000
AGT AIM	6898.594	207.395	6691.199	10950.000	4258.801	373.37	15043.03	0.00	15416.40	2.2347
AGT 93001EC	9441.445	90.206	9351.238	15467.350	6116.112	327.29	5296.06	0.00	5623.35	0.5956
AGT 93401	684.757	6.582	678.174	2076.850	1398.676	23.74	586.71	0.00	610.45	0.8915

NOV 2024 thru OCT 2025 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001F	1545.704	14.993	1530.711	6748.850	5218.139	53.57	1906.55	0.00	1960.12	1.2681
AGT Hubline	157.411	1.527	155.884	7300.000	7144.116	5.46	1679.02	0.00	1684.47	10.7011
AGT 510352	6505.773	62.428	6443.345	17520.000	11076.655	225.52	4949.40	0.00	5174.91	0.7954
AGT 93201 Ce	132.746	1.276	131.471	457.710	326.239	4.60	129.30	0.00	133.90	1.0087
AGT 93201 La	480.623	4.620	476.003	1545.775	1069.772	16.66	436.68	0.00	453.34	0.9432
AGT 94501	1407.304	13.540	1393.764	5386.670	3992.906	48.78	1521.73	0.00	1570.51	1.1160
TET 800414	62.935	0.906	62.029	385.440	323.411	3.70	92.37	0.00	96.07	1.5265
TET 800462	8074.788	155.036	7919.752	13274.685	5354.933	679.51	7787.10	0.00	8466.61	1.0485
TET 800382	502.955	7.243	495.713	1545.775	1050.062	29.59	370.43	0.00	400.02	0.7953
TET Stor Inj	1586.210	19.510	1566.699	364635.000	363068.301	65.49	0.00	0.00	65.49	0.0413
GSS Stor Inj	1488.738	18.311	1470.426	364635.000	363164.574	61.46	0.00	0.00	61.46	0.0413
GSS AMA Tran	753.515	10.851	742.664	2376.515	1633.851	44.34	0.00	0.00	44.34	0.0588
TRANSCO FT	185.283	0.945	184.338	457.710	273.372	3.27	58.53	0.00	61.80	0.3335
Total		1051.449				3763.73	109530.76		113294.50	0.9029

NOV 2025 thru OCT 2026 | Cost and Flow Summary | Units: MDT, USD (000)

Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod	
Commodity Cost	241326.	Injection Cost	204.42	Transportation Cost	3697.63	JAN 15, 2026	
Penalty Cost	0.00	Withdrawal Cost	237.16	Other Variable Cost	85.26	System Served	533.975
Other Variable Cost	0.00	Carrying Cost	0.00			System Unserved	0.000
		Other Variable Cost	0.00			Total	533.975
Total Variable	241326.	Total Variable	441.58	Total Variable	3782.89		
Demand/Reservation Co	9856450	Demand Cost	2780.79	Demand Cost	109530.		
Other Fixed Cost	0.00	Other Fixed Cost	3899.28	Other Fixed Cost	0.00		
Total Fixed	9856450	Total Fixed	6680.07	Total Fixed	109530.		
Sup Release Revenue	0.00	Sto Release Revenue	0.00	Cap Release Revenue	0.00		
Net Supply Cost	1.009e7	Net Storage Cost	7121.66	Net Trans Cost	113313.	Total Gas Cost	10218211.5
						Total Revenue	0.00
						Net Cost	10218211.5

Avg Cost of Served Demand 187.4 USD/DT
(System Cost/Served Dem.)

Avg Cost of Gas Purchased 181.2 USD/DT
(Supply Cost/LDC Purchase)

Demand Summary

Class	Demand Before DSM	DSM Impact	Net Demand	Imbal. Served	Demand After Unb.	Served	Unserved	Revenue	Peak Served	Peak Unserved
Demand	54519.772	0.000	54519.772	0.000	54519.772	54519.772	0.000	0.00	533.975	0.000
Total	54519.772	0.000	54519.772	0.000	54519.772	54519.772	0.000	0.00	533.975	0.000

Supply Summary

Source	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Beverly	210.457	364635.000	364424.543			14.8681	3129.09	0.00	3129.09	14.8681
Centerville	6533.967	364635.000	358101.033			5.6027	36607.58	0.00	36607.58	5.6027
Dawn	12399.994	364635.000	352235.006			4.5143	55976.90	0.00	55976.90	4.5143
Dracut	1197.004	364635.000	363437.996			5.9572	7130.75	0.00	7130.75	5.9572
Ellisburg	7218.268	364635.000	357416.732			3.7953	27395.16	0.00	27395.16	3.7953
Hereford	1682.672	364635.000	362952.328			3.0397	5114.78	0.00	5114.78	3.0397
LNG Inject	1892.373	364635.000	362742.627			5.7336	10850.07	0.00	10850.07	5.7336
LPG Inject	24.117	364635.000	364610.883			12.0000	289.40	0.00	289.40	12.0000
Millennium	5499.196	364635.000	359135.804			3.3547	18448.07	0.00	18448.07	3.3547

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Supply Summary

Source (cont)	Total Take	Max Take	Surplus	Take Under Daily Min	Take Under Other Min	Av Comm Cost	Total Var Cost	Total Fix Cost	Net Cost	Average Net Cost
Niagara	3380.309	364635.000	361254.691			3.8066	12867.48	0.00	12867.48	3.8066
Ramapo	1457.193	364635.000	363177.807			5.1296	7474.85	0.00	7474.85	5.1296
Repsol 30	987.000	987.000	0.000			5.0644	4998.59	12993.53	17992.11	18.2291
Repsol 40	564.000	564.000	0.000			5.0574	2852.35	5568.65	8421.01	14.9309
TETCO M2	11170.388	364635.000	353464.612			3.5237	39360.80	0.00	39360.80	3.5237
TETCO M3	1390.560	364635.000	363244.440			5.2387	7284.77	0.00	7284.77	5.2387
Waddington	103.983	364635.000	364531.017			13.0396	1355.90	0.00	1355.90	13.0396
Freepoint	5.000	50.000	45.000			18.5555	92.78	693600.00	693692.78	138738.555
CLNG	8.000	360.000	352.000			5.8685	46.95	5242788.00	5242834.95	655354.368
Direct	2.839	450.000	447.161			17.5555	49.84	3901500.00	3901549.84	1374269.05
Total	55727.321						241326.10	9856450.18	10097776.2	

Storage Summary

Storage	Starting Balance	% Full	Total Inj.	Total With.	NetInv Adj.	Inj Fuel	Final Balance	% Full	With. Fuel	Diff in Balance	Start Value	Final Value	Diff in Value
LNG Easton	731.704	100	853.989	853.989	0.000	0.000	731.704	100	0.000	0.000	4163.00	4163.00	0.00
LNG Lawrence	11.628	100	54.347	54.347	0.000	0.000	11.628	100	0.000	0.000	95.59	95.63	0.04
LNG Marshfld	7.622	100	57.721	57.721	0.000	0.000	7.622	100	0.000	0.000	74.72	74.67	-0.05
LNG Spring	919.961	97	926.316	926.316	0.000	0.000	919.961	97	0.000	0.000	5213.90	5214.71	0.80
LPG Lawrence	13.033	100	1.823	1.823	0.000	0.000	13.033	100	0.000	0.000	158.62	158.31	-0.31
LPG Meadow	70.749	100	22.294	22.294	0.000	0.000	70.749	100	0.000	0.000	851.94	851.02	-0.91
LPG NHampton	21.722	100	0.000	0.000	0.000	0.000	21.722	100	0.000	0.000	264.37	264.37	0.00
DTI GSS TET	1441.753	100	1470.426	1441.753	0.000	28.673	1441.753	100	0.000	0.000	4110.38	4110.38	0.00
Enbridge 16	1600.000	100	1600.322	1590.720	0.000	9.602	1600.000	100	9.544	0.000	5665.39	5665.39	0.00
Enbridge 18	1820.000	100	1830.986	1820.000	0.000	10.986	1820.000	100	10.920	0.000	6412.55	6412.55	0.00
Nat Fuel FSS	1100.000	100	1111.734	1099.950	0.000	11.784	1100.000	100	11.659	0.000	3626.21	3626.21	0.00
TETCO FSS-1	63.360	100	63.787	63.360	0.000	0.427	63.360	100	0.425	0.000	181.64	181.64	0.00
TETCO SS-1	1588.950	100	1502.912	1492.842	0.000	10.070	1588.950	100	26.423	0.000	4517.76	4517.78	0.01
TGP FSMA	1222.594	100	1242.726	1222.594	0.000	20.132	1222.594	100	0.000	0.000	3791.06	3791.06	0.00
Total	10613.076	100	10739.384	10647.70	0.000	91.675	10613.076	100	58.972	0.000	39127.14	39126.7	-0.42

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
TCPL 63397	2651.541	32.879	2618.662	5840.000	3221.338	4.45	4290.74	0.00	4295.19	1.6199
TCPL 63398	2266.685	14.733	2251.952	9512.630	7260.678	3.83	3389.68	0.00	3393.50	1.4971
TCPL 64198	7377.618	91.482	7286.135	21836.855	14550.720	12.39	12995.00	0.00	13007.39	1.7631
Union 12292	7283.722	47.344	7236.377	21735.750	14499.373	12.30	2254.21	0.00	2266.51	0.3112
Union 12204	2423.679	15.754	2407.925	9618.480	7210.555	4.09	997.53	0.00	1001.62	0.4133
PNG 233301 D	202.905	0.568	202.337	3407.500	3205.163	0.22	2594.70	0.00	2594.92	12.7888
PNG 233301 U	1479.421	4.142	1475.279	1812.000	336.721	1.62	1395.00	0.00	1396.62	0.9440
PNG 208535 D	3986.611	0.000	3986.611	8577.500	4590.889	4.39	6556.50	0.00	6560.89	1.6457
PNG 208535 H	3730.753	0.000	3730.753	8030.000	4299.247	4.10	6138.00	0.00	6142.10	1.6463
PNG 208540	2187.779	0.000	2187.779	5840.000	3652.221	2.41	3504.00	0.00	3506.41	1.6027
IGT RTS	2355.935	2.356	2353.579	10526.600	8173.021	10.59	1811.97	0.00	1822.56	0.7736
N Fuel FST I	1127.177	15.442	1111.734	3650.000	2538.266	18.01	543.29	0.00	561.30	0.4980
N Fuel FST W	1088.291	14.910	1073.381	3650.000	2576.619	17.39	0.00	0.00	17.39	0.0160
MLP 217524	5499.196	24.196	5475.000	5475.000	0.000	22.45	3558.20	0.00	3580.65	0.6511
TGP 95349	787.042	6.769	780.273	3567.510	2787.237	60.16	738.41	0.00	798.57	1.0146
TGP 5173	3391.925	41.381	3350.543	4653.020	1302.477	339.41	2883.03	0.00	3222.44	0.9500
TGP 5293	2728.686	33.290	2695.396	4579.655	1884.259	273.04	1078.72	0.00	1351.76	0.4954
TGP 5196	2150.907	26.241	2124.665	5611.875	3487.210	215.23	1321.85	0.00	1537.08	0.7146
TGP 5196 Wth	1077.526	0.000	1077.526	2007.500	929.974	1.19	0.00	0.00	1.19	0.0011
TGP 5291 Sup	2252.415	0.000	2252.415	2252.415	0.000	2.48	0.00	0.00	2.48	0.0011
TGP 5291 5-6	1117.864	9.614	1108.250	2252.415	1144.165	85.45	466.21	0.00	551.66	0.4935
TGP 5291 NF	1134.551	7.375	1127.177	2252.415	1125.238	70.56	0.00	0.00	70.56	0.0622
TGP Pool Law	4115.277	0.000	4115.277	13726.920	9611.643	0.00	0.00	0.00	0.00	0.0000
TGP Pool Spr	5943.851	0.000	5943.851	16214.760	10270.909	0.00	0.00	0.00	0.00	0.0000
TGP 39741	1127.894	9.700	1118.194	1489.565	371.371	86.21	308.31	0.00	394.53	0.3498
TGP 41098	1566.537	13.472	1553.065	6837.545	5284.480	119.74	1415.25	0.00	1534.99	0.9799
TGP 98775	1433.135	2.866	1430.269	2226.500	796.231	47.34	2008.20	0.00	2055.54	1.4343
TGP 330904 L	3730.753	7.462	3723.291	8030.000	4306.709	123.24	3463.81	0.00	3587.05	0.9615
TGP 330904 S	7422.728	14.845	7407.883	27156.000	19748.117	245.20	0.00	0.00	245.20	0.0330
TGP 48427	268.868	0.538	268.330	6205.000	5936.670	8.88	5596.62	0.00	5605.50	20.8485
TGP 362252	268.330	0.537	267.793	5110.000	4842.207	8.86	364.64	0.00	373.51	1.3920
TGP to AGT	366.836	0.000	366.836	2190.000	1823.164	0.00	0.00	0.00	0.00	0.0000
Unitil X Bro	514.838	0.000	514.838	1999.105	1484.267	0.00	0.00	0.00	0.00	0.0000
Unitil X Law	754.523	0.000	754.523	1861.135	1106.612	0.00	0.00	0.00	0.00	0.0000
Unitil X Spr	205.918	0.000	205.918	504.430	298.512	0.00	0.00	0.00	0.00	0.0000
AGT AIM	6932.193	208.499	6723.694	10950.000	4226.306	375.18	15043.03	0.00	15418.21	2.2241
AGT 93001EC	9287.224	88.730	9198.494	15467.350	6268.856	321.95	5296.06	0.00	5618.01	0.6049
AGT 93401	761.639	7.306	754.333	2076.850	1322.517	26.40	586.71	0.00	613.11	0.8050

NOV 2025 thru OCT 2026 Cost and Flow Summary Units: MDT, USD (000)

Transportation Summary

Segment (cont)	Total Flow	Fuel Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Cap Rel Revenue	Net Cost	Average Net Cost
AGT 93001F	1553.065	15.065	1538.000	6748.850	5210.850	53.83	1906.55	0.00	1960.38	1.2623
AGT Hubline	210.457	2.041	208.416	7300.000	7091.584	7.29	1679.02	0.00	1686.31	8.0126
AGT 510352	6575.854	63.093	6512.761	17520.000	11007.239	227.95	4949.40	0.00	5177.34	0.7873
AGT 93201 Ce	142.452	1.370	141.082	457.710	316.628	4.94	129.30	0.00	134.24	0.9424
AGT 93201 La	511.714	4.920	506.794	1545.775	1038.981	17.74	436.68	0.00	454.42	0.8880
AGT 94501	1536.817	14.783	1522.034	5386.670	3864.636	53.27	1521.73	0.00	1575.00	1.0248
TET 800414	62.935	0.906	62.029	385.440	323.411	3.70	92.37	0.00	96.07	1.5265
TET 800462	8095.441	155.432	7940.008	13274.685	5334.677	681.25	7787.10	0.00	8468.35	1.0461
TET 800382	510.522	7.352	503.170	1545.775	1042.605	30.04	370.43	0.00	400.47	0.7844
TET Stor Inj	1586.210	19.510	1566.699	364635.000	363068.301	65.49	0.00	0.00	65.49	0.0413
GSS Stor Inj	1488.738	18.311	1470.426	364635.000	363164.574	61.46	0.00	0.00	61.46	0.0413
GSS AMA Tran	745.948	10.742	735.207	2376.515	1641.308	43.89	0.00	0.00	43.89	0.0588
TRANSCO FT	185.283	0.945	184.338	457.710	273.372	3.27	58.53	0.00	61.80	0.3335
Total		1056.903				3782.89	109530.76		113313.65	0.8978

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Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	OCT 2022	Total
Forecast Demand													
Demand	5265.763	8381.122	10973.55	8189.061	6869.012	3409.410	1897.178	1263.660	1176.512	1176.512	1343.926	2890.979	52836.687
Total Demand	5265.763	8381.122	10973.55	8189.061	6869.012	3409.410	1897.178	1263.660	1176.512	1176.512	1343.926	2890.979	52836.687
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	95.757	164.507	187.483	154.599	130.400	70.130	39.146	27.398	35.512	35.576	32.991	64.082	1037.580
Injection	0.000	0.000	0.000	0.000	0.000	1.179	15.964	15.517	11.811	16.035	15.517	15.651	91.675
Withdrawal	1.207	14.162	23.306	15.612	4.684	0.000	0.000	0.000	0.000	0.000	0.000	0.000	58.972
Total Fuel	96.964	178.669	210.789	170.211	135.085	71.309	55.110	42.915	47.323	51.611	48.509	79.732	1188.226
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	155.000	150.000	155.000	132.504	150.000	11.895	754.399
LNG Lawrence	1.913	1.976	6.696	1.785	1.976	2.130	13.829	2.130	0.000	0.000	6.532	2.201	41.168
LNG Marshfld	0.835	0.863	29.758	0.780	0.863	0.990	8.645	0.990	0.000	0.000	3.036	1.023	47.783
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	300.000	0.000	0.000	164.665	4.873	779.538
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	243.468	235.614	240.121	243.468	235.614	243.468	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	191.168	246.512	238.560	246.512	246.512	238.560	182.896	1590.720
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	308.140	298.200	299.180	308.140	298.200	308.140	1820.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	185.467	179.484	184.582	185.467	179.484	185.467	1099.950
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.778	10.038	9.714	10.038	10.038	9.714	10.038	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.512	243.398	251.512	251.512	243.398	251.512	1492.842
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	244.282	240.569	0.000	248.588	240.569	248.588	1222.594
Total Inj	2.748	2.839	57.453	2.565	2.839	198.066	1976.892	1898.659	1386.945	1626.228	1769.773	1450.099	10375.106
Total Req	5365.474	8562.630	11241.79	8361.836	7006.936	3678.785	3929.180	3205.234	2610.780	2854.351	3162.207	4420.811	64400.019
Sources of Supply													
Beverly	0.000	46.865	43.195	4.605	12.391	0.000	0.000	0.000	0.000	0.000	0.000	0.000	107.057
Centerville	980.886	1133.849	1360.234	921.342	1230.376	13.416	180.115	223.690	0.000	0.000	0.000	195.687	6239.595
Dawn	1132.297	1784.137	1902.236	2097.721	1406.892	584.870	558.000	540.000	548.986	558.000	540.000	494.000	12147.139
Dracut	8.515	116.336	0.346	0.000	104.036	0.000	0.000	350.170	0.000	0.000	392.531	0.000	971.935
Ellisburg	923.288	564.523	377.093	635.457	951.310	854.593	248.304	244.530	386.694	640.291	244.530	1121.938	7192.550
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	832.723	204.619	0.000	0.000	203.788	356.032	1597.163

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	OCT 2022	Total
Sources of Supply													
LNG Inject	2.748	2.839	36.453	2.565	2.839	3.120	487.474	453.120	155.000	132.504	324.233	19.991	1622.887
LPG Inject	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
Millennium	451.989	467.055	467.055	421.856	467.055	451.989	467.055	451.989	467.055	467.055	451.989	467.055	5499.196
Niagara	308.622	318.909	318.909	288.047	318.909	308.622	191.301	185.130	318.909	318.909	185.130	318.909	3380.309
Ramapo	9.704	112.452	322.588	159.021	74.388	253.572	393.822	0.000	0.000	0.000	0.000	0.000	1325.546
Repsol 30	0.000	74.229	587.450	325.321	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	127.043	321.103	115.854	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1084.053	1149.510	1149.510	1038.267	1144.622	971.470	517.995	501.286	681.746	685.202	769.307	1394.808	11087.774
TETCO M3	187.615	141.406	149.467	109.317	378.886	186.434	0.000	0.000	0.000	0.000	0.000	0.000	1153.125
Waddington	0.000	17.661	52.983	16.824	3.532	0.000	0.000	0.000	0.000	0.000	0.000	0.000	91.000
Freepoint	0.000	0.000	5.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	5.000
CLNG	0.000	0.000	0.238	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.238
Direct	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	5089.717	6056.815	7114.862	6136.198	6095.236	3628.085	3876.790	3154.534	2558.390	2801.961	3111.507	4368.421	53992.514
Storage Withdrawals													
LNG Easton	12.514	34.564	439.999	148.984	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	758.345
LNG Lawrence	1.912	1.976	18.324	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	41.168
LNG Marshfld	0.835	0.863	37.380	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	47.783
LNG Spring	27.072	50.084	360.903	111.906	27.974	32.250	33.325	32.250	33.325	33.325	32.250	33.325	807.990
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	43.182	377.066	377.066	340.576	303.862	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	176.000	496.000	496.000	283.840	138.880	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1590.720
Enbridge 18	0.000	611.500	749.950	293.620	164.930	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1820.000
Nat Fuel FSS	14.242	270.758	310.000	266.720	238.230	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1099.950
TETCO FSS-1	0.000	1.056	32.736	24.641	4.927	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	262.141	696.338	517.237	17.127	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1492.842
TGP FSMA	0.000	399.807	587.237	235.550	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	275.758	2505.815	4126.933	2225.639	911.700	50.700	52.390	50.700	52.390	52.390	50.700	52.390	10407.505
Total Supply	5365.474	8562.630	11241.79	8361.836	7006.936	3678.785	3929.180	3205.234	2610.780	2854.351	3162.207	4420.811	64400.019
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Scenario 2247 Ventyx
EGMA 2021 F&SP - Base Case - Design Weather - Draw 0 SENDOUT® Version 14.3.0 REP 13 29-Oct-2021
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Natural Gas Supply VS. Requirements Units: MDT

	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	OCT 2022	Total
Net Storage Inv. Adj.													
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	731.704	719.190	684.627	244.628	95.644	82.713	67.383	206.542	341.212	480.371	597.034	731.704	731.704
LNG Lawrence	11.628	11.628	11.628	0.000	0.000	0.000	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	948.413	921.341	871.257	510.354	398.447	370.473	338.223	614.898	882.648	849.323	815.998	948.413	948.413
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1398.571	1021.504	644.438	303.862	0.000	0.000	243.468	479.082	719.203	962.671	1198.285	1441.753
Enbridge 16	1600.000	1424.000	928.000	432.000	148.160	9.280	200.448	446.960	685.520	932.032	1178.544	1417.104	1600.000
Enbridge 18	1820.000	1820.000	1208.500	458.550	164.930	0.000	0.000	308.140	606.340	905.520	1213.660	1511.860	1820.000
Nat Fuel FSS	1100.000	1085.758	815.000	505.000	238.280	0.050	0.050	185.517	365.001	549.583	735.049	914.533	1100.000
TETCO FSS-1	63.360	63.360	62.304	29.568	4.927	0.000	3.778	13.816	23.531	33.569	43.607	53.322	63.360
TETCO SS-1	1588.950	1588.950	1326.809	630.471	113.234	96.108	96.108	347.619	591.017	842.529	1094.040	1337.438	1588.950
TGP FSMA	1222.594	1222.594	822.787	235.550	0.000	0.000	0.000	244.282	484.850	484.850	733.438	974.006	1222.594
Total Inv	10641.52	10368.51	7865.542	3796.063	1572.989	664.127	811.493	2735.996	4583.955	5918.509	7492.347	9211.420	10641.528
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

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Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	OCT 2023	Total
Forecast Demand													
Demand	5289.531	8417.906	11044.11	8226.701	6905.046	3433.536	1899.308	1259.100	1170.250	1170.250	1340.872	2912.164	53068.783
Total Demand	5289.531	8417.906	11044.11	8226.701	6905.046	3433.536	1899.308	1259.100	1170.250	1170.250	1340.872	2912.164	53068.783
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	96.134	164.898	187.912	154.963	130.979	70.517	39.145	27.368	35.370	35.434	32.930	64.273	1039.923
Injection	0.000	0.000	0.000	0.000	0.000	1.179	15.964	15.517	11.811	16.035	15.517	15.651	91.675
Withdrawal	1.221	13.727	23.317	15.753	4.954	0.000	0.000	0.000	0.000	0.000	0.000	0.000	58.972
Total Fuel	97.355	178.626	211.229	170.716	135.933	71.696	55.108	42.886	47.181	51.469	48.448	79.923	1190.569
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	155.000	150.000	155.000	155.000	150.000	15.841	780.841
LNG Lawrence	1.913	1.976	9.533	1.785	1.976	2.130	13.829	2.130	0.000	0.000	6.532	2.201	44.005
LNG Marshfld	0.835	0.863	34.445	0.780	0.863	0.990	8.645	0.990	0.000	0.000	3.036	1.023	52.470
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	300.000	0.000	0.000	214.361	4.873	829.233
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	243.468	235.614	240.121	243.468	235.614	243.468	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	191.168	246.512	238.560	246.512	246.512	238.560	182.896	1590.720
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	308.140	298.200	299.180	308.140	298.200	308.140	1820.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	185.467	179.484	184.582	185.467	179.484	185.467	1099.950
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.778	10.038	9.714	10.038	10.038	9.714	10.038	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.512	243.398	251.512	251.512	243.398	251.512	1492.842
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	244.282	240.569	0.000	248.588	240.569	248.588	1222.594
Total Inj	2.748	2.839	64.978	2.565	2.839	198.066	1976.892	1898.659	1386.945	1648.724	1819.468	1454.046	10458.769
Total Req	5389.633	8599.371	11320.32	8399.982	7043.818	3703.298	3931.308	3200.645	2604.375	2870.443	3208.787	4446.133	64718.121
Sources of Supply													
Beverly	0.000	48.317	46.760	6.636	13.757	0.000	0.000	0.000	0.000	0.000	0.000	0.000	115.469
Centerville	985.837	1137.644	1368.929	926.650	1234.578	14.943	183.196	220.935	0.000	0.000	0.000	205.222	6277.935
Dawn	1141.689	1793.152	1904.089	2104.060	1421.945	590.543	558.000	540.000	548.986	558.000	540.000	494.000	12194.464
Dracut	9.256	146.972	1.875	0.000	109.010	0.000	0.000	347.986	0.000	0.000	391.100	0.000	1006.199
Ellisburg	923.307	564.523	377.093	635.457	951.408	855.147	248.304	244.530	384.277	637.874	244.530	1122.223	7188.675
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	832.877	204.970	0.000	0.000	204.184	364.708	1606.739

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	OCT 2023	Total
Sources of Supply													
LNG Inject	2.748	2.839	43.978	2.565	2.839	3.120	487.474	453.120	155.000	155.000	373.929	23.938	1706.549
LPG Inject	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
Millennium	451.989	467.055	467.055	421.856	467.055	451.989	467.055	451.989	467.055	467.055	451.989	467.055	5499.196
Niagara	308.622	318.909	318.909	288.047	318.909	308.622	191.301	185.130	318.909	318.909	185.130	318.909	3380.309
Ramapo	11.380	115.066	329.447	161.467	76.939	257.878	392.716	0.000	0.000	0.000	0.000	0.000	1344.893
Repsol 30	0.000	103.869	616.292	266.838	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	78.161	301.538	184.301	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1084.181	1149.510	1149.510	1038.267	1144.697	972.801	517.995	501.286	677.758	681.214	767.226	1397.688	11082.132
TETCO M3	193.745	171.651	149.467	104.284	372.039	197.555	0.000	0.000	0.000	0.000	0.000	0.000	1188.741
Waddington	0.000	17.661	53.861	17.661	3.532	0.000	0.000	0.000	0.000	0.000	0.000	0.000	92.715
Freepoint	0.000	0.000	5.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	5.000
CLNG	0.000	0.000	2.282	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.282
Direct	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	5112.754	6115.329	7157.085	6158.090	6116.710	3652.598	3878.918	3149.945	2551.985	2818.053	3158.087	4393.743	54263.298
Storage Withdrawals													
LNG Easton	12.514	35.495	454.044	152.557	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	776.895
LNG Lawrence	1.912	1.976	21.161	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	44.005
LNG Marshfld	0.835	0.863	42.067	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	52.470
LNG Spring	27.072	52.462	375.048	116.627	27.974	32.250	33.325	32.250	33.325	33.325	32.250	33.325	829.233
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	42.995	377.066	377.066	340.576	304.049	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	176.000	496.000	496.000	283.840	138.880	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1590.720
Enbridge 18	0.000	611.500	749.950	293.620	164.930	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1820.000
Nat Fuel FSS	15.551	269.449	310.000	266.720	238.230	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1099.950
TETCO FSS-1	0.000	1.056	32.736	24.641	4.927	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	238.368	696.931	525.196	32.347	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1492.842
TGP FSMA	0.000	399.807	587.237	235.550	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	276.879	2484.042	4163.241	2241.892	927.108	50.700	52.390	50.700	52.390	52.390	50.700	52.390	10454.822
Total Supply	5389.633	8599.371	11320.32	8399.982	7043.818	3703.298	3931.308	3200.645	2604.375	2870.443	3208.787	4446.133	64718.121
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	OCT 2023	Total
Net Storage Inv. Adj.													
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	727.758	715.244	679.749	225.705	73.148	60.217	44.887	184.046	318.716	457.875	597.034	731.704	727.758
LNG Lawrence	11.628	11.628	11.628	0.000	0.000	0.000	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	919.961	892.889	840.427	465.379	348.752	320.777	288.527	565.202	832.952	799.627	766.302	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1398.758	1021.692	644.626	304.049	0.000	0.000	243.468	479.082	719.203	962.671	1198.285	1441.753
Enbridge 16	1600.000	1424.000	928.000	432.000	148.160	9.280	200.448	446.960	685.520	932.032	1178.544	1417.104	1600.000
Enbridge 18	1820.000	1820.000	1208.500	458.550	164.930	0.000	0.000	308.140	606.340	905.520	1213.660	1511.860	1820.000
Nat Fuel FSS	1100.000	1084.449	815.000	505.000	238.280	0.050	0.050	185.517	365.001	549.583	735.049	914.533	1100.000
TETCO FSS-1	63.360	63.360	62.304	29.568	4.927	0.000	3.778	13.816	23.531	33.569	43.607	53.322	63.360
TETCO SS-1	1588.950	1588.950	1350.582	653.651	128.454	96.108	96.108	347.619	591.017	842.529	1094.040	1337.438	1588.950
TGP FSMA	1222.594	1222.594	822.787	235.550	0.000	0.000	0.000	244.282	484.850	484.850	733.438	974.006	1222.594
Total Inv	10609.12	10334.99	7853.795	3755.532	1516.205	591.936	739.302	2663.804	4511.763	5846.318	7442.652	9211.420	10609.129
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements

Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Forecast Demand													
Demand	5280.286	8424.517	11122.18	8499.124	6899.776	3473.300	1917.736	1269.300	1179.488	1179.488	1351.786	2956.332	53553.320
Total Demand	5280.286	8424.517	11122.18	8499.124	6899.776	3473.300	1917.736	1269.300	1179.488	1179.488	1351.786	2956.332	53553.320
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	95.800	164.992	188.439	160.500	130.892	71.205	39.349	27.444	35.601	35.665	33.166	64.719	1047.773
Injection	0.000	0.000	0.000	0.000	0.000	1.179	15.964	15.517	11.811	16.035	15.517	15.651	91.675
Withdrawal	1.113	13.019	23.415	16.472	4.954	0.000	0.000	0.000	0.000	0.000	0.000	0.000	58.972
Total Fuel	96.913	178.010	211.854	176.971	135.846	72.385	55.313	42.962	47.412	51.700	48.684	80.370	1198.420
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	155.000	150.000	155.000	155.000	150.000	30.456	795.456
LNG Lawrence	1.913	1.976	12.526	1.849	1.976	2.130	13.829	2.130	0.000	0.000	6.532	2.201	47.062
LNG Marshfld	0.835	0.863	36.172	0.807	0.863	0.990	8.645	0.990	0.000	0.000	3.036	1.023	54.225
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	300.000	0.000	0.000	226.557	4.873	841.429
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	243.468	235.614	240.121	243.468	235.614	243.468	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	191.168	246.512	238.560	246.512	246.512	238.560	182.896	1590.720
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	308.140	298.200	299.180	308.140	298.200	308.140	1820.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	185.467	179.484	184.582	185.467	179.484	185.467	1099.950
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.778	10.038	9.714	10.038	10.038	9.714	10.038	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.512	243.398	251.512	251.512	243.398	251.512	1492.842
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	244.282	240.569	0.000	248.588	240.569	248.588	1222.594
Total Inj	2.748	2.839	69.698	2.656	2.839	198.066	1976.892	1898.659	1386.945	1648.724	1831.664	1468.661	10490.391
Total Req	5379.947	8605.367	11403.73	8678.751	7038.461	3743.751	3949.941	3210.921	2613.845	2879.912	3232.134	4505.363	65242.131
Sources of Supply													
Beverly	0.000	48.822	53.955	7.762	13.494	0.000	0.000	0.000	0.000	0.000	0.000	0.000	124.033
Centerville	989.834	1141.497	1377.617	972.939	1235.360	16.781	193.365	228.535	0.000	0.000	0.000	219.621	6375.550
Dawn	1149.679	1827.281	1894.442	2174.564	1417.555	600.575	558.000	540.000	548.986	558.000	540.000	494.000	12303.081
Dracut	8.621	150.105	3.466	0.000	107.185	0.000	0.000	349.830	0.000	0.000	393.240	0.000	1012.448
Ellisburg	923.296	584.278	366.306	657.596	951.426	857.136	248.304	244.530	386.568	640.165	244.530	1124.582	7228.719
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	837.689	205.802	0.000	0.000	205.062	383.892	1632.445

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Sources of Supply													
LNG Inject	2.748	2.839	48.698	2.656	2.839	3.120	487.474	453.120	155.000	155.000	386.125	38.553	1738.172
LPG Inject	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
Millennium	451.989	467.055	467.055	436.922	467.055	451.989	467.055	451.989	467.055	467.055	451.989	467.055	5514.263
Niagara	308.622	318.909	318.909	298.335	318.909	308.622	191.301	185.130	318.909	318.909	185.130	318.909	3390.596
Ramapo	11.069	116.977	337.349	163.279	76.837	264.925	396.366	0.000	0.000	0.000	0.000	0.000	1366.803
Repsol 30	0.000	120.356	600.041	266.603	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	56.400	328.013	179.587	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1084.670	1149.510	1149.510	1075.348	1144.873	977.310	517.995	501.286	684.936	688.392	775.358	1406.361	11155.548
TETCO M3	201.967	199.520	151.198	97.879	372.142	212.593	0.000	0.000	0.000	0.000	0.000	0.000	1235.301
Waddington	0.000	17.661	54.995	17.228	3.532	0.000	0.000	0.000	0.000	0.000	0.000	0.000	93.416
Freepoint	0.000	0.000	5.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	5.000
CLNG	0.000	0.000	4.365	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	4.365
Direct	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	5132.497	6201.210	7181.920	6350.699	6111.208	3693.051	3897.551	3160.221	2561.455	2827.522	3181.434	4452.973	54751.740
Storage Withdrawals													
LNG Easton	12.514	36.050	469.128	155.479	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	795.456
LNG Lawrence	1.912	1.976	24.154	1.849	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	47.062
LNG Marshfld	0.835	0.863	43.794	0.807	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	54.225
LNG Spring	27.072	52.245	390.269	113.820	27.974	32.250	33.325	32.250	33.325	33.325	32.250	33.325	841.429
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	30.687	377.066	377.066	352.740	304.194	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	160.000	496.000	496.000	299.840	138.880	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1590.720
Enbridge 18	0.000	585.000	761.875	308.195	164.930	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1820.000
Nat Fuel FSS	14.430	260.570	310.000	276.720	238.230	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1099.950
TETCO FSS-1	0.000	2.112	31.680	24.641	4.927	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	212.223	698.829	549.443	32.347	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1492.842
TGP FSMA	0.000	380.052	598.023	244.519	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	247.450	2404.157	4221.819	2328.052	927.253	50.700	52.390	50.700	52.390	52.390	50.700	52.390	10490.391
Total Supply	5379.947	8605.367	11403.73	8678.751	7038.461	3743.751	3949.941	3210.921	2613.845	2879.912	3232.134	4505.363	65242.131
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	OCT 2024	Total
Net Storage Inv. Adj.													
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	731.704	719.190	683.141	214.012	58.533	45.602	30.272	169.431	304.101	443.260	582.419	717.089	731.704
LNG Lawrence	11.628	11.628	11.628	0.000	0.000	0.000	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	919.961	892.889	840.644	450.375	336.556	308.581	276.331	553.006	820.756	787.431	754.106	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1411.066	1034.000	656.933	304.194	0.000	0.000	243.468	479.082	719.203	962.671	1198.285	1441.753
Enbridge 16	1600.000	1440.000	944.000	448.000	148.160	9.280	200.448	446.960	685.520	932.032	1178.544	1417.104	1600.000
Enbridge 18	1820.000	1820.000	1235.000	473.125	164.930	0.000	0.000	308.140	606.340	905.520	1213.660	1511.860	1820.000
Nat Fuel FSS	1100.000	1085.570	825.000	515.000	238.280	0.050	0.050	185.517	365.001	549.583	735.049	914.533	1100.000
TETCO FSS-1	63.360	63.360	61.248	29.568	4.927	0.000	3.778	13.816	23.531	33.569	43.607	53.322	63.360
TETCO SS-1	1588.950	1588.950	1376.727	677.897	128.454	96.108	96.108	347.619	591.017	842.529	1094.040	1337.438	1588.950
TGP FSMA	1222.594	1222.594	842.542	244.519	0.000	0.000	0.000	244.282	484.850	484.850	733.438	974.006	1222.594
Total Inv	10613.07	10368.37	7967.056	3814.934	1489.538	565.125	712.491	2636.993	4484.952	5819.507	7415.841	9196.805	10613.076
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Forecast Demand													
Demand	5364.765	8591.144	11234.44	8387.533	7011.672	3509.654	1935.732	1280.170	1189.439	1189.439	1363.690	2988.335	54046.018
Total Demand	5364.765	8591.144	11234.44	8387.533	7011.672	3509.654	1935.732	1280.170	1189.439	1189.439	1363.690	2988.335	54046.018
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	97.230	166.852	189.126	156.547	132.718	71.834	39.516	27.512	35.820	35.884	33.375	65.035	1051.449
Injection	0.000	0.000	0.000	0.000	0.000	1.179	15.964	15.517	11.811	16.035	15.517	15.651	91.675
Withdrawal	1.244	13.556	23.365	15.854	4.954	0.000	0.000	0.000	0.000	0.000	0.000	0.000	58.972
Total Fuel	98.474	180.408	212.490	172.400	137.671	73.014	55.480	43.029	47.631	51.919	48.892	80.685	1202.095
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	3.361	15.330	155.000	150.000	155.000	155.000	150.000	60.728	844.419
LNG Lawrence	1.913	1.976	16.498	1.785	1.976	2.130	13.829	2.130	0.000	0.000	6.532	2.201	50.970
LNG Marshfld	0.835	0.863	38.789	0.780	0.863	0.990	8.645	0.990	0.000	0.000	3.036	1.023	56.814
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	300.000	0.000	0.000	275.326	4.873	890.198
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	243.468	235.614	240.121	243.468	235.614	243.468	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	191.168	246.512	238.560	246.512	246.512	238.560	182.896	1590.720
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	308.140	298.200	299.180	308.140	298.200	308.140	1820.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	185.467	179.484	184.582	185.467	179.484	185.467	1099.950
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.778	10.038	9.714	10.038	10.038	9.714	10.038	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.512	243.398	251.512	251.512	243.398	251.512	1492.842
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	244.282	240.569	0.000	248.588	240.569	248.588	1222.594
Total Inj	2.748	2.839	76.287	2.565	6.200	213.396	1976.892	1898.659	1386.945	1648.724	1880.433	1498.933	10594.621
Total Req	5465.987	8774.391	11523.22	8562.498	7155.543	3796.064	3968.104	3221.858	2624.015	2890.082	3293.016	4567.953	65842.733
Sources of Supply													
Beverly	0.000	55.396	65.140	17.268	19.607	0.000	0.000	0.000	0.000	0.000	0.000	0.000	157.411
Centerville	1009.154	1164.857	1388.608	956.607	1252.015	18.240	201.105	234.743	0.000	0.000	0.000	228.852	6454.181
Dawn	1160.679	1824.676	1909.275	2123.811	1458.855	612.687	558.000	540.000	548.986	558.000	540.000	494.000	12328.969
Dracut	10.429	249.255	5.572	0.000	117.142	0.000	0.000	352.745	0.000	0.000	396.944	0.000	1132.088
Ellisburg	923.634	564.523	377.093	635.457	951.897	859.340	248.304	244.530	390.836	644.433	244.530	1127.000	7211.579
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	845.177	207.615	0.000	0.000	206.475	398.531	1657.799

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Sources of Supply													
LNG Inject	2.748	2.839	55.287	2.565	6.200	18.450	487.474	453.120	155.000	155.000	434.894	68.825	1842.401
LPG Inject	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
Millennium	451.989	467.055	467.055	421.856	467.055	451.989	467.055	451.989	467.055	467.055	451.989	467.055	5499.196
Niagara	308.622	318.909	318.909	288.047	318.909	308.622	191.301	185.130	318.909	318.909	185.130	318.909	3380.309
Ramapo	17.055	128.608	345.653	176.286	86.371	270.318	399.302	0.000	0.000	0.000	0.000	0.000	1423.594
Repsol 30	0.000	70.802	637.572	278.627	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	50.023	309.914	204.063	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1086.734	1149.510	1149.510	1038.267	1145.620	980.937	517.995	501.286	690.838	694.294	782.354	1412.391	11149.735
TETCO M3	216.217	216.515	153.291	116.068	400.679	224.781	0.000	0.000	0.000	0.000	0.000	0.000	1327.551
Waddington	0.000	20.071	56.514	18.337	3.764	0.000	0.000	0.000	0.000	0.000	0.000	0.000	98.686
Freepoint	0.000	0.000	5.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	5.000
CLNG	0.000	0.000	7.614	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	7.614
Direct	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Take	5187.261	6283.040	7273.006	6277.259	6228.114	3745.364	3915.714	3171.158	2571.625	2837.692	3242.316	4515.563	55248.113
Storage Withdrawals													
LNG Easton	12.514	42.683	492.182	174.755	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	844.419
LNG Lawrence	1.912	1.976	28.126	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	50.970
LNG Marshfld	0.835	0.863	46.411	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	56.814
LNG Spring	27.072	62.256	410.528	132.319	27.974	32.250	33.325	32.250	33.325	33.325	32.250	33.325	890.198
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	21.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	21.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	42.674	377.066	377.066	340.576	304.370	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	176.000	496.000	496.000	283.840	138.880	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1590.720
Enbridge 18	0.000	611.500	749.950	293.620	164.930	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1820.000
Nat Fuel FSS	17.719	267.281	310.000	266.720	238.230	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1099.950
TETCO FSS-1	0.000	2.464	31.680	24.288	4.927	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	229.455	700.035	531.005	32.347	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1492.842
TGP FSMA	0.000	399.807	587.237	235.550	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	278.726	2491.351	4250.216	2285.239	927.429	50.700	52.390	50.700	52.390	52.390	50.700	52.390	10594.621
Total Supply	5465.987	8774.391	11523.22	8562.498	7155.543	3796.064	3968.104	3221.858	2624.015	2890.082	3293.016	4567.953	65842.733
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	OCT 2025	Total
Net Storage Inv. Adj.													
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	731.704	719.190	676.508	184.325	9.570	0.000	0.000	139.159	273.829	412.988	552.147	686.817	731.704
LNG Lawrence	11.628	11.628	11.628	0.000	0.000	0.000	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	919.961	892.889	830.633	420.105	287.787	259.812	227.562	504.237	771.987	738.662	705.337	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1399.079	1022.013	644.946	304.370	0.000	0.000	243.468	479.082	719.203	962.671	1198.285	1441.753
Enbridge 16	1600.000	1424.000	928.000	432.000	148.160	9.280	200.448	446.960	685.520	932.032	1178.544	1417.104	1600.000
Enbridge 18	1820.000	1820.000	1208.500	458.550	164.930	0.000	0.000	308.140	606.340	905.520	1213.660	1511.860	1820.000
Nat Fuel FSS	1100.000	1082.281	815.000	505.000	238.280	0.050	0.050	185.517	365.001	549.583	735.049	914.533	1100.000
TETCO FSS-1	63.360	63.360	60.896	29.216	4.927	0.000	3.778	13.816	23.531	33.569	43.607	53.322	63.360
TETCO SS-1	1588.950	1588.950	1359.495	659.460	128.454	96.108	96.108	347.619	591.017	842.529	1094.040	1337.438	1588.950
TGP FSMA	1222.594	1222.594	822.787	235.550	0.000	0.000	0.000	244.282	484.850	484.850	733.438	974.006	1222.594
Total Inv	10613.07	10337.09	7848.585	3674.657	1391.982	470.754	633.450	2557.952	4405.911	5740.466	7336.800	9166.533	10613.076
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Forecast Demand													
Demand	5407.782	8672.369	11345.82	8467.985	7063.406	3539.394	1952.803	1286.420	1193.748	1193.748	1375.420	3020.872	54519.772
Total Demand	5407.782	8672.369	11345.82	8467.985	7063.406	3539.394	1952.803	1286.420	1193.748	1193.748	1375.420	3020.872	54519.772
Forecast Rt Mrktr Imbalance													
Total Imbal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fuel Consumed													
Transport	97.923	167.730	189.744	157.587	133.554	72.338	39.661	27.553	35.917	35.981	33.529	65.385	1056.903
Injection	0.000	0.000	0.000	0.000	0.000	1.179	15.964	15.517	11.811	16.035	15.517	15.651	91.675
Withdrawal	1.266	13.474	23.385	15.893	4.954	0.000	0.000	0.000	0.000	0.000	0.000	0.000	58.972
Total Fuel	99.189	181.203	213.129	173.480	138.508	73.518	55.624	43.071	47.728	52.016	49.047	81.036	1207.549
Storage Injections													
LNG Easton	0.000	0.000	0.000	0.000	12.931	15.330	155.000	150.000	155.000	155.000	150.000	60.728	853.989
LNG Lawrence	1.913	1.976	19.875	1.785	1.976	2.130	13.829	2.130	0.000	0.000	6.532	2.201	54.347
LNG Marshfld	0.835	0.863	39.696	0.780	0.863	0.990	8.645	0.990	0.000	0.000	3.036	1.023	57.721
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	310.000	300.000	11.444	0.000	300.000	4.873	926.316
LPG Lawrence	0.000	0.000	1.823	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.823
LPG Meadow	0.000	0.000	22.294	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	22.294
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	243.468	235.614	240.121	243.468	235.614	243.468	1441.753
Enbridge 16	0.000	0.000	0.000	0.000	0.000	191.168	246.512	238.560	246.512	246.512	238.560	182.896	1590.720
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	308.140	298.200	299.180	308.140	298.200	308.140	1820.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	185.467	179.484	184.582	185.467	179.484	185.467	1099.950
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	3.778	10.038	9.714	10.038	10.038	9.714	10.038	63.360
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	251.512	243.398	251.512	251.512	243.398	251.512	1492.842
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	244.282	240.569	0.000	248.588	240.569	248.588	1222.594
Total Inj	2.748	2.839	83.688	2.565	15.770	213.396	1976.892	1898.659	1398.388	1648.724	1905.107	1498.933	10647.709
Total Req	5509.719	8856.412	11642.64	8644.029	7217.684	3826.308	3985.320	3228.150	2639.864	2894.488	3329.574	4600.841	66375.030
Sources of Supply													
Beverly	0.000	61.064	76.574	52.623	20.196	0.000	0.000	0.000	0.000	0.000	0.000	0.000	210.457
Centerville	1018.300	1178.132	1397.526	971.074	1258.675	19.713	209.686	238.740	0.000	0.000	0.000	242.121	6533.967
Dawn	1177.749	1839.482	1912.190	2132.231	1475.656	623.700	558.000	540.000	548.986	558.000	540.000	494.000	12399.994
Dracut	11.602	304.977	6.724	0.000	121.330	0.000	0.000	353.407	0.000	0.000	398.964	0.000	1197.004
Ellisburg	923.824	564.523	377.093	635.457	952.106	860.704	248.304	244.530	392.562	646.159	244.530	1128.475	7218.268
Hereford	0.000	0.000	0.000	0.000	0.000	0.000	851.944	209.248	0.000	0.000	211.375	410.104	1682.672

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Sources of Supply													
LNG Inject	2.748	2.839	59.571	2.565	15.770	18.450	487.474	453.120	166.444	155.000	459.568	68.825	1892.373
LPG Inject	0.000	0.000	24.117	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	24.117
Millennium	451.989	467.055	467.055	421.856	467.055	451.989	467.055	451.989	467.055	467.055	451.989	467.055	5499.196
Niagara	308.622	318.909	318.909	288.047	318.909	308.622	191.301	185.130	318.909	318.909	185.130	318.909	3380.309
Ramapo	19.644	133.769	352.965	183.759	91.825	274.060	401.170	0.000	0.000	0.000	0.000	0.000	1457.193
Repsol 30	0.000	0.000	664.345	322.655	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	987.000
Repsol 40	0.000	83.698	302.601	177.702	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	564.000
TETCO M2	1087.636	1149.510	1149.510	1038.267	1145.975	983.438	517.995	501.286	693.518	696.974	787.319	1418.961	11170.388
TETCO M3	226.755	236.202	156.651	121.042	414.978	234.932	0.000	0.000	0.000	0.000	0.000	0.000	1390.560
Waddington	0.000	22.256	56.515	19.795	5.417	0.000	0.000	0.000	0.000	0.000	0.000	0.000	103.983
Freepoint	0.000	0.000	5.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	5.000
CLNG	0.000	0.000	8.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	8.000
Direct	0.000	0.000	2.839	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.839
Total Take	5228.868	6362.417	7338.186	6367.072	6287.893	3775.608	3932.930	3177.450	2587.474	2842.098	3278.874	4548.451	55727.321
Storage Withdrawals													
LNG Easton	12.514	47.563	515.754	155.873	12.931	15.330	15.841	15.330	15.841	15.841	15.330	15.841	853.989
LNG Lawrence	1.912	1.976	31.503	1.785	1.976	2.130	2.201	2.130	2.201	2.201	2.130	2.201	54.347
LNG Marshfld	0.835	0.863	47.318	0.780	0.863	0.990	1.023	0.990	1.023	1.023	0.990	1.023	57.721
LNG Spring	27.072	65.516	432.666	140.676	30.336	32.250	33.325	32.250	33.325	33.325	32.250	33.325	926.316
LPG Lawrence	0.000	0.000	1.823	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.823
LPG Meadow	0.000	0.000	22.294	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	22.294
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	42.674	377.066	377.066	340.576	304.370	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1441.753
Enbridge 16	176.000	496.000	496.000	283.840	138.880	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1590.720
Enbridge 18	0.000	611.500	749.950	293.620	164.930	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1820.000
Nat Fuel FSS	19.843	265.157	310.000	266.720	238.230	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1099.950
TETCO FSS-1	0.000	2.464	31.680	24.288	4.927	0.000	0.000	0.000	0.000	0.000	0.000	0.000	63.360
TETCO SS-1	0.000	226.083	701.164	533.249	32.347	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1492.842
TGP FSMA	0.000	399.807	587.237	235.550	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1222.594
Total With	280.850	2493.995	4304.456	2276.957	929.791	50.700	52.390	50.700	52.390	52.390	50.700	52.390	10647.709
Total Supply	5509.719	8856.412	11642.64	8644.029	7217.684	3826.308	3985.320	3228.150	2639.864	2894.488	3329.574	4600.841	66375.030
Net Storage Inv. Adj.													
LNG Easton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LNG Marshfld	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Natural Gas Supply VS. Requirements Units: MDT

	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	OCT 2026	Total
Net Storage Inv. Adj.													
LNG Spring	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Lawrence	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Meadow	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG NHampton	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DTI GSS TET	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 16	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Enbridge 18	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Nat Fuel FSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO FSS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TETCO SS-1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TGP FSMA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Inv Adj	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Start of Month Inventory													
LNG Easton	731.704	719.190	671.628	155.873	0.000	0.000	0.000	139.159	273.829	412.988	552.147	686.817	731.704
LNG Lawrence	11.628	11.628	11.628	0.000	0.000	0.000	0.000	11.628	11.628	9.427	7.226	11.628	11.628
LNG Marshfld	7.622	7.622	7.622	0.000	0.000	0.000	0.000	7.622	7.622	6.599	5.576	7.622	7.622
LNG Spring	919.961	892.889	827.373	394.707	254.031	223.694	191.444	468.119	735.869	713.988	680.663	948.413	919.961
LPG Lawrence	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033	13.033
LPG Meadow	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749	70.749
LPG NHampton	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722	21.722
DTI GSS TET	1441.753	1399.079	1022.013	644.946	304.370	0.000	0.000	243.468	479.082	719.203	962.671	1198.285	1441.753
Enbridge 16	1600.000	1424.000	928.000	432.000	148.160	9.280	200.448	446.960	685.520	932.032	1178.544	1417.104	1600.000
Enbridge 18	1820.000	1820.000	1208.500	458.550	164.930	0.000	0.000	308.140	606.340	905.520	1213.660	1511.860	1820.000
Nat Fuel FSS	1100.000	1080.157	815.000	505.000	238.280	0.050	0.050	185.517	365.001	549.583	735.049	914.533	1100.000
TETCO FSS-1	63.360	63.360	60.896	29.216	4.927	0.000	3.778	13.816	23.531	33.569	43.607	53.322	63.360
TETCO SS-1	1588.950	1588.950	1362.867	661.703	128.454	96.108	96.108	347.619	591.017	842.529	1094.040	1337.438	1588.950
TGP FSMA	1222.594	1222.594	822.787	235.550	0.000	0.000	0.000	244.282	484.850	484.850	733.438	974.006	1222.594
Total Inv	10613.07	10334.97	7843.817	3623.049	1348.657	434.636	597.332	2521.834	4369.793	5715.791	7312.126	9166.533	10613.076
Unsupplied Demand													
Demand	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Unsupp	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000