PUBLIC VERSION

NAVIGANT

FINAL REPORT: ECONOMIC ANALYSIS AND FINDINGS RELATED TO PROPOSALS FOR LIQUFIED NATURAL GAS STORAGE CAPACITY

Prepared for:

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1. Executive Summary

In accordance with certain legislation, the State of Maine has sought proposals for Physical Energy Storage Contracts (PESC), specifically in the form of liquefied natural gas (LNG). The legislation, 2016 Legislative Session Public Law, Chapter 445, LD 881, provides that the Public Utilities Commission may execute or direct one or more transmission and distribution utilities, gas utilities, or natural gas pipeline utilities to execute a PESC subject to certain showings being made. Navigant has been retained by the State to assist in estimating and evaluating the relative costs and benefits of the proposed PESCs. According to the legislation, for a contract to meet program requirements the overall costs of the contract need to be outweighed by its benefits to electricity consumers, gas consumers, or both in the State.

Navigant has structured the cost-benefit analyses so as to capture the overall impact on estimated gas supply costs to a party or parties contracting for LNG storage through a PESC pursuant to the program. At a high level, the analysis starts with the avoided cost of winter-time (i.e. peak) gas purchases due to the stored LNG, less the summer-time (i.e. non-peak) gas cost to fill the storage facility, less the contract costs to provide the storage service. The net of these figures represents the net benefit of the PESC. Navigant utilized four annual "snapshot" years around which the analysis is built, and then estimated annual figures for the intervening years in order to produce an NPV result of the net benefit estimated for each of the 11 contract options bid in total by six bidders.

The parameters of PESC bids covered a range of key aspects of proposed facilities from facility size and operating characteristics, to various components of contract costs. The main physical parameters included the capacity of the proposed LNG storage tanks, the vaporization rate and/or number of storage withdrawal days, and the fill rate for the storage tanks. Cost-related parameters included fixed and variable costs and the rates of vaporization and/or liquefaction fuel loss/use. The LNG tank sizes were generally spread between one and two Bcf, with varying vaporization rates contributing to various total days of LNG use out of storage. Fill time for liquefaction-based projects varied from 100 days to about 240 days, as a function of tank size and fill rate. The estimation of contract costs for the PESC options followed from the bids as proposed. Fixed costs, variable costs, fuel use and vaporization losses were factored in as proposed. One cost factor estimated by Navigant as discussed is an LNG premium to represent extra fill costs associated with trucked-in LNG options.

For purposes of estimating the peak value of the LNG, Navigant utilized its Daily Gas Model. The price in each snapshot applicable to the avoided peak price of LNG-based supply is derived as the average of the top 15 days falling in the two-month winter period (assumed as January and February) in each snapshot year. This methodology yields a more conservative analysis (i.e. higher PESC valuation). To provide a less conservative outlook on which to analyse the PESCs, we have also presented results using average wintertime prices. In addition, Navigant has included scenarios both with the Access Northeast pipeline project and without the project, to further bookend the analyses with less conservative and more conservative price forecasts, respectively. The choice of Access Northeast, a proposed pipeline expansion in New England with potential impact on the Maine market, is discussed in more detail in Section 6.2. The pricing point used in the analysis is Tennessee Gas Pipeline Zone 6-delivered, a liquid point with applicability for northern New England and for Maine given the lack of liquid gas trading points in the Maine market itself.

Since our assumptions show that the contracting party, e.g. an LDC, may not have sufficient load by itself to use the full vaporization rate under a PESC, we assume that as "holder" or "owner" of the PESC, the

LDC would be in a position to maximize value of the PESC (say by selling excess gas at peak), in order to beneficially offset contract costs that it would be subject to paying. Thus, the operative metric for comparison is assumed to be the net benefit of a bid option incorporating the total bid volume, regardless of the ultimate disposition of the stored LNG. This assumption is consistent with the assumption that direct contract costs and benefits realized as a result of a PESC will flow to the ratepayers of the contracting entity. Nevertheless, Navigant's analysis provides breakouts of contract volume across different allocation categories (i.e. LDC, Maine, out-of-state) of the stored LNG to provide tracking for informational purposes.

After accounting for tank fill costs, annual contract costs are netted out from the commodity benefit in order to arrive at an annual cost-benefit result in each snapshot year. It should be noted that Navigant's analysis indicates minimal impact of the LNG storage projects on the actual levels of natural gas market prices applicable to Maine, as well as to the electric market prices (locational marginal prices, or LMPs) for Maine. This means that the net benefits calculated in the analyses all relate only to contract volumes, and not to any other natural gas transacted in the markets.

As can be seen in Table 1, representing the PESC option net present value (NPV, calculated at a 4% real discount rate) and return on investment (ROI) under the "with Access Northeast" scenario analysis (using peak prices), of the 11 PESC options analysed in this report perhaps unexpectedly only one provided a positive NPV, and that project only yielded a 3.2% return on investment, a low result for typical investment criteria. Thus, Navigant's findings in this instance are that if the PUC decides to go forward with any one of the PESCs as proposed, it would be for objectives other than pure economic return.

Table 1: PESC Option NPV and ROI, With Access Northeast

2015 $ in millions	NPV Net Benefit	ROI
Northstar 1	5.8	3.2%
Engie 2	(8.2)	-3.3%
Reliable 2	(11.7)	-4.5%
Engie 1	(41.8)	-15.0%
Northstar 2	(33.2)	-15.3%
Reliable 1	(43.7)	-22.2%
Cavus 2	(65.8)	-35.1%
Northern 1	(98.4)	-40.1%
Cavus 1	(97.7)	-44.4%
Eagle Partners 2	(22.0)	-69.2%
Eagle Partners 1	(28.0)	-85.1%

We note, however, the sensitivity of the results to the exclusion of the Access Northeast pipeline project, for which we have included another scenario in the report that indicates favorable results for some PESC options. If there were indications that the project would not go forward, then there could be an impact on the findings, as shown in Table 2, below, where seven PESC options have a positive NPV.

Table 2: PESC Option NPV and ROI, Without Access Northeast

2015 $ in millions	NPV Net Benefit	ROI
Northstar 1	109.1	60.7%
Engie 2	136.8	55.7%
Reliable 2	126.8	49.1%
Engie 1	103.2	37.0%
Northstar 2	70.1	32.0%
Reliable 1	42.8	21.6%
Cavus 2	3.1	1.6%
Northern 1	(15.7)	-6.4%
Cavus 1	(28.8)	-13.0%
Eagle Partners 2	(16.4)	-51.6%
Eagle Partners 1	(25.2)	-76.6%

2. Introduction

In accordance with certain legislation, the State of Maine has sought proposals for Physical Energy Storage Contracts, specifically in the form of liquefied natural gas (LNG). The legislation, 2016 Legislative Session Public Law, Chapter 445, LD 881, provides that the Public Utilities Commission may execute or direct one or more transmission and distribution utilities, gas utilities, or natural gas pipeline utilities to execute a PESC subject to certain showings being made. As a result of the State's RFP for PESCs, issued on September 14, 2016 with an ultimate due date of November 4, 2016, a number of contract proposals have been submitted to the state for evaluation. As we understand, the State has issued its Storage Contract RFP in the interest of mitigating high natural gas prices during the wintertime peak periods or in the event of upstream natural gas infrastructure disruptions. LNG storage can be located close to load centers, thereby making peak volumes of gas directly available to the system in order to reduce costs and increase reliability. Navigant has been retained by the State to assist with this evaluation.

The evaluation is specifically informed by the legislation's stated requirements for PESCs. Most notably, an important factor in the proposal evaluation concerns a cost-benefit analysis of the proposals, in addition to other stated criteria. According to the legislation, the PESC should be economically beneficial to electricity consumers, gas consumers, or both in the State, and the overall costs of the contract are to be outweighed by its benefits to electricity consumers, gas consumers, or both in the State. Navigant has structured the cost-benefit analyses so as to capture the overall impact on estimated gas supply costs to a party or parties contracting for LNG storage through a PESC pursuant to the program. At a high level, the analysis starts with the avoided cost of winter-time (i.e. peak) gas purchases due to the stored LNG, less the summer-time (i.e. non-peak) gas cost to fill the storage facility, less the contract costs to provide the storage service. The net of these figures represents the net benefit of the PESC.

In order to estimate peak period natural gas prices on a forecast basis, Navigant made use of its natural gas Daily Model, a specialized version of Navigant's fundamental GPCM long-term model. The use of a daily model in this analysis is noteworthy both because of the limited availability of daily natural gas modelling for the North American gas market, as well as the fact that daily analysis is key to the assessment of the LNG proposals as part of this RFP. Because we believe the key analysis to perform a cost-benefit analysis for the RFP is to focus upon peak period pricing, as opposed to say monthly average pricing, the use of a daily model is very helpful. In order to proceed with this somewhat unique Daily Market analysis, Navigant generated four peak day "snapshots" across the relevant time period of the contracts (i.e. 2022, 2032, 2042 and 2052), and then, using Navigant's monthly market model, estimated peak day figures for intervening years in order to produce a Net Present Value and Return on Investment (ROI) result for each contract. To have modeled each year during the contract period could have been done but due to the modelling time involved to do each year could not have been done within the Procedural Order timeline schedule.

It should be noted that Navigant's analysis indicates minimal impact of the LNG storage projects on the actual levels of natural gas market prices applicable to Maine, as well as on the electric market prices (locational marginal prices, or LMPs) for Maine.

Other criteria for consideration in meeting the requirements of the PESC is that they must be reasonably likely to materially enhance LNG storage capacity in the State or ISO-NE region, provide the opportunity for access to lower cost natural gas at times of regional peak demand for natural gas supplies or in the event of upstream natural gas infrastructure disruption, enhance electrical and natural gas reliability in the State, as well as being commercially reasonable and in the public interest. These factors will also be discussed in the report. It should be noted that the legislation put an annual cap of $25 million on the program cost of PESCs.[1]

3. Overview of Maine Natural Gas Market

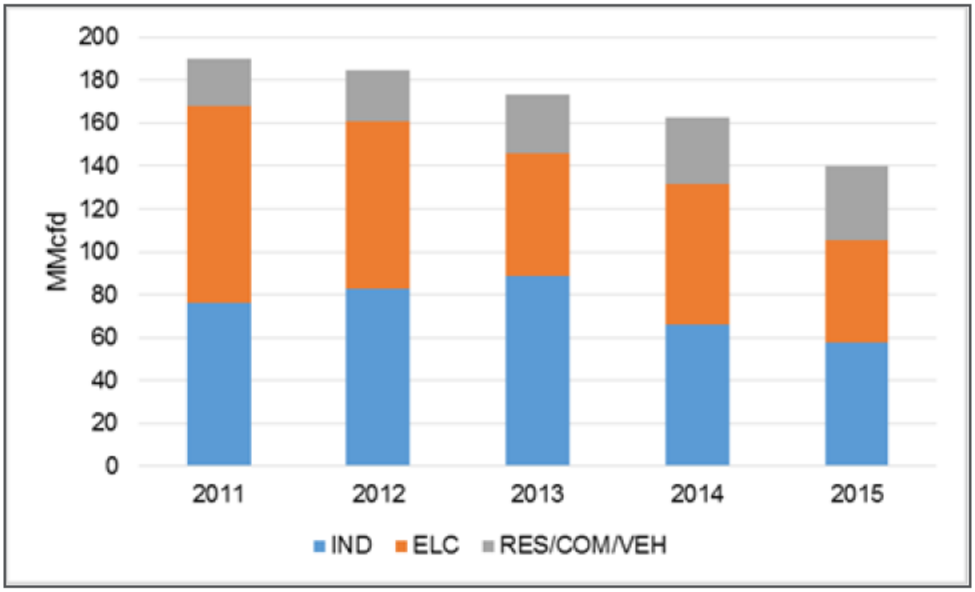
3.1. Total Gas Demand

Maine natural gas demand, at 140 MMcfd in 2015, represents a small fraction of regional gas demand, at about 6% percent of New England annual gas demand, which was 2.5.Bcfd in 2015.

As shown in Figure 1 below, the principal consumption sectors of natural gas in Maine include electric power generation, industrial consumption and the residential, commercial and natural gas vehicle fuel sectors.

[1] Some proposals may exceed the $25 million cost cap depending on interpretation. Navigant has not included such factor in its analysis, and defers to the judgment of the Commission on this matter.

Figure 1: Maine Natural Gas Consumption (2011 – 2015)



Source: Navigant Consulting Inc. / EIA

Over the 2011 to 2015 time period, total annual average daily natural gas consumption by sector has decreased from 190 MMcfd in 2011 to 140 MMcfd in 2015, with the largest decrease coming from the electric generation sector.

Demand in the industrial sector also decreased, with most of the decline related to the loss of manufacturing activity, particularly from the closure of the East Millinocket, Old Town and Bucksport pulp and paper mills in 2014.[2]. Although the residential/commercial/vehicle fuel sectors represented only about 25% of total gas consumption in Maine in 2015, this sector has experienced significant growth with a 12% compound average growth rate from 2011 to 2015 (driven in large part by cold weather) as shown in Table 3, below.

Table 3: Maine Historical Natural Gas Consumption (2011 – 2015)

MMcfd	2011	2012	2013	2014	2015	CAGR
Electric	91.9	78.0	57.3	65.3	47.8	-15%
Industrial	76.0	82.9	88.5	66.1	57.5	-7%
Res/Comm/Veh	21.9	24.1	27.5	31.2	35.0	12%
Total	189.8	184.9	173.3	162.6	140.2	-7%

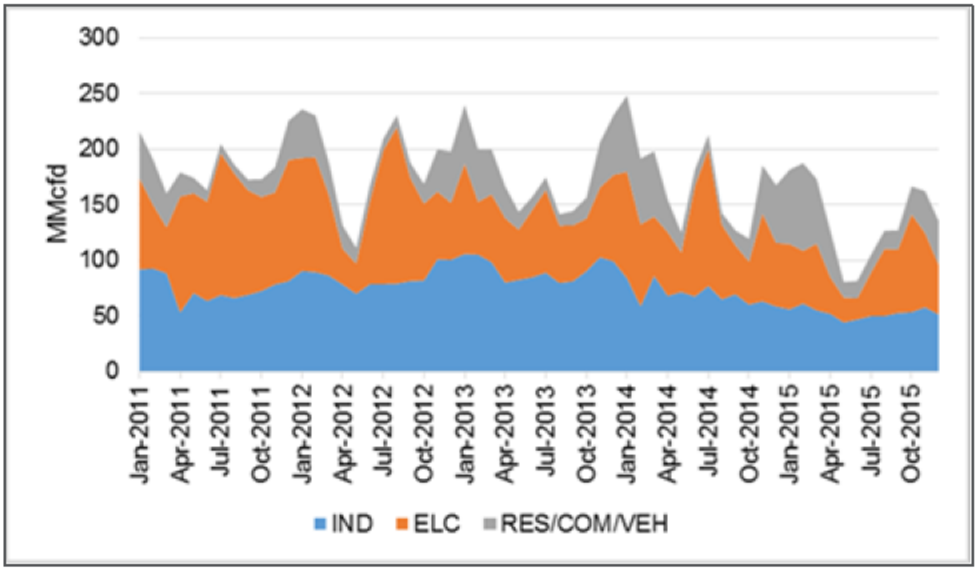
Source: Navigant Consulting Inc. / EIA

Gas demand in Maine is cyclical due to variations in consumption driven by seasonal requirements. As shown in Figure 2, below, consumption of natural gas in Maine fluctuates based upon increases in cold-weather-driven demand. In 2015, demand peaked at 187 MMcfd in February, which represents

[2] Bangor Daily News, October 2014.

an increase of 47 MMcfd over the yearly average demand of 140 MMcfd, or an increase of approximately 33%.

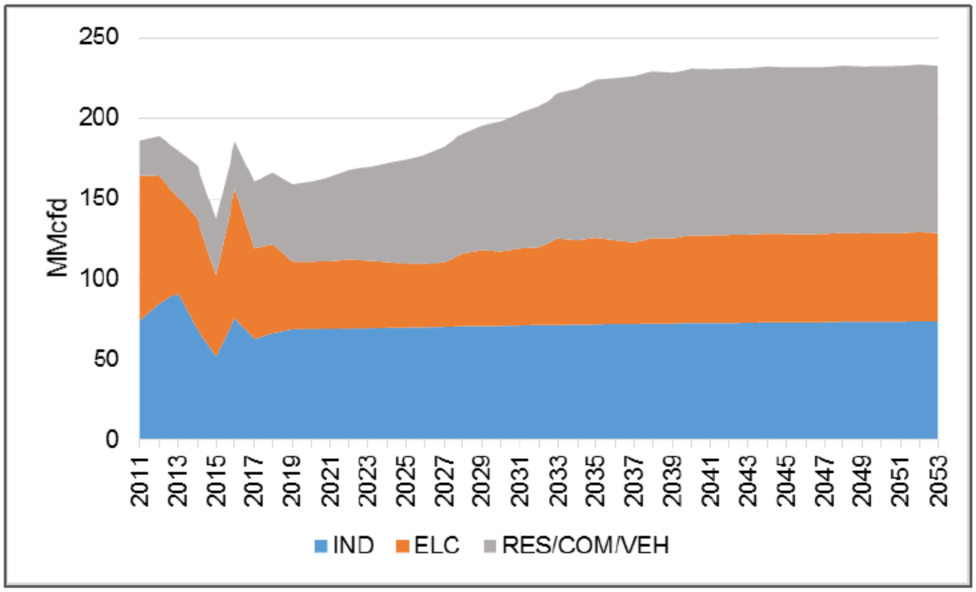
Figure 2: Maine Natural Gas Consumption Monthly (Jan 2011 – Dec 2015)



Source: Navigant Consulting Inc. / EIA

Navigant's forecast for natural gas consumption in Maine calls for a significant growth in overall demand, driven primarily by growth in residential, commercial and natural gas vehicle sectors. Overall demand is projected to increase from 140 MMcfd in 2015 to 160 MMcfd by 2020 and approximately 200 MMcfd by 2030.

Figure 3: Maine Natural Gas Consumption Yearly (2011 – 2053)



Source: Navigant's North American Natural Gas Market Outlook, Fall 2016; RBAC

3.2. Market Access and Infrastructure

Deliveries of natural gas to Maine are enabled by several major pipelines as shown in Figure 6 below.

The Portland Natural Gas Transmission System (PNGTS) is a 295-mile interstate pipeline that originates at the terminus of the TransCanada Corp. Trans-Quebec and Maritimes Pipeline at the border between Canada and New Hampshire and ends in Dracut, MA where it ultimately connects with the Tennessee Gas Pipeline System (TGP). The PNGTS system shares facilities with the Maritimes and Northeast Pipeline from Westbrook, ME to Dracut MA. PNGTS has a design capacity of 168 MMcfd at the Canadian border which increases to 210 MMcfd from Westbrook, ME to Dracut, MA. PNGTS provides access to natural gas from several regions including Western Canada, the US Rockies and the Marcellus and Utica shale plays in the US.

The Maritimes & Northeast Pipeline (M&NE) brings offshore, onshore and LNG-sourced natural gas from Atlantic Canada to North American markets. The M&NE pipeline has a design capacity of 830 MMcfd on the U.S. side and 550 MMcfd of natural gas capacity on the Canadian side. The pipeline extends from Nova Scotia into New Brunswick, Maine, New Hampshire and Massachusetts where it connects with the Algonquin Gas Transmission pipeline near Beverly, Massachusetts. M&NE pipeline provides access to offshore Canadian production from the Sable Island and Deep Panuke natural gas fields in addition to deliveries of liquefied natural gas (LNG) from the Canaport facility in New Brunswick, Canada.

The Granite State Gas Transmission (GSGT) pipeline runs from Haverhill, MA, up to Portland, ME. This pipeline is owned by Unitil Corporation, an interstate electricity and natural gas utility company that serves the areas in New Hampshire, Massachusetts and Maine. The GSGT, for most of its length, runs in parallel with the PNGTS and M&NE shared pipeline. GSGT receives gas from either the PNGTS, M&NE, or the TGP pipelines near Haverhill, MA and delivers along the Maine seacoast into Portland, where it supplies the Unitil distribution network.

In addition to these pipelines that directly serve Maine, two additional pipelines, the Tennessee Gas Pipeline (TGP) and the Algonquin Gas Transmission pipeline (AGT) deliver natural gas to the New England area.

The TGP system is an approximately 11,800-mile pipeline system that transports natural gas from Louisiana, the Gulf of Mexico and south Texas to the northeast section of the United States, including New York City and Boston. The TGP system has two legs in New England. One leg extends from New York to Connecticut with a capacity of approximately 150 MMcfd while another leg extends from New York to Massachusetts with a capacity of approximately 1.17 Bcfd.

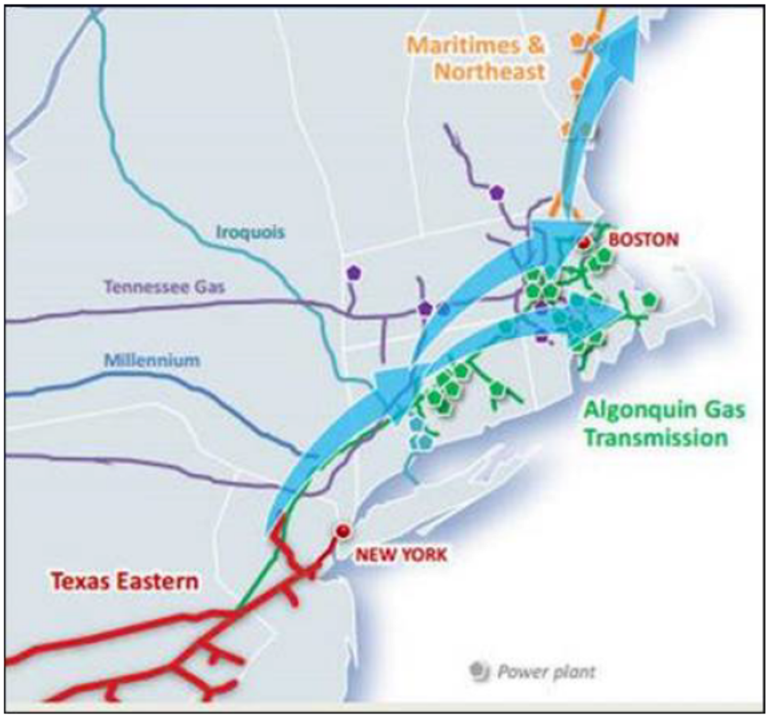
The AGT system is a 2.98 Bcfd pipeline that extends from the Texas Eastern Pipeline, which connects Texas and the Gulf Coast with the US Northeast, to the M&NE pipeline. The AGT system capacity is approximately 1.36 Bcfd from New York to Massachusetts via Connecticut.

A proposed expansion of the AGT and M&NE pipelines will add approximately 133 MMcfd per day of additional capacity. Known as the Atlantic Bridge Project, it is expected to enter service in November 2017. The Atlantic Bridge project is designed to increase capacity along the AGT and M&NE systems allowing increased deliverability to New England and to Atlantic Canada.

Another important project to the New England region is the proposed Access NE pipeline expansion project. This project is expected to increase capacity on the AGT system by 925 MMcfd. Also proposed as part of this project is an LNG peak shaving facility with a potential daily send-out of 400 MMcfd.[3] This project is designed to increases supplies of natural gas, particularly on peak days, to power plants off the AGT and M&NE systems The additional capacity brought on by Access NE will also provide access to less expensive shale gas in the Appalachian basin. Shale gas from the Appalachian basin can reach the AGT system via its interconnects with the Texas Eastern pipeline at Hanover, New Jersey and TGP at Mahwah, New Jersey. From the AGT system, the Appalachian shale gas can make its way into Maine and Atlantic Canada via the M&NE pipeline system which interconnects with AGT in northern Massachusetts.

[3] FERC Docket No. PF16-1-000

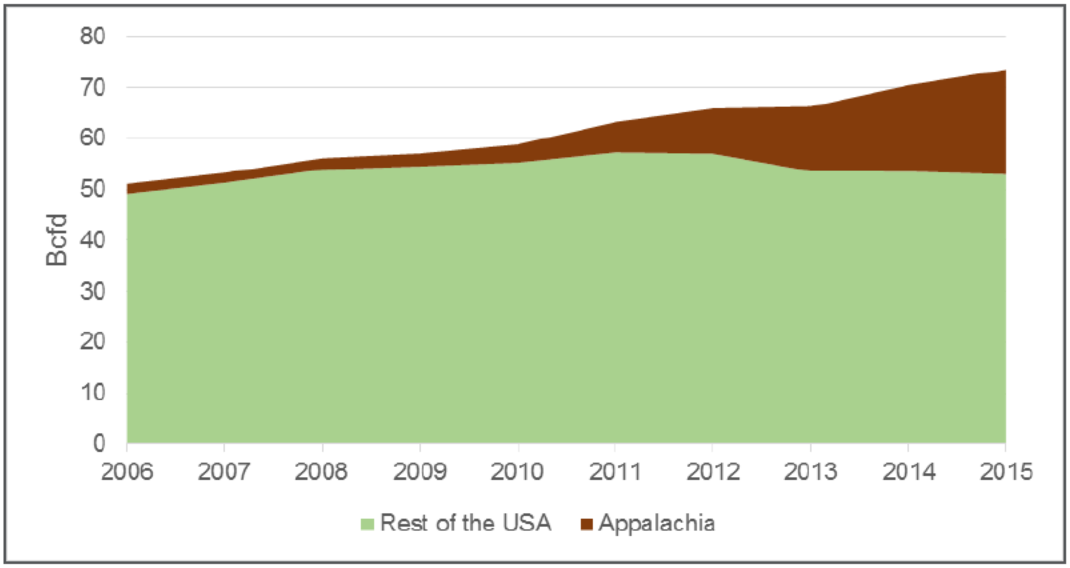
Figure 4: Proposed Access Northeast Project



Source: Spectra Energy

Outside the Algonquin system and closer to the source of Appalachian supply, multiple pipeline projects are being proposed as a response to the recent growth in Appalachian shale production. As shown in Figure 5, Appalachian gas production has grown by 37.3% annually from 2008 to 2015. As a result, the share of Appalachian gas production out of total USA production has increased from 4% to 28% between 2008 and 2015—a transformative growth in production from a region that produced almost no gas relatively before 2008.

Figure 5: Appalachian gas production VS the rest of the USA (2006-2015)



Source: Navigant Consulting Inc. / PointLogic Energy

In order to get the Appalachian production to surrounding markets, several projects have been proposed to increase take-away capacity from the Appalachian basin. Currently there are almost 30 projects representing over 21 Bcfd of takeaway capacity that are proposed and seem to be moving forward. The table below shows the projects most likely to have a significant potential impact on the Maine market, with projected volumes.

Table 4: Major New England Pipeline Expansions

Pipeline	Project	In-Service Date	Incremental Capacity (MMcfd)
Algonquin	Access Northeast	November 2019[4]	925
Algonquin	Algonquin Incremental Market (AIM)	November 2016	342
Algonquin	Atlantic Bridge	November 2017	133
Constitution	Constitution	November 2019	650
Tennessee Gas Pipeline	Connecticut Expansion Project	November 2017	72
Nexus	Nexus	November 2017	1500
ET Rover	ET Rover	November 2018	3250
Portland Natural Gas Transmission	Continent to Coast Expansion Project	November 2017	132

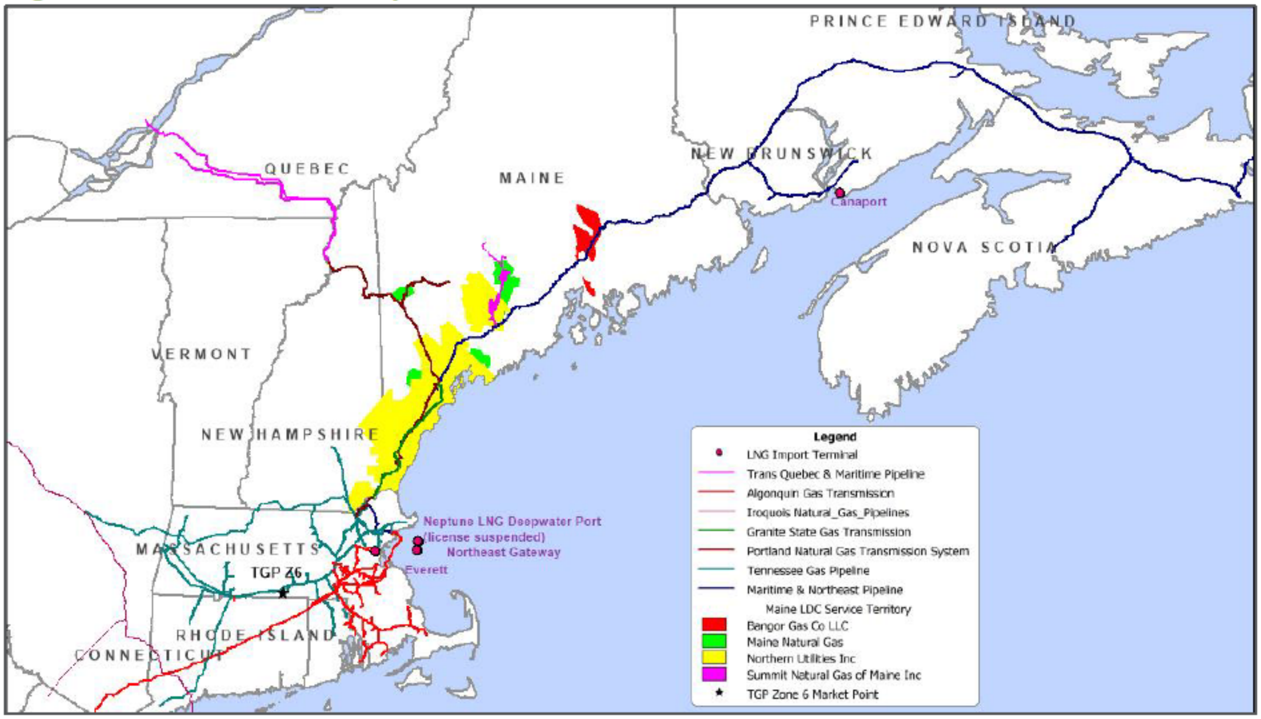
Source: Navigant's North American Natural Gas Market Outlook, Fall 2016; PointLogic Energy

3.3. Maine Local Distribution Companies

There are four local gas distribution companies (LDCs) in Maine that serve the industrial residential and commercial sectors. These LDCs receive natural gas from the interstate pipelines and deliver to end users via their distribution networks. The four LDCs in Maine are Bangor Natural Gas Company, Maine Natural Gas Corporation, Northern Utilities Inc. d/b/a Unitil, and Summit Natural Gas of Maine. The service territories of these LDCs are shown below in Figure 6. In addition, some electric and industrial consumers receive natural gas directly from the interstate pipelines.

[4] In its December 16, 2016 Monthly Progress Report to FERC, Spectra noted it will delay its FERC application for Access Northeast until late 2017.

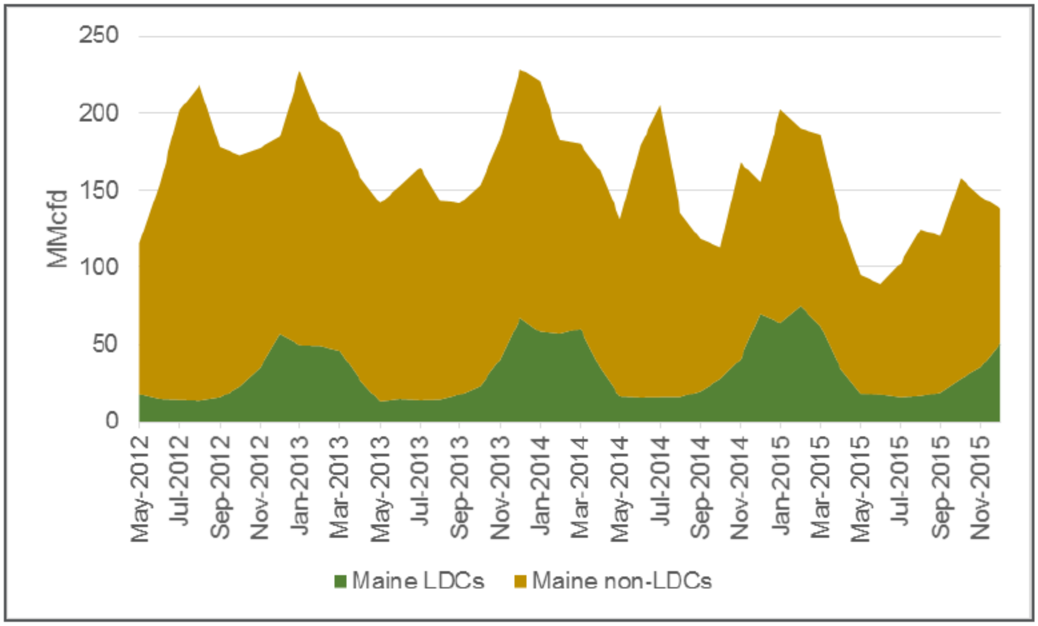
Figure 6: Maine Natural Gas Pipeline Infrastructure



Source: Navigant Consulting Inc. / Ventyx

Figure 7 below shows the Maine LDC load relative to the total load of Maine. As can be seen in the chart, the Maine LDC load represents a small but growing portion of Maine's total load. The average winter load for Maine has stayed around 190 MMcfd between 2013 and 2015. During this same time, the Maine LDC load has grown from 47 MMcfd to 62 MMcfd. As a percent of total demand, the LDC load has increased from 24% of market share in 2013 to 34% of market share in 2015.

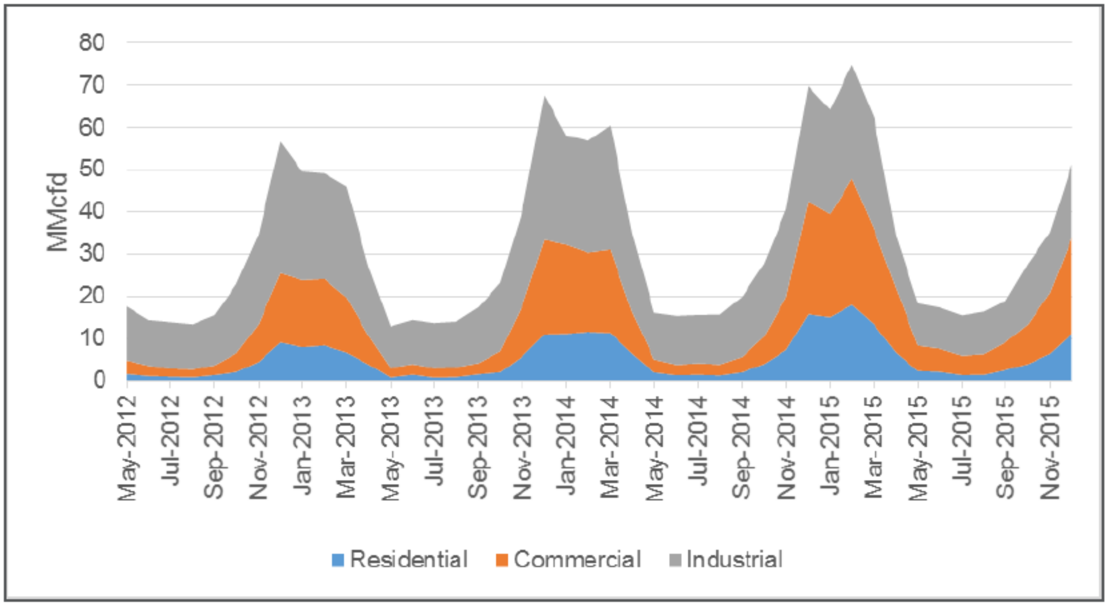
Figure 7: Maine monthly gas consumption by LDC and non-LDC (May 2012- Dec 2015)



Source: Navigant Consulting Inc. / Maine PUC

The four LDC's in Maine serve residential, commercial and industrial customers throughout the state. Of the 3 sectors, the residential and commercial sectors have shown signs of growth over the last 4 years while the industrial sector has been in decline. The residential sector has increased its share of the winter peak market from 16% to 22%. The commercial sector has shown even stronger signs of growth, increasing from 30% of the winter peak share of the market to 44%. During this same time, the industrial sector share of the winter peak market declined from 55% to 35%.

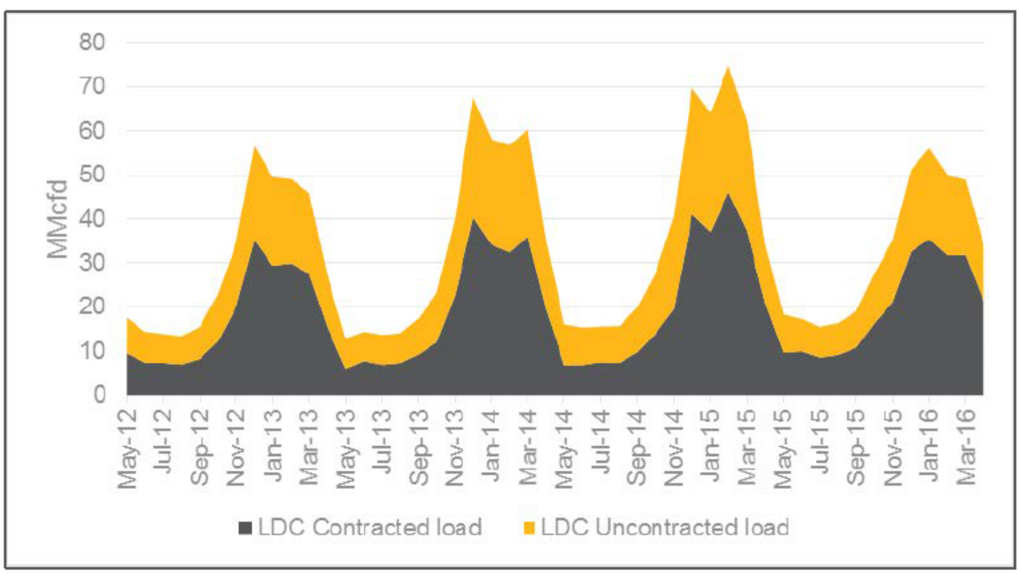
Figure 8: Maine's LDC monthly gas consumption sector (May 2012- Mar 2016)



Source: Navigant Consulting Inc. / Maine PUC

As was previously noted, the Maine natural gas market is highly seasonal, with winter peak loads growing to over 33% of annual demand. In order to reduce their exposure to high prices from swings in demand, the Maine LDC's have hedged a portion of their winter load with capacity-backed contracts. As can be seen in the chart below, over the last 4 winters, Maine's LDC's have generally secured around 62% of their load with contracts.

Figure 9: Maine LDC Contracted and Uncontracted Load

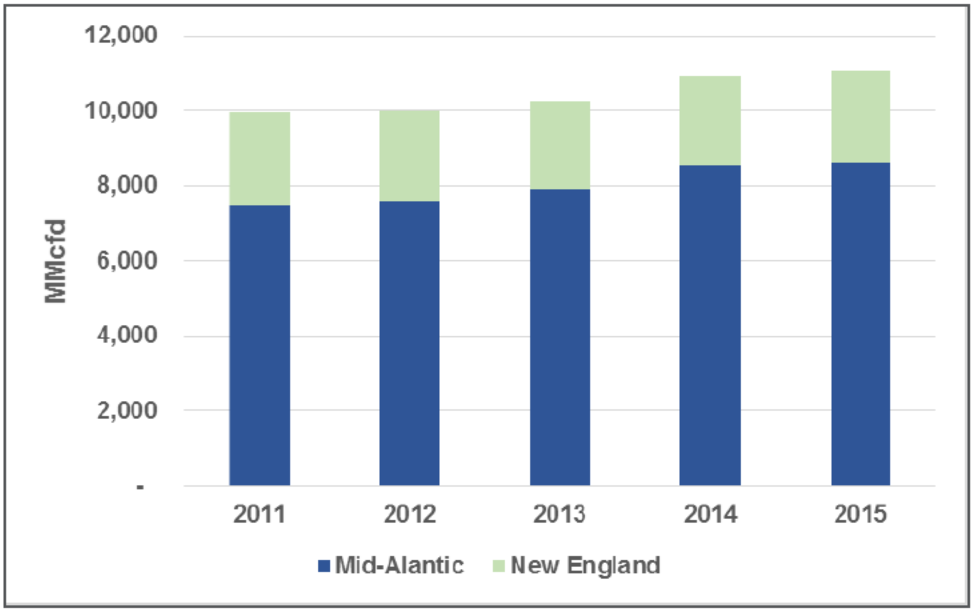


Source: Navigant Consulting Inc./ Maine PUC Staff

3.4. Regional Market Overview

As mentioned above, total natural gas consumption in Maine in 2015 was approximately 140 MMcfd and represented approximately 6% of total demand in New England. In addition, total demand in New England in 2015 was 2.5 Bcfd, which represents approximately 22% of total demand in the Northeast, comprised of New England and the Mid-Atlantic regions, or 11.5 Bcfd in 2015 – as shown below in Figure 10 below. The Mid-Atlantic region, which consumed 8.7 Bcfd of natural gas in 2015 is the largest regional market in the Northeast region. Total natural gas consumption in Maine represents 1% of total gas consumption in the Northeast. Maine's LDC gas consumption represents only 0.2% of total gas consumption in the Northeast.

Figure 10: Comparison of Annual Demand Mid-Atlantic and New England (2011 – 2015)

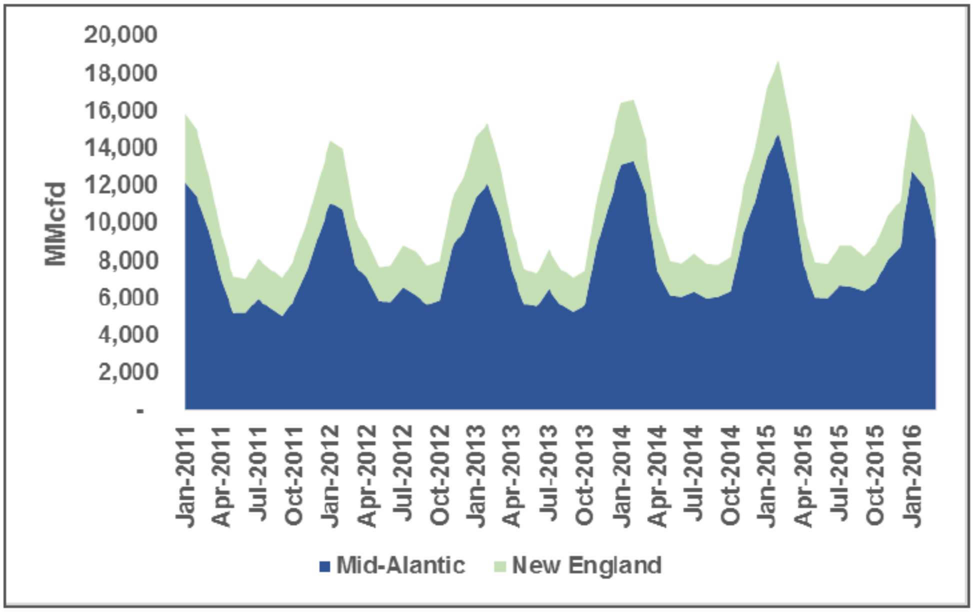


Source: Navigant Consulting Inc. / EIA

The size of the Mid-Atlantic region relative to the Northeast is underscored by a comparison of monthly demand which highlights the seasonality of natural gas consumption due to winter space heating requirements, as shown in Figure 11, below. In 2015, peak monthly load in the Mid-Atlantic was 14.8 Bcfd in the month of February while average 2015 demand is 8.6 Bcfd. This represents an increase of more than 6 Bcfd, or 1.7 times the yearly average.

In New England, the peak demand in 2015 was 3.9 Bcfd while the 2015 yearly average demand was 2.5 Bcfd, a difference of 1.3 Bcfd.

Figure 11: Comparison of Monthly Demand Mid-Atlantic and New England (Jan 2011 – Mar 2016)

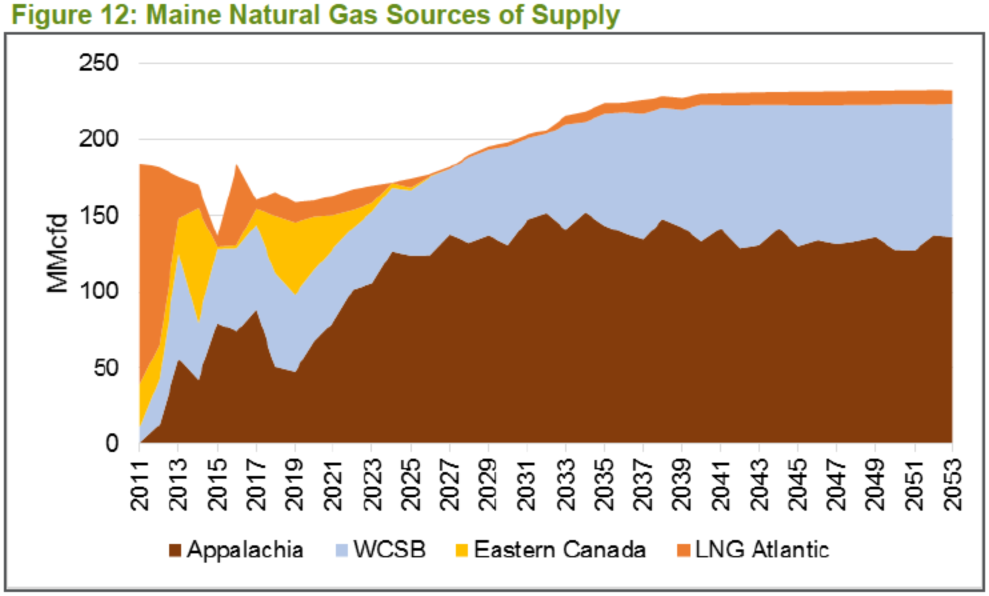


Source: Navigant Consulting Inc. / EIA

3.5. Maine Sources of Supply

Gas supply in Maine is primarily served by natural gas deliveries from Appalachia (Marcellus and Utica Shale plays), the Western Canadian Sedimentary Basin (WCSB), Eastern Canada and LNG imports from import terminals along the eastern seaboard in Canada and Massachusetts as shown in Figure 12, below.

Figure 12: Maine Natural Gas Sources of Supply

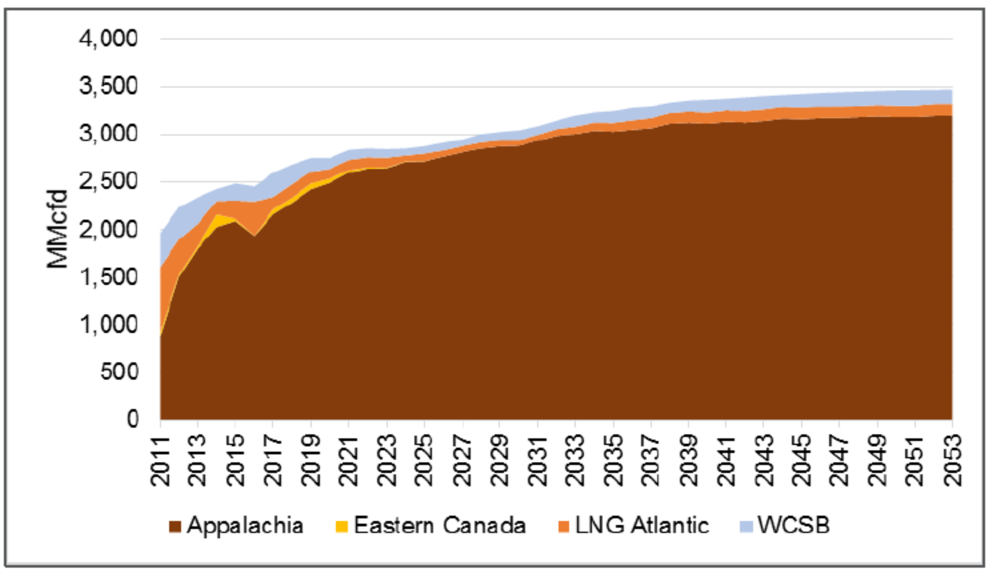


Source: Navigant's North American Natural Gas Market Outlook, Fall 2016; RBAC

The sources of gas supply in Maine vary from the sources of natural gas that serve the overall New England and Mid-Atlantic markets as shown in Figure 13 and Figure 14 below. The rapid increase in natural gas production from the Marcellus and Utica shale plays in the Appalachian region is forecast to provide the majority of natural gas in the Mid-Atlantic and New England markets and displace more traditional sources of supply such as WCSB and Eastern Canada.

While supply from the Appalachian region is projected to become a growing source of supply for Maine, it is also projected to continue to be served by gas supply from the WCSB, LNG imports and Eastern Canada. This is due to the ability of the PNGTS pipeline to deliver natural gas from the WCSB and the M&NE pipeline to provide deliveries from Eastern Canada in addition to LNG imports from the Canaport LNG import facility in Saint John, New Brunswick. The Everett LNG import facility in Everett, Massachusetts will also continue to serve load on the AGT system. Although both of the previously mentioned LNG import facilitates continue to actively serve load, the region's dependence on them has diminished over time. In fact, Repsol, the owner of the Canaport LNG facility, has reviewed the conversion of its Canaport import facility into an export facility.

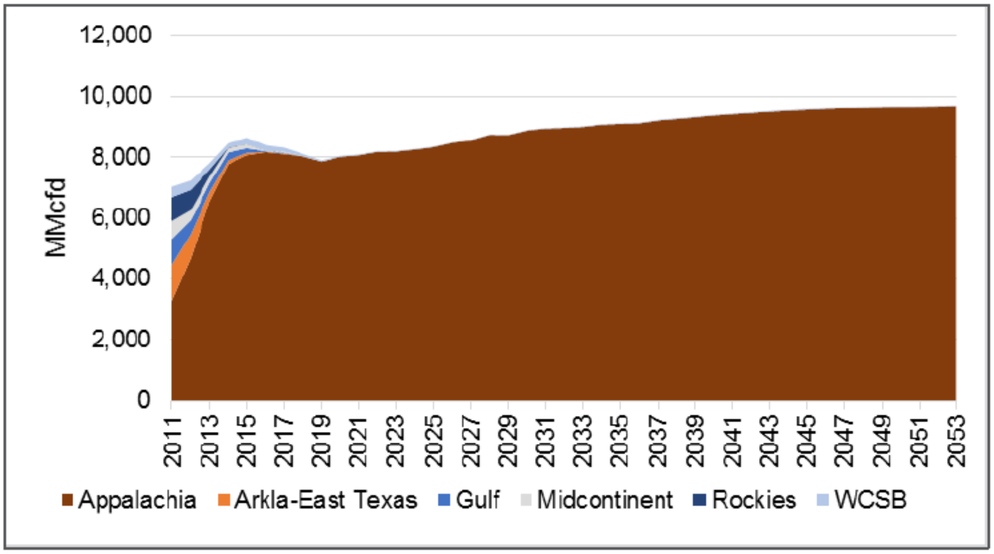
Figure 13: New England Natural Gas Sources of Supply



Source: Navigant's North American Natural Gas Market Outlook, Fall 2016; RBAC

As shown in Figure 13, the Appalachian region is expected to become the primary supplier of gas to New England. Figure 14 demonstrates how the Appalachian region is expected to almost completely displace sources of natural gas from the Rockies, Midcontinent, Permian and Gulf Coast regions by 2020 into the Mid-Atlantic Region.

Figure 14: Mid-Atlantic Sources of Supply



Source: Navigant's North American Natural Gas Market Outlook, Fall 2016; RBAC

3.6. Natural Gas Prices

The primary price hubs that influence delivered natural gas prices in Maine are Tennessee Gas Zone 6, Algonquin City Gates and Dracut.

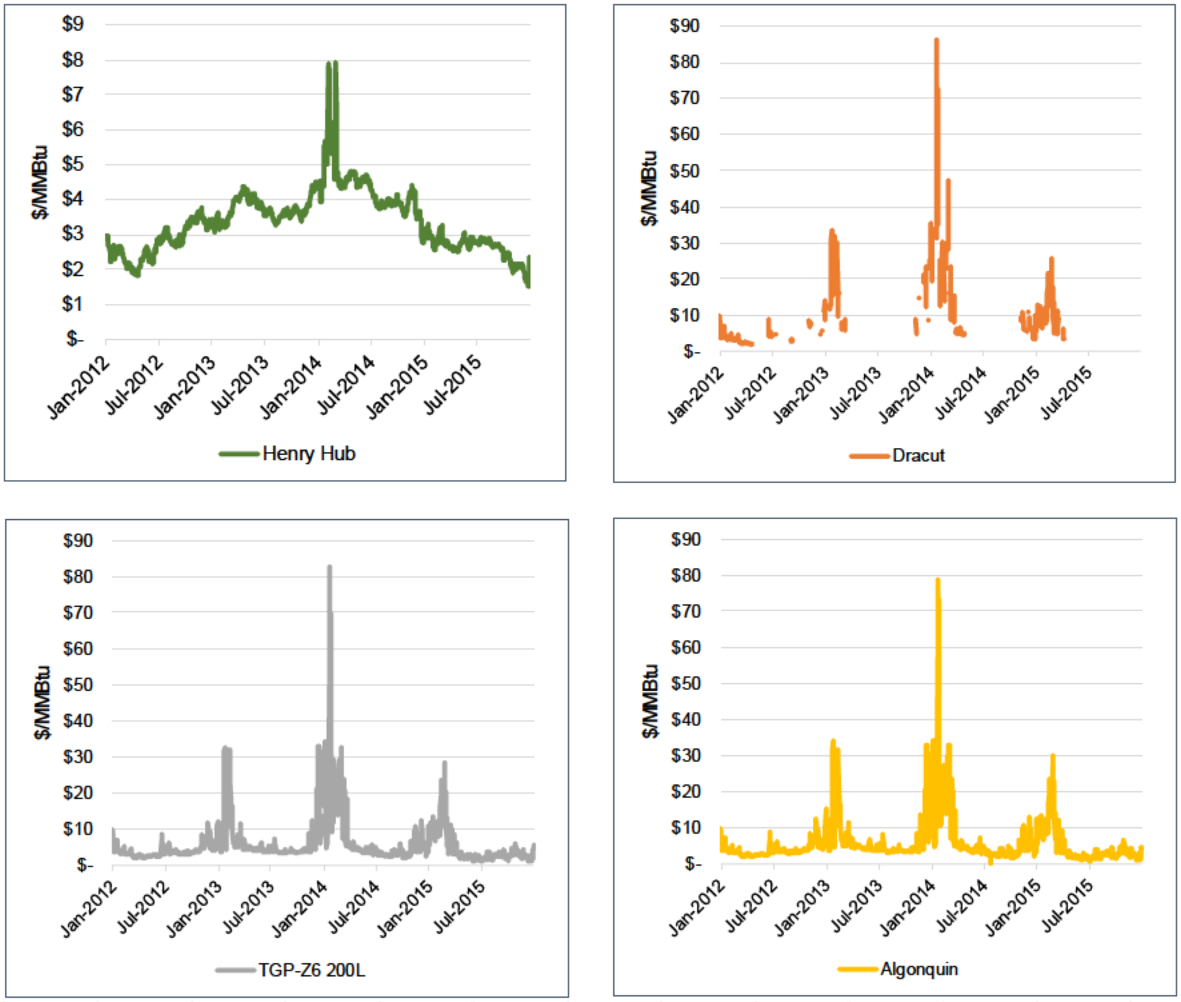
Algonquin, city-gates represents deliveries from Algonquin Gas Transmission to all distributors and end-use facilities in Connecticut, Massachusetts and Rhode Island. The Dracut, MA market price represents deliveries into Tennessee Gas Pipeline at the Dracut interconnect with Maritimes & Northeast Pipeline near Middlesex, MA and gas is generally traded during winter peak months only. The Dracut point also includes gas entering from Portland Natural Gas Transmission System.

Tennessee, zone 6 delivered represents deliveries from Tennessee Gas Pipeline on the 200 leg in Connecticut, Massachusetts, Rhode Island and New Hampshire.

A review of the relationship between natural gas prices in the Northeast and natural gas demand in the Mid-Atlantic and New England regions yields insights into natural gas market dynamics in the region.

As shown in Figure 11 above, during the winter period, defined as November through March, demand for natural gas increases significantly in both the Mid-Atlantic and New England. One result of the sharp increases in monthly demand is a pronounced increase in spot prices for natural gas at key market hubs in New England. Figure 15 below shows spot natural gas prices for Dracut, Algonquin and Tennessee Gas Pipeline Zone 6 in addition to the Henry Hub. These exhibits demonstrate that during periods of peak demand, driven by significant increases in seasonal demand during the winter, spot prices have increased sharply in response to the increase in demand.

Figure 15: Daily Spot Natural Gas Prices (Jan 2012 – Dec 2015)
Henry Hub, Dracut, TGP Z6 and Algonquin



Source: Navigant Consulting Inc. / ICE / Ventyx
Note: Gaps in the historical prices at Dracut reflect lack of reported data on trades.

A key insight from this analysis is that the significant increases in natural gas prices in New England that occurred in the winter months in 2012 through winter of 2015 were driven primarily by the seasonal increases in demand in the Mid-Atlantic. The reason for this relationship is that New England is at the end of the major interstate pipelines that serve the Northeast region, including Maine. As these pipelines move natural gas from supply sources to demand centers throughout the Mid-Atlantic towards New England, seasonally-driven increases in demand in the Mid-Atlantic push up prices at demand centers further upstream.

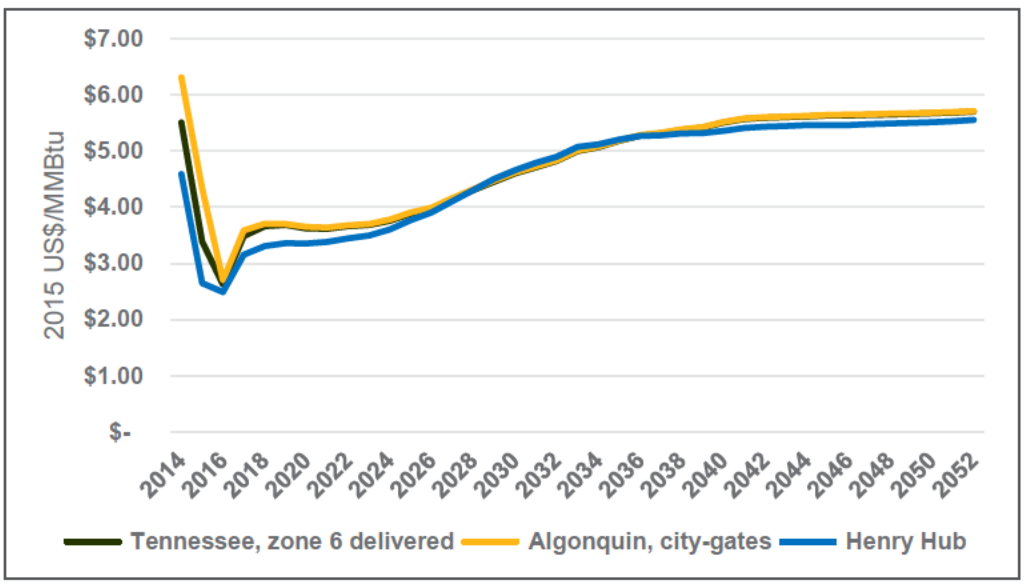
This is evidenced by the sharp increases in prices at Algonquin, Tennessee Zone 6 and Dracut. The size of the Mid-Atlantic market relative to the size of the New England market and its position in front of New England on the path of the major pipelines that serve both markets means that New England must compete for supply with the Mid-Atlantic.

Similar dynamics influence natural gas prices for the Maine market. At 2.5 Bcfd of demand in 2015, the New England regional natural gas market is significantly larger than the 2015 average of 140 MMcfd of demand in Maine. In addition, the geographic position of Connecticut and Massachusetts on the route of two of the major pipelines, Algonquin and TGP, that provide natural gas supply to Maine mean that prices in Maine are largely influenced by regional market dynamics in the Mid-Atlantic and Southern New England.

Another key takeaway from the price comparisons is the relative scarcity of reported prices for Dracut compared to Tennessee Zone 6 and Algonquin City Gate. This is due to the lack of trades at Dracut, which generally only trades on the most extreme winter days and rare occasions in the summer months. Between 2012 and 2016, the Dracut price was only reported for 22% of the total trade days over the year. In the winter the Dracut price was reported 44% of the time and in summer it was only reported 7% of the time. In contrast, the AGT price was reported for 100% of the of the trade days while the TGPZ6 price was reported for 99.6% of the trade days.

As shown in Figure 16 below, Navigant projects that natural gas prices will rebound in 2017 and 2018, then remain moderately flat until 2025 when an increase in demand from electric generation begins to put some upward pressure on prices. After 2035 price growth moderates as growth in both supply and demand begin to slow down. Dracut prices were left out of the forecast comparison due to the previously described lack of trade days and transparency.

Figure 16: Navigant Regional Natural Gas Price Forecast



Source: Navigant's North American Natural Gas Market Outlook, Fall 2016; RBAC

Natural gas prices at Tennessee Zone 6 (TGP Z6) and Algonquin are expected to trade in a close range with each other in addition to trading more closely to the Henry Hub. Prices in the Gulf are expected to rise on higher demand from the electric generation and industrial sectors as well as increased exports of LNG. Northeast prices are expected to remain low due to the abundance of supply in the Appalachian basin. Between the increasing demand in the Gulf and the additional supply in the Northeast, the basis between the two regions is expected to shrink significantly over the next few years

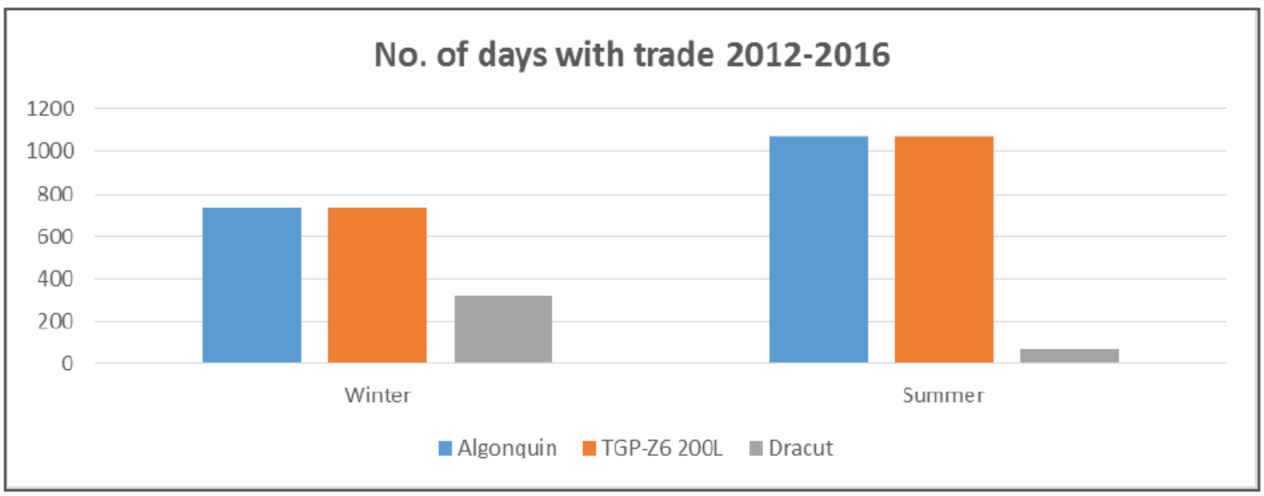
Table 5: Regional Natural Gas Price Forecast

Real 2015 US$/MMbtu	Tennessee, zone 6 delivered	Algonquin, city-gates	Henry Hub
2016	$ 2.62	$ 2.70	$ 2.49
2020	$ 3.62	$ 3.65	$ 3.36
2025	$ 3.88	$ 3.90	$ 3.77
2030	$ 4.60	$ 4.61	$ 4.66
2035	$ 5.18	$ 5.19	$ 5.20
2040	$ 5.50	$ 5.52	$ 5.36
2045	$ 5.63	$ 5.64	$ 5.46

Source: Navigant's North American Natural Gas Market Outlook, Fall 2016; RBAC

For the purposes of conducting the analysis of the proposed Physical Energy Storage Contracts, Navigant has based its analysis on the Tennessee Gas Pipeline Zone 6 (TGP Z6) as the pricing hub against which to measure the market impact of the proposed projects. As shown above in Figure 6, TGP Zone 6 is located closer to Maine than Algonquin. In addition, Dracut was not selected due to its historical lack of trading activity and therefore transparency, especially over the summer period, in comparison to TGP Z6 and Algonquin as explained above and shown in Figure 17 below.

Figure 17: Comparison of Daily Trading Activity at New England Natural Gas Hubs

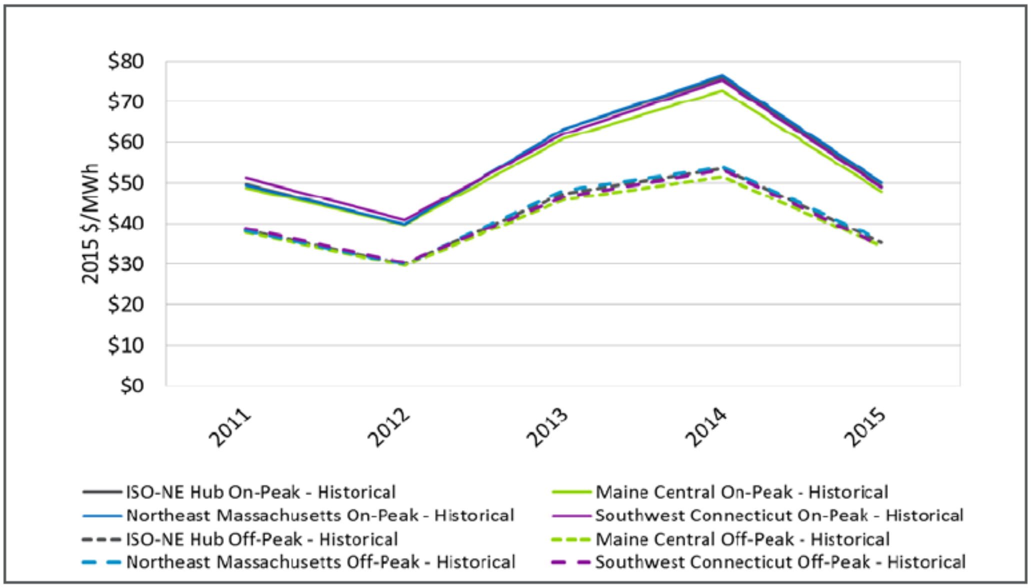


Source: Navigant Consulting Inc. / ICE / Ventyx

4. Overview of Maine Wholesale Electric Power Market

Independent System Operator New England (ISO-NE) is the regional transmission organization for Maine, Massachusetts, Connecticut, New Hampshire, Rhode Island, and Vermont, serving 6.5 million electricity customers and 14 million people. The regional generation market is largely unregulated, with the smallest proportion of generation owned by vertically integrated utilities of any market in the United States. ISO-NE administers two energy markets (day-ahead, real-time), a capacity market, three ancillary services markets, and a transmission market. Energy markets are nodal and prices peak in summer months. The sub-market areas of the ISO generally do not demonstrate strong separation of prices, indicating that intra-regional congestion is not a large issue and that prices are driven by regional factors rather than local factors. Historical annual prices for separate areas of the ISO-NE are shown in Figure 18. This is an important observation because it underscores a further conclusion that modest changes in gas supply in Maine are in turn a relatively small addition to supply to the entire ISO and will have little-to-no impact on Maine LMP.

Figure 18: ISO-NE Annual LMP



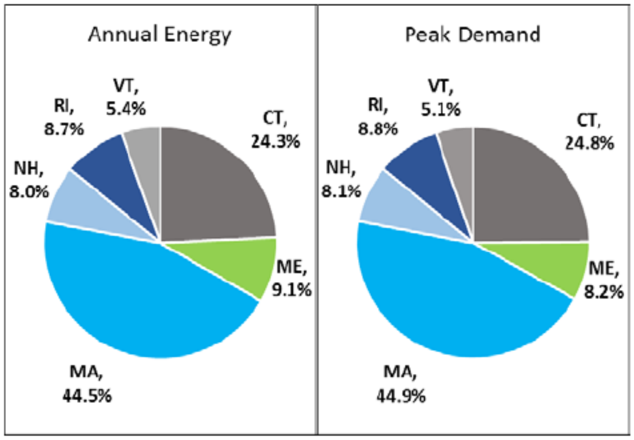
Source: Navigant Consulting Inc. / EnergyVelocity

4.1. Total Electric Demand

ISO-NE's highest single peak occurred on August 2, 2006 at 28,130 MW and in recent years reached peak levels of 24,437 MW in 2015 and 25,521 MW in 2016.

As shown below in Figure 19, over 75 percent of demand and consumption occur in the southern New England states of Massachusetts, Connecticut, and Rhode Island while Maine's electric peak demand and annual energy requirements account for about 9% of total power consumption and 8% of peak demand in the ISO.

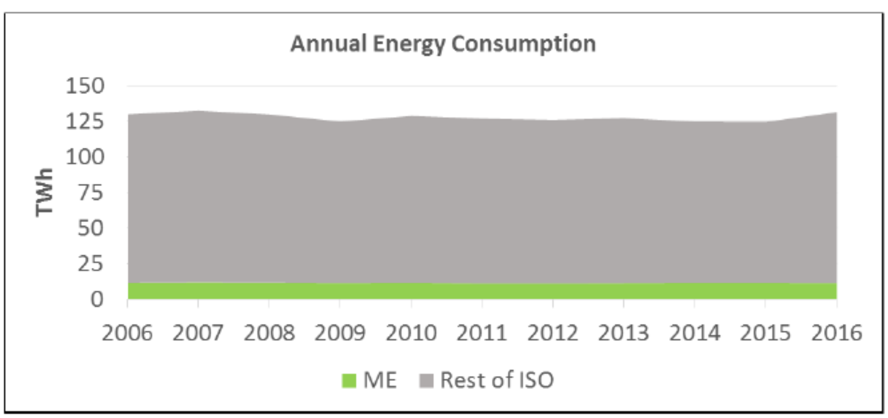
Figure 19: Maine Electric Energy and Demand Share of ISO-NE (2015)



Source: Navigant Consulting Inc. / EnergyVelocity

Over the 2011 to 2015 time period, total electric consumption in New England decreased moderately from 127 TWh in 2011 to 125 TWh in 2015, although these numbers are not weather-normalized and there is no clear trend. Beginning in 2006, prior to the so-called Great Recession of December 2007 to June 2009, electric energy consumption decreased from 130 TWh. Again, these data are not adjusted to normal weather and do not indicate a clear upward or downward trend in the region. Consumption in Maine remained flat during the period with 11.44 TWh in 2006 and 11.35 TWh in 2015 and a ten-year mean value of 11.30 TWh.

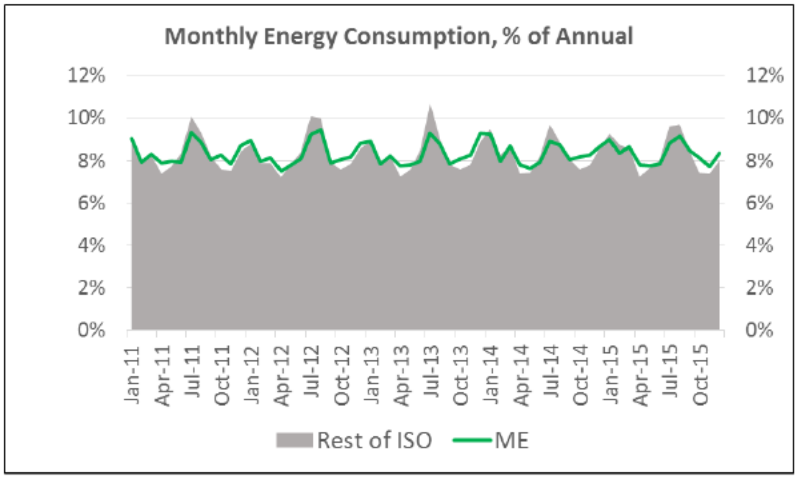
Figure 20: Total Electric Energy Consumption



Source: Navigant Consulting Inc. / EnergyVelocity

Electric demand in Maine and the rest of New England is cyclical due to variations in consumption driven by seasonal requirements for heating and cooling. As shown in Figure 21 below, electricity consumption in Maine fluctuates with a bi-modal distribution around the January and July peak months while consumption in the rest of New England has a more pronounced Summer peak.

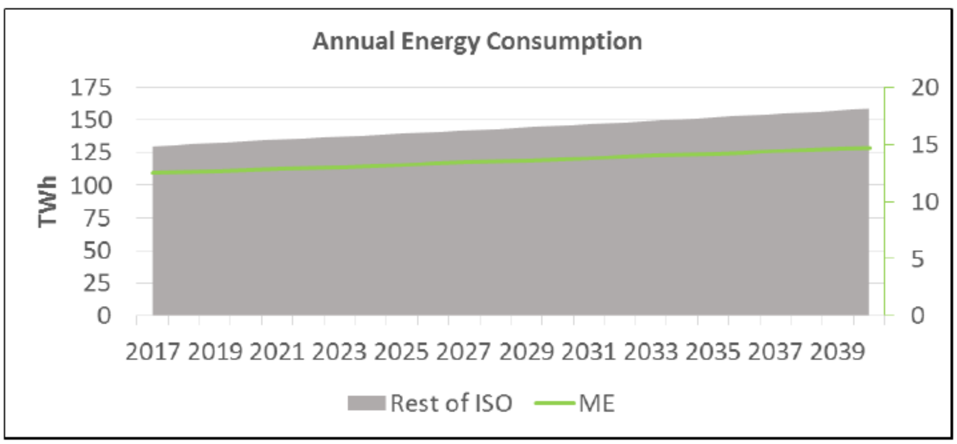
Figure 21: Monthly Electric Energy Consumption



Source: Navigant Consulting Inc. / EnergyVelocity

Navigant's forecast for electric consumption in Maine has a long term growth rate of 0.7% per year, which is slower than the long-term growth rate of 0.9% per year in the rest of New England.

Figure 22: Annual Electric Energy Growth



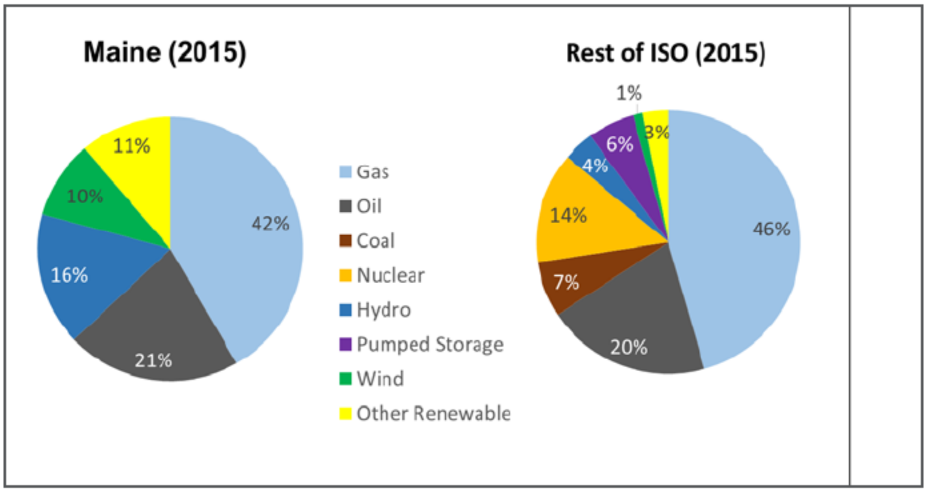
Source: Navigant Consulting Inc. (2016 CELT report with extrapolation)

4.2. Supply Sources and Trends

Most installed capacity in the New England market is thermal plant fueled by natural gas (45%), oil (19%), and coal (6%); with nuclear and combined renewables adding 12% and 18%, respectively. In total, installed capacity accounts for about 87.5% of total resources with the remaining 12.5% coming from incremental energy efficiency programs, active demand response programs, and imports. Current installed capacity in Maine is weighted more heavily to hydro, wind and other renewables (40%) than the rest of the region (16%), as shown in Figure 23.

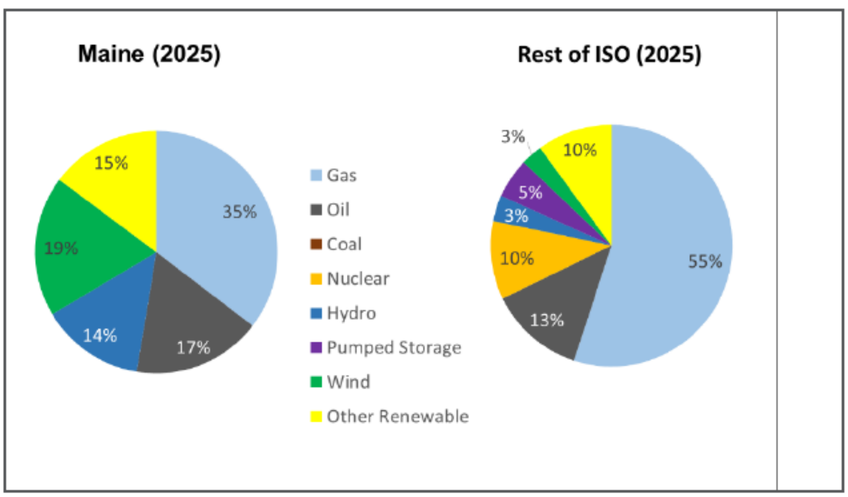
Navigant expects that natural gas additions will be about 55% of new installed capacity over the next decade with mixed renewables accounting for the remainder. This, with expected retirements of oil, coal, and nuclear facilities increase gas' capacity share from 45% to 52% and hydro and other renewables' share from 18% to 26%. However, as shown in Figure 24 new gas plants are not projected to be sited in Maine and renewables are expected to increase to nearly 50% of installed capacity. Gas and renewable shares by 2035 are little changed from 2025.

Figure 23: Installed Capacity Allocations (2015)



Source: Navigant Consulting Inc.

Figure 24: Installed Capacity Allocations (2025)

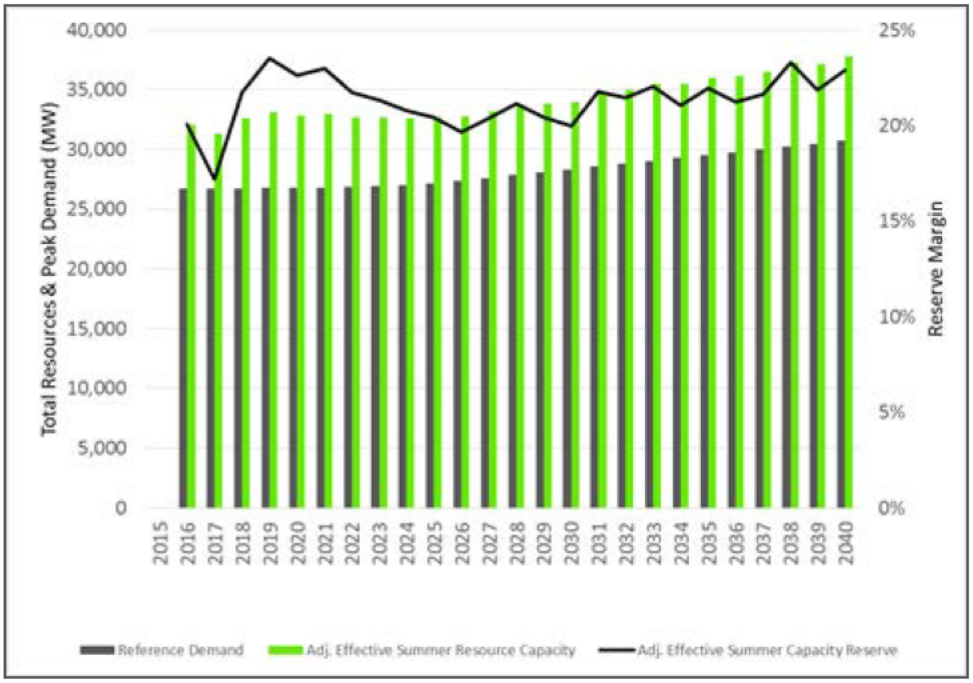


Source: Navigant Consulting Inc.

4.3. Reserve Margin

ISO-NE defines its reserve margin as total capacity minus peak demand net of rooftop solar and passive demand response. The reserve margin target will change based on year-to-year reliability calculations but is generally set at or around 14 percent. ISO-NE includes both demand response and firm purchases/sales in this calculation. The reserve margin has been above 20% in recent years and Navigant expects it remain at or above 20% for the forecast horizon due in large to expected firm purchases of a large block of hydro under the Massachusetts 2016 *Act to Promote Energy Diversity*.

Figure 25: Supply, Demand, and Planning Reserve



Source: Navigant Consulting Inc.

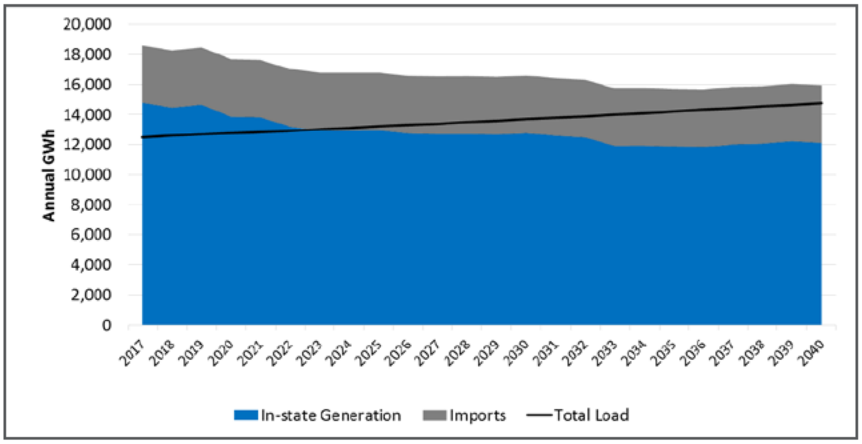
4.4. Maine Forecast Results

The ISO-NE market, including the three Maine zones of Bangor Hydro, Central and Southwest, were forecasted for the period 2017-2040 in Navigant's nodal PROMOD model. Two scenarios were run – one with the Access Northeast pipeline and the other without Access Northeast. Summary results of these two cases are presented for Maine in this section. We note that Navigant's analysis indicates minimal impact of the LNG storage projects on the actual levels of LMPs for Maine.

4.4.1. Load and Generation Balance

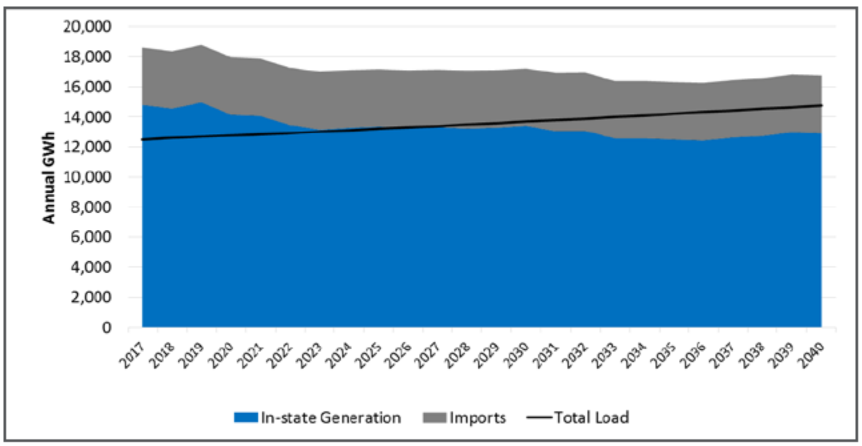
On an all-hours basis, Maine is a net-positive producer through the early years of the forecast period but that condition fades by the mid-2020s as (i) existing combined cycle plant output lag in the face of competition from new more efficient combined cycle plants in the southern New England states and (ii) new generation plant construction in Maine does not keep pace with demand growth. In that transition, an increasing amount of imports from New Brunswick are "retained" within Maine. Figure 26 and Figure 27 show these results for the two scenarios. The general market impacts on Maine of removing Access Northeast are to shift production of power from thermal generation plant into Maine, with broad scale increases in LMP, fuel consumption, and emissions.

Figure 26: Maine Load and Generation Balance (with Access)



Source: Navigant Consulting Inc.

Figure 27: Maine Load and Generation Balance (w/o Access)

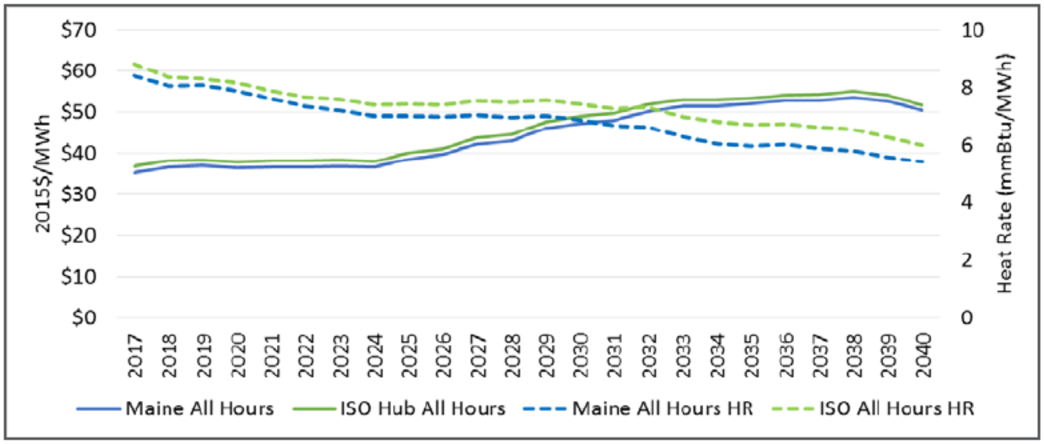


Source: Navigant Consulting Inc.

4.4.2. LMP Summary

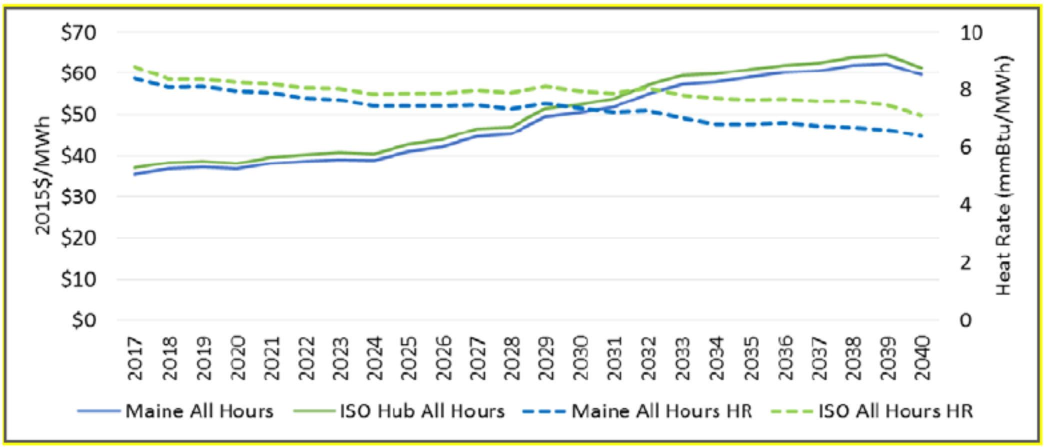
Projected changes in LMP in the Maine zones track closely with changes at the ISO Hub. Market heat rates decline steadily across all three time blocks (on-peak, off-peak, all hours) due to the penetration of more efficient gas combined cycle plants at the margin and broader penetration of renewable plant. Also, Maine heat rates fall slightly faster than the ISO heat rates. Figure 28 and Figure 29 show these results for the two scenarios. With the Access Northeast project removed, Navigant's long-term all-hours LMP forecasts are about $2 higher in the 2020s and $7 higher in the 2030s, with the gap increasing to $9 by 2040. Market heat rates are correspondingly higher.

Figure 28: Maine and ISO All-Hours LMP and Heat Rate (with Access)



Source: Navigant Consulting Inc.

Figure 29: Maine and ISO All-Hours LMP and Heat Rate (w/o Access)

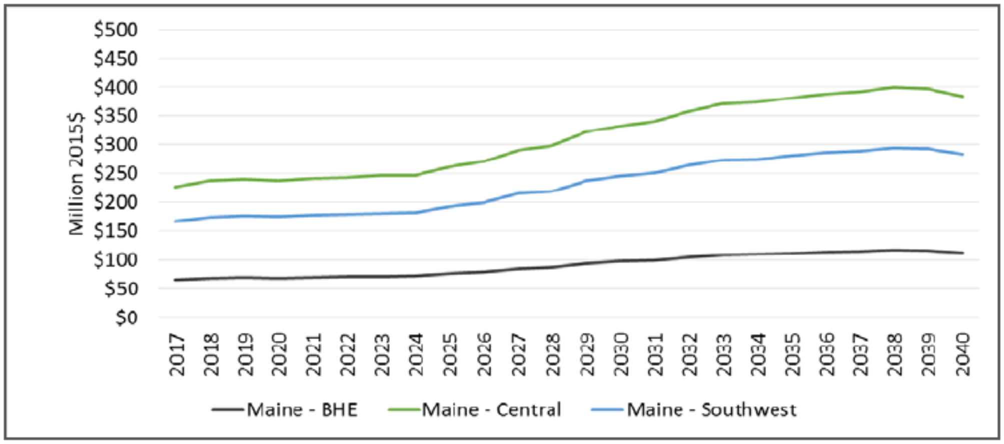


Source: Navigant Consulting Inc.

4.4.3. Consumer Wholesale Payments

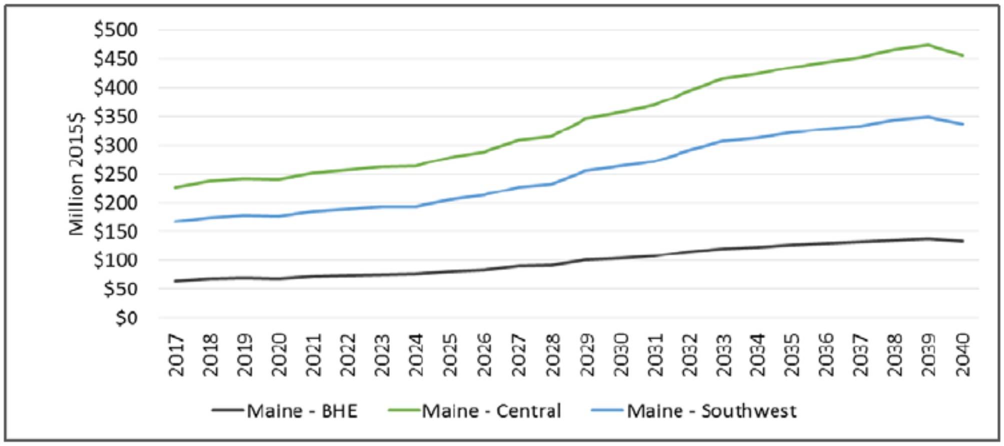
Wholesale market payments underlie the eventual retail costs to consumers as the cost of purchased power. Total LMP payments increase over the forecast period with increases in LMP and increases in demand. Figure 30 and Figure 31 show these results for the two scenarios. With the Access Northeast project removed, Navigant's long-term power payment forecasts for consumers in Maine are higher than the "with-Access scenario" by about $35 million per year in the mid-2020s, about $100 million in the mid-2030s, and $150 million by 2040.

Figure 30: Wholesale Power Payments (with Access)



Source: Navigant Consulting Inc.

Figure 31: Wholesale Power Payments (w/o Access)



Source: Navigant Consulting Inc.

4.4.4. Fuel Requirements

Over the long run, biomass consumption in Maine is expected to remain stable, natural gas consumption is expected to decline steadily until the mid-2030s before leveling off, and oil consumption is expected to slowly decline. Figure 32 and Figure 33 show these results for the two scenarios. In both scenarios, declines in natural gas consumption are driven by increasing competition from newer combined cycle plants outside of Maine but the declines are partially offset by increases in biomass capacity factors and feedstock consumption. With removal of the Access Northeast project, fuel consumption by plants in Maine increases by about 3.7 TBtu per year, on average, in the 2020s and by about 5.3 TBtu per year in the 2030s. In parallel to this increase in fuel consumption, CO2 emissions increase by about 255 thousand short tons per year in the 2020s and 340 thousand short tons in the 2030s in the scenario without Access Northeast.

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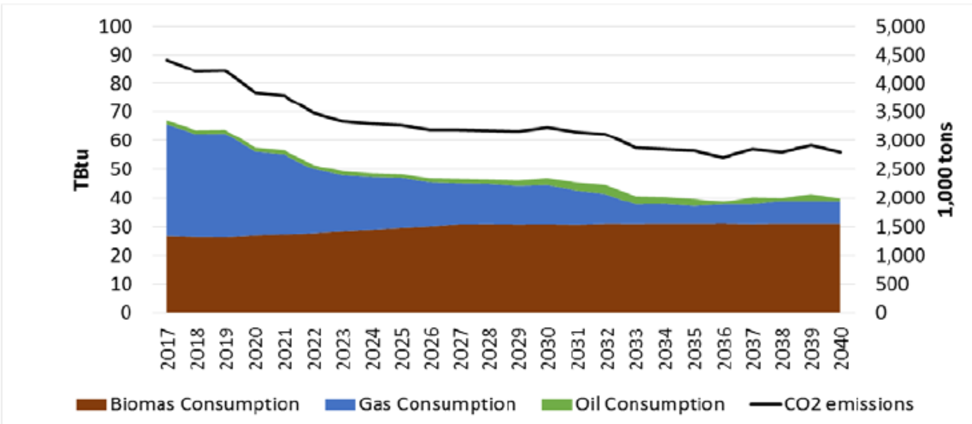
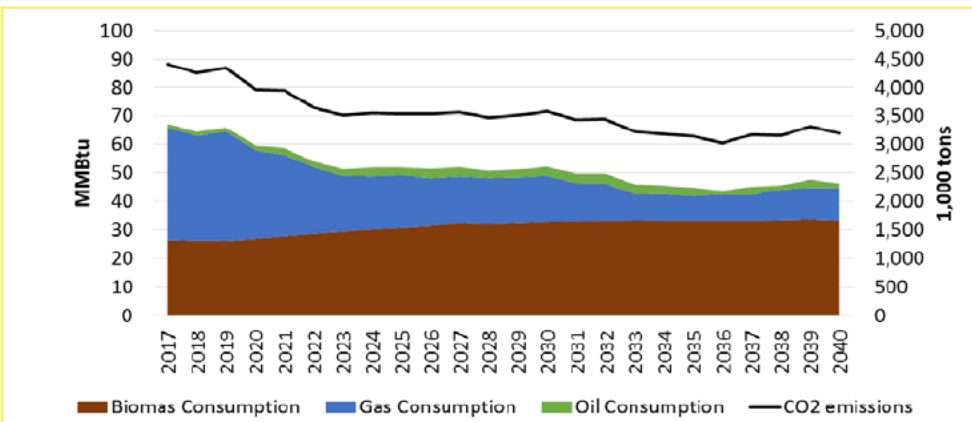
Figure 32: Fuel Consumption and CO2 Emissions (with Access)



Source: Navigant Consulting Inc.

Figure 33: Fuel Consumption and CO2 Emissions (w/o Access)



Source: Navigant Consulting Inc.

4.4.5. Comparison Between Access Northeast Scenarios

The general market impacts on Maine of removing Access Northeast are to shift production of power from thermal generation plant into Maine, with broad scale increases in LMP, consumer load payments, production costs, fuel consumption, and emissions. Table 6 shows these results.

Table 6: Summary Results (with and without Access Northeast)

Compare Average Annual values with and without Access Northeast	With Access Northeast			Without Access Northeast		
	2017-2020	2021-2030	2031-3040	2017-2020	2021-2030	2031-3040
Average On-Peak LMP (2015$/MWh)	$42.98	$46.75	$60.95	$43.18	$49.48	$69.20
Average All-Hours LMP (2015$/MWh)	$36.08	$39.06	$50.95	$36.18	$41.18	$57.41
Consumer Load Payments (million 2015$)	$5,664	$6,675	$9,209	$5,699	$7,090	$10,522
Variable Production Cost (million 2015$)	$604.07	$546.11	$615.84	$601.52	$608.82	$757.39
Fuel Use (TBtu)	63.115	48.728	41.185	64.322	52.587	46.464
CO2 Emissions (thousand short tons)	4,169	3,316	2,890	4,242	3,586	3,228
NOx Emissions (short tons)	2,051	1,912	1,903	2,068	2,038	1,999
SO2 Emissions (short tons)	432	474	712	444	852	805

5. General Overview of PESC Bids

The parameters of PESC bids covered a range of key aspects of proposed facilities from facility size and operating characteristics, to various components of contract costs. The main physical parameters included the capacity of the proposed LNG storage tanks, the vaporization rate and/or number of storage withdrawal days, and the fill rate for the storage tanks. Cost-related parameters included fixed and variable costs and the rates of vaporization and/or liquefaction fuel loss/use.

There were originally seven bidders providing more than twenty bid options. After both a procedural order requiring a reduction to two options per bidder, as well as Prometheus Energy withdrawing, there were six bidders that ultimately presented bids for analysis in this report, for a total of 11 bid options. The LNG tank sizes were generally spread between one and two Bcf, with varying vaporization rates contributing to various total days of LNG use out of storage. One bidder had a significantly smaller tank, thereby creating smaller value. Days of use were generally estimated by dividing the tank size by the vaporization rate.

The time to fill a tank was either provided in the bid or estimated from the tank size and the fill rate specified in the PESC bid. In general, an average price over the off-peak season was used to generate fill costs; in one instance, a longer time to fill led to a longer period than the generalized the off-peak period during which prices to fill would be based. Fill time for liquefaction-based projects varied from 100 days to about 240 days, as a function of tank size and fill rate.

With regard to contract costs, charges generally consisted of fixed costs, variable costs, and fuel loss/use costs. As noted previously, some contract total costs appear to exceed the $25 million annual figure appearing in the legislation. Some contracts included supply provided via on-site liquefaction, while other options were based on trucked-in LNG supply. For trucked-in LNG supply, Navigant included a cost adjustment to account for the extra costs to procure gas as LNG rather than as ordinary natural gas. A general summary of bid terms by bidder and for the limit of two bids per bidder that were requested by the Maine PUC follows.

Table 7: Overview of PESC Option Bids

Company	Option	Tank Capacity	Vaporization Rate	Use Days	Fill Method	Fill Rate	Fill Days	Contract Charges
		Bcf	MMcfd	Days		MMcfd	Days	
Cavus Energy	Base	1	200	5	Liquefaction	5.4	185	$25M fixed $50k variable $1.7M electric 2% vap loss
Cavus Energy	Alternate	1	100	10	Liquefaction	4.1	244	$21M fixed $50k variable $1.7M electric 2% vap loss
Eagle Partners	A	[redacted]	[redacted]	[redacted]	Truck			[redacted]
Eagle Partners	C	[redacted]	[redacted]	[redacted]	Truck			[redacted]
Engie	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Engie	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Northern		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Northstar Industries	Tolling 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Northstar Industries	Tolling 2	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
Reliable Energy Storage	1.1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reliable Energy Storage	2.1	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
Prometheus (WITHDRAWN)		[redacted]	[redacted]	[redacted]	[redacted]			[redacted]

6. Detailed Methodology

6.1. Model Description

Navigant's modeling uses a proprietary, in-house version of RBAC Inc.'s GPCM, a competitive, partial-equilibrium model that balances supply and demand while accounting for the costs and capacity of transport and storage. The model will balance or clear supply and demand for North America based on meeting all regional demands from the mix of available supplies, accounting for physical interconnections as well as costs associated with production, transport, and storage. Navigant's gas supply assumptions are based on currently producing gas basins, incorporating potential trends in production levels to generate ranges of likely future production. Additional producing basins or modifications to general production trends requires specific scenario modeling.

Navigant's gas infrastructure assumptions are based on existing pipelines, augmented to relieve future bottlenecks where appropriate[5], plus those announced projects deemed likely to be built. Additional pipelines require specific scenario modeling.

Navigant's forecasting methodology is conservative in that, as noted, supply and infrastructure assumptions are generally based on existing production basins or specific infrastructure that exists or appears likely to be built. With regard to supply, the forecasts assume no new gas supply basins beyond those already identified as of mid-2016. This is conservative given the steady rate at which new shale resources have been identified over the past few years and the history of increasing estimates of the North American natural gas resource base. For example, the United States Geological Survey has recently issued a new resource assessment for the Mancos Shale play in the Piceance Basin centered in Colorado, with a projected recoverable resource level of 66 Tcf. [6] Similarly, production in the Permian Basin has increased dramatically from 3.5 to 6.0 Bcfd over the last five years, according to Navigant data review.

With regard to infrastructure, Navigant's modeling is based upon existing North American pipeline and LNG import terminals, augmented by planned expansions that have been publicly announced and that appear likely to be built, including consideration of LNG export terminals. Pipelines are modeled to have sufficient capacity to move gas from supply sources to demand centers. Some local expansions have been assumed and built into the model in future years to relieve expected bottlenecks. In general, no publicly unannounced infrastructure projects have been introduced into the model. This means that no new infrastructure has been incorporated into the model post-2016, except as has been announced at the time of our forecasting in mid-2016. In the absence of specific information, Navigant limits its infrastructure expansion to those instances where an existing pipeline has become constrained as determined by the model. The remedy consists of adding sufficient capacity to relieve the constraint only.

RBAC's daily gas market model is based on the GPCM monthly model, but with additional capabilities necessary to address daily demands and flows (such as peak day) rather than monthly average data. Specific market attributes that may be assessed on a daily basis include very hot or very cold weather, and scheduled events such as LNG tanker arrivals or departures. Consequently, more granular (i.e. daily, rather than monthly average) review of natural gas demand, storage capabilities and operations, as well as pipeline system bottlenecks, allows for more focused peak day analysis of the impacts of new gas infrastructure.

6.2. Model Assumptions

Navigant performed detailed analysis of natural gas demand for Maine both by sector and by components of supply, i.e. LDC and balance of Maine, as well as contracted and uncontracted portions of supply. These breakouts were important in order to allow for assessing how the different PESC volumes would end up being deployed across different markets, as discussed in more detail in the next section.

[5] This expansion feature was not used in New England, in order to maintain existing infrastructure to represent a "status quo".

[6] United States Geologic Survey, Assessment of Continuous (Unconventional) Oil and Gas Resources in the Late Cretaceous Mancos Shale of the Piceance Basin, Uinta-Piceance Province, Colorado and Utah, 2016.

Starting with state-level natural gas demand, Navigant applied a forecasted growth rate to historical sectoral demand for residential, commercial and industrial classes as reported by the U.S. Energy Information Administration (EIA) for 2015. Growth rates from 2016 to 2020 are based on the annual sectoral growth rates reflected in Northern Utilities' Inc. 2015 Integrated Resource Plan[7] converted from gas year to calendar year. The growth rates from 2019 to 2020 were extrapolated for purposes of estimating demand growth through 2052. Electric generation sector natural gas demand was provided through an integrated solution of GPCM and Navigant's proprietary Portfolio Optimization Model (POM).

For Maine LDC-level natural gas demand, Navigant used data for LDC sectoral demand for residential, commercial and industrial classes provided by the Maine PUC for 2015, and applied the forecasted growth rates used for sectoral Maine demand to these demand levels through 2020. Beyond 2020, Navigant assumed that the LDC portion of Maine total demand, for each sector, remained at the same percentage as 2020.

With respect to assumptions for contracted versus uncontracted sources of supply, Navigant incorporated historical data for 2015 provided by the Maine PUC staff for contracted natural gas supplies by sector for LDCs. Navigant then applied the forecasted growth rates used for sectoral Maine demand to these demand levels through 2052 for the residential sector, and through 2020 for the industrial and commercial sectors. For those two sectors beyond 2020, Navigant assumed that the LDC contracted portion of Maine total demand, for each sector, remained at the same percentage as 2020. LDC uncontracted sources of supply equal the difference between total LDC demand and contracted sources of LDC supply. For the balance of Maine, contracted sources of supply are represented using the ratio of LDC contracted sources to total LDC demand. Balance of Maine uncontracted sources of supply equal the difference between total balance of Maine demand and contracted sources of balance of Maine supply.

In summary, Navigant estimates for 2022 a Maine peak demand of 220 MMcfd, with 101 MMcfd representing LDC demand and 119 MMcfd representing balance of Maine demand. Of the LDC demand, 58 MMcfd is estimated to have contracted supply, leaving 43 MMcfd uncontracted. Of the balance of Maine demand, 69 MMcfd is estimated to have contracted supply, leaving 50 MMcfd uncontracted. For the state, 127 MMcfd is estimated as having contracted supply, leaving 93 MMcfd as statewide demand with uncontracted sources of supply.

With regard to pricing, Navigant used the Daily Model to generate an estimate of peak period pricing based on a ratio of 15-day average peak demand to average winter-time demand for Maine and other regions. Specifically, Navigant calculated the average winter-time demand for each census region and for Maine using daily consumption data available from Energy Velocity for the period January and February from 2012 to 2016. For the 15-day average peak demand, Navigant utilized daily data from January and February during the five-year period from 2012 through 2016 to obtain the highest 15 demand dates per year for the Mid-Atlantic region. As outlined earlier in the report, the Mid-Atlantic regional demand is the key driver for prices that are relevant to Maine. Using these 15 specific dates for each of the five noted years, Navigant estimated a 15-day average peak demand for each census region, and for Maine. Demand levels were then factored up by the ratio of 15-day average peak demand to wintertime average demand, and the Daily Model was employed on the revised data set to

[7] Filed with Maine and New Hampshire Public Utilities Commissions, January 16, 2015.

yield a price associated with an assumed 15-day average peak demand. As previously stated, we also present summary results using a less conservative assumption of average wintertime prices.

We note Navigant's analysis indicates minimal impact of the LNG storage projects on the actual levels of natural gas market prices applicable to Maine (i.e. less than one percent), as well as on the electric market LMPs for Maine. With regard to natural gas prices, Navigant, using its daily model, modeled the largest LNG facility with a max send out of 200 MMcfd and found that the additional supply had minimal impact on prices. As noted earlier in the report, Maine's total demand represents about 1% of the total demand in the Northeast making Maine a price taker in the area. More importantly, large demand areas in the Mid-Atlantic and New England census regions drive prices during winter peak days so even the largest LNG storage facility represents only a small fraction of the regional supply that is used to meet Northeast demand on winter peak days

Finally, Navigant ran two scenarios, based on Navigant's Fall 2016 Reference Case, to account for either the inclusion or the exclusion of the Access Northeast pipeline project due to some uncertainty with respect to ultimate construction of the project. It may be noted, however, that there is likelihood that even if the Access Northeast pipeline project is not built, some other pipeline project will be built sometime in the future to better serve the Northeast and Maine markets. The choice of Access Northeast as the pipeline to exclude for the second scenario was based on its relative proximity to and potential influence on the Maine market as well as its current status as a proposed project. According to Spectra, one of the stated goals of the Access Northeast project is to increase deliverability to electric generating units on the M&NE pipeline system in Maine. Spectra intends to increase deliverability by expanding the AGT system as well as adding in an LNG storage facility with the potential daily send-out of 400 MMcfd. The total Access Northeast project is anticipated to increase deliveries in the area by 925 MMcfd on winter peak days, which is much larger than even the largest bid at 200 MMcfd.

6.3. Benefit Analysis

As noted above at the most general level the analysis starts with the avoided cost of winter-time (i.e. peak) gas purchases due to the stored LNG, less the summer-time (i.e. non-peak) gas cost to fill the storage facility, less the contract costs to obtain the storage service. The net of these figures represents the net benefit of the PESC. The analysis of peak-day prices and off-peak prices, together with the operational parameters, yields the gross commodity benefit. From this commodity benefit, the annual contract costs must be deducted in order to arrive at a net benefit figure for a PESC. Navigant developed a comprehensive spreadsheet model tool to financially analyse each PESC option using a consistent framework, assumptions and methodology.

Depending on the quantity of daily gas sendout reflected in a bid, contract volumes could exceed the need for LNG peaking supplies by the LDC, or perhaps even for the State of Maine. Thus, because of the interplay of contract volume with potential LDC demand volume, or potential State of Maine demand volume, Navigant's analysis includes breakouts of contract volume across different allocation categories (i.e. LDC, Maine, out-of-state) of the stored LNG to provide tracking for informational purposes. At the snapshot level, net benefits are shown for each contract for each estimated demand segment by allocation category. For consistency in analysis, as well as due to some uncertainties in estimated start dates, we have assumed a uniform initial start date of 2022 for all bid options. All figures have been reflected in 2015 (real) dollars in order to be consistent with Navigant's market forecast of prices, as well as the forecast results of the Daily Model. Since our assumptions show that the contracting party, e.g. an LDC, may not have sufficient load by itself to use the full vaporization rate under a PESC, we assume that as "holder" or "owner" of the PESC, the LDC would be in a position to maximize value of the PESC (say by selling excess gas at peak), in order to beneficially offset contract costs that it would be subject to paying. Thus, the operative metric for comparison is assumed to be the net benefit of a bid option incorporating the total bid volume, regardless of the ultimate disposition of the stored LNG. This assumption is consistent with the assumption that direct contract costs and benefits realized as a result of a PESC will flow to the ratepayers of the contracting entity.

Navigant's analytical tool compares each contract's parameters, including specifically vaporization days and volumes, to an estimated demand for peak supplies by Maine LDCs, and then the balance of Maine to give a view of Maine gas demand in total, with any remaining positive balance going to serve out-of-state peak sales. In order to arrive at an estimated demand for LDC peak LNG supplies, Navigant deducts from overall LDC demand estimates an estimate of LDC-contracted supplies, leaving an estimate of uncontracted LDC supply requirement. The source of the estimated LDC contracted supplies, as noted earlier, is the Maine PUC staff for this project. Similarly, for the balance of Maine, Navigant deducts from the balance of Maine demand estimates of Maine-contracted supplies, leaving an estimate of uncontracted balance-of-Maine supply requirement. Any remaining contract volumes are assumed to be used for out-of-state sales. The tool then estimates the market value of the peak LNG supplies by market, based on volume and number of vaporization days subject to the demand requirements just discussed.

For purposes of estimating the peak value of the LNG, Navigant utilized its Daily Model. The price in each snapshot applicable to the avoided peak price of LNG-based supply is derived as the average of the top 15 days falling in the two-month winter period (assumed as January and February) in each snapshot year. As discussed earlier, the pricing point used in the analysis is Tennessee Gas Pipeline Zone 6-delivered, a liquid point with applicability for northern New England and for Maine given the lack of liquid gas trading points in the Maine market itself.

Finally, annual contract costs are netted out from the commodity benefit in order to arrive at an annual cost-benefit result in each snapshot year. For purposes of the volume breakouts, we have netted the contract costs out of the LDC peak value benefit, since the LDC will be responsible for meeting the contract costs. This generally results in negative net benefits showing at the LDC level, before allowing for peak value benefit from beyond the LDC to be incorporated into the result. There are also results with negative net benefits showing at the State of Maine level, before allowing for peak value benefit from out of state sales to be incorporated into the result. Finally, we have generated a net benefit calculation reflecting the subtraction of the contract costs from the net margin on commodity for the entire contract volume, including any residual out-of-state sales. The results coming from the calculation based on total contract volumes, which may incorporate some out-of-state sales, is the appropriate measuring point for the net cost-benefit analysis as it reflects the total position of the LDC contracting party from the PESC. To clarify, such out-of-state benefits would not be accruing to out-of-state consumers, but would represent contract value from out-of-state sales, presumably realized by the LDC on account of its ratepayers.

With regard to specific categories of contract costs, most bid options contained an annual fixed charge, generally levelized over the contract term, although one bidder included a partial escalation of a portion of the fixed charge. In addition to annual fixed charges, elements of variable costs were also presented. In some instances, the variable costs were already reflected on an annual basis, in essence as an additional category of fixed costs. These were added in to the cost calculation as presented. In some instances, variable costs were noted, but had already been included in the fixed charge and therefore need not have been included as a separate item. Other bidders presented volumetric variable costs, which were incorporated based on project volume. One bidder included an electric charge based on estimated energy consumption, and this cost item was accounted for using the 2015 average Maine retail power price.

Several other parameters contributing to contract costs were liquefaction fuel requirements as well as vaporization losses. For liquefaction fuel, an adder was calculated with respect to the summer-time fill costs to reflect the additional percentage of fuel requirement. For vaporization losses, an adjustment was made to the avoided volumes of peak-period natural gas to reflect the amount of losses occurring at the vaporization stage.

Finally, for bid options relying on trucking in of pre-liquefied LNG supplies, a fill cost premium for LNG supplies versus pipeline natural gas was included. The premium is a percentage adder on top of the standard fill cost (which is based on Navigant's monthly non-peak price forecast). The percentage is derived from the historical relationship over summer periods during 2013-2016 between landed LNG costs at the Everett import facility in Massachusetts and the price at Tennessee Zone 6-delivered and was 74 percent, as shown for various trucking-related options in Table 7.

With respect to gas transport, since either summer-time fill gas or winter-time peak supplies would require pipeline transport, it was assumed to be an equivalent cost that was not included in the analysis. Similarly, due to the lack of public data on LNG transport costs, an equivalent cost was assumed for pipeline and trucking costs in the analysis and was not specifically included.

In order to estimate an NPV value for the net benefit over a proposed PESC's entire contract term, the net benefits in intervening years between the snapshot years have been estimated using a process based on the monthly price levels contained in Navigant's market assessment. Specifically, annual interpolated values between snapshot values of the ratio between the peak and its monthly average price was applied to the average prices in the intervening years in Navigant's forecast. A real discount rate of 4 percent has been utilized, accounting for the fact that the net benefit flows are already reflected in real 2015 dollars. In addition, a Return on Investment (ROI) has also been estimated to accompany each NPV result to complete the analytical results.

7. Analysis of PESC Bids

Following is a set of analyses for each PESC bidder, summarizing each bid option, and presenting gross margin, contract cost, and net benefit results across the snapshot years. More detailed results appear in Appendix A for the "with Access Northeast" scenario and in Appendix B for the "without Access Northeast" scenario.

7.1. Cavus

Cavus has proposed two options, both with liquefaction facilities. The tank size is the same at one Bcf. The vaporization rate is 200 MMcfd for the base offer (Cavus 1), yielding five effective use days, and 100 MMcfd for the alternative offer (Cavus 2), yielding 10 effective use days. The fill rate for the base offer is also faster, at 5.4 MMcfd, versus 4.1 MMcfd for the alternative offer; these fill rates yield fill times of 185 days and 244 days, respectively. The fixed costs for the higher vaporization option are higher at $25 million per year (nominal), as opposed to $21 million per year for the 100 MMcfd option. Cavus has also added a variable cost of $.05 per Dth (for a total of $50,000 per one Bcf tankful), plus power costs of 13.2 GWh per fill. At the 2015 Maine average retail power price of $.1297 per kWh, the power charge comes to about $1.7 million. Cavus has stated a vaporization loss factor of two percent, which has been applied as a deduction from the calculated value of gross sales, and thus gross margin.

7.1.1. With Access Northeast

Modeled as outlined above, Cavus 1 net benefits are negative for the LDC, for the State of Maine, and in total across each of the applicable three snapshot years. The NPV of the total annual net benefits over the term comes to negative $98 million, with an ROI of negative 44%, as shown in Section 7.7. Thus, Cavus 1 is not considered a viable option for the program, under the "with Access Northeast" scenario.

Modeled as outlined above, Cavus 2 net benefits are negative throughout the term on an LDC basis, and generally negative for the State of Maine, although at the tail end the net benefits do swing positive. The NPV of the total annual net benefits over the term comes to negative $66 million, with an ROI of negative 35%, as shown in Section 7.7, and thus Cavus 2 is not considered a viable option for the program, under the "with Access Northeast" scenario.

2015 $ in millions		**Cavus 1**	*2022*	*2032*	*2042*	*2052*
LDC						
		Gross Margin	2.17	2.28	3.37	N/A
	Less	Total Contract Cost	24.12	19.94	16.59	N/A
		Net Benefit	(21.95)	(17.67)	(13.22)	N/A
Maine						
		Gross Margin	4.76	5.82	9.22	N/A
	Less	Total Contract Cost	24.12	19.94	16.59	N/A
		Net Benefit	(19.36)	(14.12)	(7.37)	N/A
Out of State						
	Plus	Gross Margin	5.34	4.73	6.11	N/A
Total Benefit						
		Net Benefit	**(14.02)**	**(9.39)**	**(1.26)**	**N/A**

	Cavus 2	2022	2032	2042	2052
2015 $ in millions					
LDC					
	Gross Margin	4.32	4.54	6.72	N/A
Less	Total Contract Cost	20.55	17.01	14.17	N/A
	Net Benefit	(16.23)	(12.47)	(7.45)	N/A
Maine					
	Gross Margin	9.48	10.51	15.28	N/A
Less	Total Contract Cost	20.55	17.01	14.17	N/A
	Net Benefit	(11.08)	(6.50)	1.11	N/A
Out of State					
Plus	Gross Margin	0.57	0.00	0.00	N/A
Total Benefit					
	Net Benefit	**(10.51)**	**(6.50)**	**1.11**	**N/A**

7.1.2. Without Access Northeast

Modeled as outlined above, Cavus 1 net benefits are negative for the LDC and for the State of Maine, across each of the applicable three snapshot years. For total contract volumes, the net benefits do become positive at the tail end of the term. The NPV of the total annual net benefits over the term comes to negative $29 million, with an ROI of negative 13%, as shown in Section 8.1. Thus, Cavus 1 is not considered a viable option for the program, even under the "without Access Northeast" scenario.

Modeled as outlined above, Cavus 2 net benefits are negative throughout the term on an LDC basis, and generally negative for the State of Maine, although at the tail end the net benefits do swing positive. The NPV of the total annual net benefits over the term comes to $3 million, as shown in Section 8.1. However, the ROI of the Cavus 2 option is only 1.6%, insufficient financial value to meet project goals in an economically desirable manner. Thus, Cavus 2 is not considered a viable option for the program, even under the "without Access Northeast" scenario.

	Cavus 1	2022	2032	2042	2052
2015 $ in millions					
LDC					
	Gross Margin	2.92	3.76	5.86	N/A
Less	Total Contract Cost	24.19	20.08	16.81	N/A
	Net Benefit	(21.27)	(16.32)	(10.95)	N/A
Maine					
	Gross Margin	6.39	9.61	16.05	N/A
Less	Total Contract Cost	24.19	20.08	16.81	N/A
	Net Benefit	(17.80)	(10.47)	(0.77)	N/A
Out of State					
Plus	Gross Margin	7.16	7.81	10.64	N/A
Total Benefit					
	Net Benefit	**(10.63)**	**(2.67)**	**9.87**	**N/A**

Cavus 2 *2015 $ in millions*		2022	2032	2042	2052
LDC					
	Gross Margin	5.81	7.50	11.71	N/A
Less	Total Contract Cost	20.62	17.14	14.39	N/A
	Net Benefit	(14.81)	(9.64)	(2.69)	N/A
Maine					
	Gross Margin	12.73	17.37	26.64	N/A
Less	Total Contract Cost	20.62	17.14	14.39	N/A
	Net Benefit	(7.89)	0.23	12.24	N/A
Out of State					
Plus	Gross Margin	0.77	0.00	0.00	N/A
Total Benefit					
	Net Benefit	**(7.12)**	**0.23**	**12.24**	**N/A**

7.2. Eagle Partners

Eagle has proposed two different trucked-in LNG options, one with a capacity of [redacted] MMcf (Eagle 1) and one with a capacity of [redacted] MMcf (Eagle 2). Navigant has modeled Eagle 1 as having [redacted] days of sendout at [redacted] MMcfd, and Eagle 2 as having [redacted] days of sendout at [redacted] MMcfd. The fixed charges have been stated as [redacted] million for Eagle 1 and [redacted] million for Eagle 2. Both options are for [redacted] years. It should be noted that the bids state that land cost and fixed operating costs have not been accounted for nor included.

7.2.1. With Access Northeast

Modeled as outlined above, Eagle 1 net benefits are negative for the LDC, and for the State of Maine (and in total), across all three snapshot years. The NPV of the total annual net benefits over the term comes to negative $28 million, with an ROI of negative 85%, as shown in Section 7.7. Thus, Eagle 1 is not considered a viable option for the program, under the “with Access Northeast” scenario.

Modeled as outlined above, Eagle 2 net benefits are negative for the LDC, and for the State of Maine (and in total), across all three snapshot years. The NPV of the total annual net benefits over the term comes to negative $22 million, with an ROI of negative 69%, as shown in Section 7.7. Thus, Eagle 2 is not considered a viable option for the program, under the “with Access Northeast” scenario.

Eagle Partners 1 *2015 $ in millions*			*2022*	*2032*	*2042*	*2052*
LDC						
		Gross Margin	[redacted]	[redacted]	[redacted]	N/A
	Less	Total Contract Cost				N/A
		Net Benefit	(3.17)	(2.57)	(1.90)	N/A
Maine						
		Gross Margin	[redacted]	[redacted]	[redacted]	N/A
	Less	Total Contract Cost				N/A
		Net Benefit	(3.17)	(2.57)	(1.90)	N/A
Out of State						
	Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit						
		Net Benefit	**(3.17)**	**(2.57)**	**(1.90)**	**N/A**

Eagle Partners 2 *2015 $ in millions*			*2022*	*2032*	*2042*	*2052*
LDC						
		Gross Margin	[redacted]	[redacted]	[redacted]	N/A
	Less	Total Contract Cost				N/A
		Net Benefit	(2.60)	(2.06)	(1.25)	N/A
Maine						
		Gross Margin	[redacted]	[redacted]	[redacted]	N/A
	Less	Total Contract Cost				N/A
		Net Benefit	(2.60)	(2.06)	(1.25)	N/A
Out of State						
	Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit						
		Net Benefit	**(2.60)**	**(2.06)**	**(1.25)**	**N/A**

7.2.2. Without Access Northeast

Modeled as outlined above, Eagle 1 net benefits are negative for the LDC, and for the State of Maine (and in total), across all three snapshot years. The NPV of the total annual net benefits over the term comes to negative $25 million, with an ROI of negative 77%, as shown in Section 8.1. Thus, Eagle 1 is not considered a viable option for the program, even under the "without Access Northeast" scenario.

Modeled as outlined above, Eagle 2 net benefits are negative for the LDC, and for the State of Maine (and in total), across all three snapshot years. The NPV of the total annual net benefits over the term comes to negative $16 million, with an ROI of negative 52%, as shown in Section 8.1. Thus, Eagle 2 is not considered a viable option for the program, even under the "without Access Northeast" scenario.

2015 $ in millions	Eagle Partners 1	2022	2032	2042	2052
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
	Net Benefit	(3.03)	(2.30)	(1.44)	N/A
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost				N/A
	Net Benefit	(3.03)	(2.30)	(1.44)	N/A
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit					
	Net Benefit	**(3.03)**	**(2.30)**	**(1.44)**	**N/A**

2015 $ in millions	Eagle Partners 2	2022	2032	2042	2052
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost				N/A
	Net Benefit	(2.32)	(1.51)	(0.35)	N/A
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost				N/A
	Net Benefit	(2.32)	(1.51)	(0.35)	N/A
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit					
	Net Benefit	**(2.32)**	**(1.51)**	**(0.35)**	**N/A**

7.3. Engie

Engie has proposed two options, one [redacted] (Engie 1), and one [redacted] (Engie 2). The tank size is the same at [redacted] Bcf. The vaporization rate is [redacted] MMcfd under either option, yielding [redacted] effective use days. The fill rate for the [redacted] offer is [redacted] MMcfd, yielding a fill time of [redacted] days. For the [redacted] option, there is an assumption of [redacted] Dth/day, for a total of [redacted] fill days. The fixed costs for the [redacted] option are higher at [redacted] million per year, as opposed to [redacted] million per year for the [redacted] option. Engie has also stated variable costs totalling [redacted] million and [redacted] million annually, for the respective options. Fuel use and losses are stated as included in the annual costs. Engie's options are proposed for [redacted] years, the only proposed PESCs with a term that long.

7.3.1. With Access Northeast

Modeled as outlined above, Engie 1 net benefits are negative throughout the term on an LDC basis, and generally negative for the State of Maine, although for the later parts of the term the net benefits do swing positive. The NPV of the total annual net benefits over the term comes to negative $42 million, with an ROI of negative 15%, as shown in Section 7.7, and thus Engie 1 is not considered a viable option for the program, under the "with Access Northeast" scenario.

Modeled as outlined above, Engie 2 net benefits are negative throughout the term on an LDC basis, and generally negative for the State of Maine, although for the later parts of terms the net benefits do swing positive. The NPV of the total annual net benefits over the term comes to negative $8 million, with an ROI of negative 3%, as shown in Section 7.7, and thus Engie 2 is not considered a viable option for the program, under the "with Access Northeast" scenario.

Engie 1 *2015 $ in millions*	*2022*	*2032*	*2042*	*2052*
LDC				
Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Less Total Contract Cost	[redacted]	[redacted]	[redacted]	[redacted]
Net Benefit	(20.77)	(15.94)	(9.55)	(6.56)
Maine				
Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Less Total Contract Cost	[redacted]	[redacted]	[redacted]	[redacted]
Net Benefit	(14.56)	(7.44)	4.44	8.22
Out of State				
Plus Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Total Benefit				
Net Benefit	**(11.45)**	**(6.21)**	**4.44**	**8.58**

Engie 2 *2015 $ in millions*	*2022*	*2032*	*2042*	*2052*
LDC				
Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Less Total Contract Cost	[redacted]	[redacted]	[redacted]	[redacted]
Net Benefit	(15.37)	(13.32)	(8.94)	(7.11)
Maine				
Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Less Total Contract Cost	[redacted]	[redacted]	[redacted]	[redacted]
Net Benefit	(9.16)	(4.81)	5.05	7.66
Out of State				
Plus Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Total Benefit				
Net Benefit	**(6.04)**	**(3.59)**	**5.05**	**8.03**

7.3.2. Without Access Northeast

Modeled as outlined above, Engie 1 net benefits are negative throughout the term on an LDC basis, but swing positive for the State of Maine. The NPV of the total annual net benefits over the term comes to $103 million, with an ROI of 37%, as shown in Section 8.1, and thus Engie 1 is considered a viable option for the program, under the “without Access Northeast” scenario.

Modeled as outlined above, Engie 2 net benefits are negative throughout the term on an LDC basis, but swing positive for the State of Maine. The NPV of the total annual net benefits over the term comes to $137 million, with an ROI of 56%, as shown in Section 8.1, and thus Engie 2 is considered a viable option for the program, under the “without Access Northeast” scenario.

Engie 1 *2015 $ in millions*		*2022*	*2032*	*2042*	*2052*
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	[redacted]
	Net Benefit	(18.99)	(12.39)	(3.56)	(1.06)
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	[redacted]
	Net Benefit	(10.65)	1.66	20.80	23.91
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Total Benefit					
	Net Benefit	**(6.47)**	**3.67**	**20.80**	**24.52**

Engie 2 *2015 $ in millions*		*2022*	*2032*	*2042*	*2052*
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	[redacted]
	Net Benefit	(13.59)	(9.76)	(2.95)	(1.62)
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	[redacted]
	Net Benefit	(5.25)	4.28	21.40	23.35
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
Total Benefit					
	Net Benefit	**(1.07)**	**6.30**	**21.40**	**23.96**

7.4. Maine Energy Storage (Northern)

Northern has proposed one option, based on [redacted] facilities. The tank size is [redacted] Bcf. The vaporization rate is [redacted] MMcfd, yielding [redacted] effective use days. The fill rate for is [redacted] MMcfd, yield fill time of [redacted] days. The fixed costs are stated as [redacted] million per year, plus CPI escalation on a [redacted]% portion. Northern has also added a variable cost of [redacted] per Mcf, plus CPI escalation. Northern has stated a vaporization loss factor of [redacted] percent, which has been applied as a deduction from the calculated value of gross sales, and thus gross margin. Northern has also stated a [redacted] [redacted] applied as an additional fill cost.

7.4.1. With Access Northeast

Modeled as outlined above, Northern net benefits are negative for the LDC, and for the State of Maine, across all three snapshot years. The NPV of the total annual net benefits over the term comes to negative $98 million, with an ROI of negative 40%, as shown in Section 7.7. Thus, Northern is not considered a viable option for the program, under the “with Access Northeast” scenario.

		Northern 1				
2015 $ in millions			*2022*	*2032*	*2042*	*2052*
LDC						
		Gross Margin	[redacted]	[redacted]	[redacted]	N/A
	Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
		Net Benefit	(20.88)	(17.99)	(13.68)	N/A
Maine						
		Gross Margin	[redacted]	[redacted]	[redacted]	N/A
	Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
		Net Benefit	(15.70)	(10.90)	(2.02)	N/A
Out of State						
	Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit						
		Net Benefit	**(13.11)**	**(9.88)**	**(2.02)**	**N/A**

7.4.2. Without Access Northeast

Modeled as outlined above, Northern net benefits are negative for the LDC, and generally negative for the State of Maine, although for the later parts of the term the net benefits do swing positive. The NPV of the total annual net benefits over the term comes to negative $16 million, with an ROI of negative 6%, as shown in Section 8.1. Thus, Northern is not considered a viable option for the program, even under the “without Access Northeast” scenario.

Northern 1 *2015 $ in millions*		*2022*	*2032*	*2042*	*2052*
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost				N/A
	Net Benefit	(19.48)	(15.19)	(8.96)	N/A
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost				N/A
	Net Benefit	(12.53)	(3.49)	11.33	N/A
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit					
	Net Benefit	**(9.05)**	**(1.81)**	**11.33**	**N/A**

7.5. Northstar

Northstar has proposed two options, one with [redacted] (Northstar 1), and one [redacted] (Northstar 2). The tank size is the same at [redacted] Bcf.[8] The vaporization rate is [redacted] MMcfd under either option, yielding [redacted] effective use days. The fill rate for the [redacted] offer is [redacted] MMcfd, yielding a fill time of [redacted] days. For the [redacted] option, there is an assumption of 247 days for a full tank, yielding [redacted] fill days for the PESC volumes. The fixed and variable costs for both options total [redacted] million per year. [redacted] Contract terms are [redacted] years.

7.5.1. With Access Northeast

Modeled as outlined above, Northstar 1 net benefits are negative throughout the term on an LDC basis, and generally negative for the State of Maine, although for the later parts of the term the net benefits do swing positive for Maine as real gross margin increases while real contract costs decrease, and then with out-of-state sales included benefits swing noticeably positive[9]. The NPV of the total annual net benefits over the term comes to plus $6 million, as shown in Section 7.7. However, the ROI of the Northstar 1 option is only 3%, indicating insufficient financial value of the option to meet project goals in an economically efficient manner. Thus, Northstar 1 would not be considered a viable option for the program, under the "with Access Northeast" scenario.

Modeled as outlined above, Northstar 2 net benefits are negative throughout the term on an LDC basis, and generally negative for the State of Maine. While gross margins are the same as with Northstar 1 due to the same sendout and volumes, the net benefits are more negative/less positive due to the LNG premium associated with the trucked-in LNG supply in conjunction with otherwise equivalent costs. The NPV of the total annual net benefits over the term comes to negative $33 million, with an ROI of negative 15%, as shown in Section 7.7, and thus Northstar 2 is not considered a viable option for the program, under the "with Access Northeast" scenario.

[8] Northstar's proposed facility is actually [redacted] Bcf, but with only [redacted] committed to the PESC.
[9] It should be noted that relying on out-year net benefits to swing the analysis of net benefits positive may be subject to an extra risk factor as outcomes further into the future are generally more uncertain.

Northstar 1		2022	2032	2042	2052
2015 $ in millions					
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
	Net Benefit	(14.68)	(11.65)	(7.20)	N/A
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
	Net Benefit	(9.51)	(4.56)	4.50	N/A
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit					
	Net Benefit	**(3.88)**	**(0.38)**	**9.06**	**N/A**

Northstar 2		2022	2032	2042	2052
2015 $ in millions					
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
	Net Benefit	(17.59)	(15.53)	(11.67)	N/A
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
	Net Benefit	(12.41)	(8.44)	0.03	N/A
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit					
	Net Benefit	**(6.78)**	**(4.26)**	**4.59**	**N/A**

7.5.2. Without Access Northeast

Modeled as outlined above, Northstar 1 net benefits are negative throughout the term on an LDC basis, but swing positive for the State of Maine, as real gross margin increases while real contract costs decrease, and then with out-of-state sales included benefits swing noticeably positive. The NPV of the total annual net benefits over the term comes to plus $109 million with an ROI of 61%, as shown in Section 8.1. Thus, Northstar 1 would be considered a viable option for the program, under the "without Access Northeast" scenario.

Modeled as outlined above, Northstar 2 net benefits are negative throughout the term on an LDC basis, but swing positive for the State of Maine. While gross margins are the same as with Northstar 1 due to the same sendout and volumes, the net benefits are less positive due to the [redacted] in conjunction with otherwise equivalent costs. Nevertheless, the NPV of the total annual net benefits over the term comes to $70 million, with an ROI of 32%, as shown in Section 8.1, and thus Northstar 2 is considered a viable option for the program, under the "without Access Northeast" scenario.

Northstar 1 *2015 $ in millions*		*2022*	*2032*	*2042*	*2052*
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
	Net Benefit	(13.30)	(8.89)	(2.55)	N/A
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
	Net Benefit	(6.35)	2.81	17.82	N/A
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit					
	Net Benefit	**1.20**	**9.71**	**25.75**	**N/A**

Northstar 2 *2015 $ in millions*		*2022*	*2032*	*2042*	*2052*
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
	Net Benefit	(16.20)	(12.77)	(7.02)	N/A
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
	Net Benefit	(9.25)	(1.07)	13.35	N/A
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit					
	Net Benefit	**(1.71)**	**5.83**	**21.28**	**N/A**

7.6. Reliable

Reliable has proposed two options, one with [redacted] (Reliable 1), and one [redacted] (Reliable 2). The tank size for the [redacted] option is [redacted] Bcf, with a vaporization rate of [redacted] MMcfd, yielding [redacted] effective use days. The tank size for the [redacted] option is [redacted] Bcf, with a vaporization rate of [redacted] MMcfd, also yielding [redacted] effective use days but with the greater sendout. The fill rate for the [redacted] offer is [redacted] MMcfd, yielding a fill time of [redacted] days. For the [redacted] option, a total of [redacted] fill days has been stated. The fixed costs for the [redacted] option is [redacted] million per year, while fixed costs are [redacted] million per year for the [redacted] option. [redacted] Contract terms are [redacted] years.

7.6.1. With Access Northeast

Modeled as outlined above, Reliable 1 net benefits are negative throughout the term on an LDC basis, and generally negative for the State of Maine, although for the later parts of the term the net benefits do swing positive. With the sendout rate of [redacted] MMcfd, there are some limited out-of-state sales for Reliable 1. The NPV of the total annual net benefits over the term comes to negative $44 million, with an ROI of negative 22%, as shown in Section 7.7, and thus Reliable 1 is not considered a viable option for the program, under the "with Access Northeast" scenario.

Modeled as outlined above, Reliable 2 net benefits are negative throughout the term on an LDC basis, and generally negative for the State of Maine, although for the later parts of the term the net benefits do swing positive. With the sendout rate of [redacted] MMcfd and the [redacted] Bcf tank size, there are significant out-of-state sales for Reliable 2. Nevertheless, the [redacted] contributes to cost and the NPV of the total annual net benefits over the term comes to negative $12 million, with an ROI of negative 5%, as shown in Section 7.7. Thus, Reliable 2 is not considered a viable option for the program, under the "with Access Northeast" scenario.

Reliable 1 *2015 $ in millions*		*2022*	*2032*	*2042*	*2052*
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost				N/A
	Net Benefit	(17.00)	(13.32)	(8.32)	N/A
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost				N/A
	Net Benefit	(11.83)	(6.23)	3.38	N/A
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit					
	Net Benefit	**(8.73)**	**(4.69)**	**4.11**	**N/A**

Reliable 2 *2015 $ in millions*		*2022*	*2032*	*2042*	*2052*
LDC					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost				N/A
	Net Benefit	(21.35)	(19.26)	(15.28)	N/A
Maine					
	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Less	Total Contract Cost				N/A
	Net Benefit	(16.17)	(12.17)	(3.58)	N/A
Out of State					
Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit					
	Net Benefit	**(5.50)**	**(2.72)**	**8.64**	**N/A**

7.6.2. Without Access Northeast

Modeled as outlined above, Reliable 1 net benefits are negative throughout the term on an LDC basis, but swing positive for the State of Maine. With the sendout rate of [redacted] MMcfd, there are some limited out-of-state sales for Reliable 1. The NPV of the total annual net benefits over the term comes to $43 million, with an ROI of 22%, as shown in Section 8.1, and thus Reliable 1 is considered a viable option for the program, under the "without Access Northeast" scenario.

Modeled as outlined above, Reliable 2 net benefits are negative throughout the term on an LDC basis, and generally negative for the State of Maine, although for the later parts of the term the net benefits do swing positive. With the sendout rate of [redacted] MMcfd and the [redacted] Bcf tank size, there are significant out-of-state sales for Reliable 2. Despite the [redacted] the NPV of the total annual net benefits over the term comes to $127 million, with an ROI of 49%, as shown in Section 8.1. Thus, Reliable 2 is considered a viable option for the program, under the "without Access Northeast" scenario.

Reliable 1 *2015 $ in millions*			*2022*	*2032*	*2042*	*2052*
LDC						
		Gross Margin	[redacted]	[redacted]	[redacted]	N/A
	Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
		Net Benefit	(15.58)	(10.49)	(3.54)	N/A
Maine						
		Gross Margin	[redacted]	[redacted]	[redacted]	N/A
	Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
		Net Benefit	(8.63)	1.22	16.83	N/A
Out of State						
	Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit						
		Net Benefit	**(4.47)**	**3.77**	**18.09**	**N/A**

Reliable 2 *2015 $ in millions*			*2022*	*2032*	*2042*	*2052*
LDC						
		Gross Margin	[redacted]	[redacted]	[redacted]	N/A
	Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
		Net Benefit	(19.97)	(16.51)	(10.63)	N/A
Maine						
		Gross Margin	[redacted]	[redacted]	[redacted]	N/A
	Less	Total Contract Cost	[redacted]	[redacted]	[redacted]	N/A
		Net Benefit	(13.02)	(4.80)	9.73	N/A
Out of State						
	Plus	Gross Margin	[redacted]	[redacted]	[redacted]	N/A
Total Benefit						
		Net Benefit	**1.31**	**10.81**	**31.01**	**N/A**

7.7. Summary of PESC Bid Total Net Benefits

Following is a summary table showing the NPV of each PESC option annual net benefits. As can be seen, only Northstar 1 shows a positive NPV, but with an ROI of only 3%.

Table 8: PESC Option NPV and ROI, With Access Northeast

2015 $ in millions	NPV Net Benefit	ROI
Northstar 1	5.8	3.2%
Engie 2	(8.2)	-3.3%
Reliable 2	(11.7)	-4.5%
Engie 1	(41.8)	-15.0%
Northstar 2	(33.2)	-15.3%
Reliable 1	(43.7)	-22.2%
Cavus 2	(65.8)	-35.1%
Northern 1	(98.4)	-40.1%
Cavus 1	(97.7)	-44.4%
Eagle Partners 2	(22.0)	-69.2%
Eagle Partners 1	(28.0)	-85.1%

8. Other Factors

8.1. Without Access Northeast Scenario

As noted in the prior section, only one PESC option has a positive NPV using Navigant's Daily Model analysis based on the "with Access Northeast" scenario. Following is a table showing the difference in forecast average and peak prices for the snapshot years between the "with Access Northeast" scenario and the without Access Northeast" scenario.

Table 9: Winter Prices, Base Case and No Access NE Scenario

2015$/MMBtu	With Access Northeast		Without Access Northeast	
Year	February Monthly Average	15-Day Average Peak	February Monthly Average	15-Day Average Peak
2022	$4.71	$13.42	$5.24	$16.88
2032	$5.55	$14.99	$7.02	$21.86
2042	$6.57	$20.44	$9.43	$31.80
2052	$6.69	$21.24	$9.95	$32.31

As can be seen, there is a general increase in both average and peak forecasted prices when Access Northeast is excluded. The impact of these price increases on PESC option NPV and ROI is shown in the following table, where project NPVs and ROIs become more favorable, with seven PESC options having positive NPV. While Access Northeast has experienced some delays, there is no specific indication that the project is not intended to be pursued. Further, the continued need for pipeline capacity to meet existing and growing New England demand, as well as the new political environment in Washington and announced appointments in the new administration, tend to support the "with Access Northeast" scenario. In addition, even if Access Northeast is not built, the market will likely respond accordingly with some other pipeline project being built, as has historically been the case when the need for additional capacity is indicated by the market.

Table 10: PESC Option NPV and ROI, Without Access Northeast

2015 $ in millions	NPV Net Benefit	ROI
Northstar 1	109.1	60.7%
Engie 2	136.8	55.7%
Reliable 2	126.8	49.1%
Engie 1	103.2	37.0%
Northstar 2	70.1	32.0%
Reliable 1	42.8	21.6%
Cavus 2	3.1	1.6%
Northern 1	(15.7)	-6.4%
Cavus 1	(28.8)	-13.0%
Eagle Partners 2	(16.4)	-51.6%
Eagle Partners 1	(25.2)	-76.6%

8.2. Use of Average Prices

The results presented above assume that avoided costs relate to an estimated average peak price. In practice, this may be an optimistic assumption. As a contrast, Navigant also analysed net benefits and associated NPV and ROI assuming that avoided costs are based on average wintertime prices. The results of this analysis indicate consistent negative PESC valuation, as shown in the following sections.

8.2.1. With Access Northeast

Table 11 presents the NPV and ROI results in the "with Access Northeast" scenario, assuming average wintertime price avoided costs. These results are the most unfavorable of the presented results.

Table 11: PESC Option NPV and ROI, With Access Northeast, Avg. Prices

2015 $ in millions	NPV Net Benefit	ROI
Northstar 1	(153.1)	-87.8%
Reliable 2	(224.6)	-88.7%
Engie 2	(219.4)	-89.3%
Northstar 2	(192.1)	-90.0%
Engie 1	(253.0)	-90.6%
Reliable 1	(176.8)	-90.9%
Cavus 2	(171.7)	-92.6%
Northern 1	(225.5)	-93.0%
Cavus 1	(203.6)	-93.5%
Eagle Partners 2	(30.7)	-96.4%
Eagle Partners 1	(32.3)	-98.3%

8.2.2. Without Access Northeast

Table 12 presents the NPV and ROI results in the “without Access Northeast” scenario, also assuming average wintertime price avoided costs. These results are also significantly unfavorable.

Table 12: PESC Option NPV and ROI, Without Access Northeast, Avg. Prices

2015 $ in millions	NPV Net Benefit	ROI
Northstar 1	(130.9)	-74.8%
Engie 2	(185.7)	-75.6%
Reliable 2	(194.8)	-76.8%
Engie 1	(219.3)	-78.5%
Northstar 2	(169.9)	-79.4%
Reliable 1	(158.2)	-81.2%
Cavus 2	(156.9)	-84.5%
Northern 1	(207.7)	-85.5%
Cavus 1	(188.8)	-86.5%
Eagle Partners 2	(29.5)	-92.6%
Eagle Partners 1	(31.7)	-96.4%

8.3. Historical Snapshot Review

Navigant’s analytical conclusions and findings focus on the forecast analysis outlined previously. For informational purposes, Navigant also prepared snapshots of net benefits for both the Polar Vortex winter of 2013/2014 (for extreme cold) and the warmer winter of 2015/2016. Detailed results appear in Appendix C.

For the Polar Vortex, one-year net benefits show positive value for nine out of eleven PESC options, ranging from about $10 million to $47 million in one-year net benefits. As an indication of the magnitude of effects, the total net benefits for all PESC options increases by $320 million from negative $86 million to positive $234 million from the net benefits for the 2022 ”with Access Northeast” scenario snapshot, due to the much higher avoided costs following from the high historical average peak prices during that event.

For the warmer winter of 2015/2016, one-year net benefits for all PESC options show a deterioration of about $100 million, from negative $86 million to negative $185 million, when compared to the already unfavorable net benefits of the ”with Access Northeast” scenario forecast analysis for the 2022 snapshot. All eleven PESC options show negative benefit for the warmer winter, ranging up to negative $24 million.

8.4. Power Market Impacts

As indicated in Section 6.2 above, the impacts on wholesale gas market prices of these proposed LNG facilities are very small. Merchant generators purchase fuel on the market and incorporate their fuel cost into their price bids to the ISO. Since the gas price changes will be small, these price bids to the ISO and the resultant wholesale market prices will be barely affected. Navigant's conclusion is that the LNG impacts will have a de minimis effect on wholesale power prices.

9. Findings

Navigant's findings relate to the two scenarios, with and without Access Northeast. Under the “with Access Northeast” scenario, Navigant's findings reflect the almost universal negative net benefits of the PESC options, with only one option (i.e. Northstar 1) having a positive NPV (at only $6 million), but while also having an ROI of only three percent, considered insufficient under typical investment criteria. Thus, while the “gross margin” part of the analyses could indicate that an option might provide the opportunity for access to lower cost natural gas at times of regional peak demand, on a net basis including full contract costs such a benefit would be illusory as contract net benefits are almost universally negative under this scenario.

With regard to materially enhancing LNG gas storage capacity in the State, most options would actually accomplish this objective, but again in a financially undesirable manner. Put another way, any benefit of having LNG storage capacity is negated by contract costs.

These results are despite the fact that Navigant assumed that the full market value of the proposal will be available to the ratepayers of the contracting LDC(s), which could realize the value of the total volumes proposed, whether used to avoid peak priced supplies by the LDC, within the balance of Maine, or as sales providing gross margin to the contract from out-of-state sales. Thus, not only were the PESC options not beneficial at the LDC level, they were also not beneficial with respect to total contract volumes. The results also are likely generous in that Navigant's 15-day average peak price methodology assumes that projects will be able to sell into the market during the top 15 price days in the winter, which is an optimistic assumption. We would expect the actual results to be worse to the extent projects were delivering on more average-level price days, as discussed in Section 8.2.

Under the "without Access Northeast" scenario, NPV and ROI results became favorable for seven of the PESC options, reflecting the higher forecast prices at TGPZ9 under this scenario. Compared to the "with Access Northeast" scenario, gross margin estimates increase, thus increasing the net benefits of the PESC options. The best of the options end up with ROIs in the 50% to 60% range under this scenario, with several others in the 20% to 40% range. These benefits, it should be noted, are contingent on both the "without Access Northeast" assumption, as well as assuming that peak prices can be consistently avoided in practice. As discussed in Section 8.2, if avoided costs are more likely based on average-type prices, then the results (even under the "without Access Northeast" scenario) all become unfavorable, with ROIs in the negative 75% to negative 96% range.

With respect to natural gas and electric system reliability, we would expect that some of the storage facilities, especially if proposed to be located near the facilities of the Portland Natural Gas or Maritimes and Northeast pipelines, could allow for the more reliable operation of such systems. It is our understanding, however, that there have not been instances of curtailment of firm transport service in the State to date.

To conclude, we find that based on our current market view, the PESC options proposed do not appear to present positive and economically desirable net benefit analysis results under a "with Access Northeast" scenario. Other criteria could exist that may influence an ultimate decision, such that a combination of factors may warrant proceeding, without economic return being the primary driver. In contrast, under the "without Access Northeast" scenario, some results appear to be economically desirable, although such a finding would be assuming optimistic results in practice. Unexpected changes in the market could also impact all findings, but at this time any such market circumstances that would cause the findings to change are unforeseen.

APPENDIX A

(see separate document)

APPENDIX B

(see separate document)

APPENDIX C

(see separate document)

PUBLIC VERSION

NAVIGANT

APPENDIX D

(see separate document)

APPENDIX E

(see separate document)