Division 2-1

Request:

On page 5 of 37 in Schedule GJW-3, it states that B&V has not verified the validity of information provided by others. Please identify and describe in detail all such information provided by others, including but not limited to NGRID.

Response:

Black & Veatch relies upon numerous various data sources and proprietary databases to develop its natural gas and electric market perspective. On page 5 in Schedule GJW-3, the statement above is referring to these various data sources and proprietary databases where Black & Veatch did not directly verify or render an independent judgment of the validity of the information provided by others.

In regards to the analysis in Schedule GJW-3, Black & Veatch utilized the information provided in the RFP responses and supplemental RFP information from National Grid to conduct our cost benefit analysis.

Prepared by or under the supervision of: Gary J. Wilmes and Denny K. Yeung

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Division 2-2

Request:

In the last five years, has B&V performed any analysis using either PROMOD or GPCM, where PROMOD or GPCM have included representations of electric or natural gas facilities in New England? If so, please provide copies of such studies.

Response:

Black & Veatch has completed several comprehensive studies within the past five years that are publically available using PROMOD and GPCM, where representations of electric or natural gas facilities in New England are included.

NESCOE Phase I Report:
http://nescoe.com/uploads/Phase_I_Report_12-17-2012_Final.pdf

NESCOE Phase II Report:
http://nescoe.com/uploads/Phase_II_Report_FINAL_04-16-2013.pdf

NESCOE Phase III Report:
http://nescoe.com/uploads/Phase_III_Gas-Elec_Report_Sept._2013.pdf

Black & Veatch has also completed a study utilizing GPCM and modeling natural gas facilities in New England and the impact of LNG exports from Nova Scotia.

FERC FE Docket No. 15-33-LNG – Appendix B
http://energy.gov/sites/prod/files/2015/02/f20/Appendix%20B.pdf

Please also refer to Attachment DIV-2-2(a).

FERC FE Docket No. 15-33-LNG – Appendix C
http://energy.gov/sites/prod/files/2015/02/f20/Appendix%20C.pdf

Please also refer to Attachment DIV-2-2(b).

Prepared by or under the supervision of: Gary J. Wilmes and Denny K. Yeung

APPENDIX B

Black & Veatch, U.S. Market Impact Assessment for LNG Exports at the Bear Head Export Project (February 2015)

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U.S. Market Impact Assessment for LNG Exports at the Bear Head Export Project

PREPARED FOR

Bear Head LNG Corporation

FEBRUARY 2015

BLACK & VEATCH
Building a world of difference.

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BLACK & VEATCH STATEMENT

This report was prepared for Bear Head LNG Corporation ("Client") by Black & Veatch Corporation ("Black & Veatch") and is based in part on information not within the control of Black & Veatch. As such, Black & Veatch has not made an analysis, verified, or rendered an independent judgment of the validity of the information provided by others, and, therefore, Black & Veatch does not guarantee the accuracy thereof.

In conducting our analysis, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies we utilize in performing the analysis and making these projections follow generally accepted industry practices. While we believe that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected.

Readers of this report are advised that any projected or forecast price levels and price impacts, reflects the reasonable judgment of Black & Veatch at the time of the preparation of such information and is based on a number of factors and circumstances beyond our control. Accordingly, Black & Veatch makes no assurances that the projections or forecasts will be consistent with actual results or performance. To better reflect more current trends and reduce the chance of forecast error, we recommend that periodic updates of the forecasts contained in this report be conducted so more recent historical trends can be recognized and taken into account.

Neither this report, nor any information contained herein or otherwise supplied by Black & Veatch in connection with the services, shall be released or used in connection with any proxy, proxy statement, and proxy soliciting material, prospectus, Securities Registration Statement, or similar document without the written consent of Black & Veatch.

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Glossary of Terms

AIM Algonquin Incremental Market. Spectra Energy's expansion project on the Algonquin Pipeline System in New England.

Bcf One billion cubic feet. In the context of LNG, the gas-to-liquid equivalency is approximately 1 Bcf (gas) = 17,200 tonnes (liquid).

Bcf/d One billion cubic feet per day.

Btu British thermal unit. A unit of thermal energy in the context of combustion of hydrocarbon fuels, including natural gas. It is defined as the amount of heat energy required to raise the temperature of one pound of water from 60° F to 61° F at a constant pressure of one atmosphere (14.696 psi).

CPP Clean Power Plan. US Environmental Protection Agency's proposed carbon reduction plan.

EIA U.S Department of Energy **-** Energy Information Administration.

EMP Energy Market Perspective. Black & Veatch's subscription-based, bi-annual comprehensive outlook of natural gas and power markets in North America.

GPCM Gas Pipeline Competition Model. A third-party proprietary model Black & Veatch uses for natural gas market forecasting.

LNG Liquefied natural gas.

MMcf One million cubic feet. A common volume unit for (gaseous) natural gas.

MMcf/d One million cubic feet per day.

MMBtu One million British Thermal Units. 1 MMBtu = 1 Dekatherm (Dth).

M&NP Maritimes & Northeast Pipeline

MTPA One million tonnes per annum. Units of LNG production (by weight) in one year. The liquid-to-gas equivalency is approximately 1MTPA (liquid) = 0.135 Bcf/d (gas flow).

NEB National Energy Board. The principal energy regulatory agency of Canada.

PNGTS Portland Natural Gas Transmission System.

SOEP Sable Offshore Energy Project.

TGP Tennessee Gas Pipeline.

TQM Trans Québec and Maritimes Pipeline.

WCSB Western Canadian Sedimentary Basin.

1.0 Introduction

To support Bear Head LNG Corporation's ("Bear Head Corp.") application to the United States Department of Energy's Office of Fossil Energy, Black & Veatch Corporation ("Black & Veatch") was retained by Bear Head Corp. to provide an independent assessment of the market impact of Bear Head Corp.'s proposed liquefied natural gas ("LNG") export project ("Bear Head Project" or "Project"), to be sited in Point Tupper, Nova Scotia.

Black & Veatch's assessment methodology is built upon our industry expertise in the North American gas and power markets and our experience in fundamental analysis of natural gas supply, demand, and the interconnecting interstate and intrastate pipeline grid. Having served the power industry for nearly a century, Black & Veatch has hands-on experience analyzing key drivers of natural gas demand growth from the power sector such as the relative capital cost of power generation technologies, impact of the proposed Clean Power Plan ("CPP"), nuclear permitting, U.S. Environmental Protection Agency ("EPA") rules, and renewable targets. With oil and gas shale plays emerging as the primary supply source to the U.S. market, we continually monitor their development and undertake in-depth analyses to understand North American natural gas supply potential. In addition, Black & Veatch has conducted numerous analyses in New England related to evaluation of energy infrastructure solutions in the region.

Black & Veatch produces an integrated and comprehensive outlook on North American energy issues in our bi-annual Energy Market Perspective ("EMP") that incorporates our power market expertise with our views on generating fuels such as natural gas and coal. The *Base Case* assumptions and analysis in this report are based on our 2015 EMP and summarize our views on key power and natural gas market fundamental drivers that influence our projections of natural gas supply, demand and prices across North America. Black & Veatch utilized RBAC, Inc.'s GPCM™ model to assess the regional and national market price impact of liquefying and exporting 1.2 billion cubic feet per day ("Bcf/d") of U.S. or Canadian gas supplies at the Bear Head LNG Project from 2019 through 2049.

The *Base Case* incorporates the EPA's proposed CPP as the primary driver for gas demand growth in the power generation sector. It also assumes Spectra Energy's ("Spectra") Algonquin Incremental project to be in service by November 2016 and, with the numerous New England shippers having committed, the currently proposed Kinder Morgan Northeast Energy Direct project and Spectra's Atlantic Bridge and Access Northeast pipeline projects are constructed and in-service as of 2018. As currently stated, the proposed CPP plan has several major building blocks that would support natural gas demand growth because of the plan's emphasis on lower-emitting fossil fuels and the ability of gas-fired generation to mitigate the intermittence of renewable generation. The *Base Case* includes demand associated with LNG exports from various terminals in the U.S and Canada reaching 9.3 Bcf/d by 2020.

Black & Veatch explored three LNG export scenarios to test the impact of exports from the Bear Head LNG Project on prices in the New England market and across the Lower 48. The first scenario is the *With Bear Head Project Exports* scenario which included an additional 1.2 Bcf/d of natural gas demand at the Bear Head LNG Project site on top of the projected demand in the *Base Case*. The second scenario is a *High LNG Exports* scenario, which included, in addition to exports assumed in the *Base Case*, an additional 3.0 Bcf/d of natural gas demand associated with added LNG exports from the U.S. Gulf Coast and Eastern Canada starting in 2019, but no LNG exports from the Bear Head LNG Project. This stress test scenario reflects a fairly aggressive ramp up in LNG exports, but also reflects potential LNG exports levels post-2020. Black & Veatch assumed a 2019 ramp-up to make the various scenarios comparable over the analysis period. The total U.S. and Canadian LNG export-related demand will reach 12.3 Bcf/d by 2020 in this stress-test scenario.

Lastly, a third scenario, the *High LNG Exports with Bear Head Project Exports* scenario, was developed which adds an incremental 1.2 Bcf/d of demand (associated with LNG exports from the Bear Head Project) by 2019 to the *High LNG Exports* scenario.

Black & Veatch's market price assessment examines the market price impact of the Bear Head LNG Project on a regional and national level. For the regional market, Black & Veatch examined prices at Algonquin city-gates and Tennessee Zone 6 Delivered ("Tennessee Zn. 6"), as reference locations to assess the Bear Head Project's price impacts on the New England market. The price impact across a number of other pricing points across the U.S. was also examined, using prices at Henry Hub as a barometer for the national price impact.

Table 1: Scenario Descriptions

SCENARIO	DESCRIPTION
Base Case	Based on Black & Veatch's 2015 Energy Market Perspective, which incorporates our analysis of EPA's proposed Clean Power Plan. It also incorporates Black & Veatch's latest assessment of NGL uplifts to shale gas production costs and their impact on North American unconventional production. Natural gas demand associated with LNG exports from various terminals the U.S and Canada reach 9.3 Bcf/d by 2020 and 11.3 Bcf/d by 2025.
With Bear Head Project Exports	Builds upon the *Base Case* with an additional 1.2 Bcf/d of natural gas demand and pipeline infrastructure associated with LNG exports from the Bear Head Project beginning in 2019
High LNG Exports	Includes an additional 3.0 Bcf/d of natural gas demand associated with LNG exports starting in 2019 incremental to the *Base Case*, designed to stress test the results of the *Base Case*.
High LNG Exports with Bear Head Project Exports	Builds upon the *High LNG Exports* scenario with an additional 1.2 Bcf/d of natural gas demand and pipeline infrastructure associated with LNG exports from the Bear Head Project beginning in 2019, designed to stress test the results of the *With Bear Head Project Exports* case.

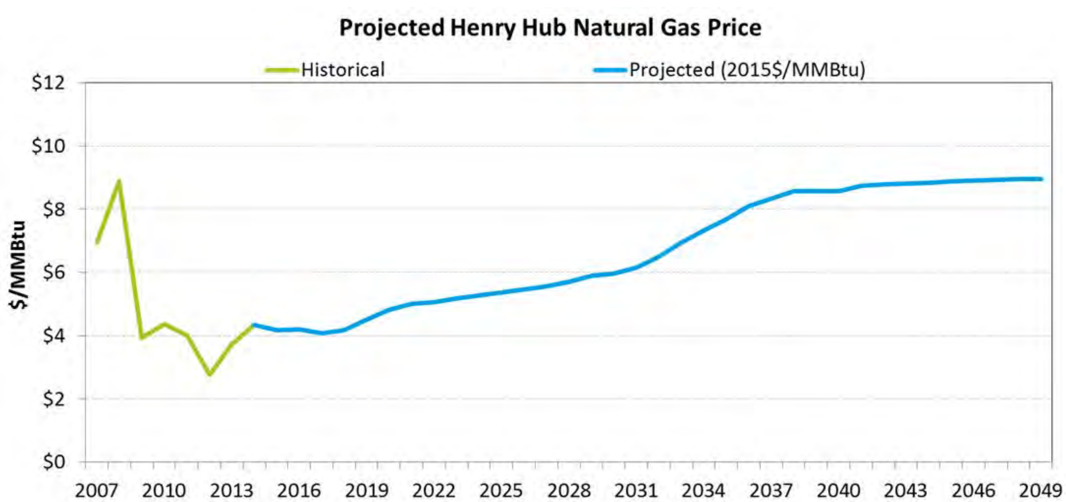
2.0 Executive Summary

Black & Veatch utilized a scenario analysis to assess the potential price impact of 1.2 Bcf/d of related gas demand related to LNG exports from the Bear Head Project. Based on our independent assessment, these proposed export volumes are expected to have a limited price impact both in New England and across the rest of the U.S. during the analysis period when incremental gas pipeline infrastructure into New England is constructed and completed by 2019.

National Price Impact

Black & Veatch's 2015 EMP projects a rising Henry Hub gas price during the analysis period. As seen in Figure 1, Black & Veatch projects that gas prices (in real 2015 dollars) will recover from the 2012 lows and stabilize at $4.50/million British thermal units ("MMBtu") by 2018. Prices then rise more moderately to average $5.57/MMBtu over the first 15 years of the analysis period (2019 through 2033), rising to an average price level of $8.55/MMBtu over the latter half of the analysis period (2034 through 2049). North American demand growth is primarily driven by increased demand for gas-fired electric generation. While some emerging shale producers will continue to benefit from liquids uplifts, continued resource depletion will force producers to drill higher cost wells, as producers' costs are expected to rise over the analysis period. The price trajectory of Henry Hub projected in the *Base Case* is determined by the interplay of all market fundamental factors modeled and cannot be solely, or even mostly, attributed to the level of LNG exports assumed in the *Base Case*.

Figure 1: Projected Base Case Henry Hub Natural Gas Prices



Black & Veatch's *With Bear Head Project Exports* analysis indicates that export volumes from the Bear Head Project would contribute to an estimated $0.04/MMBtu (0.8%) increase in gas prices at the Henry Hub during the first 15 years of operation. The price impact during the remaining 16 years is expected to be an average increase of $0.01/MMBtu (0.1%) over the *Base Case* average price of $8.55/MMBtu. See Table 2.

Black & Veatch also tested the sensitivity of national prices to additional LNG export volumes in excess of those assumed in the *Base Case*. Under the *High LNG Exports* scenario, in which an additional 3.0 Bcf/d of demand associated with Gulf Coast and Eastern Canadian LNG export terminals is assumed beginning in 2019, the price impact of exports from the Bear Head Project (as modeled in the *High LNG Exports with Bear Head LNG* scenario) to Henry Hub is estimated to be $0.05/MMBtu (0.9%) between 2019 and 2033 and $0.02/MMBtu (0.2%) between 2034 and 2049. Under this stress-test scenario, the price impact of the Bear Head Projection Gulf Coast prices remain limited even with fairly aggressive assumptions on LNG export volumes.

Table 2: Market Price Impact at Henry Hub

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.57	5.61	5.70	5.75
	Average Diff. from Base		0.04		0.05
	Percentage Increase		0.8%		0.9%
2034-2049	Average Price ($/MMBtu)	8.55	8.55	8.60	8.61
	Average Diff. from Base		0.01		0.02
	Percentage Increase		0.1%		0.2%

Table reflects prices rounded to the nearest cent.

New England Price Impact

In the *Base Case*, the New England market price as measured at the Algonquin city-gates is projected to reach $4.84/MMBtu by 2019. Similar to Henry Hub, Algonquin city-gates prices rise moderately to average $5.59/MMBtu over the first half of the analysis period (2019-2033), and to an average of $8.68/MMBtu over the second half of the analysis period (2034-2049).

A portion of the Bear Head Project export volumes are expected to originate at Dracut, Massachusetts, the pipeline interconnect between Maritimes & Northeast Pipeline ("M&NP") and Tennessee Gas Pipeline ("TGP"), and will have a higher price impact on the Algonquin city-gates than on Henry Hub. The *Base Case* price impact at Algonquin city-gates is projected to be $0.10/MMBtu (1.8%) over the first 15 years of the Bear Head Project's operations. The price impact for the latter half of the analysis period is slightly less, increasing the *Base Case* average price of $8.68/MMBtu by $0.09/MMBtu (1.0%).

The Bear Head LNG Project is expected to exert a similar, though slightly increased price impact under the *High LNG Exports with Bear Head Project Exports* scenario, raising prices at Algonquin city-gates by $0.13/MMBtu (2.2%) from 2019-2033 and $0.10/MMBtu (1.1%) from 2034-2049. See Table 3.

Table 3: Market Price Impact at Algonquin city-gates

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.69	5.79	5.84	5.96
	Average Diff. from Base		0.10		0.13
	Percentage Increase		1.8%		2.2%
2034-2049	Average Price ($/MMBtu)	8.68	8.77	8.78	8.88
	Average Diff. from Base		0.09		0.10
	Percentage Increase		1.0%		1.1%

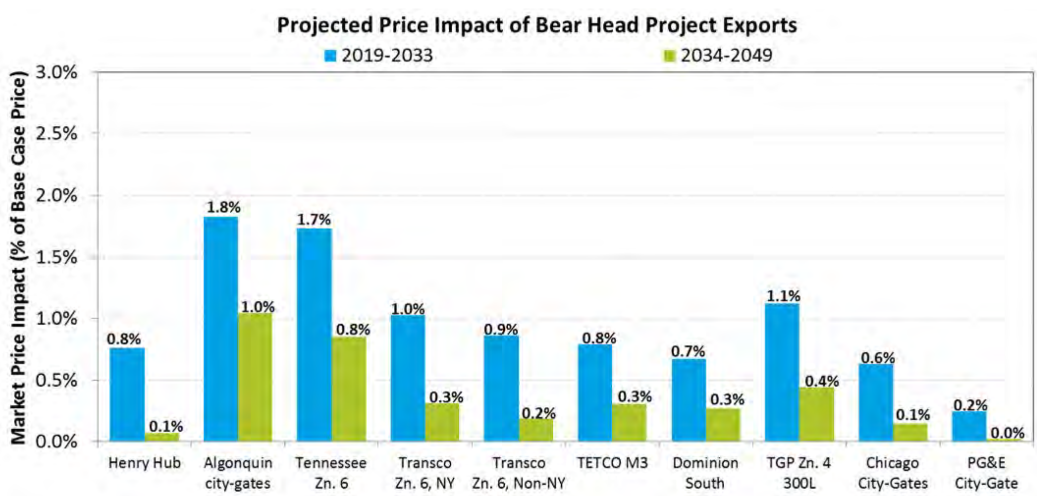
Table reflects prices rounded to the nearest cent.

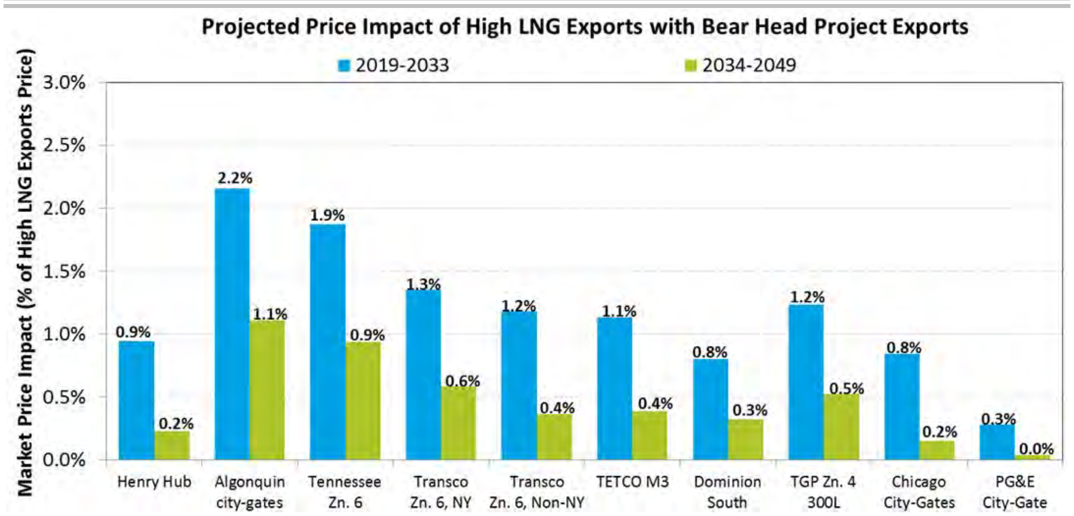
Price Impact across the Broader U.S. Market

Black & Veatch also examined the market price impact of the Bear Head LNG Project at eight additional locations (Tennessee Zn. 6; Transco Zone 6 ("Transco Zn. 6") NY; Transco Zn. 6, Non-NY; TETCO M-3; Dominion, South Point ("Dominion South"); Tennessee Zone 4 300L ("TGP Zn. 4 300L"); Chicago City-Gates; and PG&E City-Gates) and observed a similar range of price impacts, as shown in Figure 2. These trading hubs were selected for their importance to consumers and because they measure the price impact at major markets that source gas supplies from the same producing basins as the Bear Head Project.

The market price impact of the Bear Head Project exports, expressed as a percentage of market prices, slowly decreases over the analysis period as natural gas prices rise across North America. The export terminal has a much lower impact on markets outside of the Northeast, as other alternative low cost supply sources across North America are readily available to serve those markets.

Figure 2: Projected Market Price Impact across Pricing Points





Summary Conclusions

Black & Veatch's assessment demonstrates that the proposed Bear Head LNG Project has a limited impact on natural gas prices across the U.S. when incremental gas pipeline infrastructure in New England is constructed and completed by 2019. Several pipeline projects have been proposed and have received significant shipper interest from local distribution companies and power generators across New England which has led Black & Veatch to include these pipeline projects in the *Base Case*. Incremental gas pipeline infrastructure will reduce the frequency and magnitude of natural gas price spikes and reduce regional price volatility which will benefit New England energy consumers.

The estimated price impact at Henry Hub throughout the analysis period is less than 1% when compared to the *Base Case*. The Bear Head LNG Project is expected to have a higher price impact in the local New England market, with price increases at Algonquin city-gates ranging from 1.8% from 2019-2033 and 1.0% from 2034-2049 when compared to the *Base Case*.

As seen through a comparison of results from the High LNG Exports with Bear Head LNG scenario, exports from the Bear Head LNG Project exert a slightly increased, but not significant, impact on New England prices than observed in the *Base Case* in both absolute and percentage terms.

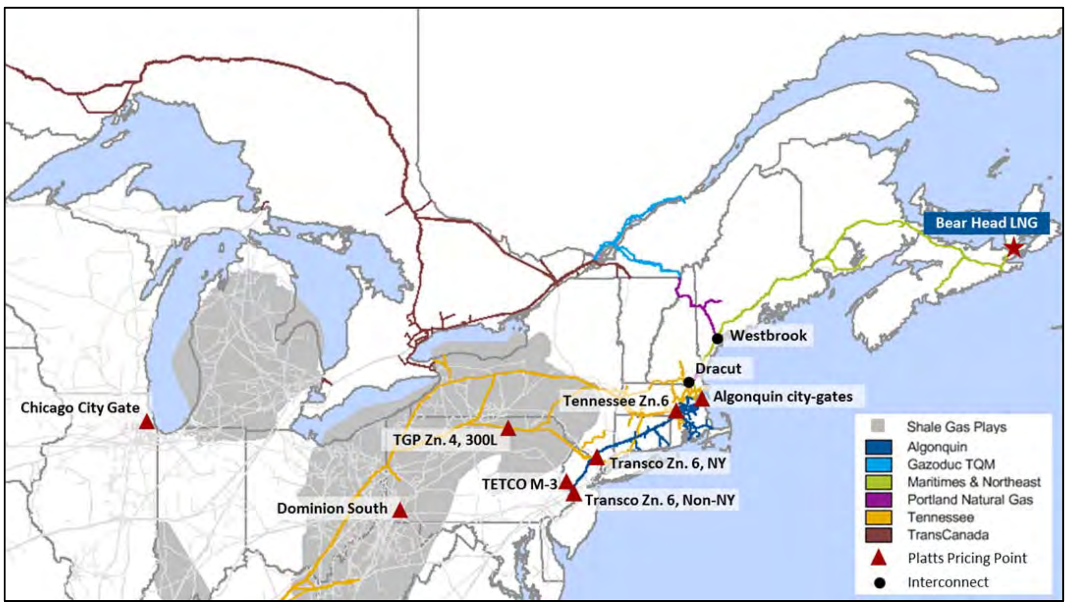
Throughout the analysis period, U.S natural gas supply will continue to outpace demand in the Lower 48 markets. The U.S Northeast market will remain a regional exporter of natural gas with the development of the Marcellus/Utica Shales. The impact of the Bear Head LNG Project on market prices across the U.S. decreases with greater geographic distance from the project. For example, Bear Head LNG exports have a minimal impact on natural gas prices in the U.S. Gulf Coast or Midwest given the robust supply expected to be available from various basins across North America.

3.0 Overview of the Proposed Bear Head LNG Project

Bear Head LNG is developing an LNG export terminal in Point Tupper, Nova Scotia. As currently proposed, the project will commence operations in 2019 with an initial liquefaction capacity of up to 8 million tons per annum ("MTPA").

The Bear Head LNG Project's proposed pipeline header will interconnect with the M&NP near Goldboro, Nova Scotia. The Project will have up to 1.2 Bcf/d of pipeline capacity originating from Dracut, MA ("Dracut") to flow north to the Bear Head LNG terminal. For M&NP to flow north, Black & Veatch has assumed additional infrastructure will be constructed to enable up to 1.2 Bcf/d of gas supplies to flow from south to north to the Bear Head LNG pipeline header. At Dracut and Westbrook, ME, the Bear Head Project will be able to access gas supplies on TGP and the Portland Natural Gas Transmission System ("PNGTS"). See Figure 3.

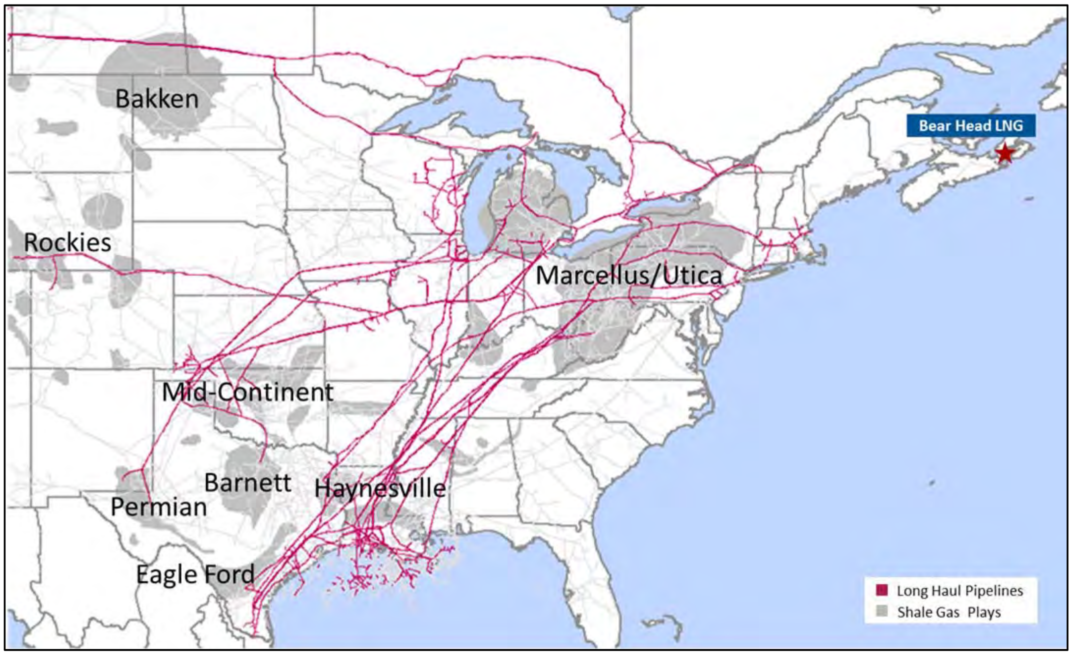
Figure 3: Map of the Bear Head Project



Bear Head LNG is well positioned to access both U.S. and Canadian gas supplies. Potential Canadian supplies include local Eastern Canadian production in Nova Scotia and Newfoundland as well as production sourced in the Western Canadian Sedimentary Basin ("WCSB").

Bear Head LNG has access to numerous U.S.-sourced gas supplies either via interconnects with other interstate pipelines into TGP or directly on the TGP system. In addition to the Appalachian shales, Bear Head LNG could reach back to the major Gulf Coast production basins or production located in the Mid-Continent region. See Figure 4 below. Through TGP and the pipelines with which it connects, the Bear Head Project would be able to access supply basins that comprise of 75% of current total Lower 48 production.

Figure 4: Mid-Continent and Gulf Coast Paths to Bear Head Project



Availability of Underground Storage in Nova Scotia

The Bear Head LNG Project would be able to access an underground storage facility located in Alton, Nova Scotia. Alton Natural Gas Storage, a subsidiary of AltaGas, is currently constructing a natural gas storage complex with three salt caverns and a gas pipeline lateral, and is targeting to commence operations in 2015. Based on its regulatory application, the initial total working gas capacity of the first three caverns will be 3.8 Bcf with maximum withdrawal rate of 0.8 Bcf/d. Alton Gas Storage may develop as many as 10 to 15 caverns at a later date.[1] The pipeline lateral from Alton will interconnect with Maritimes and Northeast Halifax Pipeline. See Figure 5 below.

[1] http://www.novascotia.ca/nse/ea/AltonNaturalGasStorage.asp

Figure 5: Alton Gas Storage Location

Source: AltaGas and B&V Analysis

Overall, additional underground gas storage in Nova Scotia could also help mitigate winter price spikes during the coldest days of the year in New England. Summer storage injections of Nova Scotia, U.S., or other Canadian production and winter storage withdrawals that serve the Maritimes and New England markets will dampen winter seasonal price spreads. The availability of additional winter supplies via Alton Natural Gas Storage's facility will reduce the severity of price spikes and the draw on Northeast supplies. The Bear Head Project's access to storage will allow it to optimize seasonal feed gas supply purchases as well. The Project's customers could purchase additional summer gas supplies when New England and Lower 48 demand is much lower and pipeline capacity to Dracut is more readily available, inject those volumes into storage, and then withdraw them on peak winter days reducing the potential market impact on natural gas prices during the winter months.

Nova Scotia Gas Supply

The availability of Nova Scotia gas supplies, may allow the Bear Head Project to offset U.S and Western Canadian sourced supplies. Currently, there are two local sources of gas supply in Nova Scotia. The Sable Offshore Energy Project ("SOEP") commenced production in 2000, delivering gas supplies to local markets in Nova Scotia and New Brunswick as well as exports to the U.S. via the M&NP pipeline to markets in Maine, New Hampshire and to Dracut. While SOEP supplies have been in steady decline since 2008, the commencement of Deep Panuke production in 2013 has somewhat offset those declines and has increased Eastern Canadian production to its highest levels in the past 10 years.

Additional studies and analysis indicate further potential for development in the region. The Play Fairway Analysis2 ("PFA") and affiliated studies made the model-dependent case for 121 Tcf of natural gas in place ("GIP") in multiple prospective reservoirs in the Nova Scotia offshore region comprising the Scotian Basin. A combination of seismic surveys and exploratory well logs have been used by investigators, including Shell Upstream Americas, to estimate the distribution of gas reservoirs by prospective size. Attention has focused on the Sable sub-basin, underlying the Sable Island area, as possibly the richest gas-prone area and with a prospective resource base of 35 Tcf GIP. A cumulative inventory of exploratory wells drilled over the history of gas assessment of the Scotian Basin, including the PFA, included at least 102 wells with shows of oil, condensate or gas. Among the wells with gas shows, a total of 222 flow tests showed a wide population of flow rates, following approximately a log-normal distribution, which could be interpreted as broadly consistent with the model distribution of prospective gas reservoirs.

Although actual production data has been too few to book significant gas reserves, as would be required to conform to the rules applied by the Canadian Securities Administrators ("CSA"), all geotechnical indications point toward a significant resource base. If referenced to historical experience in developing offshore hydrocarbon resources, it is reasonable to expect that about 10-20% of the GIP will eventually become classified as technically recoverable. Accordingly, upon future development, the Scotian Basin might yield at least 12-24 trillion cubic feet ("Tcf") with about 3-7 Tcf from the Sable sub-basin alone. Based solely on risked-based analysis of only proven discoveries (i.e., reservoirs that have produced gas), which is a more robust analysis than the estimation of GIP, the minimum expected producible gas complement is about 2 Tcf.

Recently, Shell Canada and BP announced plans to develop new deep water blocks off the coast of Nova Scotia. In an agreement in 2011 with the provincial/federal regulatory in Nova Scotia, Shell Canada plans to spend $965 Million on four blocks located about 200 kilometers southwest of Halifax over the nine-year exploration license.[3] See Figure 6. Between 2015 and 2019, Shell Canada plans to drill up to seven exploratory wells. Shell recently announced ConocoPhillips and Suncor Energy as joint venture partners on its exploration program.[4] In 2012, BP was awarded exploration rights for four deepwater blocks 300 kilometers off Halifax after submitting a $1 billion exploration bid. BP began a two-year seismic program to map the four blocks for potential hydrocarbons in May 2014, and will evaluate the seismic data before announcing future plans.[5]

While still in the exploratory phase, if additional offshore Nova Scotia oil and gas resources are produced during the analysis period, the price impact of the Bear Head Project on Henry Hub and New England natural gas prices would be even lower than reported, as less gas exports from the U.S. will be needed to provide feed gas to the terminal. The Bear Head Project will be well positioned to access these incremental Nova Scotia supply sources.

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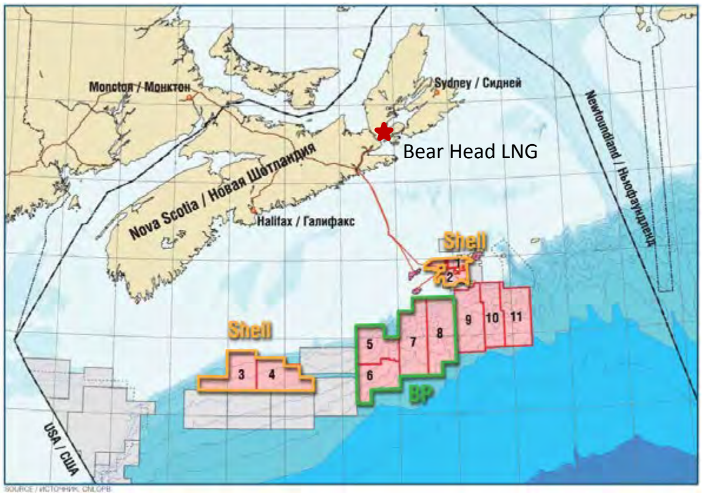
[2] http://energy.novascotia.ca/oil-and-gas/offshore/play-fairway-analysis/analysis
[3] http://www.platts.com/latest-news/oil/calgary/shell-to-drill-seven-wells-offshore-nova-scotia-21917817
[4] http://www.shell.ca/en/aboutshell/media-centre/news-and-media-releases/2014/0609shelburne.html
[5] http://thechronicleherald.ca/business/1236573-bp-wraps-great-seismic-season

Figure 6: Areas of Development in Offshore Nova Scotia



Source: Oil & Gas Euroasia

Western Canadian Sedimentary Basin Supply

There are over 10 major points of entry where WCSB supplies can enter into the U.S. interstate pipeline system, of which 4-6 may potentially be utilized to transport WCSB supplies to either Dracut or Westbrook. Figure 7 shows possible gas receipt points for WCSB gas.

In Waddington, NY, the Iroquois Gas Transmission System ("Iroquois") can receive WCSB gas supplies from the TransCanada Pipelines Mainline ("TransCanada") and can move the volumes south to its interconnect with TGP at Wright, NY. On TGP, the gas supplies would traverse from New York through Massachusetts on the TGP 200 Line and deliver to M&NP at Dracut.

In Pittsburg, NH, PNGTS can receive WCSB gas supplies transported across Canada on TransCanada to Trans Québec and Maritimes Pipeline ("TQM") which then delivers the gas to PNGTS which transports volumes south to its interconnect with M&NP near Westbrook, ME.

Other potential entry points for WCSB supplies include Noyes, Minnesota (aka Emerson), where Great Lakes Pipeline ("Great Lakes") and Viking Pipeline receive WCSB supplies from TransCanada. Volumes on Great Lakes can be re-exported at St. Clair, MI to Ontario into Union Gas and back onto the TransCanada network for delivery to Niagara, Waddington or Pittsburg. Similarly, WCSB supplies received at Port of Morgan, MT (aka Monchy) on Northern Border Pipeline can be moved south to Vector Pipeline and re-exported back to Ontario at St. Clair into Union Gas, which can then deliver the gas back to TransCanada for delivery to one of the aforementioned export points.

Figure 7: WCSB Potential Paths to Bear Head Project

Incremental Pipeline Capacity into New England

In an effort to meet the demand for additional pipeline capacity in the New England region, several pipeline expansion projects have been proposed to deliver incremental natural gas supplies into the market to serve both LDC and power generation demand. In aggregate, if all of the proposed pipeline projects are completed, these projects would almost double the current pipeline capacity serving the New England market today. Most of these proposed pipeline projects are scalable in design, and can accommodate additional pipeline shippers, which in turn would increase the contracted billing determinants and reduce the overall cost of the pipeline projects to New England LDCs and power generators.

Spectra's Algonquin Incremental Market ("AIM") project is expected to receive its FERC certificate and authorization to begin construction in the spring of 2015. Projected to be in service by November 2016, the AIM expansion project will add an additional 342 million cubic feet per day ("MMcf/d") of capacity from Ramapo, NY to markets in Connecticut, Rhode Island and Massachusetts. The anchor shippers on AIM include UIL Holdings, National Grid, NiSource, and Northeast Utilities. Figure 8 shows the projected project right-of-way.

Figure 8: Spectra AIM Expansion Project Map

Source: Spectra

Kinder Morgan's Northeast Energy Direct will extend from the Marcellus Shale along existing TGP right-of-way across New York and Massachusetts and into Dracut. As depicted in Figure 9 below, the project is currently in the pre-filing process with the Federal Energy Regulatory Commission ('FERC") and it is expected to formally file an application with FERC in the fourth quarter of 2015, with construction beginning in January 2017 to meet the projected in-service date of late 2018. The proposed project is scalable from 0.8 Bcf/d to 2.2 Bcf/d depending on shipper commitments in the region. So far, anchor shippers, including Berkshire Gas Company, Columbia Gas of Massachusetts, Connecticut Natural Gas, Liberty Utilities, National Grid, and Southern Connecticut Gas, have signed binding agreements for a minimum of 0.5 Bcf/d total firm transportation capacity.

Figure 9: Kinder Morgan Northeast Energy Direct Map

Source: Kinder Morgan

Spectra has proposed two additional pipeline projects that will complement its AIM project. As part of the Atlantic Bridge project, Spectra proposes to expand the Algonquin and M&NP Pipeline to deliver additional supplies to New England and the Maritimes Provinces, as shown in Figure 10 below. The expansion capacity will be at least 100 MMcf/d, but the project can be scaled up to 600 MMcf/d depending on customer commitments. Unitil Corporation has been announced as an anchor shipper on the project. The current projected in-service date is November 2017.

Figure 10: Spectra Atlantic Bridge

Source: Spectra

Spectra's second proposed project, Access Northeast, proposes to add as much as 1 Bcf/d of incremental pipeline capacity into New England by November 2018. The project consists of several 200 MMcf/d expansions of Spectra's existing Algonquin Pipeline and M&NP footprints depending on customer commitments. In a joint ownership venture, Northeast Utilities and Spectra will each own 50 percent of the $3 billion expansion project. As a way to accommodate power generators and their reluctance to hold firm pipeline capacity, Spectra is looking at Multiple Shipper Options where several shippers can share one contract ensuring maximum efficiency of capacity utilization within a single contract.

4.0 Methodology and Base Case Assumptions

Black & Veatch's analysis draws upon those assumptions utilized in the 2015 EMP regarding future natural gas and power infrastructure, pricing, and the outlook on other power fuels. The EMP is an integrated outlook, updated bi-annually, that assesses the direction of the natural gas, power, coal, and emissions markets. The *Base Case* incorporates the EPA's proposed CPP as the primary driver for gas demand growth in the power generation sector, and assumes the currently proposed Kinder Morgan Northeast Energy Direct and Spectra's Atlantic Bridge and Access Northeast projects are all in service by 2018.

Black & Veatch estimated the price impact of the Bear Head Project using RBAC Inc.'s GPCM™ model. The GPCM™ model uses an advanced algorithm to solve for optimal equilibrium price and quantities by balancing demand and supply nodes in the market. As a network model, GPCM™ nodes represent production regions, pipelines, storage facilities, and end-use customer groups.

Supply

Black & Veatch utilizes a basin-by-basin, play-by-play approach to assess the productive capacity, availability and cost of major natural gas supply sources in North America. For the major shale plays that will contribute to the majority of natural gas production growth, Black & Veatch utilizes in-house geoscientists and geologists to assess the resource base, technology trends in drilling and natural gas liquids content. Black & Veatch also monitors trends in finding and development costs, well type curves, estimated ultimate recoveries and tax and policy changes in order to assess the relative production costs across all production areas that will determine the dynamics of production growth based on competitive cost advantages.

Black & Veatch projects that North American natural gas production will grow from 81.6 Bcf/d to 127.7 Bcf/d, at a growth rate of 0.95% per annum from 2014 to 2049, as shown in Figure 11**Error! Reference source not found.**. This projected production is assumed to originate from basins that are currently producing natural gas. Black & Veatch assumed limited production to be sourced from yet-to-be developed sources, such as the Tuscaloosa or Mancos Shale plays. This conservative supply assumption was utilized in each scenario presented in this report.

Figure 11: Historical and Projected North American Production

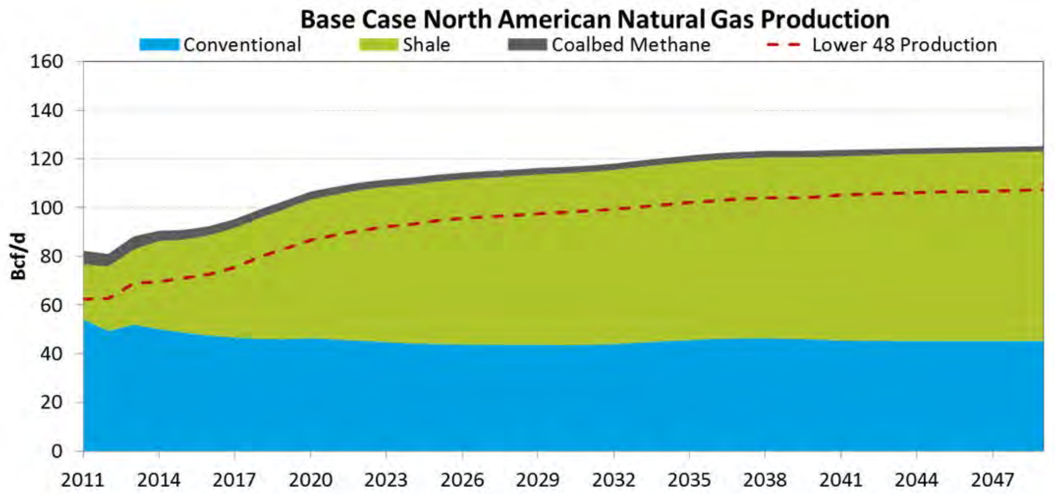
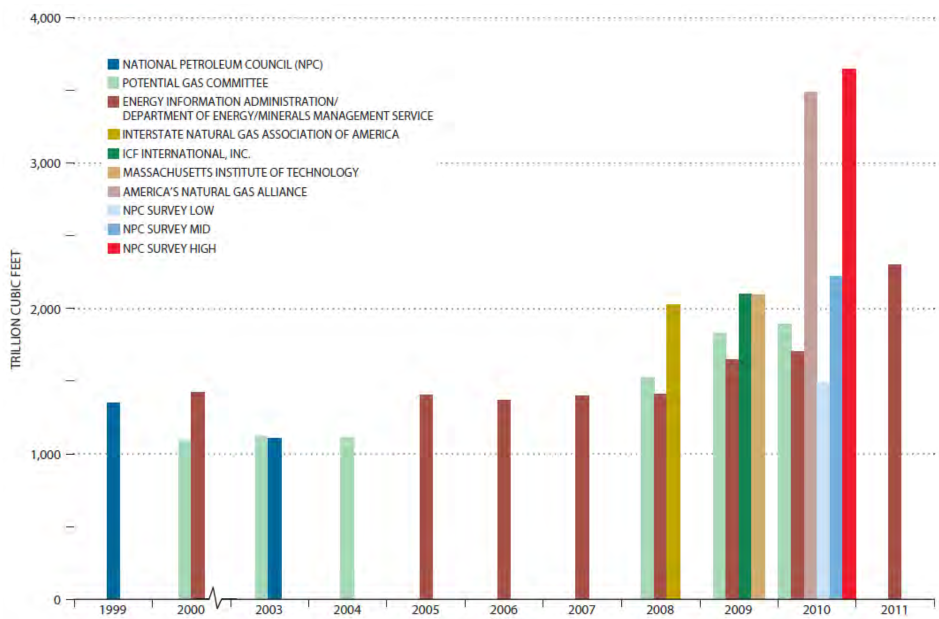


Figure 12: Evolution of U.S. Technically Recoverable Natural Gas Resource Estimates

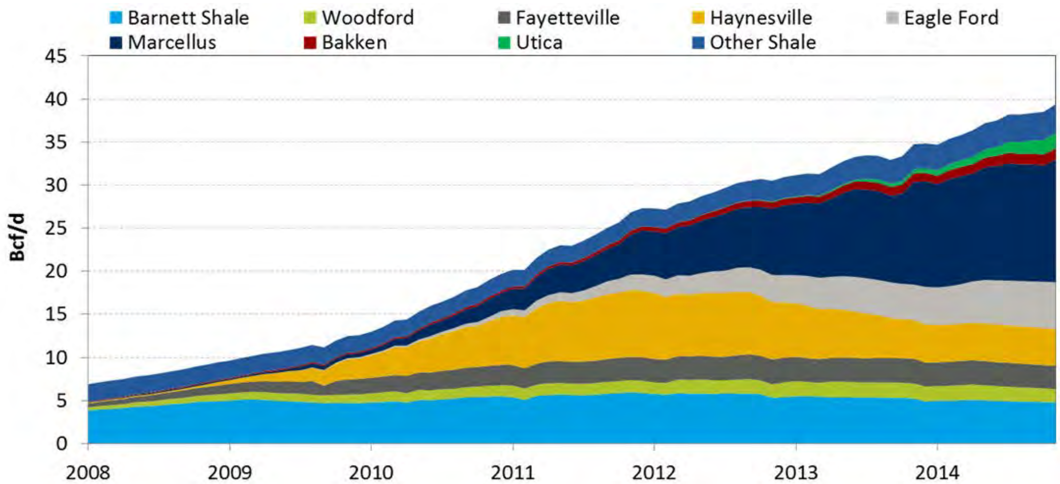


Source: National Petroleum Council. Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources (September 2011)

Rapid technological advances in horizontal drilling and hydraulic fracturing expanded the economically recoverable gas resource base that had hitherto been only technically recoverable. As new land positions were established and resources were tested, the resulting influx of shale gas reserves has dramatically increased the supply base of the North American market. Figure 12 shows that the technically recoverable natural gas resource estimates have grown substantially since 2007.

As seen in Figure 12, estimates of natural gas producible from shale plays in the U.S. have steadily increased as exploration and production work has matured. Actual U.S. production of natural gas from shales (Figure 13) increased more than five times from January 2008 to 2014, from approximately 6 Bcf/d to more than 40 Bcf/d. At Dracut, the Bear Head Project can reasonably expect to make supply arrangements from a majority of the current major shale basins in the U.S. and Canada.

Figure 13: Major Shale Production by Basin



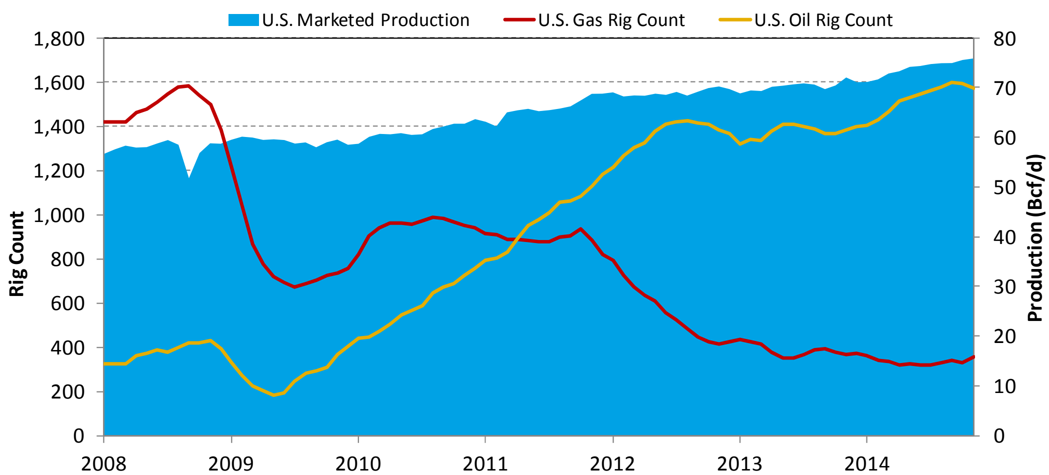
Source: LCI Energy Insight

The recent growth in shale gas production is primarily attributable to two types of plays: (a) dry gas plays that are economical to produce, mainly by close proximity to major demand centers; (b) oil or wet gas plays (rich in natural gas liquids) that have gas associated with high-value liquids. As shown in Figure 14, natural gas rig counts have been in steep decline, while oil rig counts have continued to grow. Following the steep decline of global oil prices during late 2014 and early 2015, oil drilling activity has begun to decline while gas drilling activity has remained flat. Indeed, gas production from the market-proximate gas plays, Marcellus Shale and Haynesville Shale, has remained steady and volumetrically more significant than production of associated gas from wet plays. Black & Veatch expects WTI oil prices to remain in the $45 - $55/bbl for the next 18-24 months and then begin to gradually increase up to a level of about $85/bbl by 2020. Gas prices at the Henry Hub are expected to remain in the $3.50 - $5.00/MMBtu range throughout the end of this decade.

The production/technology growth story in the U.S. has not been limited to shale opportunities. In the Permian Basin, producers are going back into previously drilled wells and using horizontal drilling to enhance oil and gas extraction. According to the EIA, from 2007 to 2010, the Permian Basin had flat oil production, averaging nearly 900,000 barrels per day. In January 2015, Permian oil production reached its highest level to date exceeding 1.8 million barrels per day. From January 2007 to January 2015, the Permian Basin added 1.6 Bcf/d of natural gas production, exceeding 6.2 Bcf/d in January 2015, representing a 36% increase over the period. By 2020, many expect the Permian Basin to have the highest production rate of tight oil in the U.S. A similar situation can be examined in the Texas

Panhandle in the Granite Wash play where horizontal drilling has extended the life of these mature reservoirs, where associated gas is producing over 1 Bcf/d. Associated gas already makes up nearly one-third of the new growth in U.S. natural gas supply; and tight oil with associated gas is expected to continue to draw more attention from producers than dry gas plays. Black & Veatch believes that reduced production of associated gas from oil plays will not occur until mid to late 2015 and will be temporary as oil prices begin to recover before the end of the year.

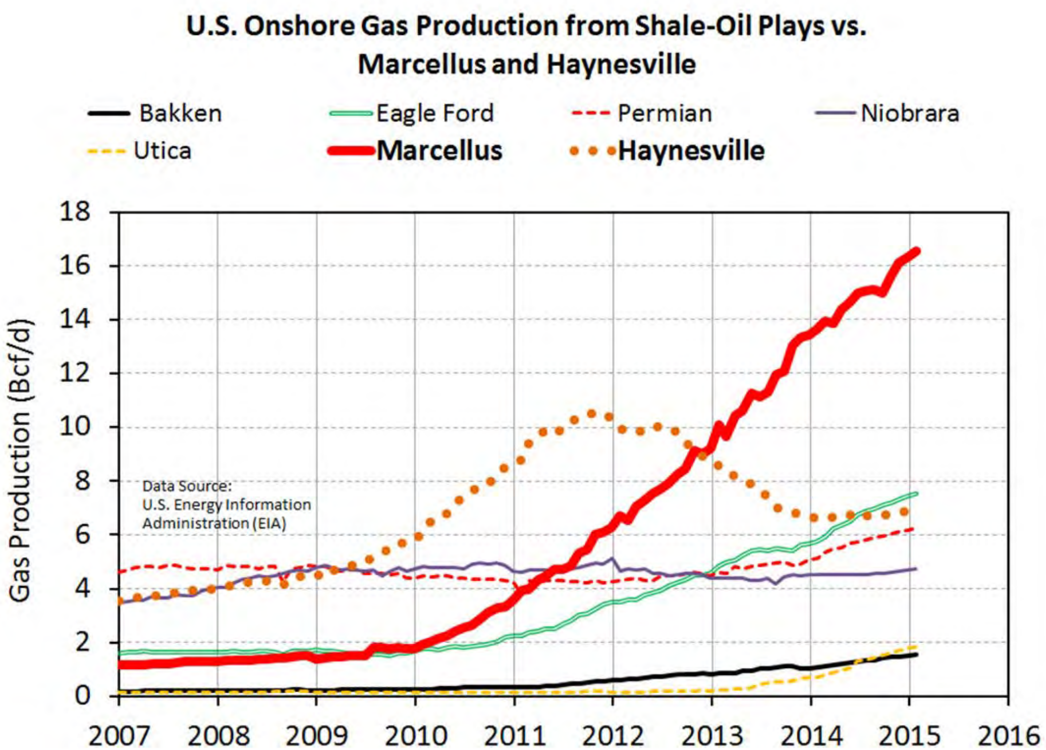
Figure 14: U.S. Natural Gas Rig Count vs. Marketed Production



Source: LCI Energy Insight

The proposed Bear Head Project is located in Nova Scotia with proximate access to U.S. production from the Marcellus Shale and Utica Shale, both of which have experienced a production boom along with other North American shale basins in recent years. Although some other shale gas plays have witnessed declining development activity as natural gas prices have remained depressed since 2011, Marcellus gas production has maintained robust growth and the Utica growth has only just begun, as shown in Figure 15.

Figure 15: Natural Gas Production from U.S. Shale Oil Plays and Key Shale Gas Plays



Prospective Gas Resources in Eastern Canada

Gas supplies from U.S. shale plays, especially the Marcellus Shale and Utica Shale, are emphasized because their resource bases are large, their production growth remains strong and their proximity to the Bear Head Project site is attractive. Additional gas supplies from eastern Canada, with even closer proximity to the Bear Head Project site, could become available in the future.

Based on the Play Fairway Analysis (PFA) which began in 2008 under sponsorship of the Nova Scotia Department of Energy, unproven resources in the Nova Scotia offshore are estimated to be 8 billion barrels of oil and 120 Tcf of gas. The estimates are based on occurrence of known or suspected petroleum reservoir rocks and geologic analogy with more extensive knowledge about the offshore area near Halifax. The PFA identified six zones across the Scotian Shelf and the Scotian Basin that have been, or could become, open to lease bids by petroleum exploration companies. Encana Corporation has produced gas from the Deep Panuke field on the Scotian Shelf since 2013. Based solely on risked-based analysis of only proven discoveries, the minimum expected producible gas complement in the Scotian Basin is about 2 Tcf.

Sable Island occurs within Zone 3, which is estimated to contain 35 Tcf of gas in place (but with the portion technically recoverable not yet established). Lease parcels for exploration in Zone 3, commonly referenced as the Sable sub-basin, were awarded to Shell Canada in 2011 and to BP in 2012. Over the next two to three years, Shell Canada and BP will need to assess the seismic analysis and exploratory well data to determine how they will meet the exploratory agreements with Nova Scotia.

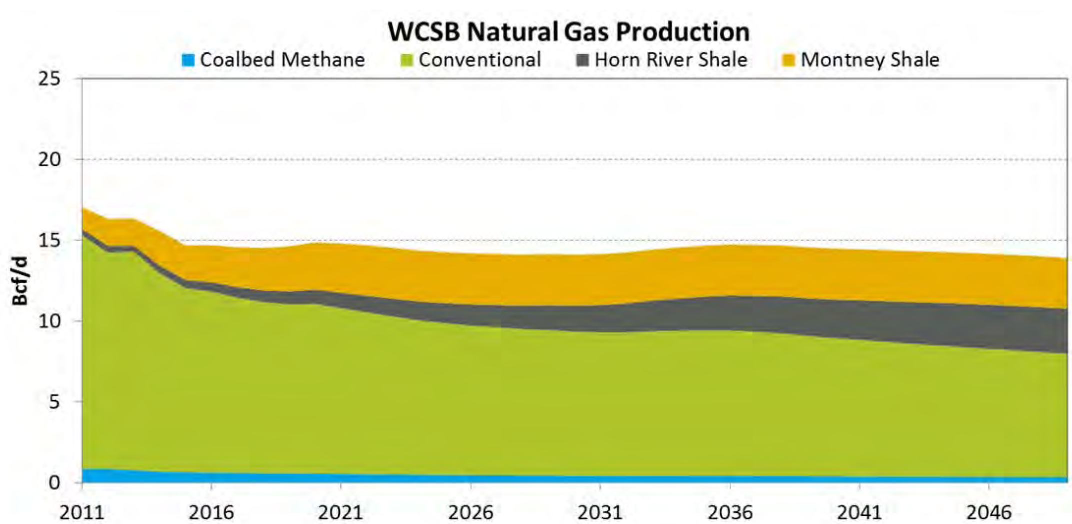
The Utica Shale extends into Quebec and the Canadian portion of the recoverable resource base has been estimated as 31 Tcf (ARI, Inc. on behalf of EIA). The Horton Bluff Shale underlies Nova Scotia and the Frederick Brook Shale underlies New Brunswick. ARI, Inc. (on behalf of EIA) estimated recoverable resources of 2 Tcf for the Horton Bluff Shale. Geologic investigation of the Frederick Brook Shale is largely incomplete although early exploration work led by Southwestern Energy, Inc. suggested that about 67 Tcf of gas in place (but with the fraction recoverable not yet determined).

None of the aforementioned onshore plays currently are in production. Indeed the recent trend in eastern Canada has been for moratoria on onshore shale gas development projects based, in part, on local objections to hydraulic fracturing. Nonetheless, the prospective gas resource base in eastern Canada is significant and might become a further advantage to the Bear Head Project in the future.

Gas Resources in Western Canada

Figure 16 presents historical and projected natural gas production in the WCSB. Production from unconventional shale and conventional production sources are projected to slowly decline from 15.5 Bcf/d in 2014 to 13.9 Bcf/d by 2049. Recent shale gas developments have slowed the pace of decline in the WCSB and are expected to offset, in part, expected production declines in conventional and coalbed methane plays.

Figure 16: Historical and Projected WCSB Production

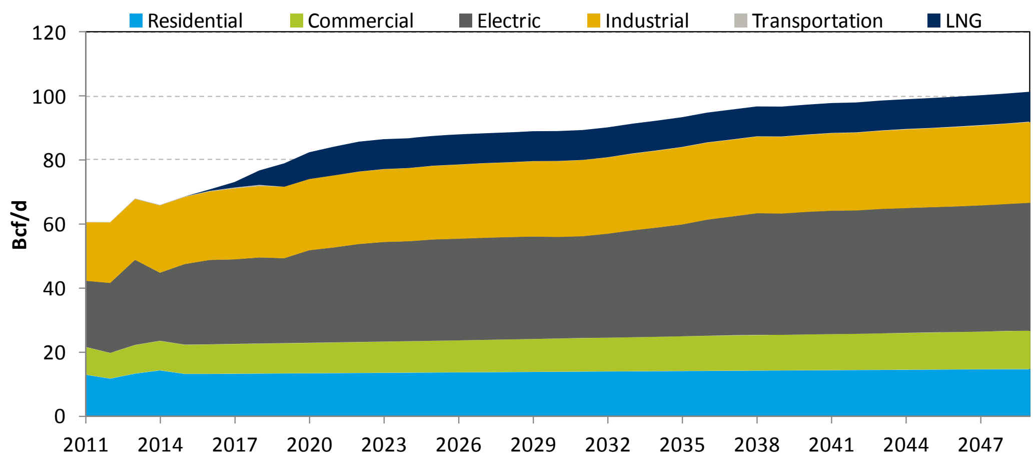


Further delays in the development of British Columbia LNG export facilities could potentially re-direct Horn River and Montney Shale production to other Canadian and Lower 48 markets. Multiple large LNG export projects in British Columbia have announced delays in development, changes in ownership, and rising pipeline infrastructure costs to monetize WCSB production. If such delays continue to hinder LNG exports in British Columbia, producers in the Horn River and Montney could choose to monetize their production by selling their gas into other Canadian or U.S. markets which would further dampen the U.S. price impacts of the Bear Head Project.

Demand

Black & Veatch expects demand for natural gas in the Lower 48 to grow from 70 Bcf/d to 96 Bcf/d over the forecast period from 2014 through 2049, an average growth rate of 0.9% per annum. This growth is largely driven by the increased demand for natural gas-fired power generation.

Figure 17: Historical and Projected Lower 48 Demand for Natural Gas



Power generation is expected to be the main driver of demand growth in the North American natural gas market. In June 2014, the U.S. Environmental Protection Agency (EPA) proposed the Clean Power Plan, with the overall objective to achieve a cumulative, nationwide reduction of GHG emissions of 30 percent below 2005 emission levels by 2030.

Based on the major building blocks of the Clean Power Plan, Black & Veatch believes that natural gas-fired generation is positioned to play a critical role in lowering emission levels as well as mitigating renewable capacity intermittency. Black & Veatch projections indicate that the share of natural gas in providing energy for the U.S. is expected to increase by 30% between 2015 and 2039.

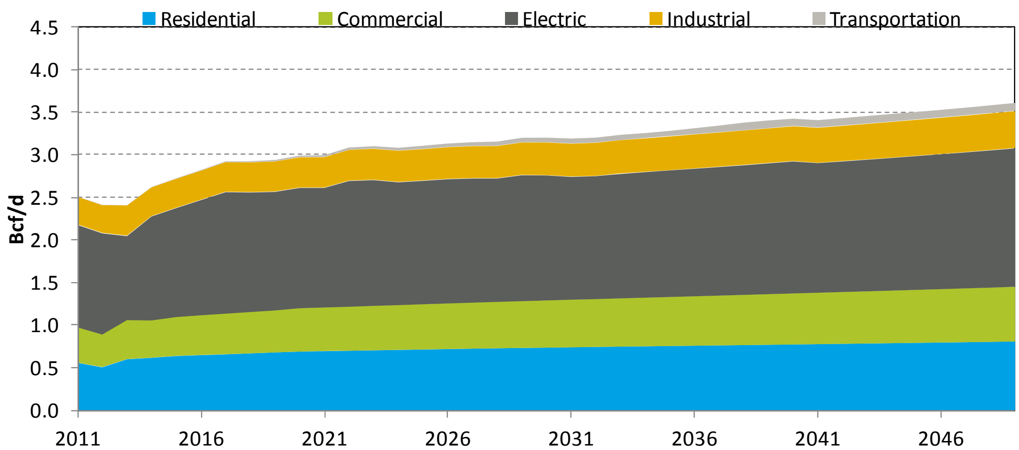
Overall, Black & Veatch anticipates a slight recovery of industrial demand from the past few years as the economy continues to recover from the 2008-2010 recession. As U.S. natural gas prices remains relatively inexpensive compared to alternative fuels and relative to other regions in the world, industrial demand is expected to experience moderate growth over the long term. Residential and commercial demand is expected to remain flat as demand growth due to population and economic growth are offset by energy efficiency gains.

New England Demand

Figure 18 shows historical and projected demand for natural gas in New England. Compared to other U.S. regions, New England is expected to experience moderate demand growth in the residential and commercial sectors in part due to state conversions programs like the one in Connecticut. Connecticut plans to increase natural gas market share from

31% to 50% by 2020, and add 250,000 residential customers. Demand from the residential sector is expected to grow at 0.79% per year while demand from the commercial sector is expected to grow at a rate of 1.1% per year. The announced retirement of the Vermont Yankee nuclear facility and Salem Harbor Power Station have recently increased the region's dependency on natural gas for power generation. The potential impact of the Clean Power Plan is expected to increase gas demand in the electric sector at 0.82% per year, and spur the associated pipeline infrastructure investment. Demand from the industrial sector is projected to grow at 0.7% per year due to increased oil to gas conversions during the analysis period.

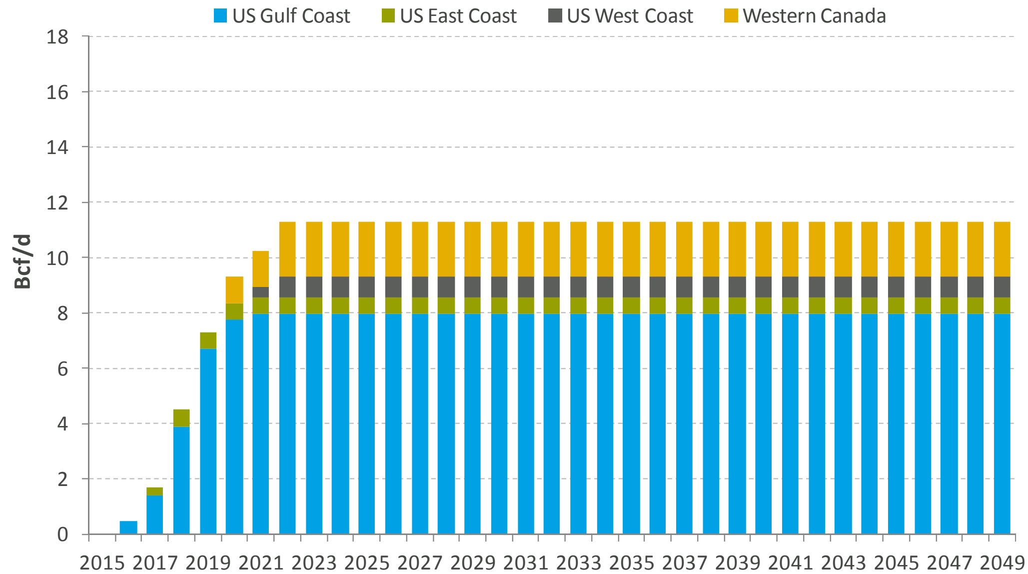
Figure 18: Historical and Projected New England Demand for Natural Gas



LNG EXPORTS

The phenomenal growth in shale gas production has transformed the U.S. natural gas market from an import market to a source of future exports. Black & Veatch included multiple U.S export terminals located in the Gulf Coast, West Coast, and East Coast, as well as a terminal in British Columbia in its *Base Case* assumptions. Figure 19 represents Black & Veatch's *Base Case* LNG export assumptions by region. In the Lower 48, Black & Veatch's *Base Case* assumptions include the following FERC approved U.S export terminals: Sabine Pass, Cameron, Freeport, Cove Point, and Corpus Christi. Jordan Cove is expected to receive its FERC approval in the summer of 2015, and was also included in the *Base Case*. In Western Canada, Black & Veatch assumed one of the NEB-approved terminals would be placed into service with a gas demand of approximately 2 Bcf/d by 2020. In terms of LNG export volumes from the Lower 48, Black & Veatch's *Base Case* is comparable to EIA AEO 2014 Reference Case. Black & Veatch's *Base Case* is projecting higher LNG exports by 2019, 7.3 Bcf/d as compared to EIA AEO 2014 Reference Case projection of 4.8 Bcf/d, but both projections reach comparable levels by 2028 at 9.3 and 9.6 Bcf/d, respectively.

Figure 19: Projected Natural Gas Demand for LNG Exports By Region – Base Case



PIPELINE INFRASTRUCTURE

Black & Veatch included all existing North American natural gas pipeline infrastructure in its projection as well as proposed interstate pipeline projects that are under construction, have held a successful binding open season, or have obtained regulatory approvals. Beyond the timeline of currently announced pipeline expansions, Black & Veatch also included some generic pipeline expansions from various supply basins to demand centers to meet growing demand and to allow gas supply access to additional markets over the analysis period that had limited impacts to the conclusions of this report.

In New England, Black & Veatch has included in its *Base Case* Kinder Morgan's Northeast Energy Direct project, as well as Spectra's Atlantic Bridge and Access Northeast projects. All three projects are at various stages of development and serve a growing market in need of incremental pipeline capacity. Several recent market analysis studies conducted by the New England State Committee on Electricity ("NESCOE") and the State of Massachusetts strongly supports the conclusion that additional pipeline infrastructure will be needed to serve New England. With numerous New England shippers committing to these various projects, Black & Veatch believes that these three projects can potentially be completed by 2018.

Appendix A includes the major announced pipeline projects that Black & Veatch incorporated in the *Base Case*.

5.0 Scenario Assumptions

Black & Veatch created three scenarios in addition to the *Base Case* in order to examine the potential impact of the Bear Head LNG Project on natural gas prices across the U.S.

WITH BEAR HEAD LNG PROJECT EXPORTS SCENARIO

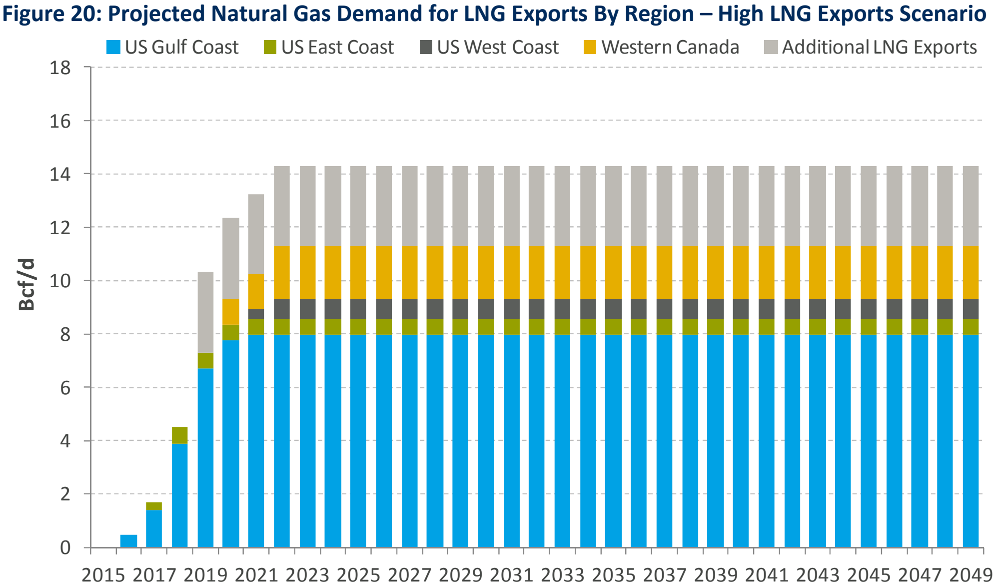
In the *With Bear Head Project Exports* scenario, an additional 1.2 Bcf/d of natural gas demand is created by LNG exports from the Bear Head Project by 2019. As part of this scenario, Black & Veatch assumed additional pipeline capacity on M&NP will be constructed by 2019, originating at Dracut to flow 1.2 Bcf/d north to the Project.

HIGH LNG EXPORTS SCENARIO

In the High LNG Exports scenario, Black & Veatch further added 3.0 Bcf/d of natural gas demand to *Base Case* assumptions for LNG exports from the Gulf Coast and Eastern Canada. This scenario tests the cumulative market price impact of additional LNG exports (relative to the *Base Case*) on regional and national market prices during the analysis period. In this scenario, total U.S. and Canadian export volumes will reach 12.3 Bcf/d by 2020, similar to the 12 Bcf/d scenario requested by the Department of Energy's Office of Fossil Energy (DOE/FE) in its May 2014 request of EIA to update its 2012 analysis on LNG exports.

Starting in 2019, Black & Veatch assumed three additional export terminals would be constructed in the Gulf Coast and Eastern Canada. In the Gulf Coast, Black & Veatch assumed two 1.2 Bcf/d terminals, one located on Lake Charles, Louisiana, and the other in Brownsville, Texas. In Eastern Canada, Black & Veatch assumed one 0.6 Bcf/d terminal located in Nova Scotia.

Figure 20: Projected Natural Gas Demand for LNG Exports By Region – High LNG Exports Scenario



HIGH LNG EXPORTS WITH BEAR HEAD Project SCENARIO

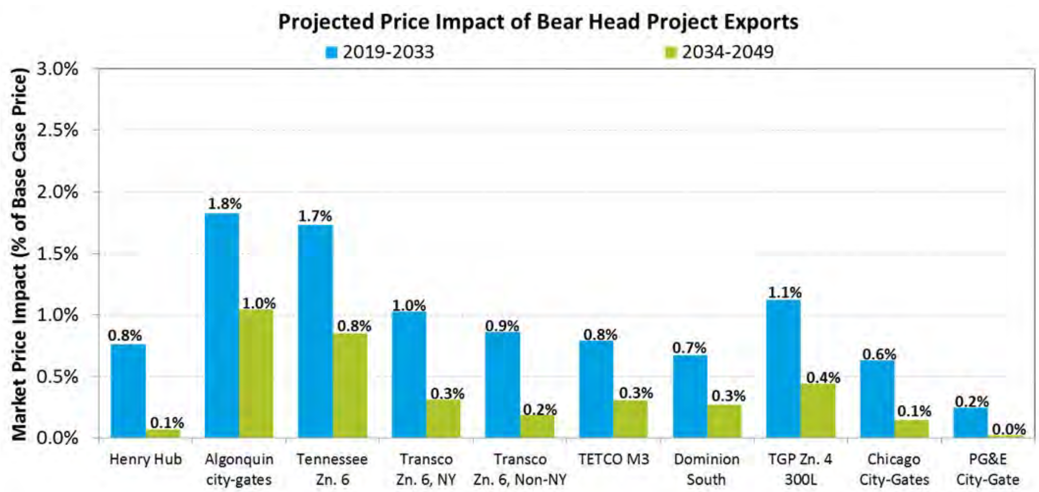
In the *High LNG Exports With Bear Head Project Exports* scenario, an additional 1.2 Bcf/d of natural gas demand is created by LNG exports from the Bear Head Project by 2019. Similar to the *With Bear Head Project Exports* scenario, Black & Veatch assumed pipeline capacity on M&NP will be constructed by 2019, originating at Dracut to flow 1.2 Bcf/d north to the Project. This scenario stress tests the regional and national market price impact of additional Eastern Canadian exports (on top of the High LNG Export Case), which already includes an Eastern Canada LNG export project, during the analysis period.

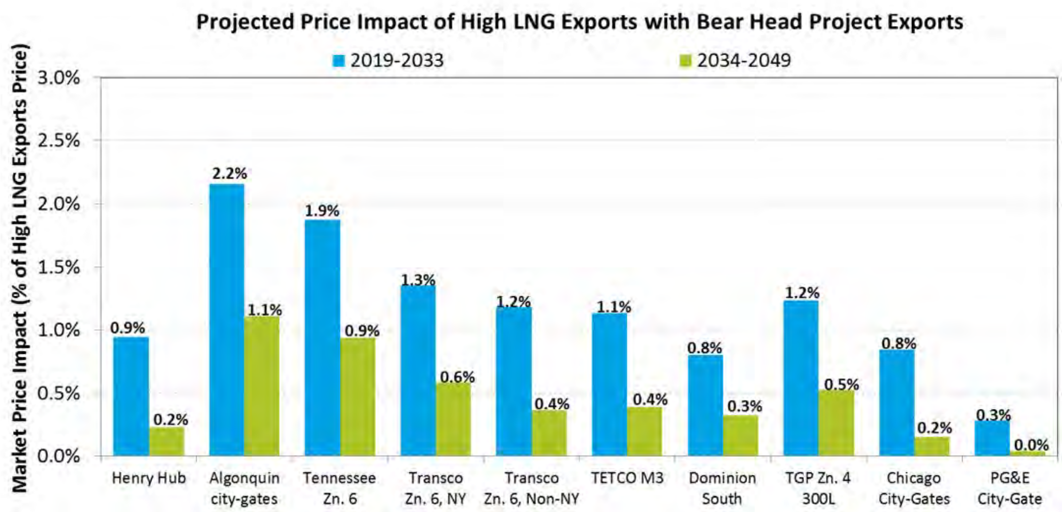
6.0 National and Regional Price Impacts

Black & Veatch's independent assessment examined the market price impacts of the proposed Bear Head Project. Across various scenarios, we found that the proposed export volumes should have limited impact on the price levels for natural gas either regionally in New England or nationally at Henry Hub during the analysis period, as shown in Figure 21.

The projected market price impact of the Bear Head Project is expected to be similar across the pricing points closest to the Bear Head Project. The impact estimated at more remote pricing points tends to be smaller in both the *Base Case* and *High LNG Exports* scenario, as shown in Figure 21.

Figure 21: Projected Market Price Impact across Pricing Points





At Dominion South, the market price impact is muted due to the continued growth of the Marcellus/Utica Shale production, which is assumed to reach 23 Bcf/d by 2019 and 32.2 Bcf/d by 2049. Black & Veatch expects Marcellus/Utica production to continue to serve market demand in the Northeast, Midwest, and Southeast U.S. The market price impact of the Bear Head Project at Dominion South is projected to be $0.03/MMBtu (0.7%) over the first 15 years of the analysis period and $0.02/MMBtu (0.3%) for the final 16 years the analysis period when compared to the *Base Case*. A similar price impact is observed when compared to the *High LNG Exports with Bear Head Project Exports* scenario, leading to an increase of $0.04/MMBtu (0.8%) from 2019-2034 that diminishes to $0.04/MMBtu (0.3%) from 2035-2049. See Table 4.

Table 4: Market Price Impact at Dominion South

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	4.93	4.96	4.98	5.02
	Average Diff. from Base		0.03		0.04
	Percentage Increase		0.7%		0.8%
2034-2049	Average Price ($/MMBtu)	7.59	7.61	7.61	7.64
	Average Diff. from Base		0.02		0.02
	Percentage Increase		0.3%		0.3%

Table reflects prices rounded to the nearest cent.

The Bear Head Project's market price impact at TGP Zn. 4, 300L is similar to what is observed at Dominion South. As one of the market prices in the Northeast Marcellus Shale, the price impact is muted in part due to continued production growth. This pricing point's proximity to Mid-Atlantic premium markets and the potential supply point for recently proposed pipeline expansions to New England makes it a key market price indicator for the Project. See Table 5.

Table 5: Market Price Impact at TGP Zn. 4 300L

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	4.88	4.93	4.95	5.02
	Average Diff. from Base		0.05		0.06
	Percentage Increase		1.1%		1.2%
2034-2049	Average Price ($/MMBtu)	7.81	7.85	7.87	7.91
	Average Diff. from Base		0.03		0.04
	Percentage Increase		0.4%		0.5%

Table reflects prices rounded to the nearest cent.

The market price impact of the Bear Head Project at the Transco Zn. 6, NY is projected to be $0.06/MMBtu (1.0%) for the first 15 years of the analysis period and $ 0.03/MMBtu (0.3%) for the remaining 15 years of the analysis period compared to the *Base Case*. A similar price impact is observed when compared to the *High LNG Exports with Bear Head Project Exports* scenario, leading to an increase of $0.08/MMBtu (1.3%) from 2019-2034 and $0.05/MMBtu (0.6%) from 2034-2049. See Table 6.

Table 6: Market Price Impact at Transco Zn. 6, NY

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.97	6.03	6.06	6.14
	Average Diff. from Base		0.06		0.08
	Percentage Increase		1.0%		1.3%
2034-2049	Average Price ($/MMBtu)	9.29	9.32	9.36	9.41
	Average Diff. from Base		0.03		0.05
	Percentage Increase		0.3%		0.6%

Table reflects prices rounded to the nearest cent.

Both Transco Zn. 6, Non-NY and TETCO M-3 represent gas delivered to the Northeast markets that stem from Northern Virginia to New Jersey. The Bear Head Project price impact at these locations is slightly greater than at upstream points like Dominion South due to the large gas consuming loads along the Mid-Atlantic coast. See Table 7 and Table 8.

Table 7: Market Price Impact at Transco Zn. 6, Non-NY

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.91	5.96	6.00	6.07
	Average Diff. from Base		0.05		0.07
	Percentage Increase		0.9%		1.2%
2034-2049	Average Price ($/MMBtu)	9.25	9.26	9.29	9.32
	Average Diff. from Base		0.02		0.03
	Percentage Increase		0.2%		0.4%

Table reflects prices rounded to the nearest cent.

Table 8: Market Price Impact at TETCO M-3

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.84	5.88	5.94	6.00
	Average Diff. from Base		0.04		0.07
	Percentage Increase		0.8%		1.1%
2034-2049	Average Price ($/MMBtu)	9.13	9.16	9.17	9.20
	Average Diff. from Base		0.03		0.03
	Percentage Increase		0.3%		0.4%

Table reflects prices rounded to the nearest cent.

Given the projection for ample North American natural gas production, Black & Veatch's assessment indicates that exports from the Bear Head Project will lead to minimal price increases of approximately 1% to nearby New England and Northeast markets.

An even lesser price impact is expected in major downstream markets with potential price impacts at Henry Hub ranging from $0.04/MMBtu (0.8%) to $0.01/MMBtu (0.1%) over the analysis period of the *Base Case*. See Table 9.

Table 9: Market Price Impact at Henry Hub

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.57	5.61	5.70	5.75
	Average Diff. from Base		0.04		0.05
	Percentage Increase		0.8%		0.9%
2034-2049	Average Price ($/MMBtu)	8.55	8.55	8.60	8.61
	Average Diff. from Base		0.01		0.02
	Percentage Increase		0.1%		0.2%

Table reflects prices rounded to the nearest cent.

The Bear Head Project has limited price impacts in the Chicago and PG&E city-gate markets. These markets have numerous supply and pipeline alternatives that will help mitigate the additional LNG exports from the Project. See Table 10 and Table 11.

Table 10: Market Price Impact at Chicago City-Gates

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.65	5.69	5.72	5.77
	Average Diff. from Base		0.03		0.05
	Percentage Increase		0.6%		0.8%
2034-2049	Average Price ($/MMBtu)	8.83	8.84	8.84	8.85
	Average Diff. from Base		0.01		0.01
	Percentage Increase		0.1%		0.2%

Table reflects prices rounded to the nearest cent.

Table 11: Market Price Impact at PG&E City-Gate

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	6.26	6.27	6.28	6.29
	Average Diff. from Base		0.01		0.02
	Percentage Increase		0.2%		0.3%
2034-2049	Average Price ($/MMBtu)	9.54	9.54	9.54	9.55
	Average Diff. from Base		0.00		0.00
	Percentage Increase		0.0%		0.0%

Table reflects prices rounded to the nearest cent.

Appendix A – Major Natural Gas Pipeline Expansions

PIPELINE	IN-SERVICE DATE	CAPACITY
Constitution Pipeline	Apr-2015	650 MMcf/d
Spectra Atlantic Bridge	Mid-2018	600 MMcf/d
Spectra Access Northeast	Nov-2018	1,000 MMcf/d
Kinder Morgan Northeast Energy Direct	Nov-2018	1,500-2,200 MMcf/d
Tennessee Connecticut Express Expansion	Nov -2016	72
Tennessee Southwest Louisiana Supply	2018	900 MMcf/d
Tennessee Broad Run	2015-2017	790 MMcf/d
NGPL Gulf Coast Market Expansion	2016-2017	450 MMcf/d
NGPL Chicago Market Expansion	2016-2017	450 MMcf/d
Transco Leidy Southeast	Late 2015	525 MMcf/d
Transco Gulf Trace	2017	1,200 MMcf/d
Transco Dalton Expansion	2017	450 MMcf/d
Transco Atlantic Sunrise	2017-2018	1,700 MMcf/d
Transco VA Southside Expansion	Sept 2015	250
NiSource Leach Xpress	2017	1,500 MMcf/d
Columbia Gulf Cameron Access	2017	800 MMcf/d
NiSource Mountaineer XPress	2018-2019	750-1,500 MMcf/d
Texas Gas Ohio-Louisiana Access	Late 2016	626 MMcf/d

PIPELINE	IN-SERVICE DATE	CAPACITY
Spectra Sabal Trail	2017	800-1,000 MMcf/d
Spectra Gulf Markets	2016-2017	650 MMcf/d
Iroquois South to North Project	Late 2017	650 MMcf/d
Iroquois Wright Interconnect Project	Spring 2016	650 MMcf/d
Nexus Pipeline	Late 2015-Early 2016	1,000 MMcf/d
NGPL Gulf Coast Markets Expansion	Late 2016	750 MMCf/d
Rockies Express East to West	Late 2015-Early 2016	950 MMcf/d
Texas Eastern Access South	Late 2017	320
Texas Eastern OPEN	Mid - 2015	550
Texas Eastern Uniontown to Gas City	Jul-2017	425

APPENDIX C

Black & Veatch, New England Market Impact Assessment for LNG Exports at the Bear Head Export Project (February 2015)

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New England Market Impact Assessment of LNG Exports at the Bear Head Export Project

PREPARED FOR

Bear Head LNG Corporation

FEBRUARY 2015

BLACK & VEATCH
Building a world of difference.

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BLACK & VEATCH STATEMENT

This report was prepared for Bear Head LNG Corporation ("Client") by Black & Veatch Corporation ("Black & Veatch") and is based in part on information not within the control of Black & Veatch. As such, Black & Veatch has not made an analysis, verified, or rendered an independent judgment of the validity of the information provided by others, and, therefore, Black & Veatch does not guarantee the accuracy thereof.

In conducting our analysis, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies we utilize in performing the analysis and making these projections follow generally accepted industry practices. While we believe that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected.

Readers of this report are advised that any projected or forecast price levels and price impacts, reflects the reasonable judgment of Black & Veatch at the time of the preparation of such information and is based on a number of factors and circumstances beyond our control. Accordingly, Black & Veatch makes no assurances that the projections or forecasts will be consistent with actual results or performance. To better reflect more current trends and reduce the chance of forecast error, we recommend that periodic updates of the forecasts contained in this report be conducted so more recent historical trends can be recognized and taken into account.

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1.0 Introduction

To support Bear Head LNG Corporation's ("Bear Head Corp.") application to the United States Department of Energy's Office of Fossil Energy, Black & Veatch Corporation ("Black & Veatch") was retained by Bear Head Corp. to provide an independent assessment of the market impact of Bear Head Corp.'s proposed liquefied natural gas ("LNG") export project ("Bear Head Project" or "Project"), to be sited in Point Tupper, Nova Scotia.

This summary report is an addendum to Black & Veatch's U.S. Market Impact Assessment of LNG Exports at the Bear Head Project and summarizes the impact of the Bear Head Project on the New England market. This report will review the key assumptions related to the natural gas pipeline infrastructure and the expectation for new incremental pipeline capacity into New England. The *Base Case* incorporates the proposed Clean Power Plan ("CPP") as the primary driver for gas demand growth in the power generation sector and assumes the currently proposed Kinder Morgan Northeast Energy Direct and Spectra Energy's ("Spectra") Atlantic Bridge and Access Northeast pipeline projects are constructed and in-service as of 2018.

Black & Veatch's assessment methodology in this report follows the methodology described in the U.S. Market Impact Assessment and utilizes the scenarios listed in Table 1 to assess the New England market price impact of liquefying and exporting 1.2 billion cubic feet per day ("Bcf/d") of U.S. or Canadian gas supplies at the Bear Head Project from 2019 through 2049. Black & Veatch examined prices at Algonquin city-gates and Tennessee Zone 6 Delivered ("Tennessee Zn. 6"), as reference locations to assess the Bear Head Project's price impacts on the New England market.

Table 1: Scenario Descriptions

SCENARIO	DESCRIPTION
Base Case	Based on Black & Veatch's 2015 Energy Market Perspective, which incorporates our analysis of EPA's proposed Clean Power Plan. It also incorporates Black & Veatch's latest assessment of Natural Gas Liquid ("NGL") uplifts to shale gas production costs and their impact on North American unconventional production. Natural gas demand associated with LNG exports from various terminals the U.S and Canada reach 9.3 Bcf/d by 2020 and 11.3 Bcf/d by 2025.
With Bear Head Project Exports	Builds upon the *Base Case* of an additional 1.2 Bcf/d of natural gas demand and pipeline infrastructure associated with LNG exports from the Bear Head Project beginning in 2019.
High LNG Exports	Includes an additional 3.0 Bcf/d of natural gas demand associated with LNG exports starting in 2019 incremental to the *Base Case*, designed to stress test the results of the *Base Case*.
High LNG Exports with Bear Head Project Exports	Builds upon the *High LNG Exports* scenario with an additional 1.2 Bcf/d of natural gas demand and pipeline infrastructure associated with LNG exports from the Bear Head Project beginning in 2019, designed to stress test the results of the *With Bear Head Project Exports* case.

2.0 Executive Summary

Black & Veatch utilized scenario analysis to assess the potential price impact of 1.2 Bcf/d of related gas demand related to LNG exports from the Bear Head Project. Based on our independent assessment, these proposed export volumes are expected to have a limited price impact in New England during the analysis period of 2019 through 2049.

A portion of Bear Head Project export volumes are expected to originate at Dracut, Massachusetts, the pipeline interconnect between the Maritimes & Northeast Pipeline ("M&NP") and Tennessee Gas Pipeline, and flow north on the M&NP to a new pipeline lateral to be connected to the Bear Head Project. Black & Veatch has assumed that additional infrastructure on M&NP will be constructed to allow 1.2 Bcf/d of gas supplies to flow south to north to the Project. Upstream of the Dracut Hub, Black & Veatch has assumed that several of the currently proposed pipeline projects, as discussed in Section 4.0, will be constructed and placed into service by 2018. These proposed projects have received interest from local gas distribution companies across New England.

The *With Bear Head Project Exports* price impact to the *Base Case* at Algonquin city-gates is projected to be $0.10/million British thermal units ("MMBtu") (1.8%) over the first 15 years of the Project's operations. The price impact for the remaining 16 years is slightly less, increasing the *Base Case* average price of $8.68/MMBtu by $0.09/MMBtu (1.0%). The Bear Head Project is expected to exert a similar, though slightly increased price impact under the *High LNG Exports with Bear Head Project Exports* scenario, raising prices at Algonquin city-gates by $0.13/MMBtu (2.2%) from 2019-2033 and $0.10/MMBtu (1.1%) from 2034-2049. See Table 2.

Table 2: Market Price Impact at Algonquin city-gates

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.69	5.79	5.84	5.96
	Average Diff. from Base		0.10		0.13
	Percentage Increase		1.8%		2.2%
2034-2049	Average Price ($/MMBtu)	8.68	8.77	8.78	8.88
	Average Diff. from Base		0.09		0.10
	Percentage Increase		1.0%		1.1%

Table reflects prices rounded to the nearest cent.

The *With Bear Head Project Exports* price impact at the Tennessee Zn. 6 is comparable to the impact at Algonquin city-gates. In the first half of the analysis period, the *With Bear Head Project Exports* impact averaged $0.10/MMBtu (1.7%). The price impact over the second half of the analysis period is slightly less, increasing the *Base Case* average price of $8.85/MMBtu by $0.07/MMBtu (0.8%). The Bear Head Project is expected to exert a similar, though slightly increased price impact under the *High LNG Exports with Bear Head Project Exports* scenario, raising prices at Tennessee Zn. 6 by $0.11/MMBtu (1.9%) from 2019-2033 and $0.08/MMBtu (0.9%) from 2034-2049. See Table 3.

Table 3: Market Price Impact at Tennessee Zn. 6

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.83	5.93	5.96	6.07
	Average Diff. from Base		0.10		0.11
	Percentage Increase		1.7%		1.9%
2034-2049	Average Price ($/MMBtu)	8.85	8.92	8.94	9.03
	Average Diff. from Base		0.07		0.08
	Percentage Increase		0.8%		0.9%

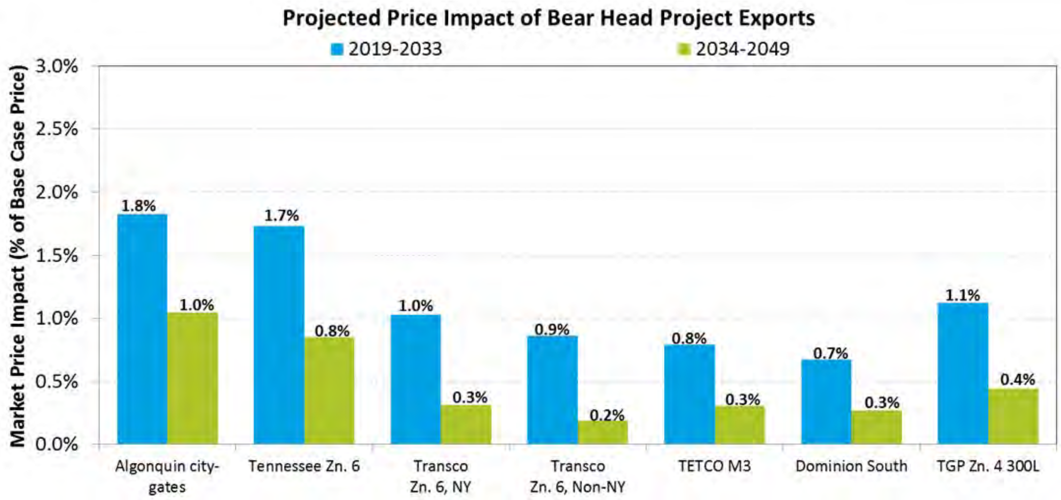
Table reflects prices rounded to the nearest cent.

Further upstream, the Bear Head Project is expected to have a limited impact at key Northeast market prices. At Dominion, South Point ("Dominion South") and Tennessee Zone 4, 300 leg ("TGP Zn. 4 300L"), the average price impact over the first half of the analysis period is $0.03/MMBtu (0.7%) and $0.05/MMBtu (1.1%), respectively. The impact at these two price locations will become more important as more gas supplies originate from the Appalachian shale region.

The Transco Zone 6 ("Transco Zn. 6"), Non-NY and NY, and TETCO M-3 were also examined because they will compete for the same source gas supplies from the producing basins as the Bear Head Project. The recent pipeline expansions from the Marcellus Shale into these markets have reduced basis differentials to Henry Hub and will moderate the seasonal winter basis blowouts. The Northeast market price impact of the Bear Head Project exports, expressed as a percentage of market prices, slowly decreases over the analysis period as Appalachian shale production growth and natural gas prices rise across North America. Key pricing points analyzed in this report can be seen below in Figure 1.

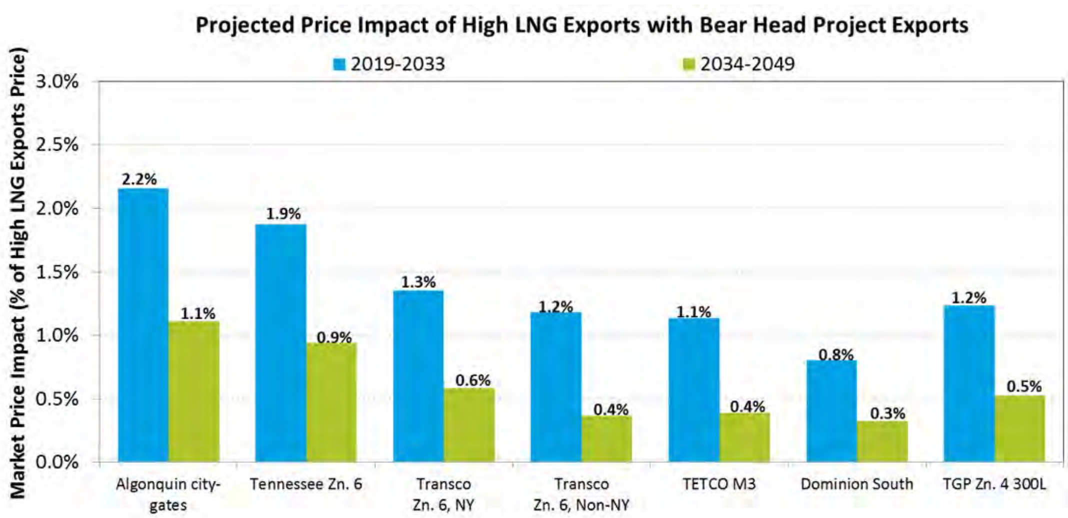
Figure 1: Key Pricing Points in New England

Figure 2: Projected Northeast Market Price Impact – Base Case



In addition to our *Base Case* analysis, Black & Veatch ran stress test scenarios which included higher LNG export volume in the U.S. Gulf Coast and Eastern Canada, in addition to the Bear Head LNG Project export volume. The Northeast price impact is still limited, as shown in Figure 3.

Figure 3: Projected Northeast Market Price Impact – High LNG Exports



Summary Conclusions

Black & Veatch's assessment demonstrates that the proposed Bear Head Project has a limited impact on natural gas prices across the Northeast, when incremental gas pipeline infrastructure in New England is constructed and completed by 2019. Several pipeline projects have been proposed and have received significant shipper interest from local distribution companies and power generators across New England which has led Black & Veatch to include these pipeline projects in the *Base Case*. This incremental gas pipeline infrastructure will reduce the frequency and magnitude of natural gas price spikes and reduce regional price volatility which will benefit New England energy consumers.

The estimated price impact at Algonquin city-gates throughout the analysis period is about 1.4% on average when compared to the *Base Case*. The Bear Head Project is expected to have the a minimal price impact across Northeast market, with price increases at Transco Zn. 6, Non-NY ranging from 0.9% from 2019-2034 and 0.2% from 2035-2049 when compared to the *Base Case*.

As seen through a comparison of results from the *High LNG with Bear Hear Project Exports* scenario stress test, exports from the Bear Head Project result in a slightly increased, but minor, impact on Northeast prices than observed in the *Base Case* in both absolute and percentage terms.

Overall, U.S natural gas supply will continue to outpace demand in the Lower 48 markets. The U.S Northeast market will remain a regional exporter of natural gas with the development of the Marcellus/Utica Shales.

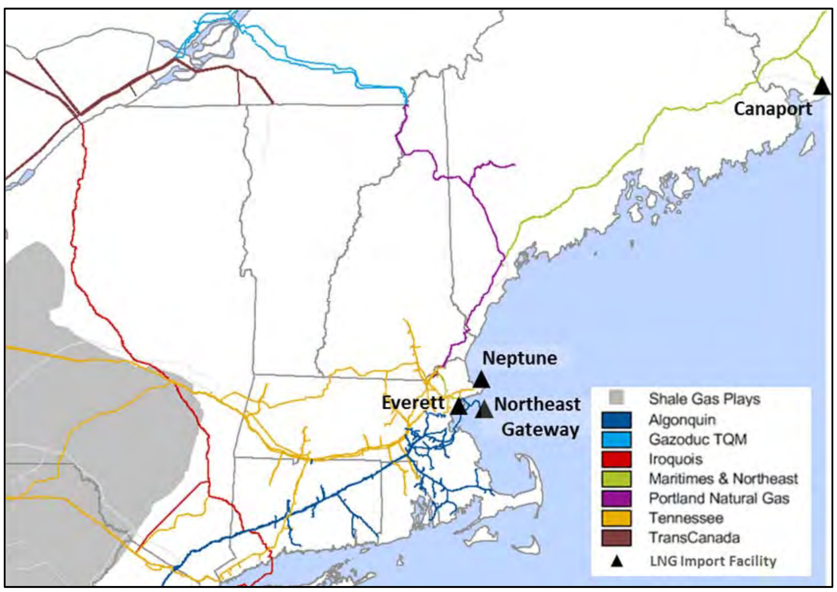
Additional offshore Nova Scotia oil and gas resources are at various exploratory stages of development. Black & Veatch did not incorporate these exploratory gas resources as part of this analysis, but if and when these resources are produced, the Bear Head Project is well positioned to utilize these resources as a potential feed gas alternative to U.S and Western Canadian supply. This could further reduce the price impacts in New England and Lower 48 natural gas prices. The on-going development of storage in Nova Scotia could also dampen regional price spikes, and the impact of the Bear Head Project, while bringing additional benefits to New England energy consumers.

3.0 Overview of the New England Natural Gas Market

The New England natural gas market is currently characterized as one of the most constrained gas markets in North America. With steady natural gas demand growth over the past fifteen years, interstate pipeline flows into the New England market have risen during peak winter and summer months to meet the needs of LDCs, power generators and industrial consumers. Unlike the Mid-Atlantic markets, New England does not have any local gas production, or abundant gas storage resources to mitigate seasonal peaking demand.

New England currently relies upon five interstate pipelines (Algonquin Gas Transmission, Iroquois Gas Transmission System, Portland Natural Gas Transmission System, M&NP, and Tennessee Gas Pipeline) and imported liquefied natural gas from the Everett and Canaport LNG terminals to serve its regional gas consumers. See Figure 4. From these five interstate pipelines, New England gas consumers can reach Canadian supply sources in the Western Canadian Sedimentary Basin, or Eastern Canada, and Lower 48 supplies from the Gulf Coast, Mid-Continent, and Appalachian basins.

Figure 4:North American Pipelines that serve the New England Market

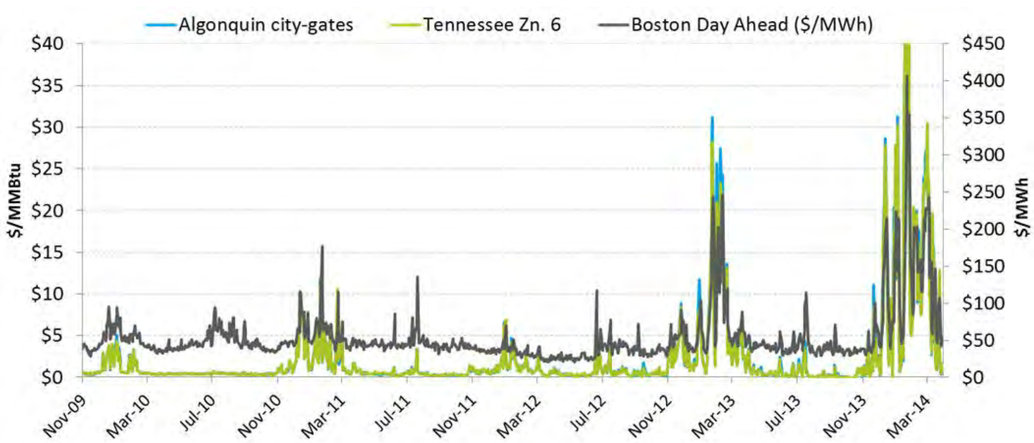


In prior years, LNG imports at the Canaport and Everett LNG terminals have been able to provide additional seasonal supplies, offsetting the need to construct incremental interstate pipeline capacity to import from western supply basins. However, global LNG prices in Europe, South America and Asia have become more lucrative markets for spot LNG cargoes than the New England market and LNG is no longer an abundant supply source in the region. Northeast Gateway and Neptune LNG terminals are also operational import facilities, but in recent years, have not received significant LNG cargoes.

The New England winter price basis reached unprecedented levels during the 2013-2014 winter heating season. Algonquin city-gates and Tennessee Zn. 6 spot prices have spiked over the last several winters, exceeding $40/MMBtu this past year. While most residential and commercial gas consumers that are served by the local distribution companies were for the most part unaffected by the price spikes, New England electric consumers felt the impact on day-ahead electric prices.

In the electric markets, during peak winter periods, gas-fired generation is often the fuel that sets the locational marginal price (“LMP”). New England power generators that do not hold firm pipeline capacity, rely upon interruptible capacity on the interstate pipelines to deliver gas supplies to the generator. As price spikes occur, the cost of that last unit of pipeline capacity and gas supply increases for the power generator, translating to a higher cost to produce each megawatt hour of power. As seen in Figure 5, the Boston day-ahead LMP prices closely follow the gas price basis at Algonquin city-gates and Tennessee Zn. 6 during peak winter periods. The 2013-2014 Winter price blowouts caused New England utilities to increase electric rates in 2015 by 23.6 to 37.0 percent.[1]

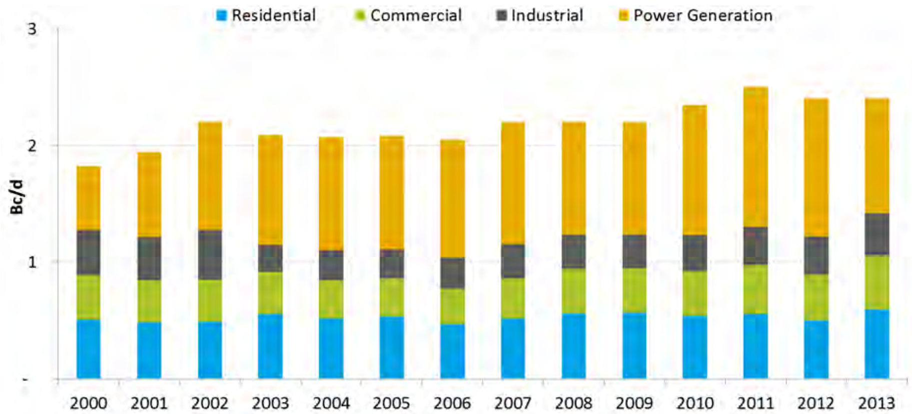
Figure 5: Historical New England Energy Price and Daily Basis (Nov 2009 – March 2014)



The lack of available pipeline capacity for gas-fired generation raises electric reliability concerns for New England as it becomes more reliant on natural gas as a fuel source. As seen in Figure 6, the natural gas demand in New England has grown since 2000 at a CAGR of 2.2% over the period.

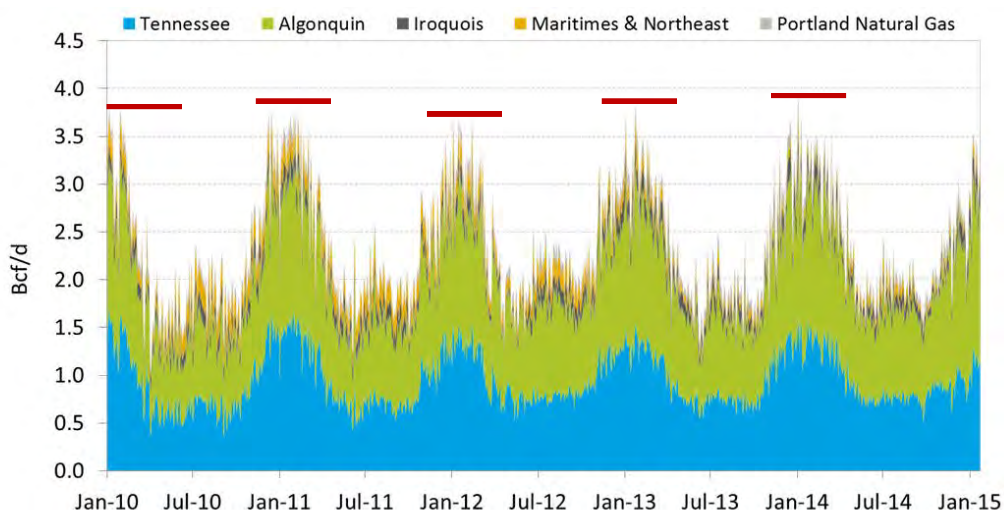
[1] http://instituteforenergyresearch.org/electricity-rate-increases-begin-new-england/

Figure 6: Historical New England Annual Average Demand (2000-2013)



The increase in natural gas demand is further complicated with increased peak day demand. As seen in Figure 7, Black & Veatch used daily interstate pipeline data as a proxy for peak demand, which reached 3.95 Bcf/d during 2013-2014 winter. The growth on peak day demand for LDCs will signal the need to subscribe for incremental pipeline capacity or invest in additional LNG peak shaving facilities.

Figure 7: Daily Interstate Pipeline Deliveries into New England



4.0 Projected Need for Incremental Pipeline Capacity

Over the past few years, New England states' regulators, power generators and regional transmission organizations have begun studying the gas-electric reliability issues and their impacts on electric consumers. Recent studies and analyses like the New England State Committee on Electricity ("NESCOE") and Massachusetts Department of Energy Resources ("DOER") report indicate that incremental pipeline capacity is needed and is a viable long-term solution to the problems facing New England.

NESCOE Observations on New England Natural Gas Infrastructure[2]

NESCOE commissioned a three-phase study to understand the regional infrastructure constraints related to gas-fired power generation in the New England area. The study focused on gas-electric reliability, including the extent and duration of regional congestion related to pipeline capacity. As short-term solutions, NESCOE suggests Spectra's Algonquin Incremental Market ("AIM") pipeline, LNG import terminals and dual-fuel generators will be a sufficient solution to reduce high gas prices. In the long term, NESCOE believes an additional incremental pipeline would offer the most economic net benefit to New England electricity customers, as it would reduce the likelihood of natural gas price spikes across the region, and the corresponding electric price spikes during peak winter months.

Massachusetts DOER Low Gas Demand Study[3]

In January 2015, Synapse Energy Economics released a report commissioned by the Massachusetts DOER detailing the expected gas shortage through 2030. The report focused on potential low demand scenarios that assumed the maximum feasible amount of alternative resources would be available, curtailing gas demand. In some cases additional electric transmission was assumed to displace gas demand in Massachusetts. Across all scenarios, gas shortages in Massachusetts ranged from 0.6 Bcf/d to 0.8 Bcf/d in 2020 and 0.6 Bcf/d to 0.9 Bcf/d in 2030 furthering the need for additional pipeline infrastructure.

Base Case Pipeline Capacity Additions into New England

In an effort to meet the demand for additional pipeline capacity in the region several pipeline expansion projects have been proposed designed to deliver incremental natural gas supplies into the New England market to serve both LDC and power generation demand. The *Base Case* includes Spectra's AIM project, Kinder Morgan's Northeast Energy Direct project, Spectra's Atlantic Bridge and Access Northeast projects. Each project has obtained interest from various stakeholders in the region and offers unique benefits to shippers. In aggregate, if all of the proposed pipeline projects are completed, these projects would almost double the current pipeline capacity serving the New England market today. Most of these proposed pipeline projects are scalable in design, and can accommodate additional pipeline shippers that would increase the contracted billing determinants and reduce the overall cost of the pipeline projects to New England LDCs and power generators. Overall,

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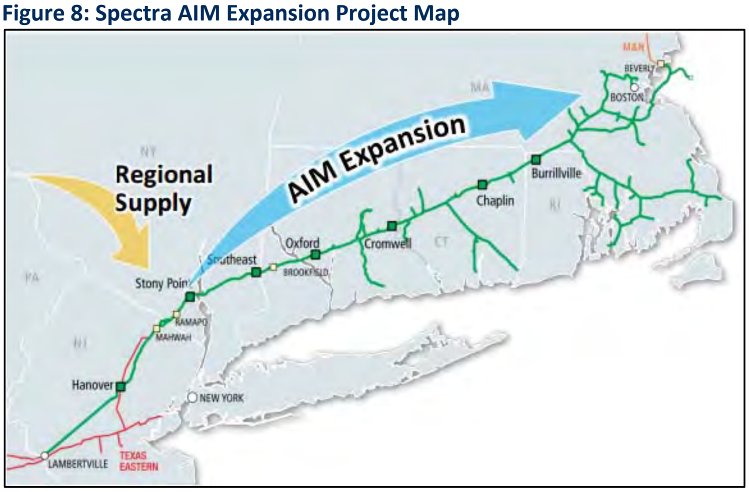
[2] http://www.nescoe.com/uploads/Notice_of_Issuance_G-E_Study_Sept_9_2013.pdf
[3] http://synapse-energy.com/sites/default/files/Massachusetts%20Low%20Demand%20Final%20Report.pdf

incremental pipeline capacity additions into New England will reduce the frequency and magnitude of price spikes during the winter, when gas demand levels are at their peak.

Spectra's AIM project is expected to be in service by November 2016, and will add an additional 342 Million cubic feet per day ("MMcf/d") of capacity from Ramapo, NY to markets in Connecticut, Rhode Island and Massachusetts. (*See* FERC Docket No. CP14-96-000). The anchor shippers on AIM include UIL Holdings, National Grid, NiSource, and Northeast Utilities. Figure 8 shows the projected project right-of-way.

Figure 8: Spectra AIM Expansion Project Map



Source: Spectra

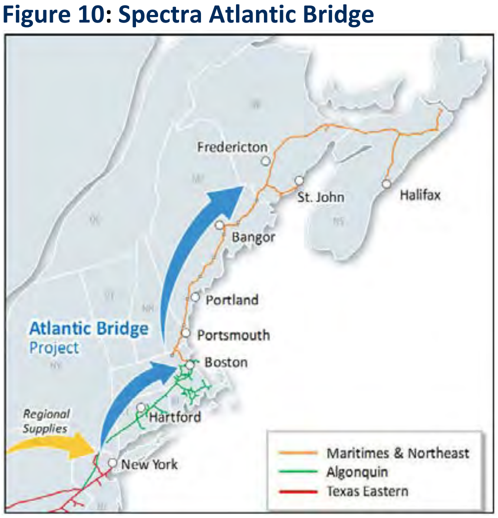
Kinder Morgan's Northeast Energy Direct project will extend from the Marcellus Shale along existing Tennessee Gas Pipeline right-of-way across New York and Massachusetts and into Dracut. As depicted in Figure 9, the project is currently in the pre-filing process with the Federal Energy Regulatory Commission ("FERC") and is expected to formally file an application with FERC in the fourth quarter of 2015, with construction beginning in January 2017 to meet the projected in-service date of late 2018. (*See* FERC Docket No. PF14-22-000) The proposed project is scalable from 0.8 Bcf/d to 2.2 Bcf/d depending on shipper commitments in the region. So far, anchor shippers include Berkshire Gas Company, Columbia Gas of Massachusetts, Connecticut Natural Gas, Liberty Utilities, National Grid, and Southern Connecticut Gas, and have signed binding agreements for a combined total of 0.5 Bcf/d of firm transportation capacity.

Figure 9: Kinder Morgan Northeast Energy Direct Map

Source: Kinder Morgan

Spectra has proposed two additional pipeline projects that will complement its AIM project. As part of the Atlantic Bridge project, Spectra Energy proposes to expand the Algonquin and M&NP to deliver additional supplies to New England and the Maritimes Provinces, as shown in Figure 10. The Atlantic Bridge project is moving forward as a request to commence the pre-filing process was submitted with FERC on January 30, 2015. (*See* FERC Docket No. PF15-12-000). The expansion capacity will be at least 100 MMcf/d but the project can be scaled up to 600 MMcf/d depending on customer commitments. Unitil Corporation has been announced as an anchor shipper on the project. The current projected in-service date is November 2017.

Figure 10: Spectra Atlantic Bridge



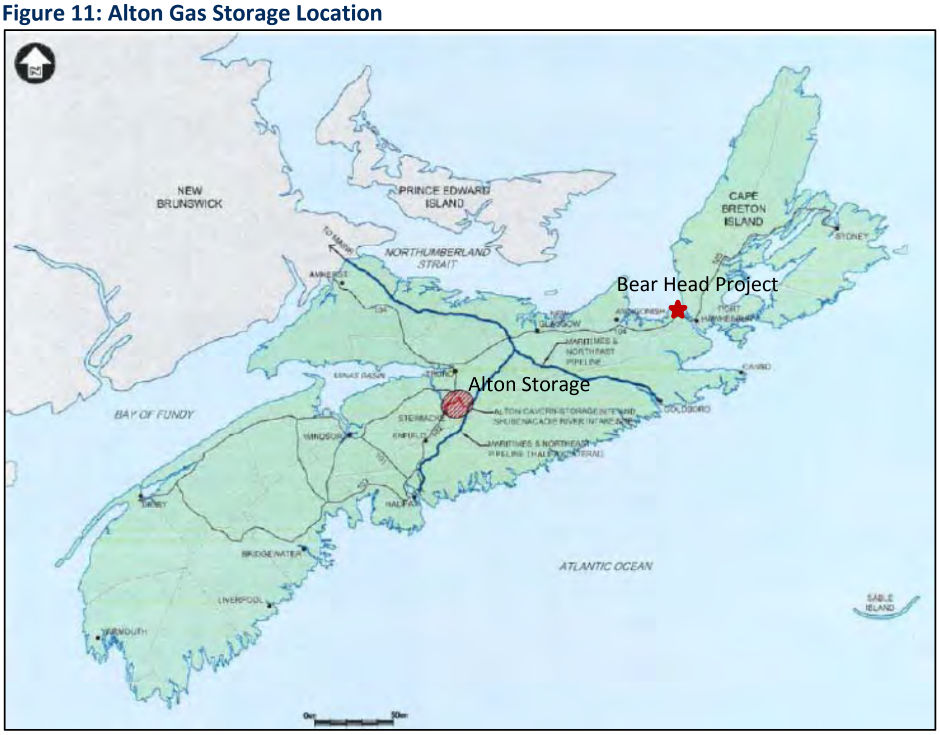
Source: Spectra

Spectra's second proposed project, Access Northeast, proposes to add as much as 1 Bcf/d of incremental pipeline capacity into New England by November 2018. The project has not yet submitted a request with FERC for approval of pre-filing review but would consist of several 200 MMcf/d expansions of Spectra's existing Algonquin Pipeline and M&NP footprints depending on customer commitments. In a joint ownership venture, Northeast Utilities and Spectra will each own 50 percent of the $3 Billion expansion project. As a way to accommodate power generators and their reluctance to hold firm pipeline capacity, Spectra is looking at multiple shipper options where several shippers can share one contract ensuring maximum efficiency of capacity utilization within a single contract.

Availability of Underground Storage in Nova Scotia

In addition to the proposed incremental pipeline capacity, the Bear Head Project would be able to access to an underground storage facility located in Alton, Nova Scotia. Alton Natural Gas Storage, a subsidiary of AltaGas, is currently constructing a natural gas storage complex with three salt caverns and a gas pipeline lateral, and is targeting to commence operations in 2015. Based on its regulatory application, the initial total capacity of the first three caverns could have a total working gas capacity of 3.8 Bcf and may develop as many as 10 to 15 caverns at a later date. The pipeline lateral from Alton will interconnect with Maritimes and Northeast Halifax Pipeline. See Figure 11 below.

Figure 11: Alton Gas Storage Location



Source: AltaGas

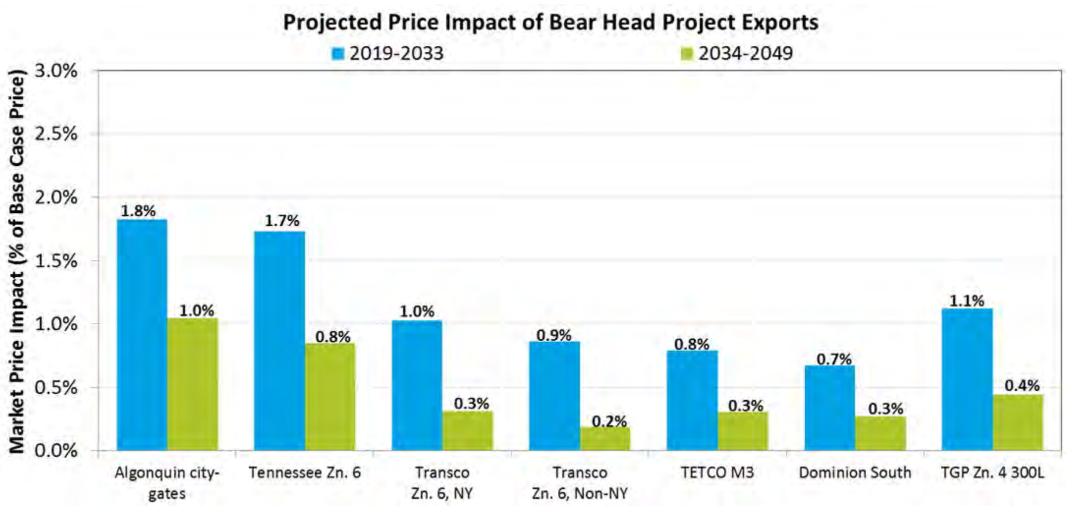
Overall, additional underground gas storage in Nova Scotia could also help mitigate winter price spikes during the coldest days of the year in New England. Summer storage injections of Nova Scotia, U.S., or other Canadian production and winter storage withdrawals will dampen winter seasonal price spreads in the M&NP and New England markets. The availability of additional winter supplies will reduce the severity of price spikes and the draw on Northeast supplies. The Bear Head Project's access to storage will allow it to optimize seasonal feed gas supply purchases. The Project could purchase additional summer feed gas supplies when New England and Lower 48 demand is much lower and pipeline capacity to Dracut is more readily available, to inject into storage and then withdraw them on peak winter days, reducing the potential market impact on natural gas prices.

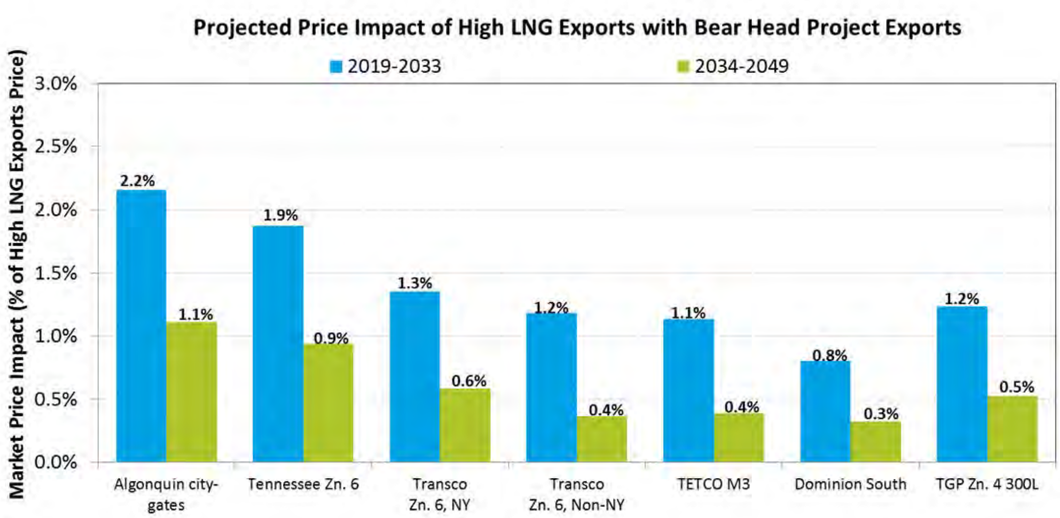
5.0 Northeast Market Price Impacts

Black & Veatch's independent assessment examined the Northeast U.S. market price impacts of the proposed Bear Head Project. Across various scenarios, we found that the proposed export volumes should have limited impact on the price levels for natural gas either directly in New England or regionally in the Northeast during the analysis period, as shown in Figure 12.

The projected market price impact of the Bear Head Project is expected to be higher in New England and smaller across the other Northeast pricing points further from the Bear Head Project, as shown in Figure 12.

Figure 12: Projected Market Price Impact across Pricing Points





At Dominion South, the market price impact is muted because of the continued growth of the Marcellus/Utica Shale production, which is assumed to reach 23 Bcf/d by 2019 and 32.2

Bcf/d by 2049. Black & Veatch expects Marcellus/Utica production to continue to serve market demand in the Northeast, Midwest, and Southeast U.S. The market price impact of the Bear Head Project at Dominion South is projected to be $0.03/MMBtu (0.7%) over the first 15 years of the analysis period and $0.02/MMBtu (0.3%) for the final 16 years the analysis period when compared to the *Base Case*. A similar price impact is observed when compared to the *High LNG Exports with Bear Head Project Exports* scenario, leading to an increase of $0.04/MMBtu (0.8%) from 2019-2034 that diminishes to $0.02/MMBtu (0.3%) from 2035-2049. See Table 4.

Table 4: Market Price Impact at Dominion South

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	4.93	4.96	4.98	5.02
	Average Diff. from Base		0.03		0.04
	Percentage Increase		0.7%		0.8%
2034-2049	Average Price ($/MMBtu)	7.59	7.61	7.61	7.64
	Average Diff. from Base		0.02		0.02
	Percentage Increase		0.3%		0.3%

Table reflects prices rounded to the nearest cent.

The Project's market price impact at TGP Zn. 4 300L is similar to what is observed at Dominion South. As one of the market prices in the Northeast Marcellus Shale, the price impact is muted in part because of continued production growth. This pricing point's proximity to Mid-Atlantic premium markets and the potential supply point for recently proposed pipeline expansions to New England makes it a key market price indicator for the Bear Head Project. See Table 5.

Table 5: Market Price Impact at TGP Zn. 4 300L

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	4.88	4.93	4.95	5.02
	Average Diff. from Base		0.05		0.06
	Percentage Increase		1.1%		1.2%
2034-2049	Average Price ($/MMBtu)	7.81	7.85	7.87	7.91
	Average Diff. from Base		0.03		0.04
	Percentage Increase		0.4%		0.5%

Table reflects prices rounded to the nearest cent.

The market price impact of the Bear Head Project at the Transco Zn. 6, NY is projected to be $0.06/MMBtu (1.0%) for the first 15 years of the analysis period and $ 0.03/MMBtu (0.3%) for the remaining 15 years of the analysis period compared to the *Base Case*. A similar price impact is observed when compared to the *High LNG Exports with Bear Head Project Exports* scenario, leading to an increase of $0.08/MMBtu (1.3%) from 2019-2034 and $0.05/MMBtu (0.6%) from 2034-2049. See Table 6.

Table 6: Market Price Impact at Transco Zn. 6, NY

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.97	6.03	6.06	6.14
	Average Diff. from Base		0.06		0.08
	Percentage Increase		1.0%		1.3%
2034-2049	Average Price ($/MMBtu)	9.29	9.32	9.36	9.41
	Average Diff. from Base		0.03		0.05
	Percentage Increase		0.3%		0.6%

Table reflects prices rounded to the nearest cent.

Both Transco Zn. 6, Non-NY and Tetco-M3 represent gas delivered to the Northeast markets that stem from Northern Virginia to New Jersey. The Bear Head Project's price impact at these locations is slightly greater than at upstream points like Dominion South because of the large gas-consuming loads along the Mid-Atlantic coast. See Table 7 and Table 8.

Table 7: Market Price Impact at Transco Zn. 6, Non-NY

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.91	5.96	6.00	6.07
	Average Diff. from Base		0.05		0.07
	Percentage Increase		0.9%		1.2%
2034-2049	Average Price ($/MMBtu)	9.25	9.26	9.29	9.32
	Average Diff. from Base		0.02		0.03
	Percentage Increase		0.2%		0.4%

Table reflects prices rounded to the nearest cent.

Table 8: Market Price Impact at TETCO M-3

		Base Case	With Bear Head Project Exports	High LNG Exports	High LNG Exports with Bear Head Project Exports
2019-2033	Average Price ($/MMBtu)	5.84	5.88	5.94	6.00
	Average Diff. from Base		0.04		0.07
	Percentage Increase		0.8%		1.1%
2034-2049	Average Price ($/MMBtu)	9.13	9.16	9.17	9.20
	Average Diff. from Base		0.03		0.03
	Percentage Increase		0.3%		0.4%

Table reflects prices rounded to the nearest cent.

Division 2-3

Request:

Please provide a copy B&V's 2016 Energy Market Perspectives referenced on schedule GJW-3, 8 of 37. Also, provide the date when B&V completed this document.

Response:

Please see Attachment AG-2-6(a) filed by the Company's Massachusetts affiliates in D.P.U. 16-05 and submitted in this proceeding in response to data request PUC-1-1, which is a copy of the Methodology and Principal Assumptions report. The report summarizes the assumptions and general conclusions in Black & Veatch's 2016 Energy Market Perspective (EMP). This document was completed January 2016.

Division 2-4

Request:

Regarding Figure 2 on page 11 of 37 of schedule GJW-3, in the last five years, has B&V performed any studies or analyses that utilized projections of the national demand for natural gas? If so, please provide copies of such studies, the New England demand forecast used, and its source.

Response:

Please see the list of studies provided in response to Data Request Division 2-2 regarding studies or analysis that utilized projections of the national demand for natural gas.

Division 2-5

Request:

Regarding Figure 3 on page 12 of 37 of schedule GJW-3, in the last five years, has B&V performed any studies or analyses that utilized projections of the demand for natural gas? If so, please provide copies of such studies, the demand forecast used, and its source.

Response:

Please see the list of studies provided in response to Data Request Division 2-2, which utilized projections of natural gas demand in New England. The New England natural gas demand forecast used in the studies listed was developed by Black & Veatch.

Prepared by or under the supervision of: Gary J. Wilmes and Denny K. Yeung

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Division 2-6

Request:

Please provide a live excel spreadsheet that lists the electric generators located in New England assumed to be in-service for each year of the B&V study of natural gas projects for this proceeding. Include the summer and winter capacity ratings for each unit. For any units assumed to be built after 2016, please provide the geographic location. Finally, show any assumptions regarding unit retirements.

Response:

Please see Attachment NEER-1-1(d) (Highly Sensitive Confidential Information) filed in Massachusetts Docket D.P.U. 16-05 and provided in response to Data Request PUC 1-1 for a list of electric generators and the capacities used in the analysis. For new unnamed unit additions, please see Attachment NEER-1-6(a) filed in Massachusetts Docket D.P.U. 16-05 and provided in response to Data Request PUC 1-1 for a list of generic unit additions assumed over the analysis period. Please see Attachment NEER-1-4(a) filed in Massachusetts Docket D.P.U. 16-05 and provided in response to Data Request PUC 1-1 for a summary of unit retirements by type.

Division 2-7

Request:

Regarding page 14 of 37 of schedule GJW-3, in the last five years, has B&V performed any studies or analyses that included assumptions about Eastern Canadian Supply or LNG imports? If so, please provide copies of such studies, the assumptions used, and source or basis for these assumptions.

Response:

As part of the NESCOE Phase III Report (the Phase III Report), Black & Veatch utilized a combination of public and proprietary sources of information to develop the projection for Eastern Canadian production and LNG imports into New England. This is shown in Figures 11, 12 and 13 of the Phase III report. As stated in footnote 9 of the Phase III Report, Black & Veatch referenced the National Energy Board projections for Eastern Canadian production. The LNG import assumptions used in the NESCOE study were developed collaboratively between Black & Veatch and NESCOE.

NESCOE Phase III Report:
http://nescoe.com/uploads/Phase_III_Gas-Elec_Report_Sept._2013.pdf

Prepared by or under the supervision of: Denny K. Yeung and Gary J. Wilmes

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Division 2-8

Request:

Regarding Figure 7 on page 16 of 37 of schedule GJW-3, please describe the generic pipeline capacity additions assumed annually for New England LDCs, and explain how these additions were modelled in GPCM.

Response:

Over the analysis period (2018-2038), Black & Veatch assumed that incremental generic pipeline capacity additions can be placed into service prior to each year's winter season to serve LDC demand growth. For each generic expansion in a given year, Black & Veatch subtracted the projected New England LDC design day demand from the current and projected known pipeline capacity held by LDCs plus any peakshaving LNG deliverability. At the start of each winter season, this incremental pipeline capacity was added to the GPCM model based on the existing right-of-way of the current pipelines that serve the region, reaching back to the nearest market hub with available firm gas supplies. Each year, incremental generic capacity additions ranged from 41 to 130 MMcf/d. Please see Exhibit Attachment NEER-1-10(a) filed by the Company's Massachusetts affiliates in D.P.U. 16-05 and provided in this proceeding in response to Data Request PUC 1-1 for the annual generic pipeline capacity addition.

Division 2-9

Request:

Regarding page 21 of 37 of schedule GJW-3, did B&V include the cost of additional pipeline capacity assumed to be needed by GDF Suez and Repsol? If so, please provide those costs. If not, please explain why not.

Response:

Black & Veatch did include the cost of additional pipeline capacity assumed to be needed by GDF Suez and Repsol. Please see Attachment DIV-1-18 (Highly Sensitive Confidential Information) for the additional pipeline capacity costs assumed.

Division 2-10

Request:

For each scenario analyzed by B&V, please provide live excel spreadsheets showing the annual costs and benefits in as much detail as possible. Also provide the calculations the resulted in the net benefit figures cited in Figures 7, 8, and 9 on pages 33 and 34 of 37 of the B&V report.

Response:

Please see Attachment DIV 2-10 (Highly Sensitive Confidential Information) for the summary showing annual costs and benefits.

REDACTED

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits					Total Annual Costs				
Line #	Year	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol
1	2019	[redacted]									
2	2020										
3	2021										
4	2022										
5	2023										
6	2024										
7	2025										
8	2026										
9	2027										
10	2028										
11	2029										
12	2030										
13	2031										
14	2032										
15	2033										
16	2034										
17	2035										
18	2036										
19	2037										
20	2038										

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits for Present Value Analysis					Total Annual Costs for Present Value Analysis				
Line #	Year	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol
1	2016	[redacted]									
2	2017										
3	2018										
4	2019										
5	2020										
6	2021										
7	2022										
8	2023										
9	2024										
10	2025										
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13	2028										
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19	2034										
20	2035										
21	2036										
22	2037										
23	2038										

REDACTED

Summary of Annual Benefits and Costs
Nominal$ (MM)

Total Project Cost-Benefits Summary 2019-2038 ($ Billions)

Column	A	B	C	D	E	F	G	H
Line #		Levelized			Present Value			
	Project	Benefits	Costs	Benefits	Benefits	Total Costs	Net Benefits	Cost Ratio
1	Reference Case - With ANE Only	[redacted]	[redacted]	$1.1	[redacted]	[redacted]	$10.2	3.5
2	Sensitivity Reference Case A - With ANE Only	[redacted]	[redacted]	$0.4	[redacted]	[redacted]	$3.5	1.9
3	Sensitivity Reference Case B - With ANE Only	[redacted]	[redacted]	$0.4	[redacted]	[redacted]	$3.5	1.9
4	Reference Case - With GDF Suez	[redacted]	[redacted]	$0.6	[redacted]	[redacted]	$4.9	2.3
5	Reference Case - With Repsol	[redacted]	[redacted]	$0.2	[redacted]	[redacted]	$2.1	1.7

REDACTED

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits					Total Annual Costs				
Line #	Year	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol
1	2019	[redacted]									
2	2020										
3	2021										
4	2022										
5	2023										
6	2024										
7	2025										
8	2026										
9	2027										
10	2028										
11	2029										
12	2030										
13	2031										
14	2032										
15	2033										
16	2034										
17	2035										
18	2036										
19	2037										
20	2038										

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits for Present Value Analysis					Total Annual Costs for Present Value Analysis				
Line #	Year	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol
1	2016	[redacted]									
2	2017										
3	2018										
4	2019										
5	2020										
6	2021										
7	2022										
8	2023										
9	2024										
10	2025										
11	2026										
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16	2031										
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19	2034										
20	2035										
21	2036										
22	2037										
23	2038										

REDACTED

Summary of Annual Benefits and Costs
Nominal$ (MM)

Total Rhode Island Cost-Benefits Summary (Based on LMP Prices) 2019-2038 ($ Billions)

Column	A	B	C	D	E	F	G	H
Line #		Levelized			Present Value			
	Project	Benefits	Costs	Benefits	Benefits	Total Costs	Net Benefits	Cost Ratio
1	Reference Case - With ANE Only	[redacted]		$0.11	[redacted]		$0.97	4.4
2	Sensitivity Reference Case A - With ANE Only			$0.04			$0.35	2.2
3	Sensitivity Reference Case B - With ANE Only			$0.04			$0.36	2.2
4	Reference Case - With GDF Suez			$0.05			$0.46	2.7
5	Reference Case - With Repsol			$0.02			$0.21	1.9

REDACTED

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits					Total Annual Costs				
Line #	Year	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol
1	2019	[redacted]									
2	2020										
3	2021										
4	2022										
5	2023										
6	2024										
7	2025										
8	2026										
9	2027										
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13	2031										
14	2032										
15	2033										
16	2034										
17	2035										
18	2036										
19	2037										
20	2038										

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits for Present Value Analysis					Total Annual Costs for Present Value Analysis				
Line #	Year	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol
1	2016	[redacted]									
2	2017										
3	2018										
4	2019										
5	2020										
6	2021										
7	2022										
8	2023										
9	2024										
10	2025										
11	2026										
12	2027										
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14	2029										
15	2030										
16	2031										
17	2032										
18	2033										
19	2034										
20	2035										
21	2036										
22	2037										
23	2038										

Summary of Annual Benefits and Costs
Nominal$ (MM)

Total Rhode Island Cost-Benefits Summary (Based on Electric Load Allocation) 2019-2038 ($ Billions)

Column	A	B	C	D	E	F	G	H
Line #			Levelized			Present Value		
	Project	Benefits	Costs	Benefits	Benefits	Total Costs	Net Benefits	Cost Ratio
1	Reference Case - With ANE Only	[redacted]		$0.07	[redacted]		$0.63	3.2
2	Sensitivity Reference Case A - With ANE Only	[redacted]		$0.02	[redacted]		$0.20	1.7
3	Sensitivity Reference Case B - With ANE Only	[redacted]		$0.02	[redacted]		$0.20	1.7
4	Reference Case - With GDF Suez	[redacted]		$0.03	[redacted]		$0.29	2.1
5	Reference Case - With Repsol	[redacted]		$0.01	[redacted]		$0.12	1.5

Division 2-11

Request:

For each scenario analyzed by B&V, please provide live excel spreadsheets showing the annual costs and benefits in as much detail as possible. Also provide the calculations the resulted in the net benefit figures cited in Figures in the Appendix on pages 36 and 37 of 37 of the B&V report.

Response:

Please see Attachment DIV 2-11 (Highly Sensitive Confidential Information) showing the annual costs and benefits used in the Appendix. Please note the correction to the summary of net benefits on page 36.

REDACTED

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits					**Total Annual Costs**				
Line #	**Year**	**Reference Case - With ANE Only**	**Sensitivity Reference Case A - With ANE Only**	**Sensitivity Reference Case B - With ANE Only**	**Reference Case - With GDF Suez**	**Reference Case - With Repsol**	**Reference Case - With ANE Only**	**Sensitivity Reference Case A - With ANE Only**	**Sensitivity Reference Case B - With ANE Only**	**Reference Case - With GDF Suez**	**Reference Case - With Repsol**
1	2019	[redacted]									
2	2020	[redacted]									
3	2021	[redacted]									
4	2022	[redacted]									
5	2023	[redacted]									
6	2024	[redacted]									
7	2025	[redacted]									
8	2026	[redacted]									
9	2027	[redacted]									
10	2028	[redacted]									
11	2029	[redacted]									
12	2030	[redacted]									
13	2031	[redacted]									
14	2032	[redacted]									
15	2033	[redacted]									
16	2034	[redacted]									
17	2035	[redacted]									
18	2036	[redacted]									
19	2037	[redacted]									
20	2038	[redacted]									

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits for Present Value Analysis					**Total Annual Costs for Present Value Analysis**				
Line #	**Year**	**Reference Case - With ANE Only**	**Sensitivity Reference Case A - With ANE Only**	**Sensitivity Reference Case B - With ANE Only**	**Reference Case - With GDF Suez**	**Reference Case - With Repsol**	**Reference Case - With ANE Only**	**Sensitivity Reference Case A - With ANE Only**	**Sensitivity Reference Case B - With ANE Only**	**Reference Case - With GDF Suez**	**Reference Case - With Repsol**
1	2016	[redacted]									
2	2017	[redacted]									
3	2018	[redacted]									
4	2019	[redacted]									
5	2020	[redacted]									
6	2021	[redacted]									
7	2022	[redacted]									
8	2023	[redacted]									
9	2024	[redacted]									
10	2025	[redacted]									
11	2026	[redacted]									
12	2027	[redacted]									
13	2028	[redacted]									
14	2029	[redacted]									
15	2030	[redacted]									
16	2031	[redacted]									
17	2032	[redacted]									
18	2033	[redacted]									
19	2034	[redacted]									
20	2035	[redacted]									
21	2036	[redacted]									
22	2037	[redacted]									
23	2038	[redacted]									

REDACTED

Summary of Annual Benefits and Costs
Nominal$ (MM)

Total Project Cost-Benefits Summary 2019-2038 ($ Billions)

Column	A	B	C	D	E	F	G	H
Line #		Levelized			Present Value			
	Project	Benefits	Costs	Benefits	Benefits	Total Costs	Net Benefits	Cost Ratio
1	Reference Case - With ANE Only	[redacted]	[redacted]	$1.3	[redacted]	[redacted]	$18.6	3.7
2	Sensitivity Reference Case A - With ANE Only	[redacted]	[redacted]	$0.6	[redacted]	[redacted]	$8.1	2.2
3	Sensitivity Reference Case B - With ANE Only	[redacted]	[redacted]	$0.6	[redacted]	[redacted]	$8.2	2.2
4	Reference Case - With GDF Suez	[redacted]	[redacted]	$0.6	[redacted]	[redacted]	$8.7	2.4
5	Reference Case - With Repsol	[redacted]	[redacted]	$0.2	[redacted]	[redacted]	$3.3	1.6

REDACTED

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits					Total Annual Costs				
Line #	Year	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol
1	2019	[redacted]									
2	2020										
3	2021										
4	2022										
5	2023										
6	2024										
7	2025										
8	2026										
9	2027										
10	2028										
11	2029										
12	2030										
13	2031										
14	2032										
15	2033										
16	2034										
17	2035										
18	2036										
19	2037										
20	2038										

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits for Present Value Analysis					Total Annual Costs for Present Value Analysis				
Line #	Year	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol	Reference Case - With ANE Only	Sensitivity Reference Case A - With ANE Only	Sensitivity Reference Case B - With ANE Only	Reference Case - With GDF Suez	Reference Case - With Repsol
1	2016	[redacted]									
2	2017										
3	2018										
4	2019										
5	2020										
6	2021										
7	2022										
8	2023										
9	2024										
10	2025										
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15	2030										
16	2031										
17	2032										
18	2033										
19	2034										
20	2035										
21	2036										
22	2037										
23	2038										

REDACTED

Summary of Annual Benefits and Costs
Nominal$ (MM)

Total Rhode Island Cost-Benefits Summary (Based on LMP Prices) 2019-2038 ($ Billions)

Column	A	B	C	D	E	F	G	H
Line #		Levelized			Present Value			
	Project	Benefits	Costs	Benefits	Benefits	Total Costs	Net Benefits	Cost Ratio
1	Reference Case - With ANE Only	[redacted]		$0.12	[redacted]		$1.77	4.6
2	Sensitivity Reference Case A - With ANE Only			$0.05			$0.79	2.6
3	Sensitivity Reference Case B - With ANE Only			$0.05			$0.79	2.6
4	Reference Case - With GDF Suez			$0.06			$0.81	2.8
5	Reference Case - With Repsol			$0.02			$0.32	1.8

REDACTED

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits					**Total Annual Costs**				
Line #	**Year**	**Reference Case - With ANE Only**	**Sensitivity Reference Case A - With ANE Only**	**Sensitivity Reference Case B - With ANE Only**	**Reference Case - With GDF Suez**	**Reference Case - With Repsol**	**Reference Case - With ANE Only**	**Sensitivity Reference Case A - With ANE Only**	**Sensitivity Reference Case B - With ANE Only**	**Reference Case - With GDF Suez**	**Reference Case - With Repsol**
1	2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	2037	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	2038	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Nominal$ (MM)

Column	A	B	C	D	E	F	G	H	I	J	K
		Total Annual Benefits for Present Value Analysis					**Total Annual Costs for Present Value Analysis**				
Line #	**Year**	**Reference Case - With ANE Only**	**Sensitivity Reference Case A - With ANE Only**	**Sensitivity Reference Case B - With ANE Only**	**Reference Case - With GDF Suez**	**Reference Case - With Repsol**	**Reference Case - With ANE Only**	**Sensitivity Reference Case A - With ANE Only**	**Sensitivity Reference Case B - With ANE Only**	**Reference Case - With GDF Suez**	**Reference Case - With Repsol**
1	2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	2037	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	2038	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Summary of Annual Benefits and Costs
Nominal$ (MM)

Total Rhode Island Cost-Benefits Summary (Based on Electric Load Allocation) 2019-2038 ($ Billions)

Column	A	B	C	D	E	F	G	H
Line #		Levelized			Present Value			
	Project	Benefits	Costs	Benefits	Benefits	Total Costs	Net Benefits	Cost Ratio
1	Reference Case - With ANE Only	[redacted]	[redacted]	$0.08	[redacted]	[redacted]	$1.16	3.3
2	Sensitivity Reference Case A - With ANE Only	[redacted]	[redacted]	$0.03	[redacted]	[redacted]	$0.48	2.0
3	Sensitivity Reference Case B - With ANE Only	[redacted]	[redacted]	$0.03	[redacted]	[redacted]	$0.48	2.0
4	Reference Case - With GDF Suez	[redacted]	[redacted]	$0.04	[redacted]	[redacted]	$0.52	2.2
5	Reference Case - With Repsol	[redacted]	[redacted]	$0.01	[redacted]	[redacted]	$0.18	1.5

Division 2-12

Request:

In the Massachusetts proceeding in docket 61-05, several intervenors filed testimony that was critical of NGRID / B&V assumptions, including but not limited to the forecasted demand for natural gas in New England, LNG prices, the capacity of LNG facilities in New England.

a. Has NGRID or B&V prepared any analysis or response to those critiques? If so, please provide copies of any relevant documentation.

b. Has B&V performed any analyses of the ANE project that use alternative assumptions suggested by these intervenors? If so, please provide copies of any relevant documentation. If not would B&V be able to perform additional sensitivity analyses of these alternative assumptions?

Response:

(a)-(b). Black & Veatch believes that its Reference Case assumptions were reasonable regarding gas demand projections and LNG import volumes. The rebuttal testimony of J. Neil Copeland of Black & Veatch specifically responds to the intervenors' critiques (see Exhibit NG-JNC-Rebuttal-1 filed in D.P.U. 16-05 and provided as Attachment DIV 2-12 (Highly Sensitive Confidential Information)). After filing in Massachusetts Docket D.P.U. 16-05, Black & Veatch performed additional analyses which were summarized in Schedule GJW-3, filed in this proceeding, and which analyzed (a) the LNG import solutions proposed and (b) additional sensitivities regarding the hypothetical additions of (i) approximately 1,100 MW of hydropower, and (ii) approximately 1,100 MW of hydropower plus 1,200 MW of wind from Maine (see also Company response to DIV-1-24-A) . The ANE Project yielded the highest level of net benefits to electric consumers when compared to both the LNG import solutions submitted in response to the Company's October 2015 request for proposals, and the hypothetical hydropower and hydropower/wind power assumptions noted above. In addition, B&V performed a sensitivity analysis using lower discount rates for both the cost and benefits of the proposed ANE Project, which still resulted in substantial net benefits to customers (see Exh. GJW-3, page 36 of 37).

Prepared by or under the supervision of: Denny K. Yeung and Gary J. Wilmes

DIV 2-12, page 2

Request (continued):

To date in Massachusetts, B&V has not been required to perform additional sensitivity analyses. Depending on the type of sensitivity analysis, such analysis could require several weeks to perform. The Company believes that the sensitivity/alternative analyses performed to date, which include analyzing the net benefits of: (1) the LNG options bid into the Company's RFP; (2) the ANE Project with various discount rates; and (3) the ANE Project, with (i) 1,100 MW of hydropower; and (2) 1,100 MW of hydropower plus 1,200 MW of Maine wind, represent a reasonable suite of sensitivity/alternatives analyses to judge whether the ANE Project meets Rhode Island's standard of review for this proceeding.

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COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

REBUTTAL TESTIMONY OF
J. NEIL COPELAND
EXHIBIT NG-JNC-1

D.P.U. 16-05

I. INTRODUCTION

Q. Please state your name and business address.

A. J. Neil Copeland, 50 Hurt Plaza, Suite 1150, Atlanta, GA 30303.

Q. By whom are you employed and in what capacity?

A. I am a Director in Black & Veatch Management Consulting, LLC. In that role, I lead the Planning Group and am responsible for the development of Black & Veatch's electric and natural gas market views. I have over 16 years of experience in preparing electric asset revenue forecasts and valuations for regulatory agencies, project developers, power generation companies and private equity investors. I have extensive experience with the use of commercial electric price forecasting tools such as ABB/Ventyx Market Power and PROMOD IV software.

Q. Are you the same J. Neil Copeland who previously filed direct testimony in this proceeding on January 15, 2016?

A. Yes, I am.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain arguments made in the direct testimonies of Mr. Jerome D. Mierzwa, on behalf of the Massachusetts Attorney General's Office ("AGO");

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Ms. Tanya Bodell, on behalf of the AGO; Mr. Vincent C. Morrissette, on behalf of Repsol Energy North America Corporation ("RENA"); Dr. Joseph P. Kalt and Mr. A Joseph Cavicchi, on behalf of NextEra Energy Resources, LLC ("NEER"); Mr. Michael Zenker, on behalf of NEER and Ms. Elizabeth A. Stanton on behalf of the Conservation Law Foundation ("CLF") .

III. REBUTTAL TESTIMONY

A Societal Cost-Benefit Test is Inappropriate

Q. Do you agree with the argument from Mr. Kalt, and Mr. Cavicchi that Black & Veatch's study is a non-standard and "incomplete" cost-benefit analysis (at 16)?

A. No. I agree with the points made by Company Witnesses Brennan and Allocca in their rebuttal testimony regarding the appropriateness of evaluating the benefits from the ANE Project based on its projected impact on wholesale electricity market prices (i.e., electricity consumer commodity cost savings) rather than looking at production costs savings as recommended by Messrs. Kalt and Cavicchi. Moreover, the cost-benefit analysis approach used in this case is one that Black & Veatch has used in many other situations where the costs and benefits of potential infrastructure investments were evaluated.

Black & Veatch's Forecast Reflects Reasonable Assumptions

A. Accepted Industry Standard for Energy Market Modeling

Q. Do you agree with the assertions from Ms. Bodell, Mr. Kalt, and Mr. Cavicchi that Black & Veatch's modeling analysis suffers from a host of incorrect or unwarranted assumptions and inputs?

A. No. The analysis that Black & Veatch conducted for National Grid in this case used as its starting point Black & Veatch's Energy Market Perspective ("EMP"). The EMP is designed

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to respond to the needs of a wide range of energy industry participants: investors, developers, lenders, utilities and energy users. In contrast to the set of assumptions that Messrs. Kalt and Cavicchi assembled for their one-off modeling analysis developed to support NEER's position in this proceeding, the cost-benefit analysis conducted for National Grid built off of a widely-used analytical framework and set of assumptions deployed in numerous contexts and for a variety of clients by Black & Veatch. As such, it would be unreasonable to believe the intervenors' claims that Black & Veatch's analysis is, in essence, riddled with unwarranted and incorrect assumptions and inputs.

Q. Please elaborate on why the Department should give weight to the Energy Market Perspective as a reliable analytical platform?

A. Put simply, Black & Veatch has an overriding commercial interest in providing reliable and accurate energy market forecasts via the EMP. Our clients rely on the market forecasts included in the EMP in situations where they have money on the line, for example, in the case of investors and lenders who rely on our market analyses for their equity or credit investments in major energy infrastructure projects.

B. Gas Price Forecast

Q. Messrs. Kalt and Cavicchi take issue with Black & Veatch's gas price forecast. Please describe how Messrs. Kalt and Cavicchi derived their primary gas price forecast for their own modeling analysis.

A. Witnesses Kalt and Cavicchi explain that "[t]he majority of our energy market modeling input assumptions mirror those used in the development of the Black & Veatch Report" and that "[t]he main difference between our modeling and that used by Black & Veatch is that we adopt different input fossil fuel prices (e.g., using actual futures market prices for gas in

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our Futures Market Forecasts Case) and do not artificially constrain LNG imports" (at 34). Specifically, in their "Futures Market Forecasts Case," Witnesses Kalt and Cavicchi assume natural gas and oil price forecasts that start with the futures market prices reported at the end of March 2016 (at 32).

Q. What is wrong with this approach?

A. Footnote 35 in Exhibit NEER-JPK/AJC-1 highlights one of two major shortcomings in this approach. This footnote explains that Messrs. Kalt and Cavicchi relied on futures prices and basis swaps through 2019 (i.e., for only one year of the 20-year time frame at issue for the cost-benefit analysis that extends through 2038); for the remainder of the years, they "inflate[d] prices based on the U.S. Energy Information Administration's long-term annual growth rate for Energy Commodities and Services" (at 33). In short, Kalt and Cavicchi relied on futures market prices for one year out of the twenty years in the cost-benefit analysis period and, for the other nineteen years, their "Futures Market Forecasts Case" actually just escalates natural gas prices based on a broad energy market price index that is not specific even to natural gas prices, let alone to natural gas prices in New England.

In contrast, Black & Veatch relied on a model that projects natural gas prices based on market fundamentals such that the Base Case price forecast and the natural gas price changes that occur in the scenarios with incremental natural gas infrastructure are internally consistent and driven by the underlying market economics of supply and demand as captured in the model. Moreover, I agree with the point made by Mr. Petak in his rebuttal

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testimony on behalf of Eversource in D.P.U. 15-181 also regarding Kalt and Cavicchi's natural gas price forecast that relies on the futures market:

> the entire basis for assuming such prices as being representative of the market without ANE and then applying them in a fundamentals model to forecast price change with ANE, is not justified. There is no basis to assume whether these prices are representative of the market with or without ANE, as no one could know the assumptions that the futures market is making, assuming that the market even does such a thing.[1]

C. Price Volatility

Q. Is there any merit to the criticisms from Messrs. Kalt and Cavicchi and Ms. Bodell of Black & Veatch's price volatility benefit analysis?

A. No. Kalt and Cavicchi and Ms. Bodell made the same assertions regarding ICF's price volatility analysis for Eversource, and I agree with Mr. Petak's and Ms. Scheller's rebuttal in D.P.U. 15-181 of those claims. Mr. Petak explains:

> It is very clear that Kalt and Cavicchi misunderstand ICF's [and Black & Veatch's] volatility analysis and, in fact, have missed the point of it altogether. ICF's [and Black & Veatch's] analysis is not contending that natural gas price volatility leads to electric retail price volatility. The purpose of ICF's [and Black & Veatch's] volatility analysis, instead, is to capture the potential impacts of daily natural gas price volatility on wholesale electric prices, and thus the potential change that volatility could create for the level of retail electric prices. ICF [and Black & Veatch] completed the analysis because the GMM [and GPCM in Black & Veatch's modeling framework] solves for monthly gas prices, and not daily prices. Therefore, the GMM [and GPCM] potentially understates the full impact of daily natural gas price changes on wholesale electric prices, which in turn, affects retail prices.
>
> Kalt and Cavicchi appear to be making the claim that, even if reduced gas-price volatility has the effect of reducing wholesale electric price volatility (which it does), it will not have an impact on electric retail

[1] Exhibit EVER-KRP-Rebuttal-1 in D.P.U. 15-181, at 23.

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> price volatility because retail customers do not pay daily electric prices. However, this tact should be recognized for what it is: a concession that reduced gas price volatility will affect wholesale electric price volatility. The point where our perspectives diverge appears to be that they do not see any value in reducing wholesale price volatility because volatility is greatest on a day-to-day basis and electric retail customers do not pay daily prices. My perspective is that elimination of wholesale price volatility, to any degree, is good for retail customers because ultimately they will be the beneficiaries of lower retail prices that inevitably result from reduced volatility in the wholesale market.
>
> To my knowledge, there is no fundamental model, like the GMM [GPCM in Black & Veatch's analysis], available that captures the impact of daily gas price variations in the future. The daily volatility in the gas market spreads into the power market in New England, driving up the average wholesale power price. Therefore, analysis that does not capture the potential impacts of the daily volatility on wholesale electric prices potentially understates the total cost savings to electric consumers. [2]

In addition, I agree with Ms. Scheller's points on behalf of Eversource:

> Although Kalt and Cavicchi correctly observe that customer retail rates are more stable than wholesale prices, they fail to recognize that retail rates, although they may be lagged, are driven on market-based pricing reflective of the marginal wholesale market pricing approach…
>
> Kalt and Cavicchi correctly identify that a significant share of load-serving entities utilize one-year contracts (signed on a rotating 6-month basis) to serve load. As a result, they argue that no volatility affects the retail pricing since the contracts are locked in at a fixed rate…
>
> Although the contract constitutes a significant tool for avoiding or mitigating wholesale market volatility, the contract will not remove entirely the impact of wholesale market volatility. The nature of contractual pricing itself is intended to provide stability in pricing and manage the risk of volatility. However, this comes at a cost to the purchaser the cost of the producer absorbing these risks in their

[2] Exhibit EVER-KRP-Rebuttal-1 in D.P.U. 15-181, at 25-26, 40.

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> pricing. That is, on average, the cost to consumers of using such a hedging program will be higher than contracting at spot prices alone; however, the volatility and exposure to wide price swings is greatly reduced. Therefore, I do agree that the retail rates are in fact more stable than wholesale rates and daily volatility is not seen in the retail rate. However, I disagree that the impact of volatility and the associated risks are not borne, at least in part, by consumers. Rather, these risks are embedded in the contractual prices for power purchase agreements which carry directly forward into consumer rates. That is, retail rates are stable, but are at a higher price than wholesale rates for power purchase costs on average.[3]

Q. Using Black & Veatch's Cost-Benefit Methodology, do Mr. Kalt and Mr. Cavicchi's modeling results indicate that the ANE project has positive net benefits to electric consumers?

A. Yes. Using the natural gas and electric price data in Attachment NEER-NG-1-47, Attachment NG -NEER-1-65(e) (CONFIDENTIAL), and Attachment NG -NEER-1-65(f) (CONFIDENTIAL), Black & Veatch was able to estimate the projected long-term benefits of ANE under Mr. Kalt and Mr. Cavicchi' s Market Model Scenario. [4] Black & Veatch used the zonal electric prices and gas price differentials from the Market Model scenario with and without ANE, and our assumptions regarding ISO-NE electric load to develop what the net benefits from Mr. Kalt and Mr. Cavicchi's analysis would be. Black & Veatch assumed that the prices provided were in nominal terms and discounted the costs and benefits at 7.06%.

In Figure 1 below, Mr. Kalt and Mr. Cavicchi's analysis under the Market Model Scenario indicates that the ANE project would generate an annual levelized net benefit of $0.6 Billion over the 2019-2038 contract term. This analysis demonstrates that, even accepting the

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3 Exhibit EVER-KRP-Rebuttal-1, D.P.U. 15-181.

4 The analysis of the modeling results provided by Kalt and Cavicchi in response to information requests is based on Black & Veatch's reasonable interpretation of those results in light of, e.g., incomplete data labeling and documentation of modeling assumptions.

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modeling inputs and assumptions used by Kalt and Cavicchi (as discussed elsewhere in this testimony, Black & Veatch does dispute certain of those inputs and assumptions), by (1) evaluating benefits to electricity customers consistent with the Department's standard of review in this case, (2) correcting Kalt and Cavicchi's failure to recognize the benefits from reductions in price volatility, and (3) applying present value analysis consistent with Department precedent and public policy analysis best practice, one finds that Kalt and Cavicchi's own modeling results find a benefit-to-cost ratio of [redacted] for the ANE Project.

Figure 1

Total Project Cost-Benefit Summary 2019-2038 ($ Billions)							
	Levelized			Present Value			
Project	Annual Benefits	Annual Costs	Annual Net Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
With ANE Only	[redacted]	[redacted]	$1.1	[redacted]	[redacted]	$10.2	[redacted]
Kalt and Cavicchi (Market Model Scenario)	[redacted]	[redacted]	$0.6	[redacted]	[redacted]	$5.6	[redacted]

Q. Please assess the validity of Mr. Kalt and Mr. Cavicchi's statements that their modeling results do not reveal any expected impact from ANE during non-winter months and that Black & Veatch's findings of non-winter months' benefits "are illogical artifacts of what appears to be faulty modeling."[5]

A. These statements are completely inaccurate. First, as context for this critique by Kalt and Cavicchi, footnote 7 in Exhibit NG-JNC-3 reported that Black & Veatch's modeling

[5] Exhibit: NEER-JPK/AJC-1 (corrected: June 28, 2016), at 110. Kalt and Cavicchi's testimony reads: "Black & Veatch's findings of non-summer months' 'benefits' are illogical artifacts of what appears to be faulty modeling." However, given the context, the assertion was clearly meant to refer to "non-winter months."

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projected that 96.7% of the total benefits for the ANE Project would occur during the winter season (i.e., only 3.3% of the total benefits reported for the ANE Project result from its projected effects on natural gas and electricity prices during non-winter months). That said, the data provided in natural gas and electric price data in Attachment NEER-NG-1-47, Attachment NG -NEER-1-65(e) (CONFIDENTIAL), and Attachment NG -NEER-1-65(f) (CONFIDENTIAL) show that Kalt and Cavicchi's modeling analysis also indicates that the ANE Project has an impact on natural gas and wholesale electricity market prices during non-winter months, which Mr. Kalt and Mr. Cavicchi referred to as "illogical artifacts of what appears to be faulty modeling" in the context of reviewing Black & Veatch's analysis. Black & Veatch believes that the ANE project will have an impact during non-winter months, which appears to be consistent with the analysis provided by Mr. Kalt and Mr. Cavicchi, making their criticism on this point unfounded.

D. Implied Heat Rate

Q. Do you agree with the general statements from Ms. Bodell, Mr. Kalt, and Mr. Cavicchi regarding the levels of the implied heat rates in your analysis and their impacts on results?

A. No. While I agree that observing implied heat rates is a useful measure for analysis, the change in gas price can also have an effect on the implied heat rate; meaning that as the gas price drops the implied heat rate can rise and vice versa. This is true in many markets, including ISO-NE, and around the country. While other factors such as generator outages or transmission issues, for example, affect the implied heat rate, the movement of gas prices plays a major role from season to season. That being said, I will turn to the reasonableness of the implied heat rates in Black & Veatch's analysis. Using the concept of implied heat

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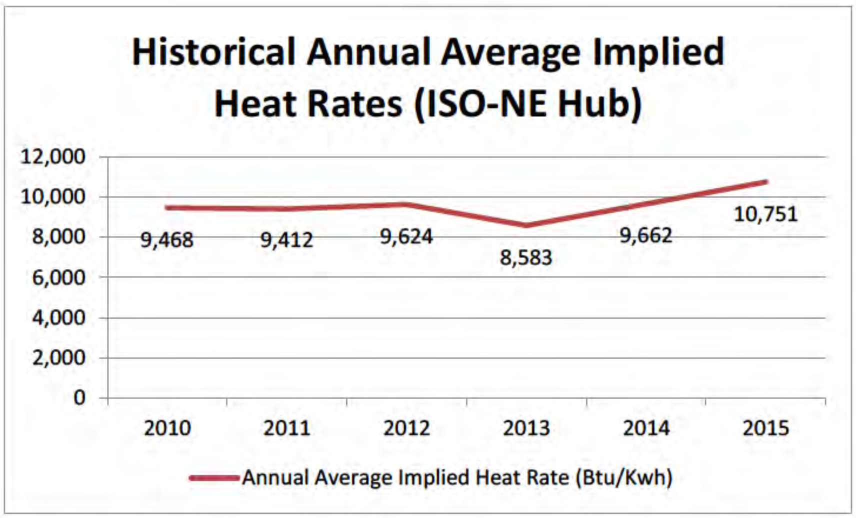
rates, Figure 2 below shows the average implied heat rates for the years of 2010-2015 for the ISO-NE Hub.

Figure 2



While remaining rather steady for the years of 2010-2012, there is an upward trend starting in 2013. Figure 8 of Exhibit AG-TB-1 provided by Ms. Bodell appears to have accurately shown the seasonal implied heat rates as an average of the New England prices and the Algonquin gas prices provided from the Black & Veatch analysis. From this it should be noted that Black & Veatch's analysis shows an average annual implied heat rate across the 20 years of Black & Veatch's analysis of 10.49 MMBtu/MWh. This is a realistic implied heat rate under our set of assumptions, the uncertainty of the future energy markets, and when compared to recent history.

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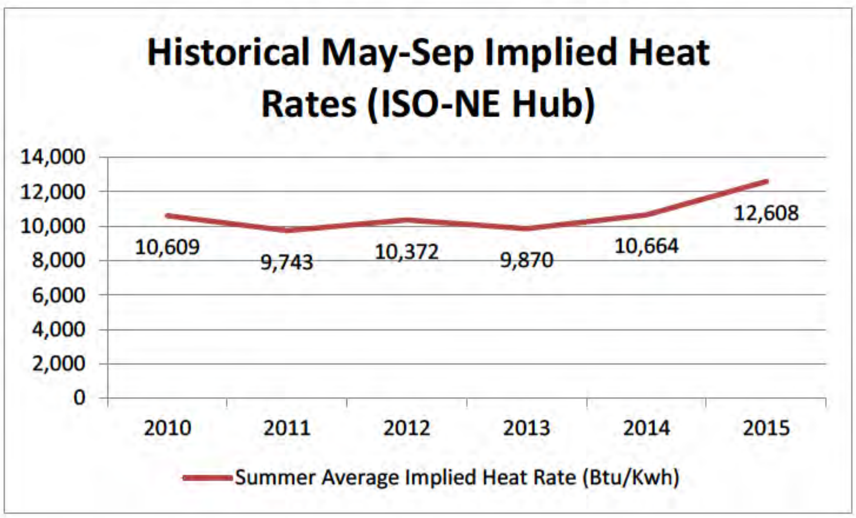
In her testimony, Ms. Bodell focused on the rather high implied heat rates that occur during July throughout the analysis. It is very common for ISO-NE to have its highest implied heat rate in July. As recently as 2015 the July average implied heat rate for ISO-NE has been above 13 MMBtu/MWh. Figure 3 shows the average historical summer (May-September) implied heat rate values from 2010-2015 for ISO-NE.

Figure 3



The average May-September implied heat rate value across the 20-year Black & Veatch analysis averages 11.87 MMBtu/MWh. This is a realistic implied heat rate under our set of assumptions, the uncertainty of the future energy markets, and when compared to recent history. Regarding the winter months of the analysis, Figure 4 shows the December-March historical average implied heat rates for ISO-NE.

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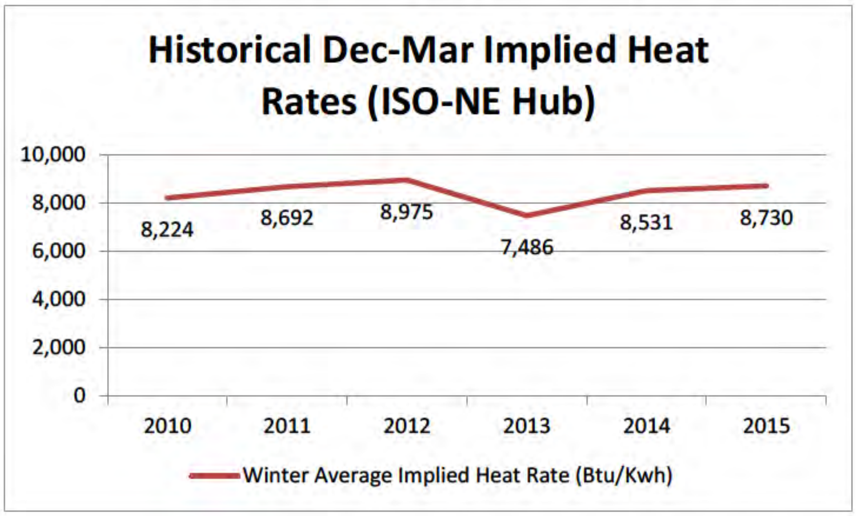
Figure 4



The average December-March implied heat rate value across the 20-year Black & Veatch analysis averages 9.31 MMBtu/MWh. Again, this is a realistic implied heat rate under our set of assumptions, the uncertainty of the future energy markets, and when compared to recent history.

E. Compliance With Environmental Policies

Q. Dr. Stanton states that the Black & Veatch analysis does not comply with Massachusetts RPS. Can you elaborate on how you capture Renewable Portfolio Standard ("RPS") compliance in Massachusetts?

A. As previously stated in response to Information Request NEER-1-12, Black & Veatch uses a proprietary model that develops the RPS forecasts for the ISO New England Regional Transmission Organization ("RTO"). Below is a description of the process used for renewable buildout. The forecast of renewable energy was provided in Attachment NEER-1-1(b), and is the same for the Base and ANE scenarios.

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To forecast additional renewable energy demand beyond the existing base of renewables, Black & Veatch employed the following steps in the process of deploying additional renewables for this analysis:

1. Estimate annual RPS requirements based on applicable load and annual targets
2. Reduce a state's requirements by respective solar or distributed generation carve-outs or set-asides, and assumed wind and small hydro imports
3. Estimate current level of RPS compliance
4. Develop net cost supply curves, accounting for unique delivery requirements of each state
5. Apply incremental annual RPS requirements to net cost supply curves to determine lowest cost options

Each state has different requirements with respect to delivery of the renewable energy to the state. Generally, states in ISO New England only require renewable energy to be delivered to the RTO. Thus, renewable energy development would be in states with the best resources within the RTO. The remaining RPS states generally require energy to be delivered to the state to count towards its RPS.

Q. Dr. Stanton indicates that your analysis falls short of the expected additional RPS needed to cover the MA requirement. Is this true?

A. I agree with Dr. Stanton's statement that the renewable growth between 2025 and 2040 is approximately 6.8 TWh in the Black & Veatch analysis. However, I disagree with the

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amount of new RPS needed to meet the Massachusetts requirement. Figure 4 shows the Black & Veatch calculations using the Massachusetts demand growth, the 86% of sales requirement subject to RPS, and the percentage of energy demand to be served by renewable energy. Figure 5 shows the growth needed to meet the Massachusetts requirement as only being 7.2 TWh, which is only slightly higher than what is achieved in the Black & Veatch analysis, and well below the 8.4 TWh as stated by Dr. Stanton.

Figure 5

Year	Retail Sales (GWh)	Retail Sales Subject to RPS (GWh)	RPS Requirement (% of Retail Sales subject to RPS)	Gross RPS Requirement (GWh)
2025	56,447	48,544	20.0%	9,709
2026	56,451	48,548	21.0%	10,195
2027	56,440	48,538	22.0%	10,678
2028	56,418	48,519	23.0%	11,159
2029	56,417	48,519	24.0%	11,644
2030	56,401	48,505	25.0%	12,126
2031	56,388	48,494	26.0%	12,608
2032	56,380	48,487	27.0%	13,091
2033	56,365	48,474	28.0%	13,573
2034	56,355	48,465	29.0%	14,055
2035	56,344	48,456	30.0%	14,537
2036	56,331	48,445	31.0%	15,018
2037	56,320	48,435	32.0%	15,499
2038	56,308	48,425	33.0%	15,980
2039	56,297	48,415	34.0%	16,461
2040	56,285	48,405	35.0%	16,942

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Q. Dr. Stanton indicates that the Black & Veatch forecast does not comply with known environmental policies seeking reductions in greenhouse gas emissions in Massachusetts, specifically the Regional Greenhouse Gas Initiative ("RGGI") and the U.S. EPA's Clean Power Plan ("CPP"). Is this true?

A. No. Black & Veatch's modeling analysis reflects both the RGGI CO2 emission reduction requirements for all participating states and compliance with the CPP. RGGI allows for trading of allowances across states and banking of allowances over time. Load growth, location of new generation and retirements, renewables, and imports can all affect the amount of emissions within a particular state, and RGGI has no requirement that any one state meet particular emission levels. As a result, Black & Veatch focused on maintaining prescribed levels of emissions across the nine-state RGGI region as opposed to forcing specific states participating in RGGI to achieve certain emission levels. While the RGGI targets do decline until 2020, it is difficult to actually state what levels of compliance would be required beyond 2020. The CPP is currently stayed, and if this were to move forward, the CPP allows flexibility as to how to comply with the regulations. This could include rate and mass-based approaches, and could be implemented on a state or region level basis. Nonetheless, Black & Veatch also models compliance with the CPP via a substantial carbon price imposed on the power sector that, in aggregate, ensures compliance with CPP overall emission levels. As Ms. Scheller explains on behalf of Eversource, "[i]n fact, most RGGI states have indicated the possibility of adopting the current RGGI program to meet the standards of the CPP, to establish a regional cap and trade system under the CPP, should the CPP move forward."[6] As such, Dr. Stanton's critique of Black & Veatch's analysis based on

[6] Exhibit EVER-MFS-Rebuttal-1, D.P.U. 15-181, at 15.

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how projected CO_2 emissions in Massachusetts (as opposed to regional CO_2 emissions) compare to RGGI and CPP emission reduction targets suggests a fundamental misunderstanding of how cap-and-trade programs work. In fact, the primary benefit of a multi-state cap-and-trade program for CO_2 is that targets can be met more cost-effectively if covered emitters do not have to meet state-specific caps owing to the heterogeneity of marginal abatement costs among states.

Q. Ms. Bodell references programs such as the Clean Energy RFP ("CERFP") and Global Warming Solutions Act ("GWSA") for Massachusetts. Would these items provide any more certainty to emissions reductions in the future?

A. No, not at this point in time. There is substantial uncertainty about what future impacts, if any, the CERFP and GWSA will have on the New England energy markets; Black & Veatch's analysis reflects reasonable assumptions based on the best information available regarding future clean energy and environmental policy requirements and market impacts. As for the GWSA, the Massachusetts Department of Environmental Protection ("DEP") has not yet promulgated regulations regarding enforceable reductions in emissions levels. The GWSA relies on hydroelectric imports from Canada, and while the CERFP promises multi-state collaboration including transmission and generation, there are as yet no firm commitments on these projects. At this point, more renewable generation, generation retirements, installation of gas-fired resources, and lower demand growth through energy efficiency and demand response will drive emissions reductions.

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Q. Despite the uncertainty regarding the eventual impacts of the GWSA and CERFP, did Black & Veatch perform any relevant sensitivity analyses?

A. Yes. Exhibit NG-TJB/JEA-Rebuttal explains how Black & Veatch developed sensitivity analyses to determine how the benefits from the ANE Project would change in light of substantial amounts of incremental clean energy.

F. Gas Demand Forecast

Q. Do you agree with Mr. Zenker's conclusion[7] that New England gas demand will not be growing?

A. No, I do not agree. Mr. Zenker relies upon the U.S. Energy Information Administration's Annual Energy Outlook ("AEO") 2015 projection to conclude that non-power New England gas demand would decline in the near term and increase in later years at a much lower rate. Mr. Zenker also concludes that New England gas demand for power generation as projected by the EIA would decline over the contract period.[8] However, using the recent AEO 2016, EIA currently projects total annual New England natural gas demand to increase by 8% from 2016-2038. Residential and Commercial demand is expected to grow by 6.7% over the 2019-2038 contract period. Gas demand for power generation is also projected to rise by 9.7% over the same time horizon. In simple terms, if more gas is needed, the risk of constraint will be higher on the facilities without the ANE Project.

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[7] Zenker page 5, line 17.

[8] Zenker, page 7, line 4.

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Q. Do you agree with Mr. Zenker's conclusion[9] that Black & Veatch relied on an unreasonable assumption of the future growth rate for natural gas in the region?

A. No, I do not agree. Black & Veatch's projections of residential and commercial demand are reasonable and follow the projections developed by the local distribution companies ("LDCs") across New England. Over the past few years, New England LDCs have filed with state regulators gas supply resource reports that indicate that gas demand growth is on the rise. As shown in Figure 6, the most recent LDC filings in the 2014-2015 time frame indicate a growth rate 0.8-2.9% higher than previous LDC filings during the 2012-2013 time frame.

Figure 6

		2012-2013			2014-2015		
State	**Gas Utility**	**Report Date**	**Total System Growth Rate**	**Time Frame**	**Report Date**	**Total System Growth Rate**	**Time Frame**
MA	Berkshire Gas Co	Aug-12	1.30%	2013-2017	Aug-14	2.31%	2015-2019
MA	Blackstone Gas Co	Oct-12	2.38%	2012-2017	Nov-14	3.24%	2015-2019
MA	Boston Gas Co & Colonial Gas Co	Feb-13	0.30%	2013-2017	Apr-15	1.71%	2015-2019
MA	Bay State Gas Co & Columbia Gas of MA	Sep-13	1.00%	2014-2018	Sep-15	1.80%	2016-2020
MA	New England Gas Co	May-12	0.07%	2012-2017	Jul-14	0.36%	2015-2019
MA	NSTAR Gas Co	Feb-12	-0.50%	2012-2016	Mar-14	1.44%	2015-2018
CT	Connecticut Natural Gas Corp	Oct-12	1.44%	2013-2017	Oct-14	3.85%	2015-2019
CT	Southern Connecticut Gas Co	Oct-12	0.91%	2013-2017	Oct-14	3.81%	2015-2019

The demand forecasts developed by the New England LDCs more accurately reflect the recent demand growth experienced in the market and provide a more accurate assessment of

[9] Zenker, page 5, line 17

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the potential growth. Black & Veatch's projection of residential demand growth of 1.4% and commercial demand growth of 1.1% over the analysis period is in line with these recent estimates.[10]

G. LNG Imports

Q. Please explain why Black & Veatch's assumptions regarding LNG imports to New England do not "artificially" constrain the marketplace as suggested by Interveners?

A. Black & Veatch's assumptions regarding LNG import volumes reflect recent historical observed import volumes and known contractual firm gas sales agreements. Any additional LNG import volumes would be considered speculative in nature without firm gas sales agreements.

Q. Do you agree with Mr. Morrisette's statement in Exh. NG-RENA-1-14 (d), that gas sales agreements are key to ensuring that gas will be available from Canaport when the market needs it?

A. Yes. I agree that gas sales agreements are key to ensuring that natural gas would be available from Canaport or other regional LNG import terminals when the market needs it. Absent firm gas sales agreement, re-gasified LNG from Canaport or other LNG import terminals may not be available during the winter. Black & Veatch's analysis modeled these known firm gas sales from LNG import terminals.

Q. Is the statement by numerous interveners valid that LNG import terminals have the regasification capabilities to solve the region's problems?

A. As stated by Mr. Kruse in D.P.U. 15-181[11], even if imported LNG supply is available, delivery to these natural gas-fired generators will be non-firm and thus subject to

[10] In Black & Veatch's report for NESCOE dated August 26, 2013, page 25 Figure 8, over the 2014-2030 analysis period, residential demand growth was 0.99%, and commercial demand growth was 2.2%.

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interruption. Mr. Kruse states that in addition to securing pipeline capacity, imported LNG solutions would need the capacity reservation and flexible character of service as proposed in the ANE Rate Schedule ERS.

Q. Does Repsol's negotiated ten-year portfolio supply contract with Shell represent a material firm supply agreement, as stated by Mr. Zenker[12]?

A. No. Based on Shell's February 26, 2013 announcement[13] of the purchase of Repsol's LNG portfolio on February 26, 2013, Shell has committed to supply around 0.1 MTPA of LNG to Repsol's Canaport LNG terminal in Canada over a period of 10 years. This is an immaterial import volume. As stated by Shell, they are committing 0.1 MTPA annually to Canaport, this would roughly equate to 13 MMcf/d on an average daily basis, without accounting for any terminal boil off or fuel use at the Canaport import terminal. This limited firm supply quantity is far less than Canaport's current regasification capacity, and would not have a material impact on Black & Veatch's projection of long-term economic impacts from the ANE project.

Q. Does LNG liquefaction capacity growth necessarily equate to LNG supply available to be imported into New England?

A. Absolutely not. Mr. Zenker and Mr. Morrissette both equate global LNG liquefaction capacity growth to LNG global supply available to New England. Due to the inevitable uncertainty around global LNG demand, currently low global LNG prices may alter the

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11 Kruse D.P.U. 15-181, page 19, lines 8-11.

12 Zenker Page 29 Line 14 and Footnote 38.

13 See Press Release: http://www.shell.com/media/news-and-media-releases/2013/shell-continues-to-expand-its-lng-leadership html.

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projected utilization rates and the available LNG supply available in the market. As stated by Mr. Morrissette in NG-RENA-1-6, Repsol cannot predict the utilization of these facilities (in reference to LNG liquefaction plants). As depicted in Figure 4 of Mr. Morrissette's testimony, worldwide liquefaction capacity will continue to exceed worldwide LNG demand from 2016 through 2025. If the global LNG markets are transparent, the more intuitive conclusion to draw would be that LNG production would slow down for the market to reach equilibrium, instead of continued LNG production growth in an oversupplied market.

H. Upstream Liquidity Will Be Sufficient to Serve the ANE Project

Q. Do you agree with Mr. Mierzwa's conclusion that it is foreseeable that there will be insufficient gas supplies at the ANE Project receipt points to fill the 500,000 MMBtu/day of capacity under the ANE Project?

A. No. I do not agree. Mr. Mierzwa's analysis utilizes historical winter electronic bulletin board information from Algonquin and Tennessee to analyze the historical utilization of upstream capacity on the Tennessee 300 Line, Millennium Pipeline. Mr. Mierzwa then concludes that for the Winter of 2015-2016, an additional 500,000 MMBtu/day was not available on 142 out of the 152 days.[14] This approach is flawed in determining if sufficient gas supplies are available to ANE. Historical interconnect volumes represent how current Algonquin capacity holders chose to utilize its capacity. Most Algonquin capacity holders have receipt options upstream or downstream of Mahwah and Ramapo and can optimize based on price and numerous other factors. Mr. Mierzwa correctly states that upstream pipeline capacity at Mahwah and Ramapo totals 1,907,000 MMBtu/day; however, by the

[14] Mierzwa, page 23, line 11-12.

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end of 2017 the upstream pipeline capacity would be [redacted] MMBtu/day as stated on page C-7 of the ANE RFP response. If we assume that the historical winter flows in 2015-2016 remained the same for all other shippers going forward and a total upstream capacity of [redacted] MMBtu/d, Mr. Mierzwa's analysis would conclude that an additional 500,000 MMBtu/d for the ANE project would be available 122 out of 152 days. An additional 450,000 MMBtu/d for the ANE project would be available 150 out of 152 days.

Q. Do you agree with Mr. Kruse's statement that getting natural gas to the Algonquin system is not a problem[15]?

A. Yes, I do. In addition to primary receipts at Ramapo, Mahwah and Brookfield, the ANE project will provide secondary access to Texas Eastern and Penn East Pipeline at Lambertville, Transcontinental Pipeline at Centerville, and Columbia Gas at Hanover. The anticipated total upstream pipeline capacity to AGT would reach [redacted] Dth/d as shown in Figure 10 of ANE's RFP response. This supports the conclusion that there would be sufficient access to gas supply for the ANE project.

Q. Did Mr. Mierzwa take into consideration upstream incremental pipeline expansion projects?

A. No. As stated in Table 12 of the Joint Rebuttal Testimony of James Stephens and Samuel Eaton in D.P.U. 15-181[16], another 2,325,000 Dth/day of proposed expansion projects could reach the primary or secondary receipt points of the ANE Project and provide sufficient supply access and market liquidity.

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15 Kruse D.P.U. 15-181, page 17, line 20.
16 Stephens and Eaton Joint Rebuttal Testimony in D.P.U. 15-181, page 67 Table 12.

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I. The ANE Project is Consistent with the Findings of the New England States Committee on Electricity ("NESCOE")

Q. What were the major findings of Black & Veatch's report to NESCOE?

A. Black & Veatch's study for NESCOE concluded that a Cross-Regional Natural Gas Pipeline solution would provide the highest net benefits to New England consumers in comparison to other alternative long-term solutions under the Base Case and High Demand Scenario. Only in a Low Demand scenario, where residential, commercial and industrial demand were kept flat at 2013 levels, would no long-term solutions be necessary.

Q. Does the conclusion in the Low Demand scenario, where no long-term infrastructure solutions are justified, still hold true given the current market conditions, as suggested by Mr. Kalt and Mr. Cavicchi[17]?

A. It is not likely that their conclusion would hold given the demand growth New England has experienced in the past 3 years, coupled with the projected declines in Eastern Canadian production. The Low Demand scenario held demand flat at 2013 levels, not at 2017 levels, which would require a reduction of approximately 120 MMcf/d. Lower production level expectations in Eastern Canadian could reduce Canadian imports which could potentially justify additional incremental infrastructure to meet 2017 demand levels.

Q. Is Black & Veatch's cost-benefit methodology consistent with the methodology used in the NESCOE study?

A. Yes. Black & Veatch utilized the same methodology used in the NESCOE study to determine the long-term economic benefits to electric consumers. These economic benefits

[17] Kalt and Cavicchi, page 67, line 7, footnote 70.

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include both monthly market energy price reductions and benefits from reduction in daily gas price volatility.

IV. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes it does.