DOWNEAST LNG, INC.
748 U.S. Route 1
Robbinston, Maine 04671

RECEIVED
By Docket Room at
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October 15, 2014

Mr. John Anderson
Office of Fuels Programs, Fossil Energy
U.S. Department of Energy
Docket Room 3F-056, FE-50
Forrestal Building
1000 Independence Avenue, SW
Washington, D.C. 20585

Re: In the Matter of Downeast LNG, Inc.
FE Docket No. 14-173-LNG
Application for Long-Term Authorization to Export Liquefied
Natural Gas to Non-Free Trade Countries

Dear Mr. Anderson:

Enclosed for filing, please find Downeast LNG, Inc.'s ("DELNG") application for long-term, multi-contract authorization to engage in exports of domestically-produced liquefied natural gas ("LNG") in an amount up to 173 million British thermal units per year, which is equivalent to approximately 168 billion standard cubic feet of natural gas per year.[1] DELNG seeks authorization for a 20-year term, commencing on the earlier of the date of first export or eight years from the date the requested authorization is granted, to export LNG to any country with which the U.S. does not now or in the future have a Free Trade Agreement requiring the national treatment for trade in natural gas and LNG, that has—or in the future develops—the capacity to import LNG, and with which trade is not prohibited by U.S. law or policy.

Should you have any questions about the foregoing, please feel free to contact the undersigned at (207) 454-3925.

Respectfully submitted,

Dean P. Girdis

Dean P. Girdis
CEO and President
Downeast LNG, Inc.

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[1] A check in the amount of $50.00 is being provided as the filing fee stipulated by 10 C.F.R. § 590.207.

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UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

In the Matter of:	)	
	)	**FE Docket No. 14-___-LNG**
DOWNEAST LNG, INC. Docket No.	)	

APPLICATION OF DOWNEAST LNG, INC. FOR LONG-TERM AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE COUNTRIES

Pursuant to Section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the Department of Energy's ("DOE") regulations,[2] Downeast LNG, Inc. ("DELNG") hereby requests that DOE, Office of Fossil Energy ("DOE/FE"), grant long-term, multi-contract authorization for DELNG to engage in exports of domestically-produced liquefied natural gas ("LNG") in an amount up to 173 million British thermal units ("MMBtu") per year,[3] which is equivalent to approximately 168 billion standard cubic feet ("Bcf") of natural gas per year[4], for a 20 year period. DELNG is seeking authorization to export LNG from the proposed Downeast LNG Import-Export Project ("DELNG Project") to be located in Robbinston, Maine,[5] to any country with which the U.S. does not now or in the future have a free trade agreement ("FTA") requiring the national treatment for trade in natural gas and LNG, that has—or in the future develops—the capacity to

1 15 U.S.C. § 717b (2012).

2 10 C.F.R. Part 590 (2014).

3 173 MMBtu is equivalent to the planned peak production rate of the export facilities of approximately 3.3 million metric tonnes per annum ("mtpa") of LNG, including a margin for excess production capacity. The authorization is requested in terms of MMBtu per year to maintain consistency with industry convention for the denomination of quantities in LNG export contracts, which are denominated in MMBtu per year.

4 Conversion based on an assumed higher heating value of exported LNG equal to 1,030 British thermal units ("Btu") per standard cubic foot.

5 The DELNG Project is being developed by DELNG together with Downeast Liquefaction, LLC, and Downeast Pipeline, LLC, at the same general locations proposed for the previously-reviewed DELNG import terminal and associated pipeline for which DELNG and Downeast Pipeline, LLC, have sought authorization from the Federal Energy Regulatory Commission ("FERC"). *See* Downeast LNG Project Final Environmental Impact Statement, FERC/EIS: 0231F, *Downeast LNG, Inc. & Downeast Pipeline, LLC*, FERC Docket Nos. CP07-52-000, CP07-53-000 & CP07-53-001 (May 15, 2014) [hereinafter DELNG Import FEIS].

import LNG, and with which trade is not prohibited by U.S. law or policy ("non-FTA Countries").

Concurrent with this Application, DELNG separately is filing with DOE/FE an application for long-term, multi-contract authorization to engage in exports of LNG in an amount up to 173 MMBtu per year to any nation that currently has—or in the future develops—the capacity to import LNG, and with which the U.S. currently has—or in the future enters into—an FTA requiring the national treatment for trade in natural gas and LNG.[6]

Substantial resources have been both expended to date and committed for future expenditure to develop the DELNG Project. DELNG respectfully requests that the DOE/FE issue an order authorizing DELNG to export LNG from the DELNG Project to non-FTA Countries as requested herein on an expedited basis as soon as this Application becomes ready for final action upon completion of DOE's National Environmental Policy Act ("NEPA") review process.[7]

In support of its Application, DELNG states as follows:

I. DESCRIPTION OF THE APPLICANT

The exact legal name of DELNG is Downeast LNG, Inc. DELNG is a Delaware corporation with its primary places of business in Washington, D.C. and Robbinston, Maine.

II. COMMUNICATIONS AND CORRESPONDENCE

All correspondence and communications concerning this Application, including all service of pleadings and notices, should be directed to the following person:

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[6] DELNG anticipates exporting up to a total of 3.3 million mtpa on an annual basis from the DELNG Project.

[7] *See* 79 Fed. Reg. 48,132, 48,135 (Aug. 15, 2014) (announcing revised procedures).

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Pursuant to Section 590.103(b) of the DOE regulations,[8] DELNG hereby certifies that the person listed above, who is also the undersigned, is the duly authorized representative of DELNG.

III. EXECUTIVE SUMMARY

DELNG is herein seeking multi-contract, long-term authorization to export up to 173 MMBtu of LNG per year, which is equivalent to approximately 168 Bcf of natural gas per year, to those countries that: (i) do not now or in the future have an FTA requiring the national treatment for trade in natural gas and LNG; (ii) which have, or in the future develop, the capacity to import LNG; and (iii) with which trade is not prohibited by U.S. law or policy (*i.e.*, non-FTA Countries). DELNG requests this authorization for a 20-year term commencing at the earlier of the date of first export or eight years from the date the requested authorization is granted.

DELNG is filing this Application in conjunction with the DELNG Project being developed by DELNG together with Downeast Liquefaction, LLC, and Downeast Pipeline, LLC, at the site previously reviewed by FERC for the DELNG import terminal and associated pipeline in Washington County, Maine.[9] Concurrent with this Application, DELNG has begun the FERC NEPA pre-filing process for authorization pursuant to Section 3(a) of the NGA to site, construct, and operate the DELNG Project Terminal facilities (the "DELNG Terminal"), and DELNG is filing an application with FERC pursuant to Section 7(c) of the NGA to construct, own and

[8] 10 C.F.R. § 590.103(b) .

[9] *See supra* note 5.

operate the Downeast Pipeline ("Pipeline") to connect the DELNG Terminal facilities to interstate and intrastate natural gas supplies and markets.[10] In approving the pre-filing request for the DELNG Project, FERC stated that it would prepare a NEPA document to "supplement the final Environmental Impact Statement issued May 15, 2014 for the Downeast LNG Import Project."[11] DOE/FE will act as a cooperating agency in FERC's environmental review process for the DELNG Project, and in the preparation of an environmental assessment ("EA") or environmental impact statement ("EIS") to satisfy DOE/FE's NEPA responsibilities. The DELNG Project's LNG import-export terminal ("DELNG Terminal") has been designed to produce approximately 173 MMBtu per year of LNG. In addition, the DELNG Terminal design includes a small amount (approximately 100,000 Btu per day) of LNG regasification capacity. The DELNG Project's natural gas pipeline ("Pipeline") is comprised of an approximately 29-mile-long, 24-inch-diameter pipeline to be located wholly within Washington County, Maine. The Pipeline has been designed to transport natural gas to the DELNG Terminal for liquefaction and export, and may be used to transport regasified LNG from the DELNG Terminal.

DELNG proposes to source natural gas to be used as feedstock for LNG production at the DELNG Project from U.S. and Canadian gas fields via the interstate pipeline system. The DELNG Project will interconnect with the Maritimes and Northeast Pipeline ("M&NP"), which in turn interconnects with Portland Natural Gas Transmission System ("PNGTS"), Algonquin Gas Transmission System ("AGT"), and the Tennessee Gas Pipeline ("TGP"). Each of these three pipelines provides a distinct route to access eastern gas fields that the DELNG Project could use to source gas. Given regional demand, Kinder Morgan (the owner of TGP), Spectra

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[10] *See* Letter of Approval of Pre-Filing Request for the Downeast LNG Import-Export Project, *Downeast Liquefaction, LLC, Downeast LNG, Inc. & Downeast Pipeline, LLC*, FERC Docket No. PF14-19-000 (Aug. 11, 2014).

[11] *Id.* at 2.

(the owner of the AGT and partial owner of M&NP), and TransCanada (the owner of PNGTS), have each separately proposed capacity expansions for their existing system, or greenfield builds that would supply the region.

The DELNG Project is encouraged by the increase in domestic natural gas production in the U.S., in particular, the rapid and sustained growth of gas fields in northeastern Pennsylvania.[12] The production of natural gas in the producing regions in Pennsylvania and West Virginia now exceeds 14 Bcf per day ("Bcf/d"), based on estimates in the U.S. Energy Information Administration ("EIA") May 2014 Drilling Productivity Report ("DPR")[13]. Despite the rapid growth of U.S. natural gas production, some question whether it can be sustained unless new markets are found, given the low wellhead gas prices and a constrained gas pipeline delivery system[14]. The EIA noted in a recent *Short-Term Energy Outlook* that

> [r]apid natural gas production growth in the Marcellus formation is contributing to falling natural gas forward prices in the Northeast, which often fall even with or below Henry Hub prices outside of peak winter demand months. Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, where prices are closer to the Henry Hub spot price.[15]

Although productivity gains have led to higher wellhead production rates, there has already been a reduction of rig count from about 140 rigs in 2012 to about 100 rigs today.[16] The potential decline in Marcellus gas production due to a re-focus by drillers on other more liquid gas basins

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12 Domestic wellhead natural gas production in 2013 totaled 30.17 trillion standard cubic feet ("Tcf"), a 17% increase in five years and the highest in U.S. history. *See* U.S. Energy Information Administration ("EIA"), Natural Gas Gross Withdrawals and Production, *available at* http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm (last visited Aug. 20, 2014).

13 EIA, *Drilling Productivity Report for Key Tight Oil and Shale Gas Regions* 6 (May 2014), *available at* http://www.eia.gov/petroleum/drilling/archive/dpr_may14.pdf [hereinafter *Drilling Productivity Report*].

14 *See, e.g.*, Bentek Energy, *Taming the Beast: Marcellus, Utica & Northeast Gas Exports*, http://www.bentekenergy.com/TamingTheBeast.aspx (last visited Aug. 20, 2014).

15 EIA, *Short-Term Energy Outlook (STEO)* 6 (May 2014), *available at* http://www.eia.gov/forecasts/steo/archives/May14.pdf.

16 *See* EIA, *Drilling Productivity Report*, *supra* note 13, at 6.

could be a concern for Northeast consumers, as any reduction in production would likely lead to higher market prices for consumers. In order to maintain and grow natural gas production to meet Northeast demand and ensure price moderation, the pipeline deliverability system must be expanded; this can only be accomplished if gas consumers, such as the DELNG Project and/or its customers, contractually commit to long-term pipeline capacity contracts.

Overall, the DELNG Project presents numerous benefits to the public. DELNG submits that the authorization sought herein is not inconsistent with the public interest. To the contrary, as discussed herein, the DELNG Project will result in a number of economic and public benefits, ranging from improving the U.S. balance of payments to stimulating state, regional and national economies through job creation, increased economic activity and tax revenues.

At the national level, the recent NERA Economic Consulting report ("NERA Report")[17] commissioned by DOE assessed the economic impact of LNG exports. "In all of the scenarios analyzed in this study, NERA found that the U.S. would experience net economic benefits from increased LNG exports."[18]

At the local and state level, the economic benefits of the DELNG Project in Maine are quantified in the DELNG-commissioned report, *Economic Impact of Proposed Downeast LNG Terminal: State and Local Economic Impacts of a Proposed Bi-directional LNG Terminal in Washington County, Maine*,[19] authored by Todd Gabe, Professor of Economics at the University of Maine.[20] Results of the study, which is submitted herewith as Exhibit D, show that:

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17 NERA Economic Consulting, *Macroeconomic Impacts of LNG Exports from the United States* (Dec. 3, 2012), *available at* http://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.

18 *Id.* at 6.

19 Todd Gabe, *Economic Impact of Proposed Downeast LNG Terminal: State and Local Economic Impacts of a Proposed Bi-directional LNG Terminal in Washington County, Maine* (Aug. 2014) .

20 A similar study (Todd Gabe et al., *Economic and Fiscal Impacts of a Proposed LNG Facility in Robbinston, Maine*, Department of Resource Economics and Policy, University of Maine, Staff Paper 556, (Nov. 2005)) was

- Constructing a bi-directional LNG facility with an annual nominal processing capacity of three million mtpa, will require an estimated $2.0 billion upfront investment.

- Over a three-year construction period, the proposed LNG terminal will generate a total statewide economic impact—including multiplier effects—of an estimated $1.5 billion in output, an average of 3,525 full- and part-time jobs, and a 3-year total of $562 million in labor income.

- The impact of facility construction on the Washington County economy—including multiplier effects—will be an estimated $660 million in output, an average of 2,195 full- and part-time jobs, and a 3-year total of $266 million in labor income.

- After the proposed LNG terminal is completed, the permanent statewide impact of its annual operations—including multiplier effects—will be an estimated $102 million in output, 505 full- and part-time jobs, and $32.4 million in labor income.

- The permanent impact of the LNG terminal's annual operations on the Washington County economy—including multiplier effects—will be an estimated $69.6 million in output, 310 full- and part-time jobs, and $20.9 million in labor income.

In addition, according to the U.S. Bureau of Labor Statistics' February 2014 *Monthly Labor Review*, increased gas production in the Marcellus region has led to most of Pennsylvania's recent substantial employment gains. The state's employment growth in the industry correlates with EIA data on gross withdrawals from shale gas wells. Specifically, "Pennsylvania had the second-highest increase in gross withdrawals (2.0 Tcf) from 2008 to 2012, trailing only Louisiana in this regard."[21] "As a result, Pennsylvania went from being the 10th-largest state by oil and natural gas employment in 2007 to being the 6th largest in 2012."[22] "The state also had the second-largest employment increase over the study period, positioning itself only after Texas, a major oil- and natural gas-producing state."[23]

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conducted in 2005, although the proposed facility at that time was a $400 million LNG import terminal—and not a bi-directional facility with liquefaction equipment.

[21] U.S. Bureau of Labor Statistics, *Monthly Labor Review*, *The Marcellus Shale Gas Boom in Pennsylvania: Employment and Wage Trends* 6 (Feb. 2014), *available at* http://www.bls.gov/opub/mlr/2014/article/pdf/the-marcellus-shale-gas-boom-in-pennsylvania.pdf.

[22] *Id.*

[23] *Id.*

Another economic benefit, as noted earlier, is the increased deliverability of natural gas and increased access to Marcellus gas the project will facilitate for New England customers by supporting incremental pipeline capacity to the region.

For the foregoing reasons, and as demonstrated fully herein, the export of LNG from the DELNG Project as proposed by DELNG is consistent with the public interest. Accordingly, DELNG requests that DOE/FE grant the authorization requested in this Application as soon as this Application becomes ready for final action upon completion of DOE's NEPA review process.

IV. AUTHORIZATION REQUESTED

DELNG requests long-term, multi-contract authorization to export up to 173 MMBtu per year of LNG, which is equivalent to approximately 168 Bcf per year of natural gas, from the DELNG Project to any country: (i) with which the U.S. does not now or in the future have an FTA requiring the national treatment for trade in natural gas; (ii) that has, or in the future develops, the capacity to import LNG; and (iii) with which trade is not prohibited by U.S. law or policy. DELNG requests this authorization for a 20-year term commencing at the earlier of the date of first export or eight years from the date of issuance of the authorization requested herein.

DELNG is requesting authorization to export LNG for itself and as agent for third parties who themselves hold title to the LNG at the time of export. DELNG will comply with all DOE/FE requirements for exporters and agents, including the registration requirements as first established in DOE/FE Order No. 2913[24] and most recently set forth in DOE/FE Order No.

[24] *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, *Order Granting Long-Term Authorization to Export Liquefied Natural Gas from Freeport LNG Terminal to Free Trade Nations*, DOE/FE Order No. 2913, FE Docket No. 10-160-LNG (Feb. 10, 2011).

3465.[25] DELNG is presently in discussions with several gas producers regarding long-term gas supply and with several parties concerning long-term export contracts in conjunction with the LNG export authorization requested herein. As these discussions are at present confidential, DELNG is not submitting transaction-specific information (*e.g.*, long-term supply agreements and long-term export agreements) at this time[26] and requests that DOE/FE make a similar finding to that in the May 2011 Sabine Pass Conditional Non-FTA Order with regard to the transaction-specific information requested in Section 590.202(b) of the DOE regulations.[27] DELNG is cognizant of the DOE/FE's 1984 *Policy Guidelines*,[28] and expects to enter into export transactions that are responsive to the relative level of natural gas prices in the United States.

V. DESCRIPTION OF LIQUEFACTION PROJECT

The DELNG Project will be located in Robbinston, Maine on the western shore of Passamaquoddy Bay and south of the City of Calais, Maine. The DELNG Project will include three million metric tonnes of nominal liquefaction capacity[29]. The DELNG Project will be designed to export 173 MMBtu of LNG annually and to import up to 100,000 Btu of LNG per

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[25] *LNG Development Co., LLC, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Oregon LNG Terminal in Warrenton, Clatsop County, Oregon to Non-Free Trade Agreement Nations*, DOE/FE Order No. 3465, FE Docket No. 12-77-LNG (July 31, 2014).

[26] In the May 20, 2011 order granting Sabine Pass Liquefaction, LLC ("Sabine Pass") long-term export authorization to non-FTA Countries, DOE/FE found that Sabine Pass was not required to submit with its application transaction-specific information pursuant to Section 590.202(b) of the DOE regulations. *See Sabine Pass Liquefaction, LLC, Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations* 41, DOE/FE Order No. 2961, FE Docket No. 10-111-LNG (May 20, 2011) [hereinafter May 2011 Sabine Pass Conditional Non-FTA Order]. DOE/FE found that given the state of development for the proposed Sabine Pass export project, it was appropriate for Sabine Pass to submit such transaction-specific information when the contracts reflecting such information were executed. *See id.*

[27] 10 C.F.R. § 590.202(b).

[28] DOE, *New Policy Guidelines and Delegation Orders from Secretary of Energy to Economic Regulatory Administration and Federal Energy Regulatory Commission Relating to the Regulation of Imported Natural Gas*, 49 Fed. Reg. 6684 (Feb. 22,1984).

[29] With debottlenecking, total potential production is 3.3 million mtpa.

day. At the DELNG Terminal, natural gas will be liquefied into LNG and stored in a single 160,000-cubic meter full-containment LNG storage tank. LNG will be exported on LNG carriers that will arrive at the DELNG Terminal through Western Passage. The DELNG Terminal will receive natural gas from the interstate and intrastate natural gas pipeline systems through interconnections with the Pipeline.

VI. EXPORT SOURCES

DELNG proposes to source natural gas to be used as feedstock for LNG production at the DELNG Project from the interstate grid interconnection with M&NP and other pipelines and points upstream of the Pipeline. The DELNG Project is located in relatively close proximity to the rapidly developing gas fields in Pennsylvania and West Virginia, an area that represents one of the most proximate and prolific potential sources of physical natural gas supply available for export. In addition, it is anticipated that the DELNG Project could also access Canadian gas from either the currently-producing Western Canadian Sedimentary Basin in Alberta, Canada (whose production is currently marketed in the Province of Quebec) or future incremental gas production in the provinces of New Brunswick and Nova Scotia.

Gas supply can be sourced in large volumes in the spot market, or more likely through a long-term supply arrangement. Given the increases in reported reserves and technically recoverable resources in the United States, and in particular the well-documented increased production associated with emerging unconventional resources, the proposed exports are not expected to have any adverse impact on the availability or pricing of natural gas. To the contrary, increased demand due to the DELNG Project will have the beneficial effect of supporting gas production, and facilitating the delivery of a competitive source of gas to the New

England region.

VII. COMMERCIAL MATTERS

DELNG is currently actively engaged in commercial discussions with potential LNG buyers to sell all the available liquefaction capacity at the DELNG Terminal. DELNG is also currently engaged in negotiations with gas producers for long-term gas supply, and with pipeline companies for long-term transportation capacity on the transmission systems connecting the DELNG Project to gas supply basins. These negotiations have been productive and DELNG expects that they will conclude successfully with commercial agreements in place within the next several months. As discussed above, DELNG will file any long-term gas supply or long-term export contracts with DOE/FE pursuant to DOE/FE regulations.

VIII. APPLICABLE LEGAL STANDARD

DELNG's request for authorization to export LNG to non-FTA countries is subject to review under Section 3(a) of the NGA, which provides that DOE/FE "*shall* issue" an order authorizing a proposed natural gas export "*unless*" DOE/FE finds that such exports "will not be consistent with the public interest."[30] Section 3(a) thus creates a presumption in favor of approval of an application to export natural gas to non-FTA countries that opponents bear the burden of overcoming.

IX. PUBLIC INTEREST ANALYSIS

The DELNG Project has been proposed due to the improved outlook for natural gas

[30] 15 U.S.C. § 717b(a) (emphases added).

production as a result of drilling productivity gains that have led to a dramatic growth in production in the U.S., and in particular in the Marcellus region of the Northeast. Where once the Northeast was a net importer of gas, it is now a net exporter of gas.

Authorization for export of natural gas as LNG will provide a market solution to allow the further responsible development of domestic natural gas, and will result in the following benefits:

- Improve the U.S. balance of payments through the export of LNG and the displacement of imports of other petroleum liquids;
- Increase economic trade and ties with foreign trading partners;
- Displace environmentally damaging fuels such as diesel and heavy fuel oil;
- Promote domestic natural gas production in the Northeast and regional price stability through increased and sustained gas production;
- Promote greater national energy security in Europe by supplying natural gas to counterbalance Russian geopolitical objectives;
- Expected sale of fixed-priced LNG minimizing price uncertainty and lowering the cost of energy in foreign nations, thereby fostering economic growth abroad and creating demand for U.S.-sourced goods and services; and
- Stimulate the regional, state, and national economies through job creation and increased economic activity, particularly in underdeveloped rural areas of Maine.

DELNG submits that these and the other benefits presented in this Application demonstrate that the LNG exports that would result from the approval of this Application are in the public interest.

A. <u>Analysis of Domestic Need for Gas to be Exported</u>

As noted in DOE precedent, "domestic need for the natural gas proposed to be exported" is "the only explicit criterion that must be considered in determining the public interest."[31] The

[31] *Phillips Alaska Nat. Gas Corp. and Marathon Oil Co., Order Extending Authorization to Export Liquefied Natural Gas from Alaska* 14, DOE/FE Order No. 1473, FE Docket No. 96-99-LNG (Apr. 2, 1999).

DELNG Project is therefore in the public interest because it: (i) does not impinge on domestic needs for natural gas; (ii) supports and encourages the continued development of natural gas resources during times when Northeast wellhead prices of natural gas are depressed; and (iii) supports the production of a quantity of natural gas that can be deployed on short notice when and if New England market prices induce the cancellation of the export of LNG cargoes, thereby mitigating price volatility that may otherwise arise, and ensuring that domestic supplies will be available over the duration of commodity market cycles.

1. National Supply

Domestic natural gas production has expanded rapidly in recent years as the application of new technologies has increased productivity of growing unconventional resource base in the U.S. Since 2005, U.S. marketed natural gas production has grown 35.3%, to 25.62 Tcf (70.2 Bcf/d) in 2013, representing the highest production levels in U.S. history.[32] Increased drilling productivity has allowed domestic production to continue its growth despite a redeployment of rigs from natural gas to oil basins.

The outlook for the U.S. natural gas supply capacity continues to be robust. DELNG commissioned a report by ICF International ("ICF"), *North American Natural Gas Supply Assessment Supporting the Downeast LNG Export Project* (July 2014) ("ICF Report"), submitted herewith as Exhibit B, to: assess the availability of U.S. natural gas resources; estimate gas demand in the Northeast region; determine the viability of transporting the gas supply to the DELNG Project; and assess if the project would negatively impact pricing in New England.[33] The ICF Report concluded that since the DELNG Project plans to contract for new incremental

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32 *See* EIA, Natural Gas Gross Withdrawals and Production, *supra* note 12; EIA, *U.S. Natural Gas Marketed Production*, http://www.eia.gov/dnav/ng/hist/n9050us2A.htm (last visited Aug. 20, 2014).

33 ICF International, *North American Natural Gas Supply Assessment Supporting the Downeast LNG Export Project* (July 2014).

firm pipeline capacity to secure a dedicated gas supply, the DELNG project would not have any effect on the New England gas market or prices.

The ICF Report provides additional independent analysis of the natural gas resource base, sources of natural gas supply and adequacy of natural gas resources for the proposed DELNG Project. It notes that the major development in North American gas production for the last five years has been the emergence of shale gas as a major resource. The potential of shale as a source of both oil and gas has been known for a long time, but until the technology was developed to exploit the resource in an economical manner, it was not considered to be a major factor in North America's gas supply. However gas price spikes of the early 2000s and further development of shale gas extraction through the application of hydraulic fracturing, combined with the advances in horizontal drilling and multiple stage well fractures, led to the rapid increase in gas supply.

The shale gas revolution is especially notable both in its vast geographic reach and in the significant amount of gas available. Shale formations underlie some of the historic gas producing zones of the U.S., but some of the largest shale formations are in the northeastern United States, in close proximity to the largest markets for gas and the DELNG Project. ICF estimates that the remaining resource base of North America (here referring to Canada and the U.S.) is just over 4,000 Tcf of economically producible gas using today's technology, of which shale represents over half, or 2,200 Tcf (with over 1,600 Tcf of the shale resources located in the U.S.).[34] Moreover, the largest shale gas basins are in the Northeast (the Marcellus, Huron, and Utica in Appalachia, and the Antrim in Michigan), and represent approximately 986 Tcf of shale gas.

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[34] *See* Ex. B at 3.

Most of this resource base is recoverable with current technology. ICF supply cost curves by major resource type indicate that approximately 1,000 Tcf of gas (about 30 years of consumption) is producible for $4.00 or less per MMBtu, about 1,750 Tcf is producible at $6.00 per MMBtu or less, and about 3,300 Tcf is producible at $14.00 per MMBtu.[35]

ICF's forecast of production is based on this resource base and cost structure, as well as on the outlook for demand. North America currently produces just over 30 Tcf per year from all sources. ICF expects this to grow to almost 45 Tcf per year by 2035, with growth from shale more than replacing declining production from conventional resources.[36]

2. Regional Supply

The DELNG Project is encouraged by the increase in domestic natural gas production in the U.S., and in particular the rapid and sustained growth of gas fields in northeastern Pennsylvania.[37] The production of natural gas in the producing regions in Pennsylvania and West Virginia now exceeds 14 Bcf/d, based on estimates in the EIA's May 2014 DPR,[38] and is expected to reach 20 Bcf/d by the end of 2016. The ICF Report also projects significant regional Marcellus and Utica gas production of 20 Bcf/d by 2015, 30 Bcf/d by 2025, and 34 Bcf/d by 2035.[39] Together, these two shale gas plays account for nearly 80% of incremental production in North America. The gas supply curve for the Marcellus and Utica, corresponding to Appalachia,

[35] *Id.* at 4.

[36] *Id.*

[37] Domestic wellhead natural gas production in 2013 totaled 30.17 Tcf, a 17% increase in five years and the highest in U.S. history. *See* EIA, Natural Gas Gross Withdrawals and Production, *supra* note 12.

[38] *See* EIA, *Drilling Productivity Report*, *supra* note 13.

[39] *See* Ex. B at 6.

shows that approximately 200 Tcf of gas is economically available at $4.00/MMBtu, using present day technology.[40]

Despite the rapid growth of Marcellus production, it is questionable whether this growth can be sustained unless new markets are found for gas production, given the low wellhead gas prices and a constrained gas pipeline delivery system[41]. The EIA noted in a recent *Short Term Energy Outlook* that the

> [r]apid natural gas production growth in the Marcellus formation is contributing to falling natural gas forward prices in the Northeast, which often fall even with or below Henry Hub prices outside of peak winter demand months. Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, where prices are closer to the Henry Hub spot price.[42]

Although productivity gains have led to higher wellhead production rates there has already been a reduction of rig count from 140 rigs in 2012 to about 100 rigs today.[43] The potential decline in Marcellus gas production due to a re-focus by drillers on other liquid-rich gas basins is a concern for consumers in the Northeast, as any reduction in production would likely lead to higher market prices. In order to maintain and grow Marcellus production to meet Northeast demand, and ensure price moderation, the pipeline deliverability system must be expanded. This can only be accomplished if baseload gas consumers, such as the DELNG Project and/or its customers, contractually commit to long-term capacity contracts.

According to Baker Hughes, as of October 10, 2014, there were 320 active gas-directed rigs (*i.e.*, as opposed to oil or liquids-directed rigs), the lowest level in the past 3 years; 81 (25%)

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[40] *See id.* at 4–5.

[41] *See, e.g.*, Bentek Energy, Taming the Beast: Marcellus, Utica & Northeast Gas Exports, http://www.bentekenergy.com/TamingTheBeast.aspx (last visited Aug. 20, 2014).

[42] EIA, *Short-Term Energy Outlook (STEO)*, *supra* note 15.

[43] *See* EIA, *Drilling Productivity Report*, *supra* note 13, at 6.

of the gas-directed rigs were operating in the Marcellus Shale.[44] In 2013, the Pennsylvania Department of Environmental Protection issued 2,966 well permits for unconventional production, down from 3,560 in 2011.[45] Despite a decrease in the Marcellus shale well and rig count, production has continued to increase. As more wells are being drilled per active rig, the time to drill wells has dropped from 23 days to 16 days, horizontal wells are extending farther, and the number of fracking stages has increased, providing more access to the resource. Production per well has continued to increase, but drilling has shifted into more liquids-rich plays that are more profitable. Gas production has continued to grow, but continued depressed wellhead prices could further shift production to liquid-rich fields as opposed to gas fields absent sufficient take-away capacity to firm gas consumers.

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[44] Baker Hughes, *North America Rotary Rig Count (Jan 2000- Current)* (Oct. 10, 2014), http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother (last visited Oct. 10, 2014).

[45] *See* Pa. Dep't of Envtl. Prot., *Dep. Office of Oil and Gas Management Permits Issued Report*, http://www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?/Oil_Gas/Permits_Issued_Detail (last visited Oct. 10, 2014).

3. National Natural Gas Demand

In its *Annual Energy Outlook 2014*[46] Reference Case, EIA predicts the domestic market to grow at only a 0.7% annual rate through 2040, expanding to 28.45 Tcf (87.2 Bcf/d) in 2040 from 23.50 Tcf (70.3 Bcf/d) in 2012 (not including pipeline, lease and plant fuel).[47]

AEO 2014 includes an alternative High Economic Growth Case scenario, which represents a more robust demand outlook if future economic growth exceeds expectations, and is used as an upper bound on potential future growth in domestic natural gas demand. Under the High Economic Growth Case, *AEO 2014* forecasts long-term annual U.S. natural gas demand to grow an average 1.0%, reaching 33.88 Tcf (92.8 Bcf/d) in 2040.[48]

a) Industrial Sector

The *AEO 2014* Reference Case projects U.S. industrial sector demand will grow an average of 0.7% annually to total 8.7 Tcf (23.8 Bcf/d) in 2040 from 7.1 Tcf (19.5 Bcf/d) consumed in 2012.[49]

b) Residential and Commercial Sectors

EIA forecasts a relatively static decline in future residential consumption of natural gas to 4.12 Tcf (11.3 Bcf/d) in 2040 from 4.17 Tcf (11.4 Bcf/d) in 2012 due to efficiency gains and household migration to milder climates.[50]

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[46] EIA, *Annual Energy Outlook 2014* (Apr. 2014), *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf [hereinafter *AEO 2014*].

[47] *See id.* at A-27.

[48] *See* EIA, *AEO 2014*, Natural Gas Supply, Disposition and Prices, High Economic Growth http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=8-AEO2014&table=13-AEO2014&region=0-0&cases=highmacro-d112913a (last visited Aug. 20, 2014).

[49] *See* EIA, *AEO 2014*, *supra* note 47, at A-27.

[50] *See id.*

Commercial sector natural gas use is projected to experience modest annual growth of 0.7% in the *AEO 2014* Reference Case, reaching 3.57 Tcf (9.78 Bcf/d) in 2040 from 2.90 Tcf (7.95 Bcf/d) in 2012.[51]

c) Electricity Sector

Electric power demand for gas is forecast in the *AEO 2014* Reference Case to increase at an average rate of 0.7% per year, expanding to 11.23 Tcf (30.77 Bcf/d) in 2040 from 9.25 Tcf (25.34 Bcf/d) in 2012.[52]

d) Transportation Sector

In 2012, 0.04 Tcf (0.11 Bcf/d) of natural gas was used in the U.S. for motor vehicle, train and ship fuel, or approximately 0.1% of the total U.S. gas market of 23.2 Tcf. EIA in its *AEO 2014* Reference Case forecasts that transportation sector demand will grow 11.3% annually to 0.85 Tcf (2.33 Bcf/d) in 2040.[53]

4. Supply-Demand Balance Demonstrates the Lack of National and Regional Need

Recent trends in the U.S. natural gas market, in particular in the U.S. Northeast, make evident that the request for authorization to export domestic natural gas as LNG from the DELNG Project is consistent with the public interest. U.S. natural gas production has been growing at more than twice the rate of domestic demand growth since 2005. The U.S. gas market has been unable to absorb the rapid increase, particularly in constrained gas production basins, leading to lower well-head prices, and forcing the shut-in of actively-producing wells, creating spare production capacity, non-productive resources, and a redeployment of production resources to unconstrained gas-producing regions and to oil fields.

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51 *See id.*

52 *See id.*

53 *See id.*

a) National Need

The Reference Case and High Economic Growth Case of the *AEO 2014* present a far more robust picture of U.S. natural gas production than domestic natural gas markets need, resulting in significant surplus production of natural gas. Based on these scenarios, discussed above, domestic demand growth for natural gas will average between 0.7% and 0.9% annually with total estimated demand of between 28.45 Tcf and 30.55 Tcf by 2040. However, over this same time period, domestic natural gas production is projected to grow between 1.5% and 1.7% annually, or approximately twice the rate of growth in domestic natural gas demand. Domestic natural gas production will exceed domestic demand by over 25% for both the Reference Case and High Economic Growth Case, or between 7.6 Tcf and 7.9 Tcf (20.9 Bcf/d to 21.7 Bcf/d) by 2040. This significant surplus of deliverable supply well in excess of foreseeable U.S. market needs demonstrates that resources are available for export and would not interfere with the public interest. The DELNG Project gas requirement represents just 1.4% of the projected annual surplus by 2040.

The ICF Report, submitted herewith as Exhibit B, presents a similar production analysis and concludes that North American natural gas reserves are sufficient to support LNG exports. ICF's analysis estimates that North America will increase production to almost 45 Tcf by 2035, with shale gas more than replacing declining production from conventional resources.[54] Of this total, there is an estimated 3,200 Tcf of U.S. remaining reserves producible based on current technology.[55]

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[54] Ex. B at 4.

[55] *Id.* at 3.

b) Regional Need

In the Northeast region, production growth has far outpaced gas consumption, with the region now a net exporter of gas. In 2008, the New England and Mid-Atlantic regions (together, the "Northeast")[56] consumed 3.25 Tcf (8.91 Bcf/d) [57] of natural gas as compared to 1.09 Tcf (2.99 Bcf/d) of production,[58] a net gas deficit of 2.16 Tcf (5.92 Bcf/d). However by 2013, gas supply and demand in the Northeast became balanced, with 3.92 Tcf of production[59] as compared to 3.90 Tcf of natural gas consumption.[60] Most dramatically the *AEO 2014* forecasts rapid growth in Northeast gas production to 8.08 Tcf (22.74 Bcf/d) by 2040, a 3.2% annual rate of increase from 2012 to 2040, as compared to an estimated 4.06 Tcf (11.12 Bcf/d) of consumption in 2040.[61] By 2040 the Northeast region is projected to have a net surplus gas production of 4.02 Tcf (11.01 Bcf/d). The DELNG Project would consume only 2.7% of the surplus regional gas production.

As noted earlier, the ICF Report also confirms the regional gas market surplus production and the lack of market need for additional natural gas resources. The ICF Report notes that its

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56 EIA defines New England and Mid-Atlantic gas production as the Northeast.

57 *See* EIA, *Annual Energy Outlook 2011* ("*AEO 2011*"), Natural Gas Consumption by End-Use Sector and Census Division, Reference Case, http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2011&subject=17-AEO2011&table=77-AEO2011&region=0-0&cases=ref2011-d020911a (last visited Aug. 20, 2014).

58 *See* EIA, *AEO 2011*, Lower 48 Natural Gas Production and Wellhead Prices by Supply Region, Reference Case, http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2011&subject=17-AEO2011&table=72-AEO2011&region=0-0&cases=ref2011-d020911a (last visited Aug. 21, 2014).

59 *See* EIA, *AEO 2014*, Lower 48 Natural Gas Production and Wellhead Prices by Supply Region, Reference Case, http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=17-AEO2014&table=72-AEO2014&region=0-0&cases=ref2014-d102413a (last visited Aug. 21, 2014).

60 *See* EIA, *AEO 2014*, Natural Gas Consumption by End-Use Sector and Census Division, Reference Case, http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=17-AEO2014&table=77-AEO2014&region=0-0&cases=ref2014-d102413a (last visited Aug. 21, 2014).

61 *See id.*; EIA, *AEO 2014*, Lower 48 Natural Gas Production and Wellhead Prices by Supply Region, Reference Case, http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=17-AEO2014&table=72-AEO2014&region=0-0&cases=ref2014-d102413a (last visited Aug. 21, 2014).

estimates of regional Marcellus and Utica gas production of 30 Bcf/d by 2025 and 34 Bcf/d by 2035 will greatly exceed regional gas market requirements.[62]

5. Price Impacts

a) National

Several econometric studies by EIA and other third-party analysts have assessed the potential impact of LNG exports on domestic natural gas markets. As requested by DOE/FE, EIA prepared an analysis ("EIA Export Report"), which estimates that future LNG export levels between 6 Bcf/d and 12 Bcf/d would result in an average increase of 3% to 9% in domestic natural gas prices over a 20-year period.[63]

Several third-party reports have identified several limitations in the EIA Export Report methodology, noting that the large hypothetical price impacts resulting from LNG exports are unlikely to occur. For example, the National Energy Modeling System ("NEMS") utilized by EIA for the simulations presented in the EIA Export Report are not integrated into a global energy model.[64]

Deloitte Marketpoint LLC prepared an alternative analysis ("Deloitte Report") that utilizes a dynamic pricing model to forecast the market impacts of LNG exports.[65] The Deloitte Report projects that the export of 6 Bcf/d from the Gulf Coast region will result in a weighted average citygate price impact of $0.12 per MMBtu from 2016 to 2035, representing a 1.7%

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62 *See* Ex. B at 6.

63 EIA, *Effect of Increased Natural Gas Exports on Domestic Energy Markets, as requested by the Office of Fossil Energy* 15 (Jan. 2012), *available at* http://energy.gov/sites/prod/files/2013/04/f0/fe_eia_lng.pdf.

64 *See id.* at 3.

65 Deloitte Center for Energy Solutions & Deloitte MarketPoint LLC, *Made In America: The Economic Impact of LNG Exports from the United States* (2011), *available at* http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/Energy_us_er/us_er_MadeinAmerica_LNGPaper_122011.pdf.

increase in average consumer prices over that time period.[66] The forecast Henry Hub price impact was higher in the Gulf Coast at $0.22/MMBtu as compared to New York and Illinois where natural gas prices are projected to increase by less than $0.10/MMBtu.[67]

Further the Deloitte Report notes that the North American natural gas market is highly integrated, and that wholesale price impacts would be much lower in downstream markets that are not proximate to the source of LNG exports.[68] This and other studies support the general conclusion within the industry and policy community that the impact on domestic natural gas prices resulting from LNG exports would be small.[69]

b) Regional

DELNG also commissioned a second report by Concentric Energy Advisors ("Concentric"), *Evaluation of the Impact of Downeast LNG on New England Natural Gas Markets* (Aug.t 2014) ("Concentric Report"), submitted herewith as Exhibit C, to provide an overview of the New England natural gas market, to assess the pipeline routes to the DELNG Project, and to provide an assessment of the potential New England natural gas price impact of

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66 *Id*. at 2.

67 *Id.*

68 The Deloitte Report predicts that Henry Hub and Houston Ship Channel gas prices would increase by $0.22/MMBtu and $0.20/MMBtu, respectively, as a result of 6 Bcf/d of LNG exports from the Gulf Coast, while downstream consumers in places such as Illinois, New York, and California would experience price increases of about $0.10/MMbtu or less. *Id*. at 8.

69 *See id.* at 1 ("[T]the magnitude of domestic price increase that results from the export of natural gas in the form of LNG is likely quite small."); *see also* Charles Ebinger, Kevin Massy & Govinda Avasarala, Brookings Institution Energy Security Initiative, *Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas* at 46 (May 2012), *available at* http://www.brookings.edu/~/media/research/files/reports/2012/5/02%20lng%20exports%20ebinger/0502_lng_exports_ebinger.pdf [hereinafter Brookings Report] ("While it is clear that domestic natural gas prices will increase if natural gas is exported, most existing analyses indicate that the implications of this price increase are likely to be modest."); Kenneth B. Medlock, James A. Baker III Institute for Public Policy, Rice University, *U.S. LNG Exports: Truth and Consequence* 33 (Aug. 10, 2012), *available at* http://bakerinstitute.org/files/842/ ("[T]he export of LNG in any reasonable volume from the US should not have a significant impact on price at the margin.").

the proposed DELNG Project.[70]

The Concentric Report, as did the ICF Report, determined that there are three primary potential transportation routes available to the DELNG Project. Further the Concentric Report concluded that the DELNG Project would not exacerbate the existing natural gas price premiums in New England. It stated that "[a]t a minimum, the Facility's impact on existing market circumstances in the region would be neutral, and in fact, could help mitigate the existing pipeline constraints during peak periods."[71]

The Concentric Report further concluded that development of the DELNG Project would not exacerbate the natural gas price premiums in New England. Specifically the Concentric Report noted that:

- All of the gas to be exported from the DELNG Project will be transported using incremental firm pipeline capacity to be contracted by DELNG shippers[72]; thus, gas transported through New England for liquefaction and export at the DELNG Terminal will not reduce the level of unutilized capacity into the region, and therefore will not contribute to the existing price volatility and price spikes.

- Pursuant to FERC's open access provisions for interstate pipelines, shippers on proposed pipelines will not be able to prohibit or exclude other shippers from participating in open seasons for future pipeline capacity additions into New England.

- Shippers are expected to utilize the Facility for export in a baseload manner, meaning that DELNG shippers will likely utilize their firm pipeline capacity at or close to a 100% load factor. As such, there is expected to be little to no unutilized pipeline capacity offered in the secondary market by the DELNG shippers and, therefore, the DELNG Project and any associated shipper transportation contracts should have no impact on the existing market.[73]

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70 Concentric Energy Advisors, *Evaluation of the Impact of Downeast LNG on New England Natural Gas Markets* (Aug. 2014).

71 Ex. C at 2.

72 The one possible exception is the Zone 1 segment of the Iroquois pipeline on the TransCanada Route. It is possible that Iroquois' South-to-North project, which would reverse this pipeline segment, could accommodate 300 million cubic feet per day ("MMcf/d") of DELNG shipper volumes using existing capacity, but incremental capacity may also be required. *See id.* at 21–22.

73 *See id.* at 2–3.

B. Other Public Interest Considerations

1. Promote Long-term Gas Market Stability in New England

The New England gas market has traditionally been dependent upon gas imports from distant producing basins in the U.S. and Canada, and on LNG imports. Demand is highly seasonal and New England is characterized by high winter prices. The discovery and development of the proximate Marcellus and Utica gas fields presents a shift in the gas supply paradigm for New England. With the development of Marcellus production, surplus low-priced gas supply is available that can moderate the traditional high prices experienced in the region. However delivering this gas supply to the region will require the development of new gas pipeline capacity that can only be built if a sufficient number of gas consumers commit to financing the construction costs through long-term capacity contracts. As noted earlier, the DELNG Project and local gas companies represent the most likely customers that can fulfill this requirement under current market structures. The DELNG Project will facilitate the increase of gas supply to the region, which could moderate peak prices and thus promote gas market stability.

2. Benefits to U.S., Maine, and Pennsylvania Economies

The NERA Report[74] commissioned by DOE, assessed the economic impact of LNG exports. "In all of the scenarios analyzed in this study, NERA found that the U.S. would experience net economic benefits from increased LNG exports…. Across [all] scenarios, U.S. economic welfare consistently increases as the volume of natural gas exports increased."[75] Despite the slight potential rise in domestic natural gas prices due to LNG exports, the value of those exports also rises so that there is a net gain for the U.S. economy measured by a broad

[74] *See* NERA Report, *supra* note 17.

[75] *Id.* at 6.

metric of economic welfare or by more common measures such as real household income or real GDP. Although there are costs to consumers of higher energy prices and lower consumption and producers incur higher costs to supply the additional natural gas for export, these costs are more than offset by increases in export revenues along with a wealth transfer from overseas received in the form of payments for liquefaction services.[76]

3. Benefits to Maine Local and Regional Economies

Professor Todd Gabe of the University of Maine completed an economic impact study of a proposed three million-mtpa export project[77]. The purpose of this study was to examine the state and local (*i.e.*, Washington County) economic impacts of the DELNG Project.[78] Economic impact is defined as the output (*i.e.*, revenue), employment and labor income (*e.g.*, wages and salaries) that are directly related to the DELNG Project's spending, as well as the multiplier effects supported by the expenditures made in Maine (and Washington County) by companies and workers that are associated with the DELNG Project. Separate economic impact assessments were conducted for the DELNG Project's temporary construction phase and its permanent operations.

a) Construction Impacts

The economic impact analysis is based on a 3-year construction period, with expenditures evenly split across the three years (*i.e.*, $661 million per year).[79] The construction costs cover a

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76 *Id.* (internal citation omitted).

77 *See* Ex. D.

78 A similar study (*see* Gabe et al., 2005) was conducted in 2005, although the proposed facility at that time was a $400 million LNG import terminal—and not a bi-directional facility with liquefaction equipment.

79 Actual expenditures will differ in each year of construction. This means that the employment and labor income impacts, shown later in the report, will also vary by year; however, the estimated impacts over the entire three-year construction project will be similar to those implied in Exhibit D's Tables 2 and 3.

wide variety of expenditure categories, including—among other things—the berthing facility and tugboats, trestle and pier, the DELNG Terminal, and engineering and management services.

The direct output of $305 million is interpreted as the estimated amount of DELNG Project investment (of the $661 million per year) that would take place in Maine (estimated by the Maine IMPLAN economic model). In-state spending of $305 million is equivalent to 46% of the DELNG Project's annual construction costs. The direct employment of 1,651 full- and part-time jobs, and $118.7 million in labor income are the estimated (by the Maine IMPLAN model) in-state labor market activity that would be supported by the $305 million of construction spending.[80]

Including multiplier effects, the construction of the DELNG Project (based on a total investment of $2.0 billion) would have a statewide annual economic impact—in each of the three years—of an estimated $485 million in output, 3,525 full- and part-time jobs, and $187 million in labor income. These figures indicate that the workers directly and indirectly involved in the construction of the DELNG Project would earn an average of $53,167 in labor income per year.

Including multiplier effects, the three-year statewide economic impacts of the DELNG Project's construction are an estimated $1.5 billion in output, an average of 3,525 full- and part-time jobs, and a three-year total of $562 million in labor income.

b) Operations Impacts

The direct output of $56 million per year is interpreted as the estimated amount of annual operating expenditures that would take place "in and around" the DELNG Project. These expenditures include—among other things—the wages and salaries paid to employees of the facility, vessel services, and contract services and maintenance. This amount of spending would

[80] The IMPLAN model is based on an employment headcount, which does not distinguish between full- and part-time workers.

support, based on figures from the Washington County IMPLAN model, an estimated 185 full- and part-time jobs (including the contract services and maintenance providers) and $16.9 million in labor income, which translates into an estimated $91,420 in labor income per (direct) employee.[81]

The total annual local (*i.e.*, Washington County) economic impact of DELNG Project operations, including multiplier effects, is an estimated $69.6 million in output, 310 full- and part-time jobs, and $20.9 million in labor income. These figures indicate that the workers directly and indirectly involved in the local operations of the DELNG Project would earn an average of $67,564 in labor income per year.

The multiplier effects are the additional output, employment, and labor income that would be supported elsewhere in Maine as a result of the DELNG Project's operations. Results of the analysis indicate that, including multiplier effects, the DELNG Project would have an ongoing annual impact on the Maine economy of an estimated $102 million in output, 505 full- and part-time jobs, and $32.4 million in labor income.

4. Benefits to Marcellus/Pennsylvania Economies

The impacts of Marcellus gas production have been well documented in a series of economic impact studies by Pennsylvania State University. The third in a series of studies estimated natural gas production for the Pennsylvania Marcellus of nearly 7 Bcf per day by 2012 and 12 Bcf/d by 2015.[82] As noted above, current production in 2014 already exceeds this

[81] The direct employment and labor income estimates are also based on figures from: "An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon," prepared by ECONorthwest and filed in FERC Docket Nos. CP09-6-001 and CP09-7-001; and "Application of Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C., for Authorization Under Section 3 of the Natural Gas Act and Application of Southern LNG Company, L.L.C. for Abandonment Under Section 7 of the Natural Gas Act," filed to FERC by Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C. in FERC Docket No. CP14-103-000.

[82] *See* Timothy J. Considein, Robert Watson & Seth Blumsack, Pennsylvania State University, *The Pennsylvania Marcellus Natural Gas Industry: Status, Economic Impacts and Future Potential* iv (July 20, 2011), *available at* http://marcelluscoalition.org/wp-content/uploads/2011/07/Final-2011-PA-Marcellus-Economic-Impacts.pdf.

estimate by 2 Bcf/d.

At production of 12 Bcf/d, according to the study, the Marcellus gas industry would generate $17 billion in value added, $1.6 billion in state and local tax revenues, and support more than 215,000 jobs.[83] In 2020, the projected impacts grow even larger with more than $20 billion in value added, $2 billion in state and local tax revenue, and a Marcellus-supported workforce of 250,000.[84] The DELNG Project will support continued job growth in the Marcellus region.

5. Increased Gas Deliverability Capacity to New England

a) Elimination of Pipeline Constraints

As the Concentric Report highlights, despite the abundance of natural gas in the Northeast, pipeline infrastructure, delivering gas to New England from the Mid-Atlantic is fully contracted and fully utilized most days of the year.[85] In 2013, AGT was unable to provide interruptible capacity on any day during the year due to increased reliance on supplies from the south because of local distribution company ("LDC") load growth, electric generation demand growth, and decreased supplies from Atlantic Canada. Similarly, TGP had restrictions on interruptible service through meter stations near the New England border on most days of 2013.

To date, only two pipeline expansions that would increase capacity into New England have executed contracts and have filed applications with FERC.[86] The first is the Algonquin Incremental Market ("AIM") expansion project, which would provide approximately 342 MMcf/d of additional capacity on the existing AGT system between Ramapo, New York and

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83 *See id.*

84 *See id.*

85 *See* Ex. C at 12.

86 Most recently, on September 15, 2014, TGP filed in FERC Docket No. PF14-22-000 a request to use FERC's NEPA pre-filing process for its proposed Northeast Energy Direct Project, which is designed to provide up to 2.2 Bcf/d of additional natural gas transmission capacity to meet the growing energy needs in the Northeast, particularly New England.

Mendon, Massachusetts starting in November 2016. AGT filed an application with FERC in Docket Nos. CP14-96-000 and PF13-16-000 on February 28, 2014, seeking NGA Section 7(c) authorization to construct and operate the AIM expansion project. In addition, TGP filed an application with FERC in Docket No. CP14-529-000 on July 31, 2014, seeking NGA Section 7(c) authorization to construct and operate the fully-subscribed Connecticut Expansion Project, which would provide approximately 72 MMcf/d of additional capacity to serve Connecticut LDC growth starting in November 2016. Most recently, Spectra and Northeast Utilities announced the Access Northeast Project designed to provide up to 1 Bcf/d of additional natural gas transmission capacity on the AGT system by 2018.

The Concentric Report notes that incremental pipeline capacity needed to serve the growth associated with natural gas demand for electric generation has not yet been addressed, since most electric generators rely on interruptible or secondary capacity on the pipelines to obtain their natural gas supplies. The shortage of pipeline capacity has become critical in recent winters, "since existing electric market rules fail to provide incentives for gas-fired generation to contract for firm pipeline capacity, and pipelines are unwilling to build additional pipeline infrastructure without long-term firm contracts."[87]

As existing pipelines are fully utilized, and there is no immediate solution to increase incremental pipeline capacity, additional pipeline expansions will be necessary to serve incremental natural gas demand growth in New England, and to serve the DELNG Project.

b) Role of DELNG Project in Increasing Pipeline Capacity

Concentric concludes that the DELNG Project will help support the development of new pipeline capacity to the New England region. This could be accomplished in multiple ways. A

[87] *See* Ex. C at 15.

DELNG Project shipper participating in new pipeline expansion projects could serve as a large, anchor shipper, and thus create opportunities for participants with smaller incremental capacity requirements to participate in a pipeline expansion project that otherwise might not be constructed due to a lack of sufficient support. Additionally, DELNG Project shipper participation in a pipeline expansion could also reduce the cost of that infrastructure for all participants by providing economies of scale that might not otherwise be achieved with the existing shipper base.

6. International Considerations

U.S. international trade law, general U.S. trade policy and DOE's longstanding policy that the public interest is best served by the principles of free trade all strongly support exportation of domestic natural gas as LNG. Exportation of LNG will positively impact the U.S. balance of trade, diversify global supply, and contribute to the security interests of the U.S. and its allies. Furthermore, the exportation of LNG will advance initiatives underway by the current Administration to promote investment in energy infrastructure in neighboring Caribbean and Central/South America nations. Finally, it also would be inconsistent with U.S. obligations under the World Trade Organization ("WTO") Agreements to restrict in any manner exports of domestically produced LNG to other WTO Countries.[88]

a) Balance of Payments

Exports of LNG from the DELNG Project will have a beneficial impact for the U.S. on its balance of payments with the rest of the world by reducing the overall U.S. trade deficit. According to the U.S. Department of Commerce, Bureau of Economic Analysis, in 2012 the net annual U.S. trade deficit totaled $535 billion, of which more than half was attributable to a

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[88] *See Marrakesh Protocol to the General Agreement on Tariffs and Trade 1994*, Schedule XX – United States of America, Part I, Section II, 54 at HTS 2711.11.00 "Liquefied Natural Gas."

negative balance in crude oil.[89] A recent paper by the Manhattan Institute noted that expansion of the domestic production of hydrocarbons will not only reduce imports, but also increase exports and function as an enormous subsidy-free stimulus to the U.S. economy, thereby stimulating job growth and reducing the current account deficit.[90] The DELNG Project through the export of LNG could reduce the total future trade deficit by $1 billion annually.[91]

b) Geopolitical Benefits

The export of domestically produced natural gas as LNG will support and promote U.S. national security interests and security interests of U.S. allies through the diversification of global natural gas supplies. This diversification is particularly important in markets reliant upon limited natural gas supply sources such as in Eastern Europe. DOE/FE recognized these geopolitical benefits when authorizing LNG exports from the Sabine Pass LNG Terminal:

> First, the export of natural gas produced in the United States will help to promote new international markets for natural gas, thereby encouraging the development of additional productive resources in this country … and internationally. Second, augmentation of global natural gas supplies will support efforts by overseas electric power generators to switch away from oil or coal, both more carbon intensive and environmentally damaging than natural gas. Third, an improvement in natural gas supplies internationally will help certain countries that currently have limited sources of natural gas supplies to broaden and diversify their supply base. This will contribute to greater overall transparency, efficiency, and liquidity of international natural gas markets, encouraging a liberalized global natural gas trade and a greater diversification of global natural gas supplies. Fourth, these developments may encourage the decoupling of international natural gas prices from oil prices in some international natural gas markets and may exert downward pressure on natural gas market prices in relation to oil prices in those markets.[92]

Many of the geopolitical benefits recognized by DOE/FE have been further endorsed by

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[89] *See* U.S. Bureau of Economic Analysis, *U.S. International Trade in Goods and Services: Annual Revision for 2012* 1, 43 (June 8, 2012), *available at* http://www.bea.gov/newsreleases/international/trade/2013/pdf/trad1313.pdf.

[90] *See generally* Mark P. Mills, Manhattan Institute, *The Case for Exports: America's Hydrocarbon Industry Can Revive the Economy and Eliminate the Trade Deficit* (May 2013), *available at* http://www.manhattan-institute.org/pdf/pgi_03.pdf.

[91] This calculation is based on exports of 300 Mmcf/d priced at $9 per thousand cubic feet.

[92] May 2011 Sabine Pass Conditional Non-FTA Order, *supra* note 26, at 37.

other energy experts and policymakers, such as the Brookings Institution, which notes a large increase in U.S. LNG exports would have the potential to increase U.S. foreign policy interests in both the Atlantic and Pacific basins.[93] The issue is particularly apparent in what is defined as "pipeline politics," wherein Russian exports to Europe comprise over 30% of total supply, and as much as 90% for some countries. The risk of this high reliance on Russian gas is readily apparent given the recent gas price increases imposed on the government of Ukraine, and the escalating gas debt. The recent actions by Russia in the Crimea have prompted the U.S. to develop a strategy to move aggressively to deploy the advantages of U.S. natural gas and technology to undercut Russian natural gas sales to Ukraine and Europe. Carlos Pascual, former head of the U.S. State Department's Bureau of Energy Resources, recently stated that "[i]n the coming years, Gazprom's influence will be further weakened as American [LNG] supplies are shipped onto the global market …."

DELNG respectfully requests that DOE/FE consider the geopolitical implications of LNG exports in a context of rising domestic U.S. gas production and the benefit of LNG exports to U.S. allies.

c) Economic Trade and Ties with Neighboring Countries

The U.S. has promoted increased economic trade with global allies and neighboring countries that meet the U.S national interest. The export of LNG from the DELNG Project would support these economic interests, and support initiatives that are currently being pursued by the Administration to expand international trade and economic development. Specifically, the President is promoting expanded investment in energy infrastructure in the Caribbean and South

[93] *See* Brookings Report, *supra* note 70, at 46–47.

American nations through the Energy and Climate Partnership of the Americas ("ECPA").[94] The promotion of LNG use in the Caribbean and Latin America will support these policy goals. Currently both the World Bank and Inter-American Development Bank are taking initiatives to promote LNG development in the region, which is dependent upon North American sourced LNG. The DELNG Project provides additional international trade opportunities that are consistent with these policies and initiatives.

X. ENVIRONMENTAL IMPACT

On May 15, 2014, DELNG received from FERC its Final Environmental Impact Statement for the originally proposed regasification project.[95] The DELNG Import FEIS concludes that the project minimizes impacts to the environment if constructed as proposed and in compliance with the conditions as set forth in the FEIS.

The potential environmental impacts associated with the newly proposed DELNG Project will be reviewed and evaluated by FERC in accordance to NEPA regulations. DELNG anticipates that DOE/FE will serve as a cooperating agency in FERC's environmental review process for the DELNG Project. DELNG has received approval from FERC to initiate the NEPA pre-filing review process for the DELNG Project.[96] In approving the pre-filing request for the DELNG Project, FERC stated that it would prepare a NEPA document to "supplement"

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94 ECPA is a set of voluntary initiatives that promote energy efficiency, renewable energy, cleaner fossil fuels, and modernized energy infrastructure. President Obama endorsed the goals of the ECPA in his address to the Summit of the Americas in April 2009, and invited countries of the Western Hemisphere to join the partnership. *See* Press Release, The White House, The United States and the 2009 Summit of the Americas: Securing Our Citizens' Future (Apr. 19, 2009), *available at* http://www.whitehouse.gov/the_press_office/The-United-States-and-the-2009-Summit-of-the-Americas-Securing-Our-Citizens-Future/.

95 *See* DELNG Import FEIS, *supra* note 5.

96 Letter of Approval of Pre-Filing Request for the Downeast LNG Import-Export Project, *Downeast Liquefaction, LLC, Downeast LNG, Inc. & Downeast Pipeline, LLC*, FERC Docket No. PF14-19-000 (Aug. 11, 2014).

the DELNG Import FEIS.[97] This month, FERC published a Notice of Intent to prepare an environmental impact statement for the DELNG Project that will supplement FERC's prior NEPA review.[98]

On August 15, 2014, DOE/FE published a Federal Register notice announcing its adoption of revised procedures whereby it will act on applications to export LNG to non-FTA countries only after NEPA review has been completed, thereby suspending its practice of issuing conditional decisions prior to final authorization decisions.[99] Contemporaneously, DOE/FE issued its *Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States*, which noted that, despite the inclusion of potential environmental impacts in the DOE non-FTA export analysis, "[f]undamental uncertainties constrain the ability to predict what, if any, domestic natural gas production would be induced by granting any specific authorization or authorizations to export LNG to non-FTA countries."[100] Furthermore, DOE also noted that the "current rapid development of unconventional natural gas resources will likely continue, with or without the export of natural gas." [101] Lastly, the report stated, "by preparingthis discussion of natural gas production activities, DOE is going beyond what NEPA requires."[102] DOE further recognized that it

> cannot meaningfully analyze the specific environmental impacts of such production, which are nearly all local or regional in nature. Nor can DOE meaningfully consider alternatives or mitigation measures as they relate to natural gas production, given that

97 *Id.* at 1–2.

98 Notice of Intent to Prepare an Environmental Impact Statement for the Planned Downeast LNG Import-Export Project, Request for Comments on Environmental Issues, and Notice of Public Scoping Meeting, *Downeast Liquefaction, LLC,* FERC Docket No. PF14-19-000 (Oct. 3, 2014).

99 79 Fed. Reg. 48,132 (Aug. 15, 2014).

100 DOE, *Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States* 1 (Aug. 2014), *available at* http://energy.gov/sites/prod/files/2014/08/f18/Addendum.pdf.

101 *Id.* at 2.

102 *Id.*

> DOE's regulatory jurisdiction extends only to the act of exportation. As DOE explained in *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961-A (Aug. 7, 2012), lacking an understanding of where and when additional gas production will arise, the environmental impacts resulting from production activity induced by LNG exports to non-FTA countries are not "reasonably foreseeable" within the meaning of the Council on Environmental Quality's (CEQ) NEPA regulations (40 CFR § 1508.7).[103]

XI. RELATED AUTHORIZATIONS

The siting, construction and operation of the DELNG Project is subject to approval by FERC pursuant to Section 3 of the NGA. As discussed above, DELNG has initiated the preparation of an application to FERC for such authorization.

XII. EXHIBITS

The following exhibits are attached hereto and incorporated by reference herein:

Exhibit A: Opinion of Counsel;

Exhibit B: ICF International, *North American Natural Gas Supply Assessment Supporting the Downeast LNG Export Project* (July 2014);

Exhibit C: Concentric Energy Advisors, *Evaluation of the Impact of Downeast LNG on New England Natural Gas Markets* (Aug. 2014);

Exhibit D: Todd Gabe, *Economic Impact of Proposed Downeast LNG Terminal: State and Local Economic Impacts of a Proposed Bi-directional LNG Terminal in Washington County, Maine* (Aug. 2014).

XIII. CONCLUSION

For the foregoing reasons, DELNG respectfully requests that DOE/FE grant DELNG's request for long-term, multi-contract authorization to engage in exports of domestically-produced LNG in an amount up to 173 million MMBtu per year, which is equivalent to

[103] *Id.*

approximately 168 Bcf per year of natural gas, from the DELNG Terminal to countries that (i) do not have an FTA requiring the national treatment for trade in natural gas and LNG, (ii) which have, or in the future develop, the capacity to import LNG, and (iii) with which trade is not prohibited by U.S. law or policy, for a 20-year term commencing the earlier of the date of first export or eight years from the date of the issuance of such authorization. DELNG respectfully requests that DOE/FE grant such authorization on an expedited basis as soon as this Application becomes ready for final action upon completion of DOE's NEPA review process.

Respectfully submitted,

Dean P. Girdis, CEO and President
Downeast LNG, Inc.
6431 Barnaby Street, NW
Washington, D.C. 20015
Telephone: (202) 249-9035
Facsimile: (202) 249-9035
Email: dgirdis@downeastlng.com

Dated: October 15, 2014

VERIFICATION

State of Maryland)
County of Prince George's)

BEFORE ME, the undersigned authority, on this day personally appeared Dean P. Girdis, who, having been by me first duly sworn, on oath says that he is the Chief Executive Officer and President for Downeast LNG, Inc., and is duly authorized to make this Verification; that he has read the foregoing instrument; and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

Dean P Girdis

Dean P. Girdis

SWORN TO AND SUBSCRIBED before me on the 15 day of October, 2014.

Name: Brenda N CruzRamirez

Title: Notary Public

My Commission expires: 10/25/2015

Citibank, NA-Chevy Chase
5700 Connecticut Ave NW
Washington, DC 20015

BRENDA N. CRUZ-RAMIREZ
Notary Public
Prince George's County
Maryland
My Commission Expires Oct 25, 2015

EXHIBIT A

THOMPSON & KNIGHT LLP

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PARIS

October 15, 2014

Office of Fuel Programs, Fossil Energy
U.S. Department of Energy
Docket Room 3F-056, FE-50
Forrestal Building
1000 Independence Ave., SW
Washington, D.C. 20585

Re: **In the Matter of Downeast LNG, Inc.**
FE Docket No. 14-___-LNG
Application of Downeast LNG, Inc. for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Countries
Opinion of Counsel

Ladies and Gentlemen:

We have acted as special counsel for Downeast LNG, Inc., a Delaware corporation (the "Company"), in connection with its formation, initial organization and certain corporate matters. The Company is applying to the Office of Fuel Programs, Fossil Energy of the U.S. Department of Energy (the "Department") pursuant to Section 590.202(c) of the Department's regulations, 10 C.F.R. § 590.202(c) (2014). This opinion letter is furnished to you solely for purposes of complying with Section 590.202(c) of the Department's regulations. We have not advised the Company with respect to the Company's application to the Department.

In connection with this opinion letter, we have examined originals or copies of the certificate of incorporation, bylaws, certificates of public officials and of officers of the Company and such other records of the Company as we have deemed necessary as a basis for the opinions expressed below.

In rendering the opinions expressed below, we have assumed:

(i) The genuineness of all signatures.

(ii) The authenticity of the originals of the documents and records submitted to us.

(iii) The conformity to authentic originals of any documents and records submitted to us as copies.

(iv) As to matters of fact, the truthfulness of the representations and statements contained in such documents and records and those made in certificates of public officials and officers.

We have not independently established the validity of the foregoing assumptions.

Based upon the foregoing, and subject to the qualifications and limitations herein set forth, we are of the opinion that:

1. The Company has the corporate power to export liquefied natural gas and to engage in foreign commerce.

2. Based solely on certificates of public officials, the Company is authorized to do business in Maine.

The opinions set forth above are subject to the following qualifications and exceptions:

(a) Our opinions are limited to (i) Applicable Laws and (ii) in the case of our opinion in paragraph 2, to the limited extent set forth therein, the law of the state referred to in paragraph 2, and we do not express any opinion herein concerning any other laws. "Applicable Laws" means those laws, rules and regulations of the State of Texas and the federal laws, rules and regulations of the United States of America, that in our experience are normally applicable to the Company and, for purposes of our opinion in paragraph 1 above, include the General Corporations Law of the State of Delaware. However, the term "Applicable Laws" does not include:

(i) Any state or federal laws, rules or regulations relating to: (A) pollution or protection of the environment; (B) zoning, land use, building or construction; (C) occupational safety and health or other similar matters; (D) labor or employee rights or benefits, including without limitation the Employee Retirement Income Security Act of 1974, as amended, and the Fair Labor Standards Act, as amended; (E) the regulation of utilities; (F) antitrust and trade regulation; (G) tax; (H) securities, including without limitation federal and state securities laws, rules or regulations and the Investment Company Act of 1940, as amended; (I) corrupt practices, including without limitation the Foreign Corrupt Practices Act of 1977, as amended, and the Currency and Foreign Transactions Reporting Act of 1970, as amended; (J) insurance; (K) the Dodd-Frank Wall Street Reform and Consumer Protection Act; and (L) copyrights, patents, service marks and trademarks.

(ii) Any laws, rules or regulations of any county, municipality or similar political subdivision or any agency or instrumentality thereof.

(iii) The laws of the State of Delaware except to the extent based on our review of the General Corporations Law of the State of Delaware, without consideration of any judicial or administrative interpretations thereof.

(b) Our opinions are subject to (i) bankruptcy, insolvency, fraudulent transfer, reorganization, receivership, moratorium or similar laws affecting the rights and remedies of creditors generally and (ii) possible judicial action giving effect to governmental actions or foreign laws affecting creditors' rights.

(c) When used in this opinion, the words "our knowledge" or "known to us" signify that, in the course of our representation of the Company as described in the introductory paragraph of this letter, no information with respect to statements in such opinion has come to the actual, conscious attention of any of our attorneys who have been directly involved in representing the Company that would lead such attorney to conclude that such statements are untrue. We have not made any examination of our files or the files of the Company, any investigation of court or other public records, any inquiry with any other person or a general canvass of our attorneys, to determine the existence or absence of such facts.

This opinion letter is rendered to you in connection in connection with the Company's application to the Department. This opinion letter may not be relied upon by any person other than you or by you for any other purpose, without our prior written consent.

This opinion letter has been prepared, and is to be understood, in accordance with customary practice of lawyers who regularly give and lawyers who regularly advise recipients regarding opinions of this kind. This opinion letter is limited to the matters expressly stated herein and is provided solely for purposes of complying with Section 590.202(c) of the Department's regulations, and no opinions may be inferred or implied beyond the matters expressly stated herein. The opinions expressed herein are rendered and speak only as of the date hereof and we specifically disclaim any responsibility to update such opinions subsequent to the date hereof or to advise you of subsequent developments affecting such opinions.

Respectfully submitted,

Thompson + Knight LLP / AMC

AMC/cjr

ARC

519928 000002 11175651.1

EXHIBIT B

North American Natural Gas Supply Assessment Supporting the Downeast LNG Export Project

Prepared for

Downeast LNG

Prepared by

ICF International

9300 Lee Highway
Fairfax, VA 22031

1331 Lamar, Suite 660
Houston, TX 77010

1. Introduction

Downeast LNG engaged ICF International (ICF) to assess the sources of natural gas supply and adequacy of natural gas resources for a proposed LNG export facility located at Mill Cove in Robbinston, Maine, on Passamaquoddy Bay. The project will require up to 300,000 dekatherms per day (Dth/d) of natural gas, with the supply accessed at the major trading points in the Northeast U.S. and eastern Canada. The export project is expected to begin operations in 2019 with an export capability of approximately 2 MTPA.

The foundation for this analysis is ICF's North American Gas Market Model (GMM©) Base Case, vintage April 15, 2014.[1] Below we present the results of our base case and the implications of this outlook for Downeast LNG gas supply. In the following sections, we present an overview of the North American gas resource base and supply outlook, including ICF's estimate of gas supply cost curves. Next we provide ICF's outlook for gas demand and gas demand. This is followed by the gas price forecast, including gas prices for New England, Dawn, Ontario, and Henry Hub. We also review the development of the Eastern U.S. and New England regional gas pipeline networks to support increased gas supply deliveries to the Downeast LNG facility.

ICF's analysis and deep experience in the North American and regional natural gas markets, supports our finding that the North American gas resource base to support Downeast is robust and that LNG exports at Downeast LNG will not contribute to significant regional price increases, and indeed may lower prices in the region. In particular:

- North American gas resources are substantial and geographically broad based, with shale resources accounting for over half of the remaining economically recoverable gas at today's technology. More than 30 US states are estimated to hold non-conventional gas reserves. This reserve base is sufficiently large and geographically accessible to support Downeast LNG exports.
- Downeast LNG off-takers will have options to secure pipeline capacity on existing and proposed pipelines that provide access to multiple gas producing sources serving the Northeastern U.S. and Canada. These sources include Western Canadian, Gulf Coast, Rocky Mountain and Appalachian basins. ICF projections for North American gas production growth support our finding that Downeast LNG exports will have a minimal effect on gas supply available for U.S. domestic markets, or on gas prices.
- New pipeline capacity is being planned to provide Northeast U.S. and eastern Canadian buyers with access to growing production, particularly from Appalachia. Spectra, Kinder Morgan, and Portland Natural Gas Transmission System are among a group of pipeline operators proposing expansions into New England to meet demand growth in the power sector as well for residential and commercial uses. These pipelines can support incremental volume deliveries to supply Downeast LNG exports.

[1] A description of GMM© is provided in Appendix 1. The assumptions used for the 2nd Quarter 2014 Base Case are in Appendix 2.

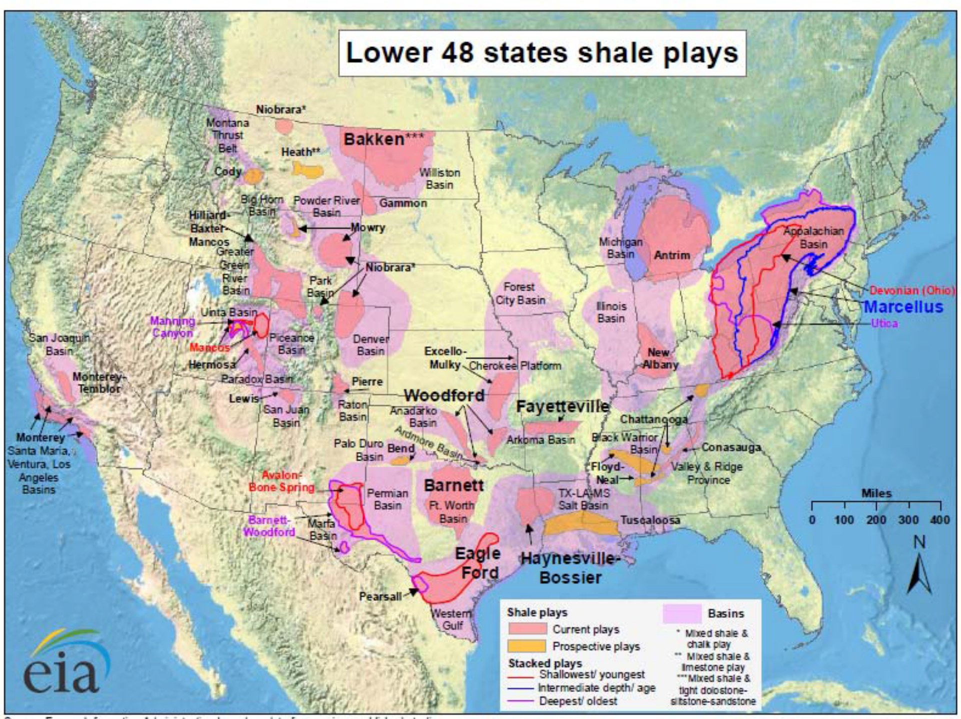
- Downeast LNG off-taker commitments to utilize existing regional pipeline capacity and contract for incremental pipeline capacity as required will support the efficient utilization of New England's gas pipeline grid, and help mitigate the impact of gas demand growth on regional gas prices. ICF analysis projects that New England basis premiums to overall North America gas prices will narrow as new supply sources are introduced into the region.

2. North American Natural Gas Resource Base and Gas Supply Outlook

The emergence of shale gas has driven significant increases in North American gas production over the last five years. While developers have long recognized shale's potential for both oil and gas, they lacked the technology to exploit the resource economically, limiting its role in North America's gas supply. Dramatic increases in gas prices in the early 2000s demonstrated a shortfall in supply, a gap that has been filled by the technology of hydraulic fracturing of shale rock, combined with advances in horizontal drilling.

The shale gas revolution has been accelerated by two significant factors. First, as shown in Exhibit 1, shale resources are geographically distributed Relevant to Downeast LNG, some of the largest shale formations are in the Northeastern U.S. and are accessible to market buyers through a well-developed U.S. and Canadian gas pipeline network.

Exhibit 1. Lower 48 States Shale Basins



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Second, the shale resource base is very large. ICF estimates that U.S. and Canadian resource base is comprised of slightly over 4,000 Tcf of recoverable and economically producible gas, using today's technology. Just over half of this, or 2,200 Tcf, is from shale (see Exhibit 2.) Within the U.S.U.S. alone, there are about 3,200 Tcf of remaining reserves producible with current technology, 1,650 Tcf of which is from shale. While the largest basin of shale gas is in the Northeast, the Marcellus, Huron, and Utica in Appalachia, and the Antrim in Michigan, have about 1,100 Tcf of resource remaining, of which 986 Tcf are in shale. Other large concentrations of resources and shales are along the Gulf Coast and in the Western Canadian Sedimentary Basin (WCSB), mostly Alberta.[2] The Gulf Coast, onshore and offshore, has over 1,000 Tcf in recoverable reserves while the WCSB has over 500 Tcf. Downeast LNG buyers will have access to all of these basins via the pipeline network serving New England and the Northeast.

Exhibit 2. U.S. and Canada Natural Gas Resource Base[1]

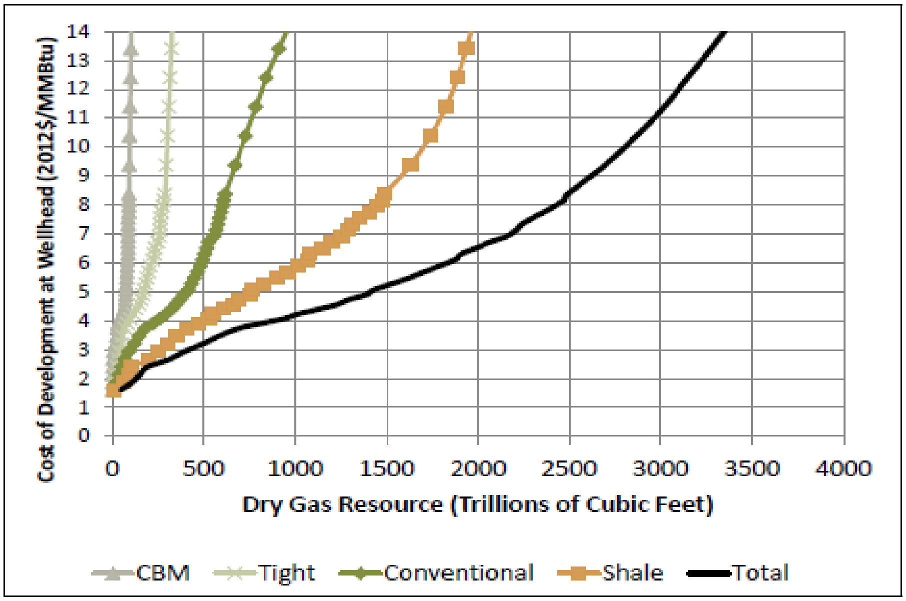
	Proven Reserves	Unproved Plus Discovered Undeveloped	Total Remaining Resource	Shale Resource[2]
Alaska	9.4	153.6	163.0	0.0
West Coast Onshore	2.9	24.6	27.5	0.3
Rockies & Great Basin	81.8	388.3	470.1	37.9
West Texas	20.4	47.7	68.1	17.5
Gulf Coast Onshore	97.6	684.7	782.3	476.9
Mid-continent	65.3	205.0	270.3	133.9
Eastern Interior [3,4]	45.2	1,053.7	1,098.9	986.1
Gulf of Mexico	10.7	238.6	249.3	0.0
U.S. Atlantic Offshore	0.0	32.8	32.8	0.0
U.S. Pacific Offshore	0.8	31.7	32.5	0.0
WCSB	68.8	664.0	732.8	508.8
Arctic Canada	0.0	45.0	45.0	0.0
Eastern Canada Onshore	0.8	15.9	16.7	10.3
Eastern Canada Offshore	0.3	71.8	72.1	0.0
Western British Columbia	0.5	10.9	11.4	0.0
US Total	**334.1**	**2,860.6**	**3,194.7**	**1,652.5**
Canada Total	**70.4**	**807.6**	**878.0**	**519.1**
US and Canada Total	**404.5**	**3,668.1**	**4,072.6**	**2,171.6**

1. ICF updated its gas resource assessment in December 2011; while these regional totals may not fully reflect the current assessment, the U.S./Canada economically recoverable resource is similar.
2. Shale Resource is a subset of Total Remaining Resource
3. Eastern Interior includes Marcellus, Huron, Utica, and Antrim shale.
4. Reference case assumes drilling levels are constant at today's level over time, reflecting restricted access to the full resource development.

[2] While we differentiate U.S. and Canadian resources, the markets are highly integrated and supply moves freely across the border in response to demand in both countries. Gas prices reflect the entire U.S.-Canadian gas market balance.

Exhibit 3 shows ICF's estimated cost of supply curves by major resource type: conventional, shale, coal bed methane (CBM), and tight.[3] It shows that approximately 1,000 Tcf of gas (equivalent to about 30 years at current domestic consumption rates) is producible for $4.00 or less per MMBtu (2012$) and about 1,750 Tcf is producible at $6.00 per MMBtu or less. Looking at the total resource base, about 3,300 Tcf are producible at $14.00 per MMBtu or less (the current approximate price for LNG in Japan). These estimates are based on current technology, and do not reflect expectations for technology improvements that will increase supply and lower costs.

Exhibit 3. North American Resource Cost Curves

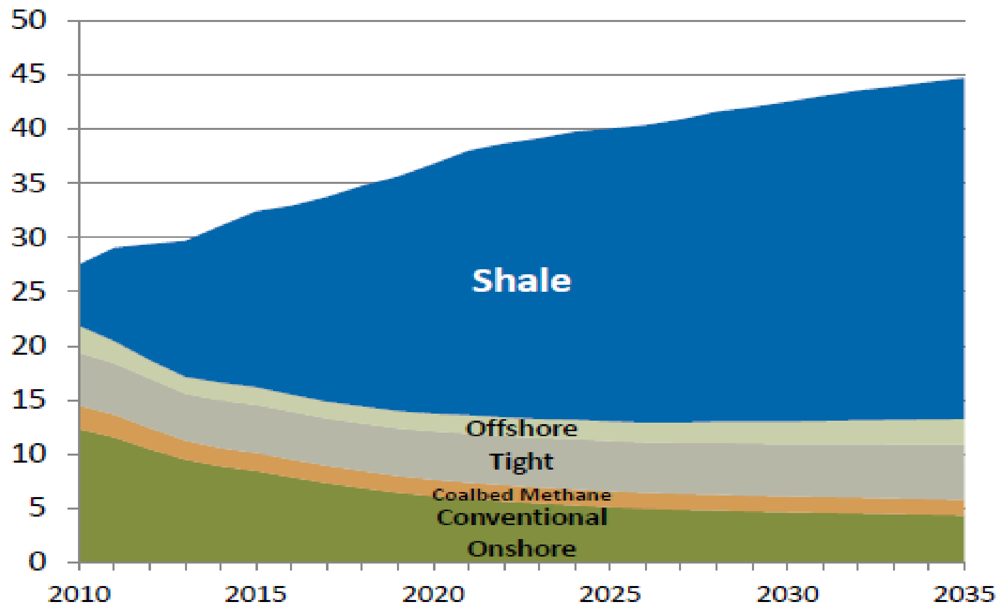


Source: ICF

Exhibit 4 shows ICF's forecast of production based on this resource base, and cost structure, and the outlook for demand. North America currently produces just over 30 Tcf per year from all sources. ICF expects this to grow to almost 45 Tcf by 2035 with all of the growth coming from shale, replacing declining production from conventional resources. Conventional production falls from 8.9 Tcf in 2014 to 4.3 Tcf in 2035. CBM will see a slight decline while tight gas will increase by about 17 percent. Offshore production will increase as well between 2013 and 2035.

[3] Tight gas refers to gas in very hard low permeability rock, usually sandstone, that requires hydraulic fracturing to develop. CBM is gas entrained in deep underground coal seams. Tight, CBM, and shale are unconventional; conventional gas requires no special actions to produce once the well is completed.

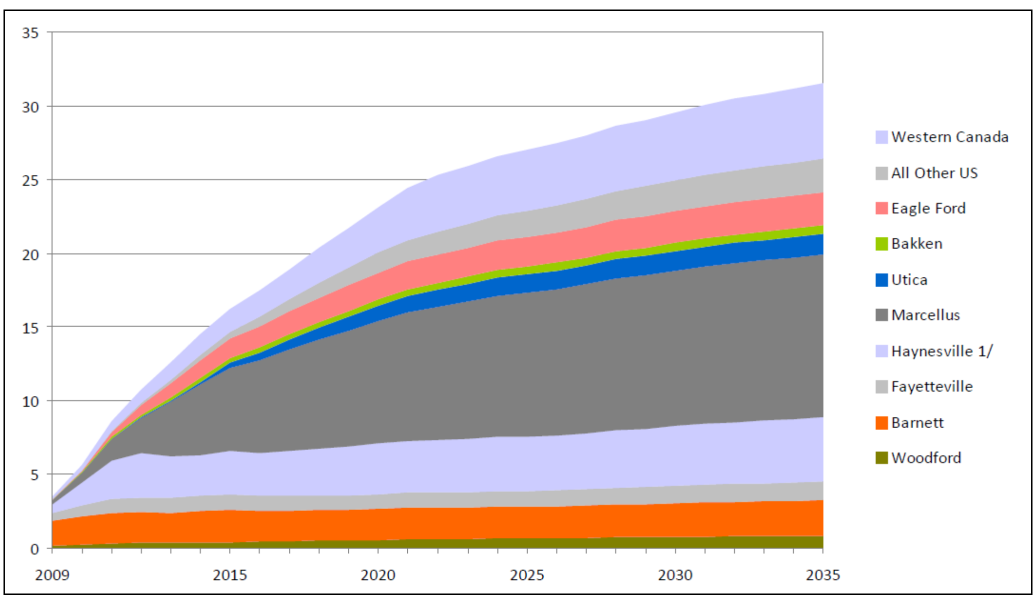
Exhibit 4. U.S. and Canada Gas Production (Tcf)



Source: ICF 2Q 2014 Base Case

Exhibit 5 shows that total U.S. and Canada shale gas production is projected to increase from 14.5 Tcf in 2014 to over 31 Tcf in 2035. The Marcellus Shale accounts for roughly 40 percent of the 17 Tcf of incremental production growth from shale formations. Major growth is also expected in Western Canadian shale plays (Montney, Horn River, and Cordova & Liard) which grows to 5 Tcf from their current production level around 1.4 Tcf.

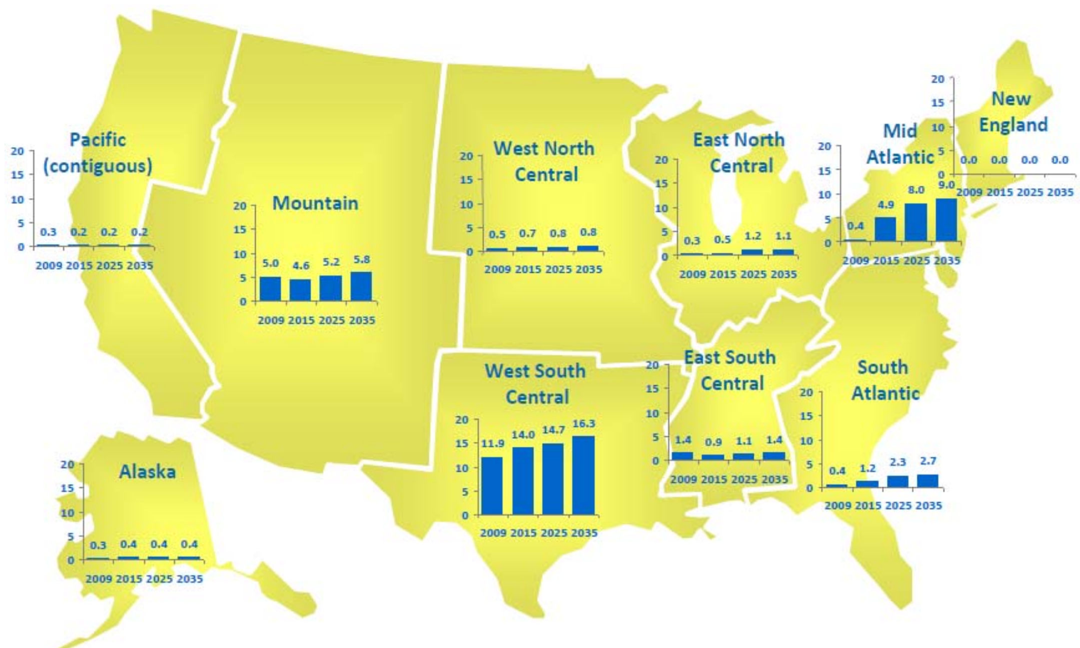
Exhibit 5. U.S. and Canada Shale Gas Production (Tcf/year)



Source: ICF 2Q 2014 Base Case

ICF projects increasing gas production in all U.S. producing regions in the as shown in Exhibit 6. Significant production growth is forecast for the Marcellus and Utica Shales (Mid-Atlantic in the map below), with annual production reaching 8 Tcf in 2025 and 9 Tcf by the end of our forecast in 2035. We also forecast Gulf Coast production increases as shale output replaces and far exceeds that from conventional sources.

Exhibit 6. Production by Region (Tcf)



ICF's outlook for WCSB production grows from about 5.4 Tcf in 2010 to 6.1 Tcf by 2025 and 6.7 Tcf by 2035. These increases are distinct from the sharp growth projected from BC Shale reserves, as noted above.

In summary, ICF believes that the North American production outlook is robust and can be produced at prices that are consistent with supporting both domestic U.S. and Canadian demand as reviewed below, as well as LNG exports to international markets via Downeast LNG and other potential LNG terminals.

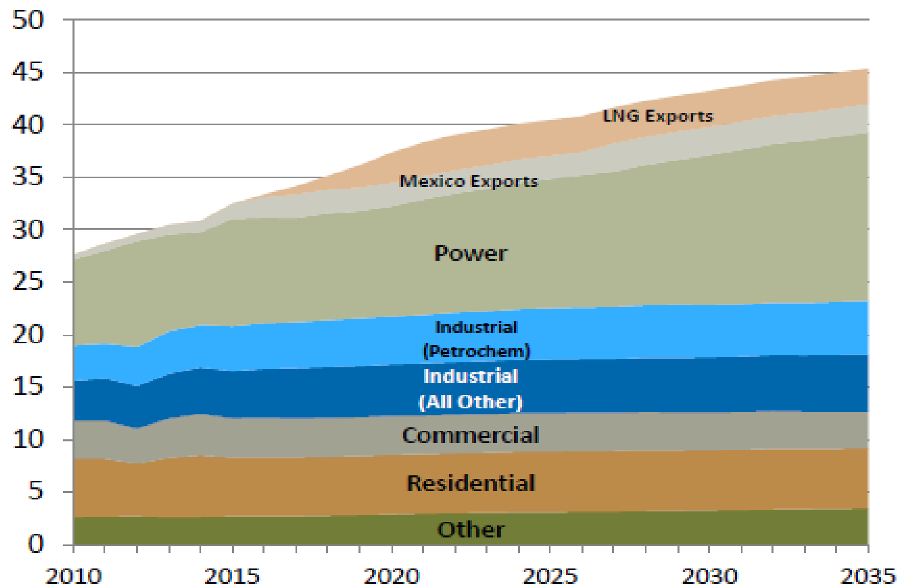
3. North American Natural Gas Demand Outlook

ICF's U.S. gas demand outlook is presented in Exhibit 7. By 2035, U.S. consumption is projected to increase by nearly 10 Tcf, an average growth rate of about 1.3% per year. Over 70% of the consumption growth comes from the power sector, which grows to nearly 16 Tcf based on expectations that gas prices will remain low both in absolute terms and relative to coal. In addition, new environmental regulations will add to coal generation costs and lead to the retirement of many older coal units. In the more distant future, gas will replace nuclear power plants whose licenses will begin to expire after 2025.

ICF projects strong industrial gas demand for petrochemical feedstock as well as for manufacturing. LNG exports are also expected to increase, with most exports originating in the Gulf Coast. ICF's review of LNG export terminal development may prompt upward revisions to LNG exports projections in future Base Case updates. Such revisions may include LNG exports from all major North American coastlines.

Mexico represents an emerging source of demand growth for U.S. production, where a liberalizing market and new gas-fired electric generation plants may require more Bcf/d by 2025. New pipeline development in Mexico and interconnections with existing and expanded U.S. pipelines are underway.

Exhibit 7. U.S. Gas Demand Outlook (Tcf)

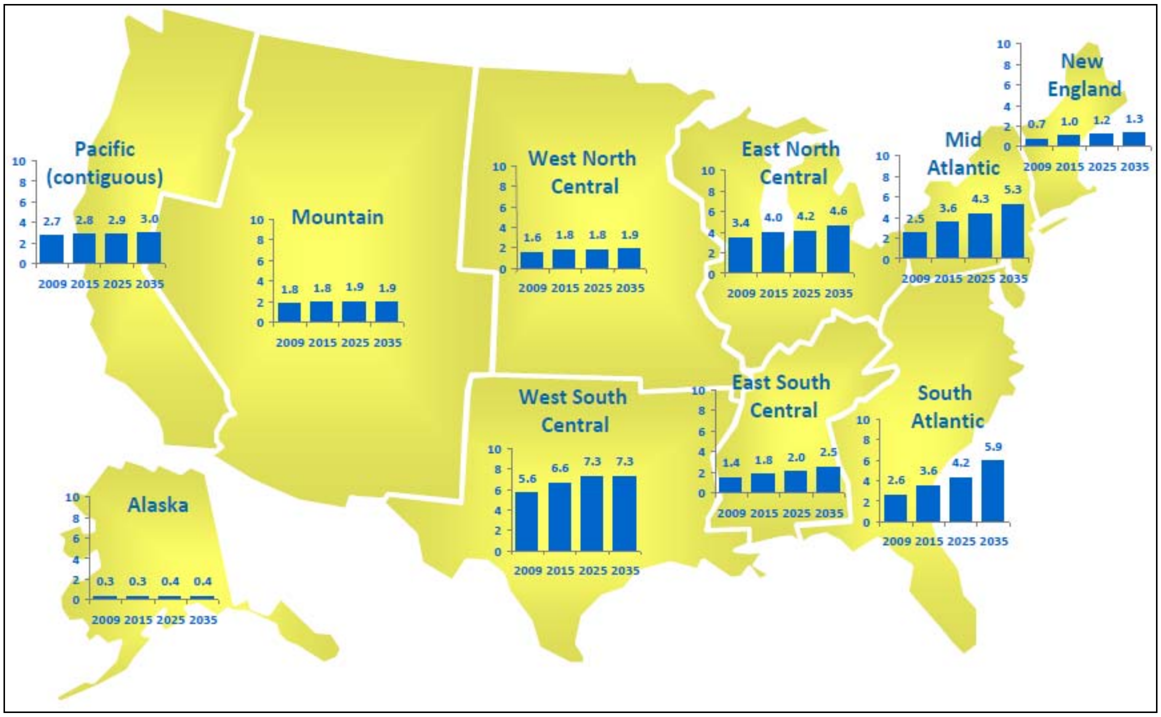


Source: ICF 2Q 2014 Base Case

Exhibit 8 shows estimated U.S. demand growth by region. The largest increases occur across the south, driven by both power and industrial demands where annual consumption increases by 6 Tcf through 2035. Significant growth will also occur in the Mid-Atlantic and East North Central, mostly driven by power sector growth. These consumption changes do not include increases in LNG exports or Mexican exports.

ICF forecasts LNG exports could reach 2.5 Tcf by 2025 (including Downeast LNG). Exports to Mexico grow from 343 Bcf in 2009 to over 3 Tcf by 2025. Exports to Canada will grow to 1.6 Tcf by 2025, up from 1.1 Tcf in 2009.

Exhibit 8. Regional Gas Demand to 2035 (Tcf)



Source: ICF 2Q 2014 Base Case

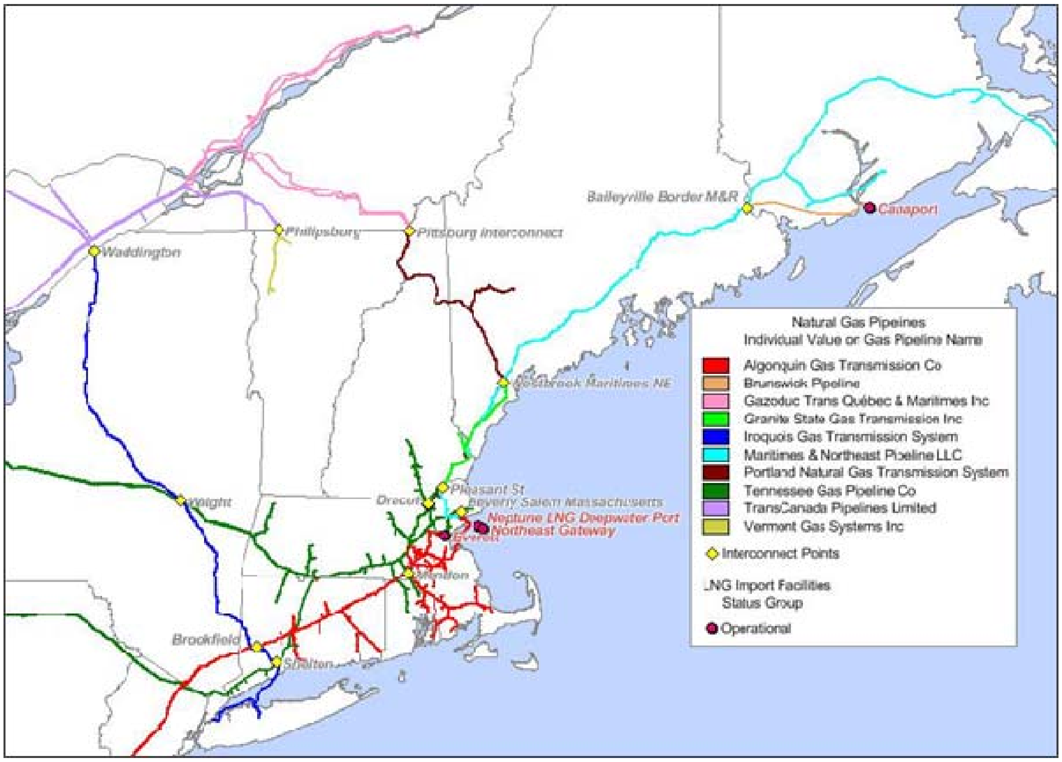
ICF also forecasts growing markets for natural gas in Canada, with the strongest growth occurring in Alberta and British Columbia, driven by the oil sands developments and the retirements of coal-fired power generation. ICF also forecasts that by 2025, Canada will export approximately 1.0 Tcf of LNG from British Columbia and about 2.2 Tcf to the U.S. Domestic Canadian demand will reach approximately 5 Tcf per year in 2025.

4. Pipeline Network Flows and Future Infrastructure

Over many decades New England pipeline operators have steadily developed an expansive network of interstate pipelines that serve large areas of the region. These systems are interconnected with a network of interprovincial pipelines in Eastern Canada that facilitate trade and operational redundancy. Together, as seen in Exhibit 9, these pipeline systems link New England gas buyers with gas reserves in every major North American basin, including the Gulf of Mexico, Western Canada, the U.S. Rockies, and Appalachia.

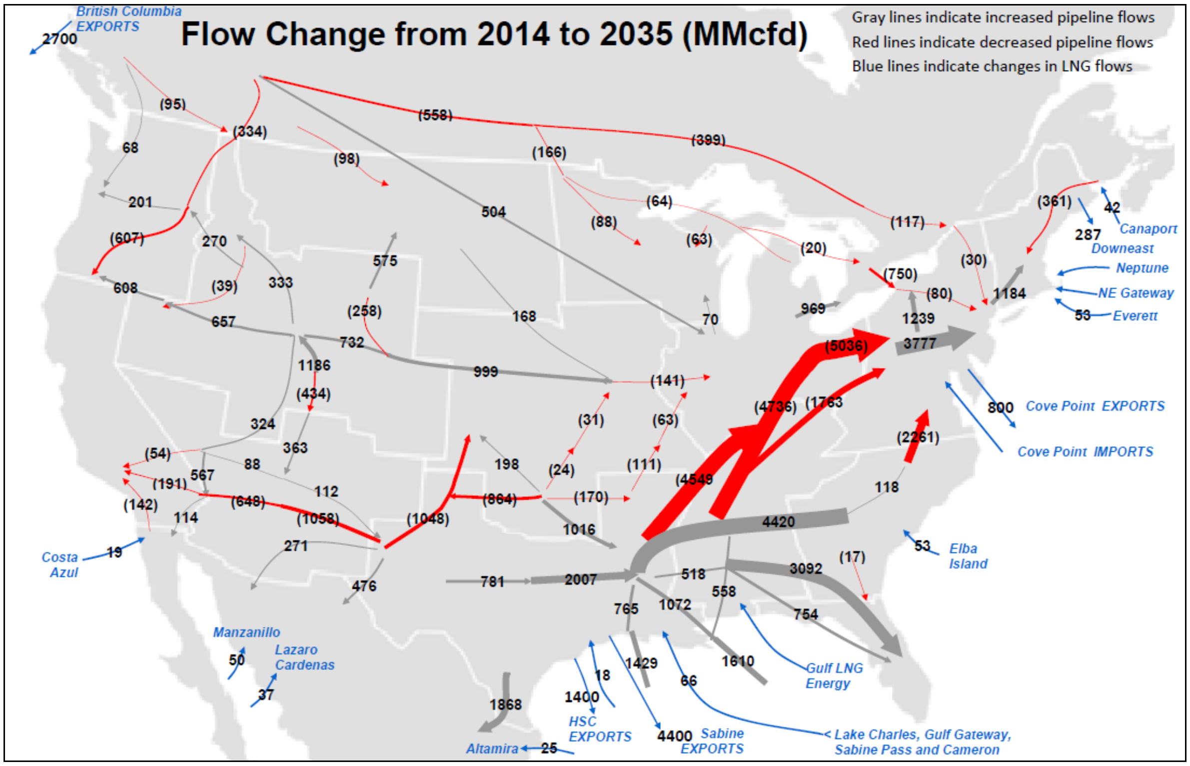
Downeast LNG off-takers, like all New England gas buyers, will have the pipeline capacity options to purchase and ship supplies directly from any of these basins, or buy “delivered” supplies closer to the market at Northeast U.S. and Canadian trading hubs and pipeline interconnects. The interconnected nature of the New England pipeline grid means that regardless of where supplies are purchased, the actual gas delivered will be the commingled streams of production sourced from across North America.

Exhibit 9. New England Natural Gas Pipelines



Gas flows on the interstate and interprovincial pipeline grids are responding rapidly to emerging sources of gas production. Exhibit 10 shows the changes expected over the coming 20 years, elements of which have already begun to occur. Among the most dramatic changes is the reduction in flows from Texas, Oklahoma and Louisiana to the Northeast, a consequence of rapidly growing Marcellus Shale production. Continued production increases from the Marcellus Shale are expected to support nearly 10 Bcf/d of reversed pipeline flows southward from Appalachia to the Gulf Coast as early as 2015.

Exhibit 10. Change in North American Gas Flows by 2035



Source: ICF 2Q 2014 Base Case

The changes in pipeline flows are driving new pipeline investments to accommodate growing North American production in the Marcellus Shale, but also from the Utica, Eagle Ford, Haynesville, Barnett and Montney Shales. Exhibit 11 lists major pipeline additions and expansions that are planned or underway in the Eastern U.S.

Exhibit 11. Eastern U.S. Gas Pipeline Expansions

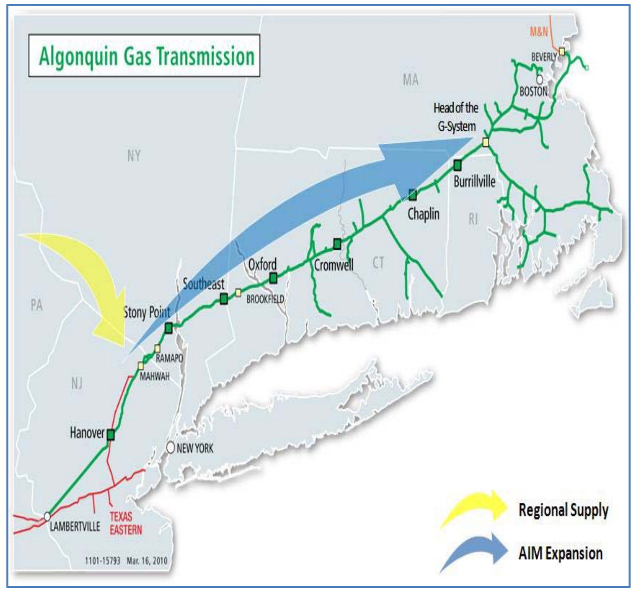
Company - Project Name	Capacity (MMcfd)	Planned In Service	Status
Dominion Transmission - Natrium-to-Market	185	Jun-14	FERC Approved
ANR Pipeline - Lebanon Lateral Reversal	350	Jun-14	Planned
ANR Pipeline - Southeast Mainline System Reversal	600	Mar-15	Announced
Texas Eastern - TEAM 2014	600	Nov-14	Under Construction
Texas Eastern - Ohio Pipeline Energy Network (OPEN)	550	Nov-15	FERC Approved
Texas Eastern - Uniontown to City Gas	425	Nov-15	Planned
Algonquin - AIM Project	342	Nov-16	Filed with FERC
Spectra - NEXUS Gas Transmission	1000	Nov-16	Announced
Texas Eastern - Gulf Markets - North to South	415	Nov-17	Announced
National Fuel - Mercer Expansion Project	105	Nov-14	Under Construction
National Fuel - West Side Expansion	95	Nov-15	Filed with FERC
National Fuel - Northern Access 2015	140	Nov-15	Filed with FERC
Empire Pipeline - Central Tioga County or (TCE2)	260	Sep-15	Announced
Tennessee Gas Pipeline - Rose Lake Expansion Project	230	Nov-14	Under Construction
Tennessee Gas Pipeline - Broad Run Flexibility Project	590	Nov-15	Announced
Tennessee Gas Pipeline - Broad Run Expansion Project	200	Nov-17	Announced
Rockies Express Pipeline - East to West Project	1800	Jun-15	Announced
Iroquois Gas Transmission - Wright Interconnect Project	650	Mar-15	Filed with FERC
Columbia Gas Transmission - West Side Exp - Smithfield III	444	Nov-14	Under Construction
Columbia Gas Transmission - East Side Exp	310	Dec-15	Under Construction
Columbia Gas Transmission - Leach Express	1500	Nov-16	Announced
Columbia Gulf Transmission - Rayne Express	1500	Nov-16	Announced
Millennium Pipeline - Hancock Compression	108	Jun-14	Under Construction
Williams Transcontinental - Leidy Southeast	525	Nov-15	Filed with FERC
Williams/Cabot Oil/Piedmont Nat Gas - Constitution Pipeline	650	May-15	Filed with FERC
Williams Transcontinental - Virginia Southside Expansion	270	Sep-15	Under Construction
Williams Transcontinental - Atlantic Sunrise	1700	Jul-17	Announced
Texas Gas Transmission - Ohio-Louisiana Access Project	600	Jun-16	Announced

Compiled by ICF from various sources.

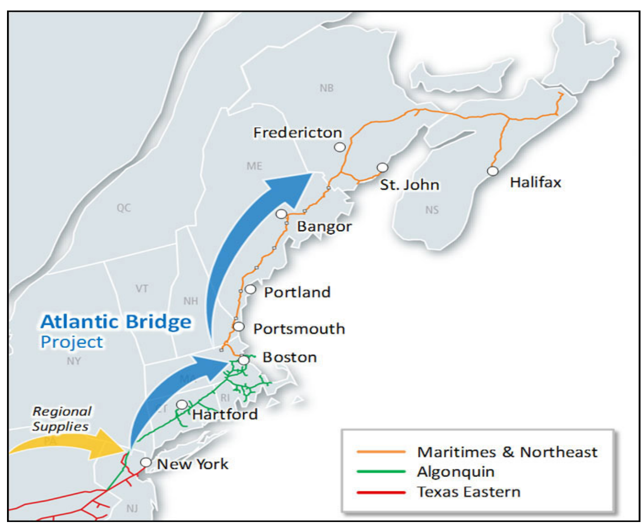
The realignment of North American gas demand to new supply sources has affected gas procurement strategies for many buyers. Value is often found in shorter term pipeline and gas supply contracts that take advantage of shifting supply and demand conditions, and a portfolio approach that relies on multiple pipeline paths and basins. This means that should they choose, Downeast LNG off-takers will likely find capacity in both the primary and secondary market on each of the Northeast and New England regions' pipelines, which they would continuously re-optimize that portfolio over time.

Since the New England market often has little or no spare capacity during peak demand periods, it may be necessary for Downeast LNG off-takers and other regional gas buyers to incorporate incremental pipeline transportation capacity in their supply portfolios. Several interstate pipelines have proposed capacity expansions into New England, and among other choices Downeast LNG off-takers may have the potential to negotiate for pipeline capacity on projects sponsored by Tennessee Gas Pipeline (TGP), Algonquin Gas Transmission (AGT), Portland Natural Gas Transmission System (PNGTS), and Maritimes and Northeast Pipeline (M&NP). ICF models assume incremental capacity expansions into New England in the post 2020 period. In the paragraphs below, we summarize the particulars of potential Downeast LNG pipeline and supply options.

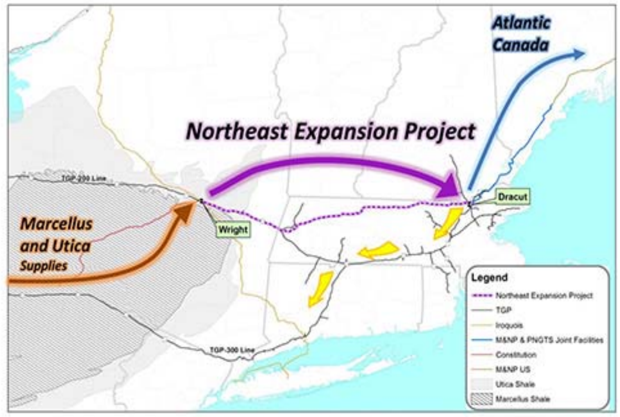
AGT's Algonquin Incremental Market (AIM) expansion is a Spectra Energy project created to expand capacity into New England markets. An open season to secure requests for firm service was held in the fall of 2012. No announcement has been made as to how many shippers signed up or the ultimate capacity of the line, but the open season notice indicated that a binding precedent agreement had been completed with an anchor shipper. The project could include expansions of the AGT interconnection with M&NP. Spectra investor documents list the company as planning to spend over $2 billion on this project, suggesting a major looping or parallel line for AGT. AIM would link New England to an array of upstream supplies and pipeline interconnections. .



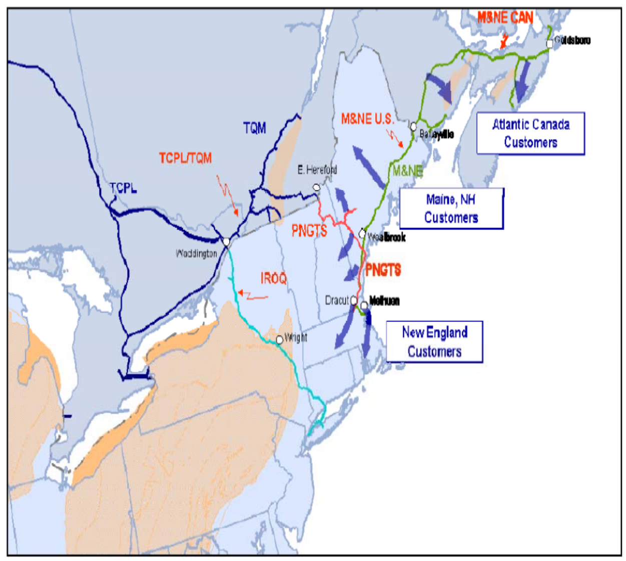
AGT and M&NP also are proposing the Atlantic Bridge Project, which will expand capacity on the existing AGT and M&N Pipelines to serve New England and Maritime markets. Atlantic Bridge recently completed an open season in February 2014 with Unitil Corporation as an Anchor Shipper. The project's capacity is uncertain, ranging between 100 and 600 MMcfd as market interest dictates. The project is projected to come online in November 2017. This expanded capacity of Atlantic Bridge into New England is separate from, and in addition to, that of AIM.



Tennessee Gas Pipeline (TGP) is proposing the Northeast Energy Direct project as part of its Northeast Expansion to bring Marcellus gas into New England. This line would consist of new, greenfield pipe from Wright, New York to Dracut, Massachusetts and looping of the existing 317 line to Wright. Its capacity is expected to be between 0.8 and 1.4 Bcfd. From Wright, New York interconnections TGP shippers can procure supplies from a diverse set of U.S. and Canadian sources. TGP's expansion is expected to enter service in November 2018.



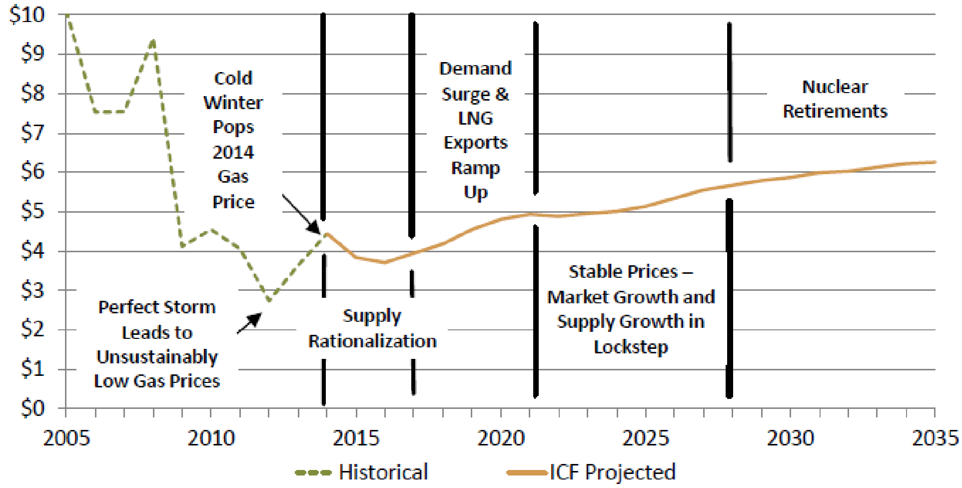
PNGTS, which connects the Trans Quebec and Maritimes Pipeline (TQM) with M&NP-US at Westbrook, Maine and has announced a new offering that would combine available unused capacity on its pipeline with new capacity from compression investments. The project would raise system capacity nearly by nearly 60 MMcfd to 300 MMcfd, and make up to 140 MMcfd available to interested shippers. The PNGTS expansion may also be paired with upstream expansions on TQM and TransCanada Pipelines (TCPL) that expand shipper supply choices. .



5. Gas Prices

ICF's gas price forecast is provided below in Exhibit 12. Over the long term, we expect Henry Hub gas prices will range between $5.00 per MMBtu and $6.00 per MMBtu. In the near term, prices will decline from recent spikes as producers focus resources on liquids-rich plays. The lower prices in turn support rising demand for gas-fired power generation and industrial use, including LNG and Mexican exports. This demand growth moderately outpaces production growth, such market prices rise gradually from 2020 to 2030. After 2030, with the retirement of nuclear generating capacity, demand for gas will increase and push prices further upward.

Exhibit 12. Annual Average Henry Hub Gas Price (2012$/Dth)



Source: ICF 2Q 2014 Base Case

Exhibit 13 presents ICF's annual price forecasts at four key trading points relevant to Downeast LNG. These are:

- Henry Hub, the U.S. national reference price;
- Leidy hub in Pennsylvania, a proxy for Marcellus Shale gas;
- Dawn, Ontario, a benchmark for Canadian supply delivered from the WCSB, and
- New England, the proxy for gas supplies on Tennessee Gas Pipeline, Algonquin Gas Transmission, and Iroquois Gas Transmission

As seen in the table, New England prices effectively track overall U.S. gas prices, as benchmarked at the Henry Hub. New England basis spreads (to the difference to Henry Hub) begin to narrow in 2020 and remain at 2010 levels through the end of our forecast period. This reflects a market in general equilibrium. To the extent large new demand sources are created in the region, ICF would expect to integrate incremental supply capacity from numerous sources into its projections. In matching new demand with new supply, New England basis spread projections would be relatively constant across our forecast period.

Exhibit 13. Base Case Price Forecast
2012$/MMBtu

Year	Henry Hub	Marcellus (Leidy)	Dawn	New England
2010	4.55	4.76	4.93	5.50
2011	4.06	4.21	4.45	5.12
2012	2.74	2.84	3.06	3.94
2013	3.63	3.52	3.97	6.90
2014	4.45	4.38	6.77	8.62
2015	3.34	3.19	4.05	4.49
2016	3.74	3.51	4.46	4.83
2017	4.04	3.80	4.61	5.07
2018	4.06	3.83	4.66	5.16
2019	4.45	4.16	5.04	5.62
2020	5.13	4.76	5.73	6.27
2021	4.85	4.43	5.48	5.89
2022	4.82	4.35	5.53	5.81
2023	4.99	4.44	5.69	5.97
2024	5.05	4.41	5.79	5.95
2025	5.00	4.40	5.75	5.73
2026	5.36	4.68	6.12	5.97
2027	5.68	5.08	6.41	6.38
2028	5.63	5.01	6.42	6.32
2029	5.72	5.14	6.49	6.58
2030	6.03	5.41	6.80	6.83
2031	5.87	5.33	6.60	6.58
2032	6.08	5.52	6.82	6.84
2033	6.15	5.62	6.89	6.97
2034	6.18	5.66	6.93	7.04
2035	6.35	5.83	7.11	7.25

Source: ICF 2Q 2014 Base Case

6. Concluding Observations

Based on this review, ICF believes the gas resources are adequate for meeting Downeast LNG's export requirements and that pipeline capacity will be available to supply the project. ICF's concluding observations are as follows.

- North America's gas resources are very large, with shale resources accounting for over half of the remaining, economically recoverable gas. ICF estimates over 4,000 Tcf of gas is producible with today's technology.
- This large resource base has been a key driver underlying the general decline in gas prices and the growth of gas demand for power, industrial use, and exports. In the future, gas prices are expected to be between $4.00 and $6.00 per MMBtu (2012$), considerably below prices as recently as a few years ago.
- Pipeline capacity is being developed to support this growth in production, including expansions into New England to meet demand growth in the power sector as well for residential and

commercial uses. The New England states are seeking regulatory support for expanded capacity into the region, which would also support Downeast LNG.

- Downeast LNG off-takers will be able to acquire gas at one or more locations in the Northeast from supplies coming over the existing and planned pipelines from the Gulf Coast, Marcellus, WCSB or other producing areas. These choices provide Downeast LNG with a robust portfolio of gas sufficient for its requirements.
- Downeast LNG supplies will provide additional supplies to the New England market that should contribute to moderated gas prices.

Appendix 1 – ICF Gas Market Model

ICF's Gas Market Model (GMM©), a nationally recognized modeling and market analysis system for the North American gas market, was used to forecast gas prices and avoided costs for this project. GMM© was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. Subsequently, GMM© has been used to complete strategic planning studies including:

- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

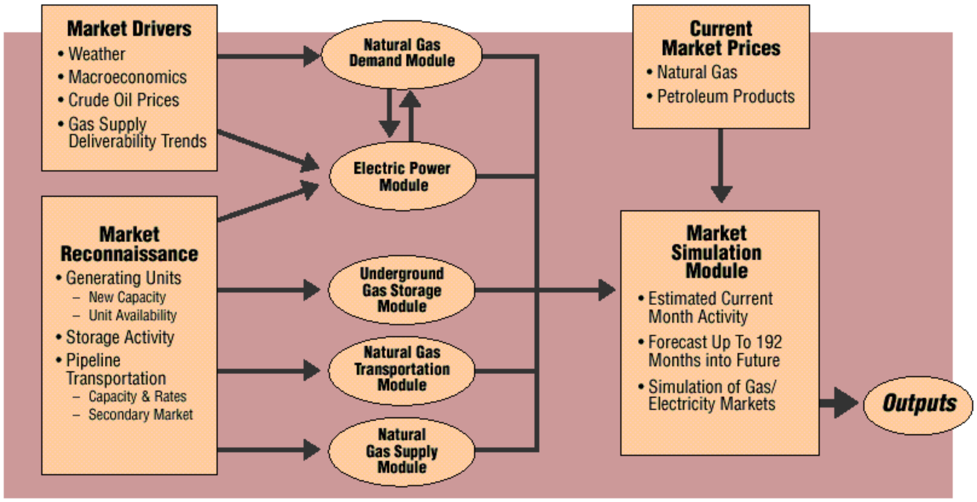
In addition to its use for strategic planning studies, the GMM© has been widely used by a number of institutional clients and advisory councils, including INGAA, which relied on the model for the 30 Tcf market analysis completed in 1998 and again in 2004. The model was also the primary tool used to complete the widely referenced study on the North American Gas Market for the National Petroleum Council in 2003.

GMM© is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization. Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and demand curves. ICF does significant back-casting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

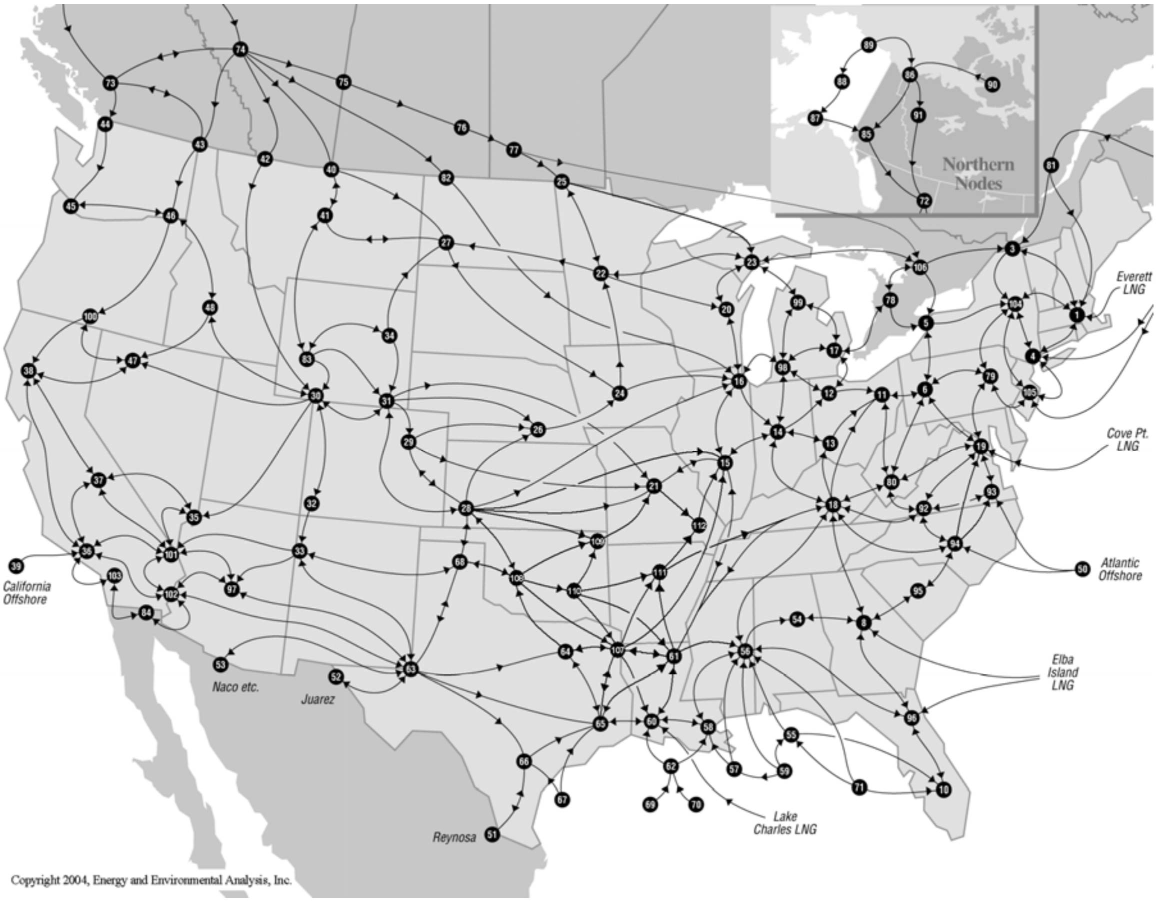
There are nine different components of the GMM©, as shown in Exhibit B-1. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

Exhibit A-1: GMM© Structure



The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Exhibit A-2 and the nodes are identified by name in Exhibit A-7. The gas supply component of the model solves for node-level natural gas deliverability or supply capability. The Hydrocarbon Supply Model (HSM), as discussed in the next section may be integrated with the GMDFS to solve for deliverability. The supply module also creates LNG supply curves that are used by the model to solve for LNG imports. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, Markets, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module. Exhibit A-2 provides an illustrative map of supply sources, demand centers, and pipeline linkages.

Exhibit A-2: GMM© Transmission Network



Appendix 2 – Key ICF Quarter 2 Base Case Assumptions

- Our assumptions include the BEA's third GDP growth estimate for Q4 2013 (released March 27th) of 2.6% and no changes for previous quarters. For the first quarter of 2014 we assume 1.9% growth, and for the rest of 2014 and all of 2015 we assume U.S. GDP growth of 3.0%. The 2014 and 2015 GDP growth assumptions are based on the Wall Street Journal's March 2014 Survey of Economists. From 2016 forward, we assume U.S. GDP grows at 2.6% per year.
- U.S. oil price (refiner's average cost of crude) is assumed to be $100 per barrel (in 2012$).
- Demographic trends consistent with trends during the past 20 years. U.S. population growth averages about 1% per year.
- Electric load growth averages 1.2% per year.
- ICF's Base Case reflects one plausible outcome of EPA's proposals for major rules that have been drawing the attention of the power industry – these include Mercury & Air Toxics Standards Rule (MATS), water intake structures (often referred to as 316(b)), and coal combustion residuals (CCR, or ash). It also includes a charge on CO2 reflecting the continuing lack of consensus in Congress and the time it may take for direct regulation of CO2 to be implemented. The case generally leads to retirement and replacement of some coal generating capacity with gas generating capacity.
- In terms of power plant mix: we assume increased generation from renewables to meet state RPS benchmarks, coal generation decreasing, and other forms of non-gas generation remaining fairly flat. Gas generation grows to fill the gap between electric load and the total amount of generation from other sources.
  - Assumes a maximum lifespan of 60 years for all nuclear units; this results in 11 GW of nuclear retirements between through 2035.
- Adoption of DSM programs and conservation and efficiency measures continues, consistent with recent history.
- Weather in forecast months (beginning April 2014) is assumed to be consistent with the 20-year average.
- Current U.S. and Canada gas production from over 300 trillion cubic feet of proven gas reserves.
- The substantial North American natural gas resource base totaling about 4,000 trillion cubic feet of unproved plus discovered but undeveloped gas resource can supply U.S. and Canada gas markets for about 150 years.
- Shale gas accounts for over 50 percent of the remaining resource.
- Gas supply development is permitted to continue at recently observed activity levels – no significant restrictions on permitting and fracturing are introduced beyond current restrictions.
- No significant hurricane disruptions to natural gas supply (disruption consistent with a 20-year average).
- No Arctic projects (specifically no Alaska and Mackenzie Valley gas pipelines).
- Near-term midstream infrastructure development assumed per project announcements. Unplanned projects included when market signals need of capacity, and there are no significant delays in permitting and construction.

EXHIBIT C

Evaluation of the Impact of Downeast LNG on New England Natural Gas Markets

Prepared for:

Downeast LNG

August 2014

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TABLE OF CONTENTS

I. INTRODUCTION

A. Scope of Report

Downeast LNG ("DELNG") retained Concentric Energy Advisors, Inc. ("Concentric") to provide a high-level, qualitative assessment of the potential impact that DELNG's proposed liquefied natural gas ("LNG") export facility located in Robbinston, Maine ("Facility") could have on New England natural gas markets. DELNG's proposed facility would be capable of liquefying 450 MMcf/d for export and is expected to be in-service in 2019. Specifically, DELNG asked Concentric to:

- Provide an overview of the New England natural gas market, including existing gas transportation infrastructure, current infrastructure constraints and prices, and supply and demand factors driving current market conditions (Section II);
- Assess the pipeline routes that could be used to deliver gas from Mid-Atlantic United States ("Mid-Atlantic") or eastern Canadian source locations to DELNG's proposed LNG export facility (Section III); and
- Provide a qualitative assessment of the potential New England natural gas price impact resulting from the development of DELNG's export facility (Section IV).

It is Concentric's understanding that this report is to support DELNG's application to the U.S. Department of Energy ("DOE") for LNG export authority.

B. Executive Summary

Based on Concentric's understanding of the New England natural gas market, future potential pipeline routes that could be used to deliver gas from the Mid-Atlantic or eastern Canada to the Facility, and its assessment of the potential directional impact on New England natural gas prices associated with the proposed Facility, the primary conclusions are as follows:

- New England is considered a market area from a natural gas delivery infrastructure perspective; unlike adjacent regions, there are no natural gas production fields or underground storage facilities located in New England, and therefore, the region relies on natural gas sourced outside of New England and delivered by interstate pipelines.
- New England natural gas markets are currently characterized by premium natural gas prices relative to other regions of the country as a result of a combination of insufficient pipeline capacity into the region from the south, increasing demand in the region and decreasing supply from Atlantic Canada and imported LNG. Specifically:
    - On the supply side, although natural gas production in the Marcellus/Utica shale basins has increased substantially over the last several years, the pipelines into New England from the south and west are either currently fully contracted and utilized nearly all days of the year, or from the north are not connected to sufficient supplies

to utilize their full capacity. Specifically, natural gas supply from Atlantic Canada has been declining as diminishing Sable Island production cannot be fully replaced by the new Deep Panuke production. In addition, LNG imports have also been declining as relatively more lucrative international markets for LNG have attracted cargoes away from New England.

    - Demand for natural gas in New England is growing, both from local distribution company ("LDC") customers and from electric generation. The price and environmental advantage that natural gas has over oil and petroleum-based products has prompted many LDC customers in New England to switch from oil-based products to natural gas, and the trend is expected to continue. Likewise, demand for natural gas from electric generation is expected to grow as several large power plants in New England that are not fueled by natural gas are expected to retire over the next several years with much of this capacity expected to be replaced by gas-fired generation.

- There are currently two pipeline expansions that would increase capacity into New England from the south that have either already filed for or have announced a filing date for FERC certification authorization: the Algonquin Incremental Market ("AIM") expansion project, and Tennessee's Connecticut Expansion project. Even with these projects, the pipeline capacity into New England is expected to continue to be fully utilized most days of the year. As a result, additional pipeline expansions will be necessary to serve incremental natural gas demand growth in New England.

- Based on existing pipeline projects that have been announced, and assuming that DELNG shippers would source gas from either the Mid-Atlantic or eastern Canada, three potential transportation routes available to DELNG shippers have been analyzed and are depicted in Figure 1: (i) the Kinder Morgan Route (represented by the red arrow); (ii) the Spectra Route (represented by the blue arrow); and (iii) the TransCanada Route[1] (represented by the green arrows). These three routes offer viable means of transportation to DELNG shippers, as well as access to natural gas sourced from multiple producing regions across North America. Depending on how the 450 MMcf/d of capacity for the Facility is distributed among these transportation routes and the timing of when DELNG shippers would contract for such transportation service, these transportation options could be available either based on the expansion projects that are currently announced, or through future expansions on these same routes.

- It is not expected that the development of the Facility will exacerbate the natural gas price premiums currently being experienced in New England. At a minimum, the Facility's impact on existing market circumstances in the region would be neutral, and in fact, could help mitigate the existing pipeline constraints during peak periods. Specifically:

    - All of the gas to be exported from the Facility could be transported using incremental firm pipeline capacity made available by pipeline projects that have already been announced or are under development to serve the growing demand in New England; thus, gas transported through New England for liquefaction and

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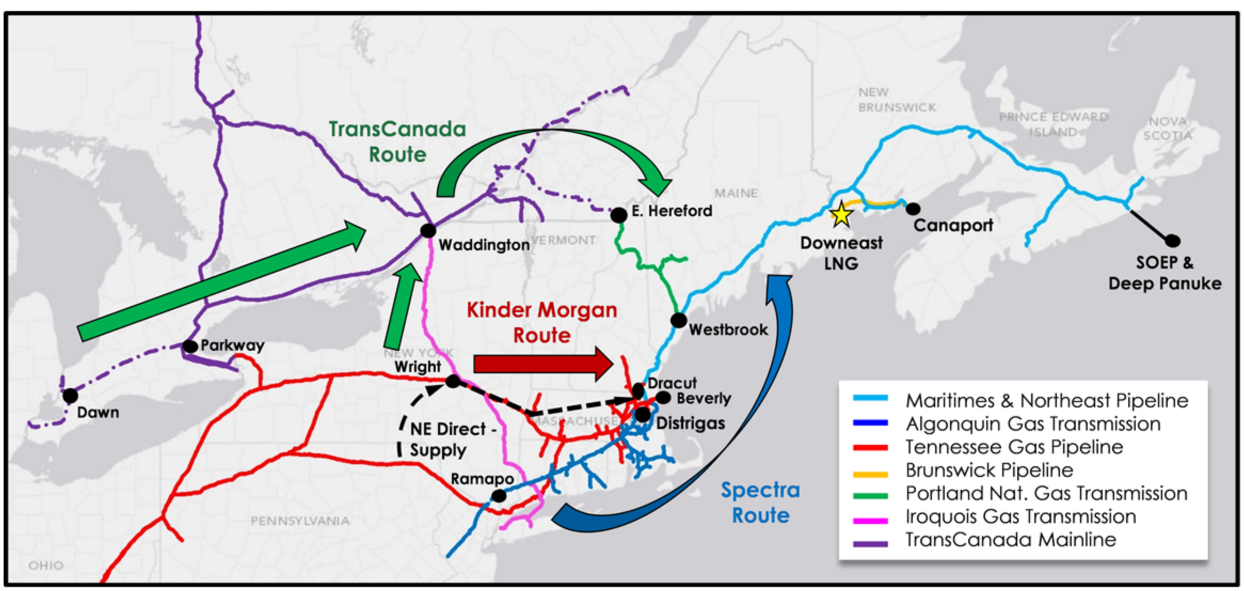
[1] TransCanada provides an integrated transportation service from the Dawn hub in southern Ontario to East Hereford, Quebec that includes transportation on the Union Gas ("Union") and Trans-Quebec & Maritimes ("TQM") pipelines.

export at the Facility would not reduce the level of unutilized capacity into the region, and therefore would not contribute to the existing price volatility and price spikes.

- Pursuant to FERC's open access provisions for interstate pipelines, shippers on proposed pipelines will not be able to prohibit or exclude other shippers from participating in open seasons for future pipeline capacity additions into New England.
- Shippers are expected to utilize the Facility for export in a base load manner, meaning that DELNG shippers will likely utilize their firm pipeline capacity at or close to a 100% load factor. As such, there is expected to be little to no unutilized pipeline capacity offered in the secondary market by the DELNG shippers and, therefore, the Facility and any associated shipper transportation contracts should have no impact on the existing market.
- However, should the DELNG shippers export less than the design capacity of the DELNG facility during certain periods or if shippers were able to utilize on-site storage at the Facility to meet export requirements during certain periods, then it is possible that the DELNG shippers would not use 100% of their firm pipeline capacity during these periods. Under this circumstance, there is the potential for alternative transportation contracts, *e.g.*, 345-day service or multi-party contracts, which could help mitigate winter price spikes in New England by making additional pipeline capacity available during peak periods. If DELNG shippers were to create firm pipeline capacity that could be used by other parties during periods when the pipelines are especially constrained, it could reduce the prices that would have otherwise occurred, providing a direct benefit.

Figure 1: Map of Pipeline Transportation Options



- One or more DELNG shippers participating in new pipeline expansion projects could affect the viability of an expansion and thus create opportunities for participants with smaller incremental capacity requirements to participate in pipeline expansion projects that otherwise might not be constructed due to a lack of sufficient support or being uneconomic due to the fixed costs being spread over a relatively small volume.
- DELNG shipper participation in one or more pipeline expansions could also reduce the cost of that infrastructure for all participants by providing economies of scale that might not otherwise be achieved with the existing shipper base absent such participation.

- The natural gas requirements associated with potential exports from the Facility (*i.e.*, 450 MMcf/d) are unlikely on a stand-alone basis to affect the overall North American natural gas market or regional natural gas prices in the Mid-Atlantic or eastern Canadian markets.
- There is the potential for natural gas price increases from greater exports of LNG from North America. The overall volume of exports from North America, in total, could affect the natural gas supply/demand balance, and in turn natural gas prices, in North America. However, these potential market developments may occur regardless of whether DELNG is constructed, since, as just noted, DELNG's liquefaction capability of 450 MMcf/d is not large enough on a stand-alone basis to have a material impact on the overall North American market or regionally in the Mid-Atlantic and eastern Canadian natural gas markets.

II. New England Natural Gas Market Overview

A. Existing Infrastructure

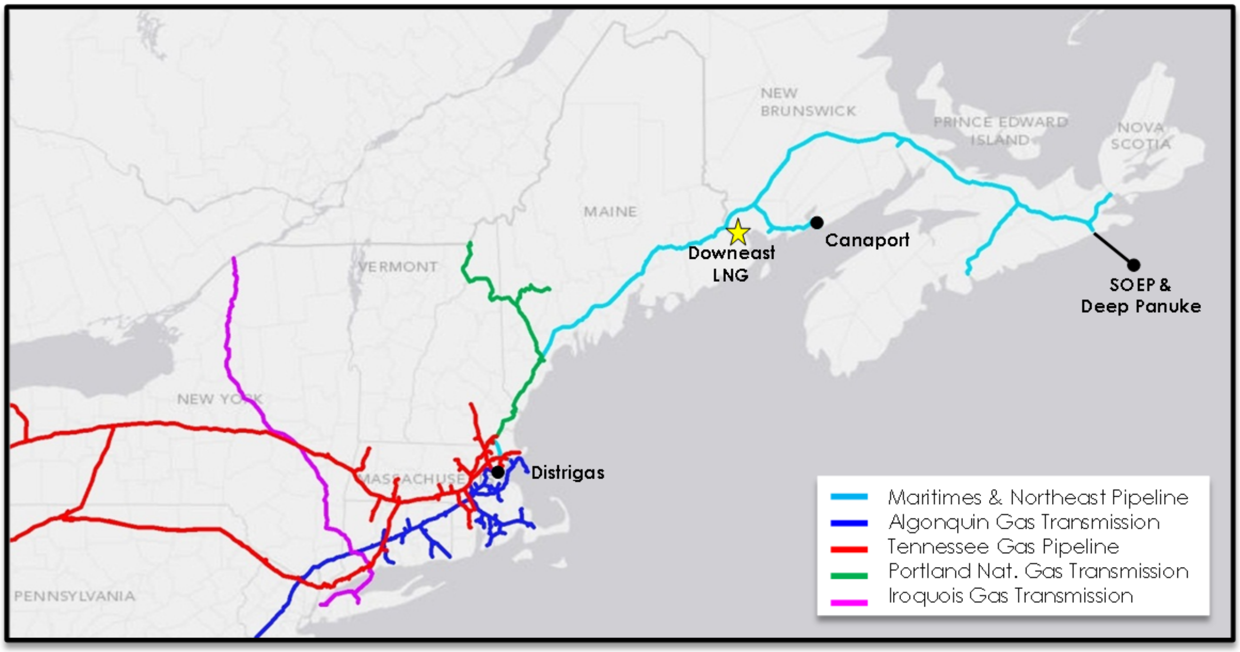
New England natural gas markets are at the "end of the line" from a natural gas delivery infrastructure perspective, and are currently characterized by pipeline constraints and premium and volatile natural gas prices. Unlike adjacent regions there are no natural gas production fields or underground storage facilities located in New England; therefore, the region relies on natural gas sourced outside of New England and delivered by interstate pipelines.

Four major pipelines deliver gas to New England; two deliver gas sourced from the south (*i.e.*, Algonquin Gas Transmission ("Algonquin") and Tennessee Gas Pipeline ("Tennessee")), and two deliver gas sourced from the north (*i.e.*, Maritimes & Northeast Pipeline – US ("M&NP-US"), and Portland Natural Gas Transmission System ("PNGTS")). In addition, Iroquois Gas Transmission ("Iroquois") delivers gas directly to customers in southern Connecticut, but the majority of natural gas that enters New England on Iroquois is either delivered into other pipelines in southern Connecticut or passes through Connecticut to customers in New York City and Long Island. New England also has access to LNG from import terminals (*i.e.*, the Distrigas LNG import terminal in Everett, Massachusetts and the Canaport LNG facility in St. John, New Brunswick),[2] and numerous smaller-scale LNG peaking facilities utilized directly by LDCs in New England.[3] The map below illustrates the major natural gas infrastructure in New England.

2 There are also two off-shore LNG import facilities in New England – Neptune LNG and Northeast Gateway LNG – but neither have been or are currently utilized to provide natural gas supplies to the region.

3 In total, there is approximately 16 Bcf of on-system LNG storage capacity with a combined vaporization capability of 1.44 Bcf/d in New England. (Northeast Gas Association, 2013 Statistical Guide).

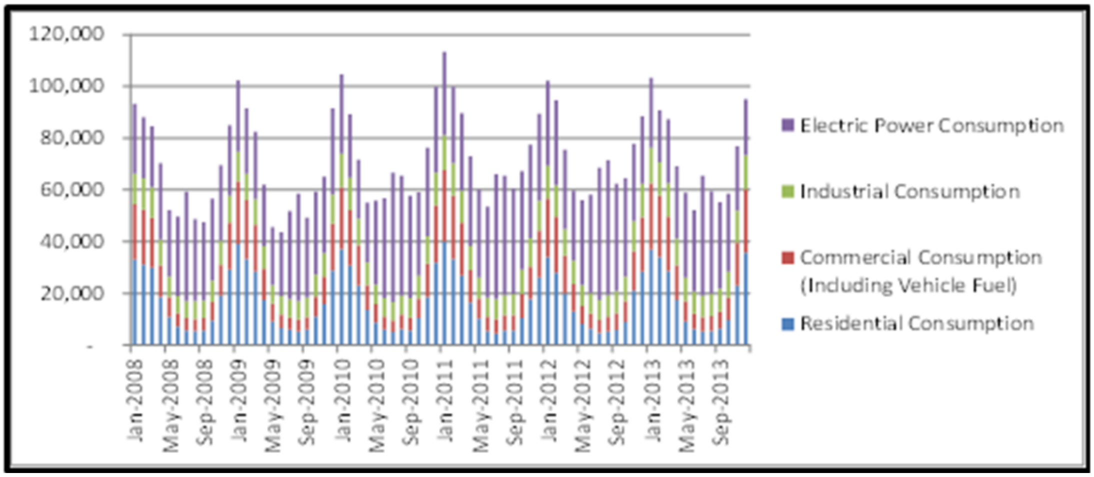
Figure 2: Map of Existing Natural Gas Pipeline Infrastructure Serving New England



B. Demand

Historically, natural gas demand in New England has been dominated by winter peaking LDC heating load. However, on an annual basis, natural gas-fired electric generation has become the predominant source of demand. New England annual demand for natural gas during 2013 was approximately 872,000 MMcf (*i.e.*, 2,390 MMcf/d), and as shown in Figure 3, the electric generation segment comprised approximately 41% of the total New England natural gas consumption, followed by the residential, commercial and industrial segments representing 25%, 19%, and 15%, respectively.

Figure 3: New England Consumption of Natural Gas by Sector (MMcf)[4]



The price and environmental advantage that natural gas has over oil has prompted many customers in New England and across the country to switch from oil and other petroleum products to natural gas. These oil to gas conversions have increased the demand for natural gas in recent years, and the trend is expected to continue. For example, in February 2013, the Connecticut Department of Energy and Environmental Protection released a Comprehensive Energy Strategy that includes a goal of converting 300,000 consumers to natural gas within seven years.

In addition, as shown in Figure 4, the demand for natural gas from electric generators has increased significantly over the last decade. This trend in consumption by natural gas-fired generation is expected to continue as older coal, oil and nuclear plants in New England are retired, and replacement power is expected to largely be fueled by natural gas. For example, over 3,200 MW of non-natural gas fired generation is scheduled for retirement in New England in the next few years, as Vermont Yankee (604 MW), Brayton Point (1,535 MW), Norwalk Harbor (342 MW) and Salem Harbor (749 MW), have submitted retirement requests to ISO New England.[5]

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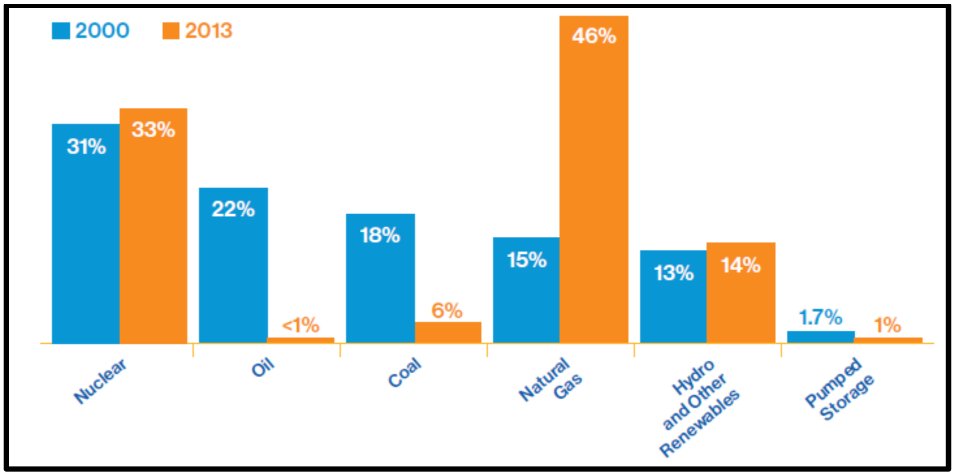
4 EIA Natural Gas Consumption by End Use, released April 30, 2014

5 ISO New England Status of Non-Price Retirement Requests, February 2, 2014

Figure 4: New England Electric Energy Production by Fuel[6]



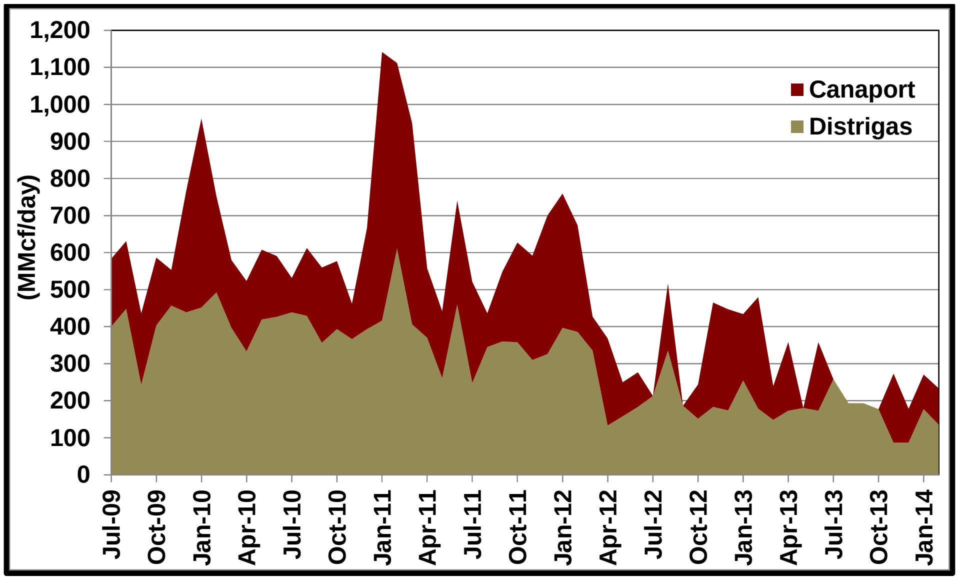
C. Supply

As discussed previously, New England does not have indigenous natural gas supply, so gas must be delivered from outside the region. Historically, natural gas serving New England has predominantly been sourced from the Gulf of Mexico, western Canada, offshore Atlantic Canada and imported LNG from the Distrigas facility. In the last decade, supplies in New England have also been sourced from the Marcellus shale regions, eastern Canada, and LNG imports into the Canaport facility.

Due to a number of factors, gas sourced from the north and LNG imports have been in a state of decline, and this trend is expected to continue. As shown in Figure 5, LNG imports from Canaport and Distrigas have been declining over recent years as worldwide LNG markets provide greater profit opportunities. In January and February 2011, average daily supply from LNG imports at Canaport and Distrigas exceeded 1.1 Bcf/d; however, in January and February 2014, average daily supply from LNG imports at Canaport and Distrigas dropped to approximately 250 MMcf/d. Given the abundance of low cost natural gas in the United States, this downward trend in LNG imports is expected to continue.

6 ISO New England 2014 Regional Electricity Outlook, February 25, 2014

Figure 5: Canaport and Distrigas LNG Imports (MMcf/d) [7]

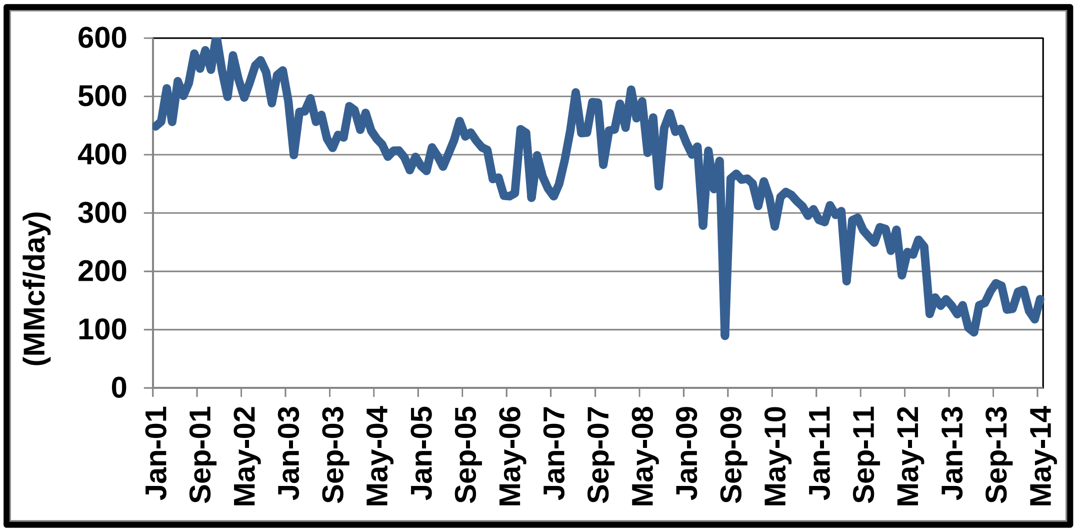


In addition, offshore supplies in Atlantic Canada from Sable Island have been declining steadily since 2007, and have averaged below 250 MMcf/d since mid-2012, as shown in the graph below. While additional supplies from Deep Panuke came online in November 2013 and mitigated some of that decline, its maximum daily production is 300 MMcf/d and its average daily production for December 2013-May 2014 was 250 MMcf/d.[8] In addition, Deep Panuke is only expected to produce for up to ten years, and much of the production is likely to be absorbed in Atlantic Canada.

7 National Energy Board, Imports of Natural Gas, May 6, 2014; US DOE Office of Fossil Energy, LNG Reports

8 Nova Scotia-Canada Offshore Petroleum Board, Deep Panuke Monthly Production Reports

Figure 6: Sable Island Production (MMcf/d)[9]



In contrast, natural gas production in the Marcellus and Utica shale basins in the Mid-Atlantic region has significantly increased in recent years, and is expected to continue to grow. Production currently exceeds 16 Bcf/d and is expected to reach 22 Bcf/d by 2019, which compares to only 2 Bcf/d of production from the region prior to the natural gas shale revolution.[10] Coupled with the increased production, there are numerous pipeline projects that have recently been placed in service or are in development (*i.e.*, new greenfield projects, reversals and expansions of existing pipelines) that will increase the take-away capacity from the Marcellus/Utica basins and provide the necessary capability to deliver that gas to market.

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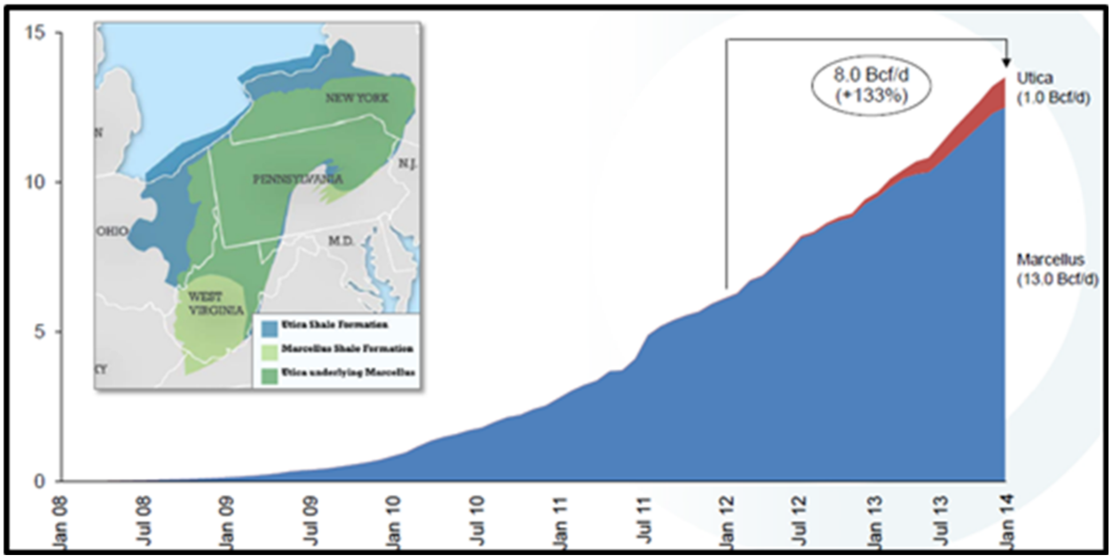
[9] Canada-Nova Scotia Offshore Petroleum Board, Sable Offshore Energy Project, Monthly Production Reports

[10] Platts Gas Daily, "NYMEX below $4.50; Northeast cash spikes", June 24, 2014; RBN Energy, "They Long to be Close to You – Moving Marcellus/Utica Natural Gas South and West", May 15, 2014

Figure 7: Northeast Natural Gas Production (Bcf/d)[11]



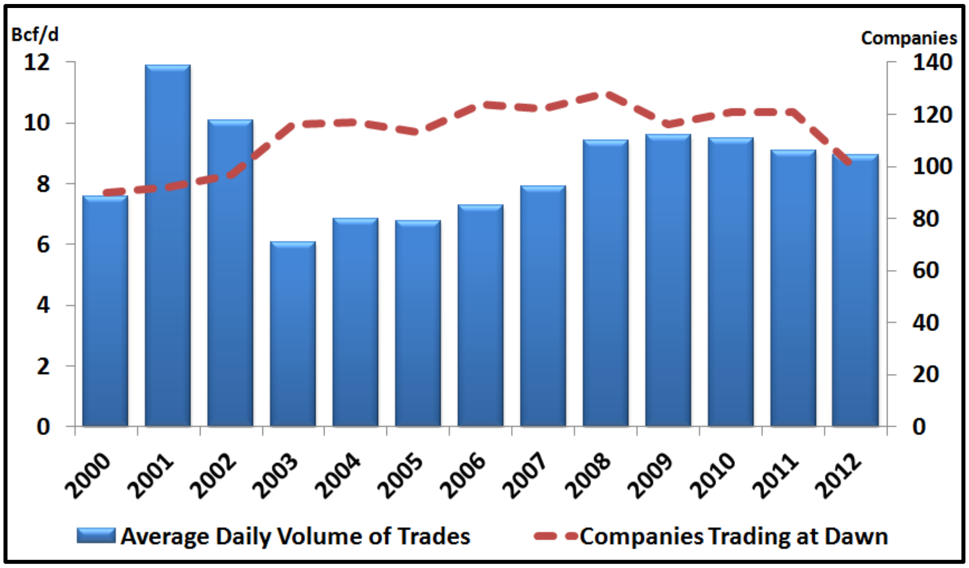
The Dawn trading hub in eastern Canada also continues to be a viable location for parties to procure natural gas supplies for New England. While not a producing region itself, Dawn is the largest underground natural gas storage complex in North America with over 155 Bcf of high deliverability storage.[12] Strategically located in southeastern Ontario, Dawn provides access to supply basins in western Canada, the Rockies, Mid-Continent, the Gulf of Mexico, and the Marcellus/Utica shale basins as well as downstream markets in eastern Canada and the northeastern U.S. As depicted in Figure 8, daily trade activity at Dawn has averaged approximately 9 Bcf/d and involved more than one hundred counterparties. There are also a number of pipeline projects in development that could deliver significant additional supplies from the Marcellus/Utica basins to the Dawn Hub.[13]

11 Millennium Pipeline Company, Northeast Gas Association Regional Market Trends Forum, May 1, 2014

12 RBN Energy, "Return to Sender Natural Gas Exports – The Battle for a New Dawn", February 12, 2013

13 Spectra Energy held an open season in late 2012 for the proposed NEXUS Gas Transmission Pipeline which would deliver at least 1 Bcf/d from northeastern Ohio to the Dawn Hub. In June 2014, Energy Transfer Partners ("ETP") announced an open season for the Rover Pipeline Project that would connect Marcellus/Utica supplies to the Dawn hub. The ETP pipeline would have a capacity of at least 2.2 Bcf/d, and long-term agreements have already been signed with multiple shippers.

Figure 8: Dawn Hub Trading Activity[14]



D. Market Constraints

The abundance of natural gas in the Mid-Atlantic region could replace the decline in LNG imports and supplies from the north into New England; however, the pipeline infrastructure delivering gas to New England from the Mid-Atlantic is fully contracted and fully utilized most days of the year. For example, because of the large winter-peaking loads in New England and the additional supplies available from Atlantic Canada and imported LNG, historically Algonquin had capacity available for interruptible transportation on most days of the year. However, in 2013, Algonquin was unable to provide interruptible capacity on any day during the year due to increased reliance on supplies from the south because of LDC load growth, electric generation demand growth, decreased supplies from Atlantic Canada, and decreased LNG imports, as shown in the graph below. Similarly, Tennessee had restrictions on interruptible service through meter stations near the New England border on most days of 2013.[15]

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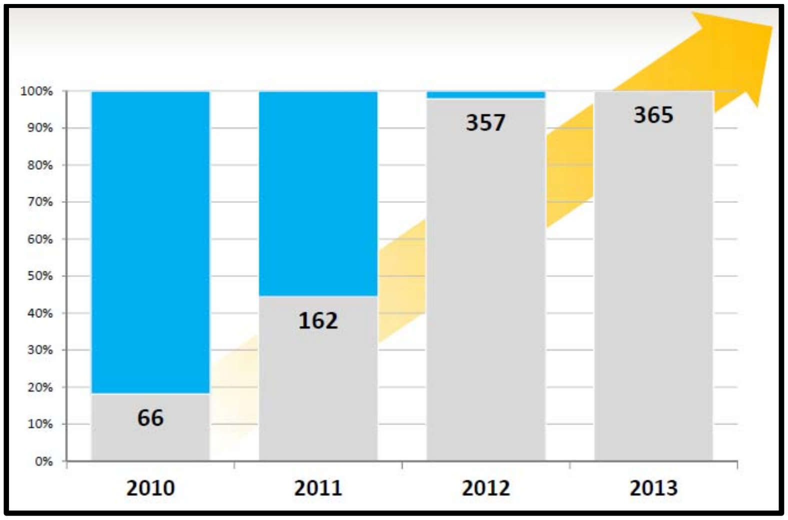
14 Union Gas website, https://www.uniongas.com/storage-and-transportation/about-dawn/dawn-hub/trading-at-dawn, accessed June 25, 2014

15 Tennessee Gas Pipeline Company, NGA Regional Market Trends Forum, May 1, 2014

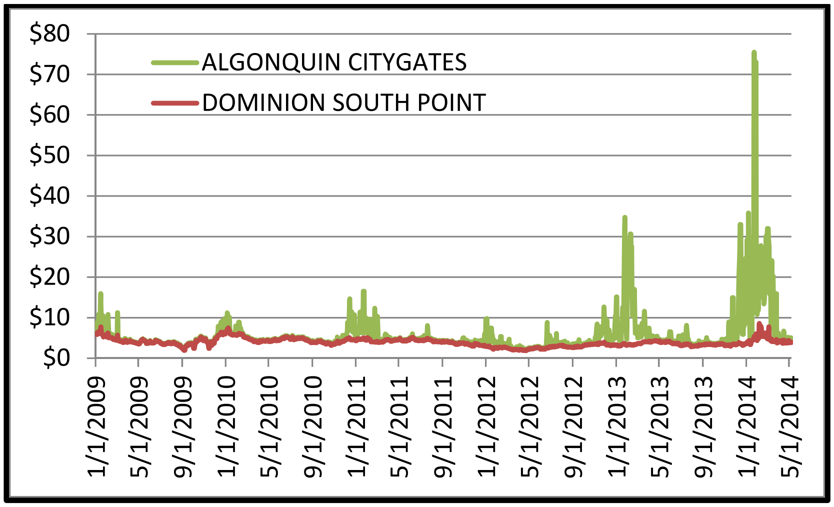
Figure 9: Number of Days with No Interruptible Capacity Available on Algonquin[16]



These pipeline constraints into New England have placed upward pressure on natural gas prices in the region and significantly increased price volatility. For example, as shown in Figure 10, during the most recent winter, prices at the Algonquin Citygates index were more than double the prices experienced on average over the previous four winters, and the price spikes were more frequent and more extreme. The constraint is especially apparent when comparing the Algonquin Citygates index prices with prices at the Dominion South Point index price in the Mid-Atlantic, which is only a few hundred miles away.

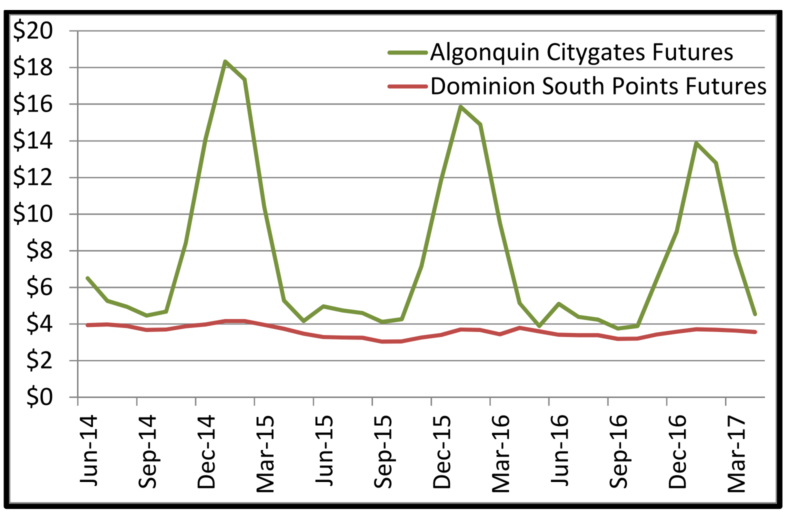
16 Spectra Energy, Regional Market Trends Forum, May 1, 2014

Figure 10: Algonquin Citygates and Dominion South Point Prices ($/MMBtu)[17]



High natural gas price differentials between New England and the Mid-Atlantic are expected to continue. As shown in Figure 11, the natural gas futures price for the Algonquin Citygates index for January 2015 is trading at a $14/MMBtu premium to the Dominion South Point index.

Figure 11: Algonquin City Gates and Dominion South Point Futures Prices ($/MMBtu)[18]



To date, only two pipeline expansions that would increase capacity into New England have executed contracts and have indicated FERC filing timelines. On February 28, 2014, Algonquin submitted an

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17 Platts Gas Daily

18 Bloomberg Futures Prices, April 1, 2014-May 6, 2014 Trade Dates

application to FERC for the Algonquin Incremental Market ("AIM") expansion project, which would provide approximately 342 MMcf/d of additional capacity on the existing Algonquin system between Ramapo, New York and Mendon, Massachusetts starting in November 2016.[19] Tennessee expects to file at FERC before the end of 2014 for the fully subscribed Connecticut Expansion project, which would provide approximately 72 MMcf/d of additional capacity to serve Connecticut LDC growth starting in November 2016.[20]

While these pipeline projects are supported by growing LDC demand for natural gas, incremental pipeline capacity needed to serve the growth associated with natural gas demand for electric generation has not yet been addressed. Most electric generators rely on interruptible or secondary capacity on the pipelines to obtain their natural gas supplies. As LDC demand has grown and supplies into New England from Atlantic Canada have declined, less natural gas pipeline capacity throughout the year, and particularly during peak periods, has been available to the electric generators. This shortage of pipeline capacity has become critical in recent winters, leading to discussions about electric reliability concerns related to the inability of gas-fired generators to obtain natural gas supplies. However, existing electric market rules fail to provide incentives for gas-fired generation to contract for firm pipeline capacity, and pipelines are unwilling to build additional pipeline infrastructure without long-term firm contracts. The New England Governors and other market participants have been actively studying the issue; however, no solution to the problem has been implemented. Therefore, it is expected that the existing capacity on Algonquin and Tennessee, as well as the incremental capacity on the AIM and Connecticut Expansion projects, will likely be fully utilized most days of the year going forward. As a result, additional pipeline expansions will be necessary to serve incremental natural gas demand growth in New England.

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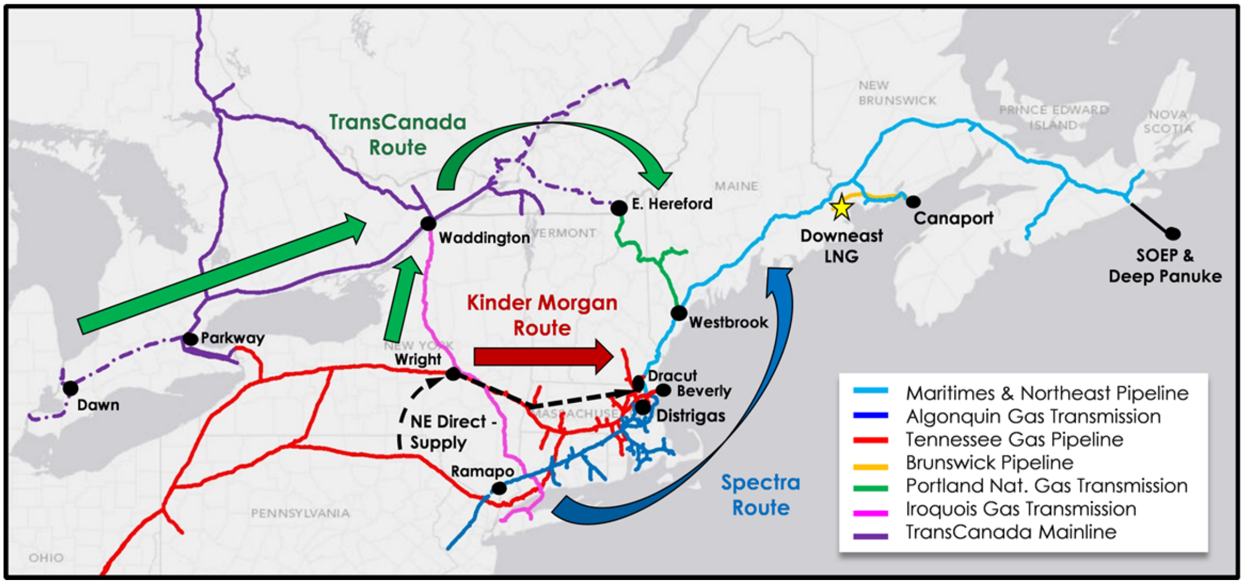
19 Spectra Energy, Algonquin Incremental Market (AIM) Project website, http://www.spectraenergy.com/Operations/New-Projects-and-Our-Process/New-Projects-in-US/Algonquin-Incremental-Market-AIM-Project/, accessed May 6, 2014

20 Kinder Morgan, 2014 Analysts Conference Presentation, January 29, 2014

III. New England Pipeline Transportation Options

For purposes of this report, it is assumed that shippers seeking to export LNG from the Facility would procure natural gas supplies from Mid-Atlantic or eastern Canadian sources. As discussed in the previous section, existing pipeline capacity from the Mid-Atlantic to New England is fully contracted and highly constrained, and the AIM and Connecticut Expansion projects are also fully contracted. Likewise, segments of TransCanada's Mainline, which connects the Dawn hub to New England via interconnections with the Iroquois and PNGTS pipelines are also fully utilized. As a result, shippers using the DELNG facility to export natural gas will likely participate in future pipeline expansion projects in order to transport incremental natural gas supplies from the Mid-Atlantic or eastern Canada to eastern Maine. Based on potential expansion projects that have currently been announced, Concentric has analyzed three potential transportation routes that would be capable of serving incremental demand in New England. DELNG shippers could use one or more of these routes to transport natural gas for the export of LNG from the Facility. These potential routes, which are depicted in Figure 12 and described more fully below, are: (i) the Kinder Morgan Route (represented by the red arrow); (ii) the Spectra Route (represented by the blue arrow); and (iii) the TransCanada Route (represented by the green arrows). These three routes offer viable means of transportation for incremental natural gas demand in New England, as well as access to natural gas sourced from multiple producing regions across North America. Depending on how the 450 MMcf/d of capacity for the Facility is distributed among these potential transportation routes and the timing of when DELNG shippers would contract for transportation service, these transportation options could be available either based on the expansion projects that are currently announced, or through future expansions on these same routes.

Figure 12: Primary Incremental Pipeline Transportation Options into New England



A. Kinder Morgan Route

Under the Kinder Morgan Route, DELNG shippers could receive gas at Wright, New York ("Wright"). Wright is the point of interconnection for the Tennessee and Iroquois pipelines in eastern upstate New York which, through these two interstate pipelines, has access to supplies from the Marcellus/Utica basins, western Canada, and the Gulf of Mexico. Two additional pipeline development projects—Tennessee's Northeast Energy Direct Project and the Constitution Pipeline—would connect Wright to additional Marcellus production in northeastern Pennsylvania, with the Northeast Energy Direct Project also continuing on from Wright to an interconnection with M&NP-US at Dracut, Massachusetts. DELNG shippers could then transport gas sourced at Wright on (i) the Market Segment of Tennessee's proposed Northeast Energy Direct Project, which spans from Wright to the interconnect with M&NP-US at Dracut, Massachusetts; and then (ii) on M&NP-US from Dracut to DELNG. The details of each of the segments in this route are described below.

Tennessee – Northeast Energy Direct Project

In 2012, Tennessee announced the Market Segment of its proposed Northeast Energy Direct Project ("Market Segment"), a 179-mile greenfield pipeline project that would offer incremental capacity between Wright and the interconnection with M&NP-US at Dracut. Tennessee held an open season for this project, which closed on March 28, 2014. Then in May 2014, Tennessee announced the complimentary Supply Segment of the Northeast Energy Direct Project ("Supply Segment") that is directly upstream of the Market Segment and would connect gas supplies from key Marcellus producing counties in northeastern Pennsylvania to Wright. The Supply Segment would involve the looping of up to 50 miles of Tennessee's 300 Line and then approximately 117 miles of greenfield pipeline from northeastern Pennsylvania to Wright. The two project segments spanning from northeastern Pennsylvania to Dracut are known, collectively, as the Northeast Energy Direct Project. While a full list of participants in the open season has not yet been announced publicly, on July 30, 2014 it was announced that Kinder Morgan has reached an agreement with a group of New England LDCs that would serve as anchor shippers for approximately 500 MMcf/d on the Market Segment.[21] It is Concentric's understanding that the proposed capacity of the Supply Segment of the Northeast Energy Direct Project will range from 800 MMcf/d to 1.0 Bcf/d, while the capacity of the Market Segment will range from 1.2 Bcf/d to 2.2 Bcf/d, with the actual capacity of both segments depending on shipper interest and signed precedent agreements. The expected in-service date for the Northeast Energy Direct Project is November 1, 2018.[22]

<u>*M&NP-US*</u>

All of the transportation routes from the Mid-Atlantic or eastern Canada that are discussed would likely rely on the M&NP-US system to connect upstream gas flows to DELNG in eastern Maine. Under the Kinder Morgan Route, DELNG shippers could contract for capacity on M&NP-US from the interconnection with Tennessee's proposed Northeast Energy Direct Project at Dracut, north to the Facility. Currently, M&NP-US has a capacity of approximately 830 MMcf/d that is configured to flow north-to-south from the New Brunswick/U.S. border to Dracut, and a smaller interconnection with both the Algonquin and Tennessee systems in Beverly, Massachusetts. To deliver natural gas to DELNG, M&NP-US would likely require reversal.

Of the 830 MMcf/d of capacity on the M&NP-US system, Repsol has contracted for 730 MMcf/d of this capacity through February 2034. Repsol obtained this capacity on M&NP-US in 2009 with the intention of delivering gas imported to its Canaport LNG facility to markets in the Northeast. However, with increased global demand for LNG driving up prices in overseas markets, LNG

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21 SNL Financial, "New England gas LDCs support Kinder Morgan's Northeast Energy Direct project", July 30, 2014.

22 Tennessee Gas Pipeline Company, Presentation by Curtis Cole to the Northeast Energy and Commerce Association, Cambridge, Massachusetts, June 5, 2014

imports to Canaport have been diverted to other markets and Repsol's contracted capacity on M&NP-US has gone largely unutilized in the past few years. It is possible that a DELNG shipper could contract for Repsol's capacity on M&NP-US via capacity release. In addition, since all other existing contracts on M&NP-US are currently set to expire before the end of 2019,[23] and with Repsol's contractual capacity going unutilized, it is possible that nearly all of the capacity of the M&NP-US system generally could be available for DELNG shippers to flow gas from south-to-north as of 2019.[24]

B. Spectra Route

The Spectra Route provides an opportunity for DELNG shippers to source natural gas from the Marcellus/Utica region at upstream points on Algonquin's system (*i.e.*, Lambertville, New Jersey or Ramapo, New York) and then transport it on one of Spectra's proposed pipeline expansions into New England. Spectra's current Atlantic Bridge project includes infrastructure additions/modifications of two pipelines: (i) the Algonquin system to the interconnect with M&NP-US at Beverly, and (ii) the M&NP-US system to transport gas from Beverly to DELNG. Specifically, on February 5, 2014, Spectra Energy announced the Atlantic Bridge Project, which would expand the existing Algonquin pipeline and reverse the M&NP-US system in order to provide between 100 MMcf/d and 600 MMcf/d of additional capacity from Marcellus and Utica production to markets in New England and Atlantic Canada. An open season for the Atlantic Bridge Project concluded on March 31, 2014, and the project is expected to be placed in service in 2017.[25] Additionally, in response to the New England Governors initiative to expand energy infrastructure into New England to address electric reliability concerns, on June 27, 2014 Spectra announced a new expansion project to bring up to an additional 1 Bcf/d of capacity to New England, which is in addition to the AIM and Atlantic Bridge Projects. While the primary purpose of this project is to serve electric generators in New England, this new project could also provide an additional opportunity for DELNG shippers.

23 Excludes contracts for service on M&NP-US lateral lines.

24 Maritimes & Northeast Pipeline, LLC, Information Postings, Index of Customers, accessed May 14th, 2014

25 Atlantic Bridge Open Season Notice for Firm Service, February 5, 2014-March 31, 2014

C. TransCanada Route

Under the TransCanada Route, DELNG shippers could source natural gas from the Dawn trading hub in southeastern Ontario. Located in southeastern Ontario, Dawn is one of North America's largest natural gas supply and storage hubs, with access to supply basins in western Canada, the Rockies, Mid-Continent, the Gulf of Mexico, and the Marcellus/Utica shale basins. The gas sourced at Dawn could be transported on: (i) the TransCanada Mainline from Dawn to the interconnect with PNGTS at East Hereford[26], (ii) PNGTS from East Hereford to the interconnect with M&NP-US at Westbrook; and (iii) M&NP-US from Westbrook to DELNG. In a variation of the TransCanada Route, DELNG shippers could alternatively source natural gas at Wright, as opposed to Dawn, and then transport these supplies on the Iroquois pipeline from Wright to the interconnection with TransCanada's Mainline at Waddington. From Waddington, the remainder of the TransCanada Route would be identical to the path used for supplies sourced at Dawn, with supplies shipped on the TransCanada Mainline, PNGTS, and M&NP-US.

<u>*TransCanada*</u>

TransCanada completed the 2016 New Capacity Open Season ("2016 NCOS") in January 2014 for firm transportation capacity to connect natural gas supplies to Canadian and U.S. Northeast markets, including transportation to East Hereford from the Union Parkway Belt in Ontario and the interconnection with the Iroquois pipeline at Waddington. The results of the 2016 NCOS have not yet been made public. TransCanada has not indicated the quantity of pipeline capacity available under the 2016 NCOS, but a previous open season held last summer that did not result in contractual commitments or an expansion of the Mainline, had offered up to approximately 300 MMcf/d to East Hereford.[27] Service would commence November 1, 2016, and TransCanada has indicated that it is offering such transportation service pursuant to fixed rates for a contract term of 15 years. As previously noted, TransCanada provides an integrated transportation service from Dawn to East Hereford, that includes the use of the Union Gas pipeline system. Under the TransCanada Route, gas sourced at Dawn could be transported from Dawn to Parkway on a Union Gas pipeline before entering TransCanada's Mainline. Union's pipeline from Dawn to Parkway

26 TransCanada provides an integrated transportation service from Dawn to East Hereford that includes transportation on the Union Gas ("Union") and Trans-Quebec & Maritimes ("TQM") pipelines.

27 TransCanada Corporation, 2015/16 NCOS Materials

would also likely have to be expanded in coordination with TransCanada's Mainline to accommodate expanded capacity from Dawn into New England via this route.

PNGTS

PNGTS also conducted an open season for its proposed Continent-to-Coast ("C2C") expansion project from December 2013 to January 2014, with the project expected to be in-service as of November 2016. While the C2C open season officially closed in January 2014, PNGTS has indicated that the open season deadline will be unofficially extended until upstream regulatory uncertainty pertaining to tolls on TransCanada's Mainline can be resolved.[28] While the C2C project is being offered in coordination with TransCanada's 2016 NCOS, unlike the TransCanada project, PNGTS has stated that the C2C project is expected to increase the total capacity of its system from 168 MMcf/d to approximately 335 MMcf/d.[29] It is Concentric's understanding that the existing PNGTS system could be expanded through compression beyond the capacity reflected in the C2C open season for deliveries on M&NP-US north of Westbrook to accommodate additional volumes.

M&NP-US

Similar to the Kinder Morgan and Spectra Routes, the northern portion of M&NP-US could be reversed to accommodate receipts from PNGTS at Westbrook to be delivered to DELNG.

Iroquois

As noted above, DELNG shippers could use a variation of the TransCanada Route to source gas supplies at Wright as an alternative to Dawn. Iroquois is currently configured to flow north-to-south from the interconnection with TransCanada at Waddington to various interstate pipeline and utility interconnections in New York and Connecticut. Under the TransCanada Route, gas sourced at Wright could be transported northward to Waddington via a reversal of Iroquois' Zone 1 pipeline segment. In January 2014, Iroquois completed an open season for the South-to-North Project ("So-No"), which would provide up to 300 MMcf/d of capacity for delivery to TransCanada's Mainline at

28 PNGTS, Presentation by Cynthia Armstrong at the Northeast Gas Association's Market Trends Forum, Hartford, Connecticut, May 1, 2014

29 PNGTS, C2C Open Season Documents

Waddington beginning in November 2016, but the results of this open season have not yet been made public.[30]

[30] The open season for Iroquois' "South-to-North" project was coordinated with open seasons for TransCanada's "2016 NCOS" project and PNGTS' "Continent-to-Coast" project, in order to provide expanded capacity from Wright to an interconnection with the M&NP-US system at Westbrook.

IV. Evaluation of Potential New England Market Impact Associated with DELNG

As noted, Concentric was asked to evaluate whether the construction and commercial operation of the Facility would likely exacerbate the existing natural gas market circumstances in New England that have been characterized by high and volatile prices. Based on our review and understanding of the New England natural gas market, it is expected that the impact of the Facility on existing market circumstances would, at a minimum, be neutral and not exacerbate the current conditions. In fact, depending on how the Facility is utilized by shippers, development of the Facility may also help mitigate future natural gas prices in New England if DELNG shipper pipeline capacity is made available to the marketplace on certain highly constrained days. In addition, DELNG shippers may provide additional opportunities for New England market participants to participate in projects to bring low-cost natural gas from either the Mid-Atlantic or eastern Canada to New England, and could also lower the cost of such incremental capacity by providing economies of scale.

First, the market impact of the Facility is expected to be neutral in New England because all of the gas to be exported from the Facility would likely be transported using incremental firm pipeline capacity made available by one or more pipeline projects that have already been announced or are under development to serve growing demand in New England. In other words, natural gas transported through New England for liquefaction and export at the Facility will not reduce the very limited unutilized capacity into the region for which shippers already actively compete, and therefore will not contribute to the existing price volatility and price spikes that have been experienced. Recent price spikes in New England are the result of multiple market participants who do not hold firm contracts competing for small amounts of unutilized capacity on the existing pipeline infrastructure. It is expected that shippers using the Facility to export LNG will likely use their contracted firm pipeline capacity at a fairly high load factor (*i.e.*, at or close to 100% of the time) unless they commit to release capacity to increase the amount of gas supply available on high consumption winter days. If shippers commit to release capacity to the secondary market (through either capacity release or to be used as interruptible capacity), the construction of the Facility could help to mitigate high gas prices.

The construction and operation of the Facility may also benefit the New England natural gas market by providing increased availability of pipeline capacity during peak periods and creating an opportunity for lower cost pipeline capacity into the region. Specifically, should the DELNG shippers export less than the design capacity of the Facility during certain periods, or if shippers were able to utilize on-site storage at the Facility to meet export requirements during certain periods, then it is possible that the DELNG shippers would not utilize 100% of their firm pipeline capacity on a daily basis. Rather, under this circumstance, there is the potential that a portion of the DELNG shippers' pipeline capacity, particularly during peak winter months, could be made available to the regional market (*e.g.*, 345-day service or multi-party contracts), thus helping to mitigate winter price spikes in New England. Under a 345-day service contract, DELNG shippers would have firm pipeline capacity rights on 345 days of the year, but would agree to be interrupted up to 20 days of the year. Under a multi-party contract, DELNG shippers would share annual firm capacity rights with one or more other parties. For example, another party may have firm capacity rights for the month of January, and DELNG shippers may hold firm capacity for the rest of the year.[31] It is Concentric's understanding that DELNG may be amenable to some form of scaled back operations during peak demand periods which would facilitate these types of arrangements. Therefore, if DELNG shippers contract for firm transportation capacity to New England, but operationally do not fully utilize such capacity on an annual basis and create firm pipeline capacity to be used by other parties during periods when the pipelines are especially constrained, it could reduce the prices that would have otherwise occurred, providing a direct benefit to the region.

Moreover, as discussed above, there are multiple pipeline projects that have been proposed to expand capacity into New England from the Mid-Atlantic and eastern Canada. There is the potential that the construction of the Facility, and the associated firm transportation contracts signed by shippers exporting from it, could positively affect the viability and potentially lower the cost of incremental pipeline capacity into New England. For example, many of the currently proposed pipeline projects into New England are scalable and, as a result, will be sized to accommodate the market need and ability of shippers to sign firm long-term contracts. DELNG shipper participation in one or more of these pipeline expansion projects could affect the viability of an expansion and thus provide a benefit to other market participants by offering opportunities for customers with smaller incremental needs to participate in a pipeline expansion project that otherwise might not be constructed due to lack of sufficient contractual underpinning.

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[31] On March 20, 2014, FERC issued a Notice of Proposed Rulemaking (Docket No. RM14-2-000) that, among other things, requires interstate pipelines to offer firm contracts where multiple shippers can share pipeline capacity under a single contract (*i.e.*, multi-party firm transportation contracts).

Under current electric market rules in New England, electric generation lacks a means of recovering the costs associated with firm pipeline contracts; however, as discussed above, natural gas demand for electric generation is growing. At the same time, natural gas in New England trades at a premium (with record-setting spikes experienced during cold snaps this past winter), while Marcellus basin prices are depressed due to constraints on the existing pipeline infrastructure connecting New England to Mid-Atlantic production. Thus, in this market environment, many pipelines are eying expansions, but have struggled to attract the contractual commitments necessary to move ahead with these projects. For example, Spectra's AIM project was originally expected to be 500 MMcf/d, but ended up at 342 MMcf/d, due to contractual support being limited to LDCs with no electric generators contracting for firm capacity.[32] By contracting for some or all of its capacity needs, a larger volume base load shipper, such as at the Facility, could have a significant effect on a proposed pipeline project's ability to be constructed and serve future load requirements in New England, thus allowing smaller market participants access to production that they otherwise might not have had.

Further, at a minimum, it is expected that the Facility would not hinder any proposed pipeline projects. Participation in any of these incremental pipeline projects by DELNG shippers will not eliminate or prohibit the opportunity for other market participants to participate in any of these projects. Due to the open access nature of the interstate pipeline system, all parties requiring firm pipeline capacity will be able to participate in the various open seasons offered by the pipelines.

DELNG shipper participation in pipeline expansions could also potentially reduce the cost of incremental natural gas pipeline infrastructure for all participants by providing economies of scale that might not otherwise be achieved with the existing shipper base. The extent to which DELNG shipper participation reduces the unit cost of pipeline infrastructure will depend on how the 450 MMcf/d of capacity is distributed among the available transportation routes and the nature of the facilities required to achieve expansions on the various pipelines, among other things, but the per unit costs associated with a project could be lower if spread over larger volumes that could be achieved with the participation of DELNG shippers.

32 SNL Financial, "Lack of generator interest prompts Spectra to shrink planned capacity for pipe," September 11, 2013

While North American natural gas prices may be affected by the overall level of LNG ultimately exported from the continent, the Facility on a stand-alone basis is not expected to have a material impact on pricing due to its relatively small size. The volume of such exports from North America, in total, could affect the natural gas supply/demand balance in North America, and therefore North American natural gas prices. However, these potential market developments may occur regardless of whether DELNG is constructed, and DELNG's liquefaction capability of 450 MMcf/d is not large enough on a stand-alone basis to have a material impact on the overall North American market or regional markets in the Mid-Atlantic or eastern Canada depending on where DELNG shippers opt to source their gas supplies. As discussed previously, the current level of natural gas production from the Marcellus/Utica basins is approximately 16 Bcf/d, and is expected to continue to grow rapidly in the future. In contrast, the demand requirements associated with the Facility would represent only 3% of total current production levels, and clearly even less of the projected future natural gas production out of this region. Dawn is already one of the most liquid trading points in North America, with average daily trading volumes of 9 Bcf/d. The demand requirements of DELNG shippers would represent approximately 5% of the total daily trade volume at the Dawn hub. Therefore, the incremental demand requirements associated with the Facility on a stand-alone basis are not expected to materially increase natural gas prices otherwise paid by customers sourcing supplies in the Mid-Atlantic or eastern Canada.

EXHIBIT D

STATE AND LOCAL ECONOMIC IMPACTS OF A PROPOSED BI-DIRECTIONAL LNG TERMINAL IN WASHINGTON COUNTY, MAINE

August 2014

Todd Gabe, Ph.D.[1]

Commissioned by: Downeast LNG

Results of the study show that:

- Constructing a bi-directional liquefied natural gas (LNG) facility, with an annual processing capacity of three million tonnes, will require an estimated $2.0 billion upfront investment.
- Over a three-year construction period, the proposed LNG terminal will generate a total statewide economic impact—including multiplier effects—of an estimated $1.5 billion in output, an average of 3,525 full- and part-time jobs, and a three-year total of $562 million in labor income.
- The impact of facility construction on the Washington County economy—including multiplier effects—will be an estimated $660 million in output, an average of 2,195 full- and part-time jobs, and a three-year total of $266 million in labor income.
- After the proposed LNG terminal is completed, the permanent statewide impact of its annual operations—including multiplier effects—will be an estimated $102 million in output, 505 full- and part-time jobs, and $32.4 million in labor income.
- The permanent impact of the LNG terminal's annual operations on the Washington County economy—including multiplier effects—will be an estimated $69.6 million in output, 310 full- and part-time jobs, and $20.9 million in labor income.

[1] Todd Gabe (todd.gabe@yahoo.com) is a Professor of Economics at the University of Maine. This study was conducted under a private consulting contract with Downeast LNG.

STATE AND LOCAL ECONOMIC IMPACTS OF A PROPOSED BI-DIRECTIONAL LNG TERMINAL IN WASHINGTON COUNTY, MAINE

1. BACKGROUND AND INTRODUCTION

Downeast LNG is proposing to build and operate a bi-directional liquefied natural gas (LNG) terminal in Robbinston, Maine. The facility would include a pier; one or more LNG storage tanks; equipment used to convert natural gas into a liquid (i.e., liquefaction) and to transform LNG from a liquid to a gas; and a natural gas pipeline. The proposed LNG terminal would take three years to build and, once operational, it would have the capacity to process three million tonnes of LNG per year (MMtpy).

The purpose of this study is to examine the state and local (i.e., Washington County) economic impacts of the proposed bi-directional LNG terminal in Robbinston, Maine.[2] Economic impact is defined as the output (i.e., revenue), employment and labor income (e.g., wages and salaries) that are directly related to the project's spending, as well as the multiplier effects supported by the expenditures made in Maine (and Washington County) by companies and workers that are associated with the LNG facility. Separate economic impact assessments will be conducted for the terminal's temporary construction phase and its permanent operations. The economic impact analysis is based on data and information from a variety of sources, including studies of other LNG facilities that have been proposed elsewhere in the United States.

[2] A similar study (see Gabe et al., in the references section) was conducted in 2005, although the proposed facility at that time was a $400 million LNG import terminal—and not a bi-directional facility with liquefaction equipment.

A key factor influencing the proposed facility's impact on the state and local economies—in both the construction and permanent operations phases of the project—is the amount of spending that is likely to occur in the region. This is determined by the total amounts of spending required for the construction and operations of a 3 MMtpy bi-directional LNG facility, and the percentages of these expenditures that are likely to take place in Maine and Washington County.

Table 1 shows the estimated construction costs for a 3 MMtpy LNG terminal and its estimated annual operating expenditures. The estimated construction cost of $661.4 million per million tonnes of annual processing capacity is an average figure calculated using information from the following sources: "LNG: A Liquid Market," published in *The Economist* magazine; "LNG Ready for Export: Shale Gas Ignites Change," published in *EnergyBiz* magazine; "An Economic Impact Analysis of the Construction of an LNG Terminal and Natural Gas Pipeline in Oregon," prepared by ECONorthwest for the Jordan Cove Energy Project, L.P.; and "Current State & Outlook for the LNG Industry," presented at the Rice University Global E&C Forum. The estimated operating expenditures of $31.5 million per million tonnes of annual processing capacity are based on figures from "An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon," prepared by ECONorthwest. The annual operating expenditures cover the wages and salaries of individuals employed by the facility, as well as expenditures on—among other things—contract services and maintenance, and vessel services.

Table 1. Estimated Construction and Operating Expenditures

Construction Costs ($ / MMtpy)	$661,430,210
Proposed Capacity	3 MMtpy
Estimated Construction Costs	$1,984,290,630
Annual Operating Expenditures ($ / MMtpy)	$31,456,889
Proposed Capacity	3 MMtpy
Estimated Operating Expenditures	$94,370,667

Notes. Construction costs of $661,430,210 per MMtpy are based on figures from the following sources: "LNG: A Liquid Market," published in *The Economist* magazine; "LNG Ready for Export: Shale Gas Ignites Change," published in *EnergyBiz* magazine; "An Economic Impact Analysis of the Construction of an LNG Terminal and Natural Gas Pipeline in Oregon," prepared by ECONorthwest for the Jordan Cove Energy Project, L.P.; and "Current State & Outlook for the LNG Industry," presented by Gerald Humphrey at the Rice University Global E&C Forum. Annual operating expenditures of $31,456,889 per MMtpy are based on figures from "An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon," prepared by ECONorthwest.

2. ECONOMIC IMPACT ANALYSIS

Table 2 presents information on the temporary statewide economic impacts associated with the construction of Downeast LNG's proposed bi-directional LNG facility in Robbinston, Maine. The economic impact analysis is based on a three-year construction period, with expenditures evenly split across the three years (i.e., $661 million per year).[3] The construction costs cover a wide variety of expenditure categories, including—among other things—the berthing facility and tugboats, trestle and pier, the LNG terminal, and engineering and management services.

[3] Actual expenditures will differ in each year of construction. This means that the employment and labor income impacts, shown later in the report, will also vary by year; however, the estimated impacts over the entire three-year construction project will be similar to those implied in Tables 2 and 3.

The direct output of $305 million is interpreted as the estimated amount of project investment (of the $661 million per year) that would take place in Maine (estimated by the Maine IMPLAN model, which is described below). In-state spending of $305 million is equivalent to 46 percent of the proposed LNG facility's annual construction costs. The direct employment of 1,651 full- and part-time jobs, and $118.7 million in labor income are the estimated (by the Maine IMPLAN model) in-state labor market activity that would be supported by the $305 million of construction spending.[4]

The multiplier effects shown in Table 2 are the additional output (i.e., revenue), employment and labor income (e.g., wages and salaries) in Maine that are supported by the purchases of businesses and workers that are impacted by the LNG facility's construction. The IMPLAN model, used to estimate the multiplier effects, is an input-output framework that traces the flows of expenditures and income through the Maine economy with a complex system of accounts that are uniquely tailored to the region. Underlying these accounts is information regarding transactions occurring among businesses located in Maine, the spending patterns of households, and transactions occurring between Maine business and households and the rest of the world. Some of the data sources used to develop the IMPLAN model include County Business Patterns of the U.S. Census Bureau, Regional Economic Information System (REIS) data and input-output accounts from the U.S. Bureau of Economic Analysis, and ES-202 statistics from the U.S. Bureau of Labor Statistics.

[4] The IMPLAN model is based on an employment headcount, which does not distinguish between full- and part-time workers.

Table 2. Estimated Temporary Statewide Economic Impacts of LNG Terminal Construction: Years 1 to 3

	Direct Impact	Multiplier Effects	Total Impact
Output	$305,413,565 per year	$179,411,717 per year	$484,825,282 per year
Employment	1,651	1,874	3,525
Labor Income	$118,748,651 per year	$68,666,296 per year	$187,414,947 per year
Output	$916,240,696 3-year impact	$538,235,152 3-year impact	$1,454,475,848 3-year impact
Employment	1,651	1,874	3,525
Labor Income	$356,245,954 3-year impact	$205,998,887 3-year impact	$562,244,841 3-year impact

Notes: Direct output of $305.4 million (or $916.2 million over three years) is interpreted as the estimated amount of construction expenditures that would take place in Maine. The direct impact estimates are based on an overall project cost of $2.0 billion (see Table 1); figures from "The Economic Impacts of Increased LNG Import Capacity on Louisiana, 2004-2009," published by the Tulane-Entergy Energy Institute; figures from "Application of Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C., for Authorization Under Section 3 of the Natural Gas Act and Application of Southern LNG Company, L.L.C. for Abandonment Under Section 7 of the Natural Gas Act," submitted to the Federal Energy Regulatory Commission by Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C; and information from the Maine IMPLAN model. Multiplier effects are estimated by the Maine IMPLAN model. The "3-year impact" figures for output and labor income are the "per year" impacts multiplied by three. The "3-year impacts" for employment are average figures, because some of the construction jobs could last over the entire period.

Including multiplier effects, the construction of the proposed Downeast LNG terminal (based on a total investment of $2.0 billion) would have a statewide annual economic impact—in each of the three years—of an estimated $485 million in output, 3,525 full- and part-time jobs, and $187 million in labor income. These figures indicate that the workers directly and indirectly involved in the construction of the proposed bi-directional LNG facility would earn an average of $53,167 in labor income per year.

The statewide output multiplier of 1.59, defined as the ratio of total output ($485 million) to direct output ($305 million), suggests that every $1.00 of spending in Maine on the construction of the proposed LNG terminal would support a total of $1.59 in statewide economic activity; that is, the "initial" $1.00 in spending plus an additional $0.59 spread across other Maine locations and sectors of the economy. The statewide employment multiplier of 2.14, calculated as the ratio of total (3,525 jobs) to direct (1,651 jobs) employment, implies that the economic activity associated with each person directly related to the LNG facility's construction would support a total of 2.14 Maine jobs; that is, the person related to the terminal's construction and an additional 1.14 full- and part-time jobs elsewhere in the state.

The bottom panel of Table 2 shows the estimated aggregate statewide economic impacts of the proposed LNG terminal's construction over the entire construction phase. The employment impacts are reported as average values, and not the sum of impacts for all three years, because some of the construction jobs could last over the entire period. Including multiplier effects, the three-year statewide economic impacts of the proposed LNG facility's construction are an estimated $1.5 billion in output, an average of 3,525 full- and part-time jobs, and a three-year total of $562 million in labor income.

Table 3. Estimated Temporary Washington County Economic Impacts of LNG Terminal Construction: Years 1 to 3

	Direct Impact	Multiplier Effects	Total Impact
Output	$176,099,226 per year	$43,897,281 per year	$219,996,507 per year
Employment	1,097	1,098	2,195
Labor Income	$68,469,603 per year	$20,211,684 per year	$88,681,287 per year
Output	$528,297,677 3-year impact	$131,691,844 3-year impact	$659,989,521 3-year impact
Employment	1,097	1,098	2,195
Labor Income	$205,408,809 3-year impact	$60,635,053 3-year impact	$266,043,862 3-year impact

Notes: Direct output of $176.1 million (or $528.3 million over three years) is interpreted as the estimated amount of construction expenditures that would take place in Washington County. The direct impact estimates are based on an overall project cost of $2.0 billion (see Table 1); figures from "The Economic Impacts of Increased LNG Import Capacity on Louisiana, 2004-2009," published by the Tulane-Entergy Energy Institute; figures from "Application of Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C., for Authorization Under Section 3 of the Natural Gas Act and Application of Southern LNG Company, L.L.C. for Abandonment Under Section 7 of the Natural Gas Act," submitted to the Federal Energy Regulatory Commission by Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C; and information from the Washington County IMPLAN model. Multiplier effects are estimated by the Washington County IMPLAN model. The "3-year impact" figures for output and labor income are the "per year" impacts multiplied by three. The "3-year impacts" for employment are average figures, because some of the construction jobs could last over the entire period.

Table 3 presents information on the temporary county-level economic impacts of the proposed bi-directional LNG terminal's construction. The local (i.e., Washington County) economic impacts are lower than those estimated for the entire state for a couple of reasons. First, IMPLAN estimates for the percentage of construction spending captured by the region are much higher for Maine than Washington County. Second, the multipliers are higher for Maine than Washington County because the state offers a wider variety of products and services that could be purchased by the companies involved in the construction project, and their suppliers and employees.

The direct output of $176 million is the estimated amount of annual construction expenditures (of the $661 million per year) that would take place in Washington County. This amount of local spending, along with the local employment of 1,097 full- and part-time jobs and labor income of $68.5 million per year, is estimated by the IMPLAN model for Washington County. Including multiplier effects, the three-year impact of the proposed LNG terminal's construction on the Washington County economy is an estimated $660 million in output, an average of 2,195 full- and part-time jobs, and a three-year total of $266 million in labor income.

The county-level output multiplier of 1.25, defined as the ratio of total output ($220 million) to direct output ($176 million), suggests that every $1.00 of spending in Washington County on the construction of the proposed LNG facility would support a total of $1.25 in local economic activity; that is, the "initial" $1.00 in spending plus an additional $0.25 spread across the county. The county-level employment multiplier of 2.00, calculated as the ratio of total (2,195 jobs) to direct (1,097 jobs) employment, implies that the economic activity associated with each person in Washington County directly related to the LNG facility's construction would support a total of two local jobs; that is, the person related to the terminal's construction and one additional full or part-time job elsewhere in Washington County.

Permanent Impacts of the Proposed LNG Terminal's Annual Operations

After the three-year construction phase of the proposed LNG terminal is completed, the facility will provide ongoing impacts on the Maine and Washington County economies through its permanent operations. As shown in Table 1, the annual operating expenses—based on information from "An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon," prepared by ECONorthwest—are an estimated $94.4 million for a bi-directional LNG terminal with a proposed capacity of three million tonnes per year.

Table 4 shows information on the estimated county-level economic impact of the proposed LNG facility's permanent operations, starting in "year 4" and continuing into the future. The direct output of $56.0 million per year is interpreted as the estimated amount of annual operating expenditures that would take place "in and around" the terminal. These expenditures include—among other things—the wages and salaries paid to employees of the facility, vessel services, and contract services and maintenance. This amount of spending would support, based on figures from the Washington County IMPLAN model, an estimated 185 full- and part-time jobs (including the contract services and maintenance providers) and $16.9 million in labor income, which translates into an estimated $91,420 in labor income per (direct) employee.[5]

[5] The direct employment and labor income estimates are also based on figures from "An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon," prepared by ECONorthwest; and "Application

The total annual local (i.e., Washington County) economic impact of LNG terminal operations, including multiplier effects, is an estimated $69.6 million in output, 310 full- and part-time jobs, and $20.9 million in labor income. These figures indicate that the workers directly and indirectly involved in the local operations of the proposed bi-directional LNG facility would earn an average of $67,564 in labor income per year.

Table 4. Estimated Permanent Washington County Economic Impacts of LNG Terminal Operations: Year 4 and into the Future

	Direct Impact	Multiplier Effects	Total Impact
Output	$55,978,511 per year	$13,666,878 per year	$69,645,389 per year
Employment	185	125	310
Labor Income	$16,912,743 per year	$4,032,191 per year	$20,944,934 per year

Notes: Direct output of $56.0 million per year is interpreted as the estimated amount of operating expenditures that would take place "in and around" the facility. The direct impact estimates are based on figures from "An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon," prepared by ECONorthwest; figures from "Application of Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C., for Authorization Under Section 3 of the Natural Gas Act and Application of Southern LNG Company, L.L.C. for Abandonment Under Section 7 of the Natural Gas Act," submitted to the Federal Energy Regulatory Commission by Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C; and information from the Washington County IMPLAN model. Multiplier effects are estimated by the Washington County IMPLAN model.

of Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C., for Authorization Under Section 3 of the Natural Gas Act and Application of Southern LNG Company, L.L.C. for Abandonment Under Section 7 of the Natural Gas Act," submitted to the Federal Energy Regulatory Commission by Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C.

Table 5 shows information on the estimated statewide annual economic impact of the proposed Downeast LNG bi-directional terminal in Robbinston, Maine. For this part of the analysis, the direct impact is—once again—the economic activity that is estimated to take place "in and around" the proposed facility. The multiplier effects are the additional output, employment and labor income that would be supported elsewhere in Maine as a result of the LNG terminal's operations. Results of the analysis indicate that, including multiplier effects, the proposed Downeast LNG terminal would have an ongoing annual impact on the Maine economy of an estimated $102 million in output, 505 full- and part-time jobs, and $32.4 million in labor income.

Table 5. Estimated Permanent Statewide Economic Impacts of LNG Terminal Operations: Year 4 and into the Future

	Direct Impact	Multiplier Effects	Total Impact
Output	$55,978,511 per year	$46,081,643 per year	$102,060,154 per year
Employment	185	320	505
Labor Income	$16,912,743 per year	$15,502,066 per year	$32,414,809 per year

Notes: Direct output of $56.0 million per year is interpreted as the estimated amount of operating expenditures that would take place at the facility. The direct impact estimates are based on figures from "An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon," prepared by ECONorthwest; figures from "Application of Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C., for Authorization Under Section 3 of the Natural Gas Act and Application of Southern LNG Company, L.L.C. for Abandonment Under Section 7 of the Natural Gas Act," submitted to the Federal Energy Regulatory Commission by Elba Liquefaction Company, L.L.C., and Southern LNG Company, L.L.C; and information from the Maine IMPLAN model. Multiplier effects are estimated by the Maine IMPLAN model.

The statewide employment multiplier of 2.73, defined as the ratio of total employment (505 jobs) to direct employment (185 jobs), suggests that the economic activity associated with each person involved in the proposed LNG facility's annual operations would support a total of 2.73 Maine jobs; that is, the person working "in and around" the facility—including contract services and maintenance employees—and an addition 1.73 full- and part-time jobs elsewhere in the state. This multiplier is larger than the one calculated for Washington County [i.e., 1.68, which is the ratio of total (310 jobs) to direct (185 jobs) employment] because the state offers a wider variety of products and services that could be purchased by the proposed LNG terminal, and its suppliers and employees.

3. SUMMARY AND CONCLUSIONS

The purpose of this study was to examine the state and local (i.e., Washington County) economic impacts of a proposed bi-directional LNG facility in Robbinston, Maine. This project, which involves a terminal with the capacity to process three million tonnes of LNG annually, would impact the economy through its temporary construction phase and the facility's permanent operations. The construction of a LNG facility of this size would have upfront costs of an estimated $2.0 billion, and an estimated $94.4 million per year in ongoing operating expenditures.

Results of the study show that the construction of the proposed LNG facility would generate $305 million in direct in-state expenditures per year. Including multiplier effects, the total annual statewide economic impact of this spending would be an estimated $485 million in output, 3,525 full- and part-time jobs, and $187 million in labor income for three years. Over the entire three-year construction project, the total statewide economic impact—including multiplier effects—would be an estimated $1.5 billion in output, an average of 3,525 full- and part-time jobs, and a three-year total of $562 million in labor income.

The total three-year impact of the proposed LNG facility's construction on the Washington County economy would be, including multiplier effects, an estimated $660 million in output, an average of 2,195 full- and part-time jobs, and a three-year total of $266 million in labor income. The impacts on the Washington County economy are lower than those determined for the entire state because the percentage of construction spending captured by the region would be much higher for Maine than Washington County. Likewise, the multiplier effects are higher for Maine than Washington County because the state offers a wider variety of products and services that could be purchased by the companies involved in the construction project, and their suppliers and employees.

After the proposed bi-directional LNG facility is completed, it would generate an ongoing economic impact through its expenditures on operations and maintenance, and the jobs created "in and around" the terminal (i.e., the LNG facility's employees, and contract services and maintenance workers). Including multiplier effects, the ongoing operations of the proposed LNG facility would have a permanent annual statewide economic impact of an estimated $102 million in output, 505 full- and part-time jobs, and $32.4 million in labor income. The LNG terminal's operations would have an annual impact on the Washington County economy, including multiplier effects, of an estimated $69.6 million in output, 310 full- and part-time jobs, and $20.9 million in labor income. This employment impact of 310 jobs in Washington County includes an estimated 185 positions available "in and around" the proposed LNG facility.

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