INTERVENORS' COMMENTS ON PENNEAST'S APPLICATION

FERC DOCKET #CP15-558

SUBMITTED ON BEHALF OF:

NEW JERSEY CONSERVATION FOUNDATION

AND

STONY BROOK-MILLSTONE WATERSHED ASSOCIATION

BY:

Edward Lloyd, Esq.
Columbia University Environmental Law Clinic
435 West 116th Street
New York NY 10027[1]

Jennifer Danis, Esq.
Eastern Environmental Law Center
744 Broad Street, Ste. 1525
Newark, NJ 07102

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[1] Columbia University Law students Anthony Fares, Channing Jones, and Archan Hazra provided invaluable assistance in preparing these comments.

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INTERVENORS' COMMENTS ON PENNEAST'S PROPOSED ANSWER

Intervenors submit the following comments on the Proposed Answer of the PennEast Pipeline Company ("PennEast"), FERC Docket #CP15-558, Document Accession #20151113-5247.[2] In Part I, Intervenors provide the Federal Energy Regulatory Commission ("FERC," or the "Commission") with evidence and analysis showing that the PennEast Pipeline Project ("PennEast project") cannot meet the Natural Gas Act legal standard for need, and that the economics do not support this project. In Part II, Intervenors demonstrate that the PennEast application also forms an insufficient basis to conduct the required National Environmental Policy Act ("NEPA") analysis of project purpose and need. In Part III, Intervenors provide compelling reasons for FERC to suspend review of this project pending a regional gas market planning initiative. Part IV contains Intervenors' preliminary critique of the current data and analysis contained in the inconsistent record with respect to alternatives. Part V demonstrates that PennEast's proposed narrow interpretation of cumulative impacts from similar actions will not suffice under NEPA. And in Part VI, Intervenors renew their request that FERC hold an evidentiary hearing given the inaccurate and misleading record data that PennEast has submitted. Part VII concludes by requesting that FERC suspend review of this application, or, in the alternative, deny a certificate of public convenience and necessity given the

[2] The Commission's regulations generally do not permit answers to protests. See 18 C.F.R. § 385.213(a)(2) (2015) ("An answer may not be made to a protest . . . unless otherwise ordered by the decisional authority") (emphasis in original). Where, as here, PennEast's proposed answer serves to muddy the record rather than clarify it, the Commission should reject PennEast's request for a waiver of 18 C.F.R. § 385.213(a)(2) (2015). If, however, the Commission does accept PennEast's answer, Intervenors submit the following comments to dispel the misleading arguments contained therein.

updated data and analysis in this record demonstrating that the project does not meet the statutory standard under either the Natural Gas Act or under NEPA.

I. PENNEAST FAILS TO PROVIDE ANY CREDIBLE EVIDENCE UPON WHICH FERC COULD FIND THAT THE PROPOSED PROJECT IS REQUIRED BY THE PUBLIC CONVENIENCE AND NECESSITY

To approve the construction of a pipeline project by issuing a certificate under section 7 of the Natural Gas Act ("NGA"),[3] FERC must find that the proposed project "is or will be required by the present or future public convenience and necessity."[4] To execute this statutory directive, FERC has developed a policy guiding its determination of whether a proposed project is so required.[5] In evaluating a new pipeline proposal under section 7 of the Natural Gas Act, FERC acknowledges that it must examine impacts to the following interests: "the existing customers of the pipeline proposing the project, existing pipelines in the market and their captive customers, . . . landowners and communities affected by the route of the new pipeline."[6] If, after its own assessment, it has developed a record showing that none of these interests will be adversely affected by the proposed pipeline after mitigation measures are taken, FERC may proceed to complete review under the National Environmental Policy Act ("NEPA").[7] However, where these interests are adversely affected

> then the Commission will proceed to evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits

[3] 15 U.S.C. § 717f.
[4] 15 U.S.C. § 717f(e).
[5] See Certification of New Interstate Nat. Gas Pipeline Facilities (Certificate Policy Statement), 88 FERC 61,227 (1999), clarified, 90 FERC ¶61,128, further clarified, 92 FERC ¶61,094 (2000).
[6] Id at 61,745.
[7] Id.

> outweigh the adverse effects on economic interests will the Commission then proceed to complete [NEPA review] where other interests are considered.[8]

As a threshold matter, the PennEast Pipeline Company ("PennEast") has failed to provide credible evidence that indicates this project is required by public convenience and necessity. PennEast's application for the PennEast Pipeline Project ("PennEast project") violates both FERC's certificate policy and the NGA by: (a) failing to demonstrate public need and demand; (b) considering an improperly narrow set of private interests; and (c) considering an impermissibly narrow set of adverse impacts.[9] FERC requires that "[t]o demonstrate that its [pipeline] proposal is in the public convenience and necessity, an applicant must show public benefits that would be achieved by the project that are proportional to the project's adverse impacts."[10] Here, PennEast has not shown that there is any public need that could yield such benefits, much less that its project outweighs the project's adverse impacts. FERC should reject PennEast's application as not required by the public convenience or necessity.

A. PennEast Fails to Provide Credible Evidence of Public Need

PennEast fails to adduce evidence demonstrating that there is public need for its project. This ought to be the end of FERC's inquiry, providing a sound legal basis to deny PennEast's certificate of public convenience and necessity. As set out in great detail

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[8] Id.

[9] See FERC Docket #CP15-558, Accession #20150925-5029, 20150925-5030 (PennEast application for certificate of public convenience and necessity)

[10] Certificate Policy Statement at 61,748.

below, Intervenors and other commenters have provided FERC with affirmative data and analyses demonstrating that, in fact, there is no "need" for the PennEast project. PennEast has given FERC several different conclusory descriptions of the alleged need for its project:

- "to provide a long-term solution to bring the lowest cost natural gas available in the country produced in the Marcellus Shale region in northern Pennsylvania to homes and businesses in New Jersey, Pennsylvania and surrounding states";
- to respond "to market demands in New Jersey and Pennsylvania";
- "to serve markets in the region with firm, reliable access to the Marcellus supplies versus the traditional, more costly Gulf Coast regional supplies and pipeline pathways" and to "enhance[e] the region's supply diversity"; and
- to "provide a benefit to consumers, utilities and electric generators by providing enhanced competition among suppliers and pipeline transportation providers."[11]

These assertions of public need can be distilled down to the following three claims: (1) the project will increase reliability; (2) the project will lower costs; and (3) the project will fill unmet market demand.[12] As set forth in more detail below, and in the expert report attached hereto as Exhibit A, PennEast has not provided sufficient factual evidence to support these claims, and the record now contains evidence directly contradicting them. Accordingly, FERC cannot substantiate a of public convenience and necessity, which it could then weigh against adverse impacts in its NGA section 7 certification process.

[11] FERC Docket No. CP15-558, Accession No. 20150925-5028, Resource Report 1 ("PennEast R.R. 1") at 1-2.
[12] Id.

1. PennEast fails to demonstrate that its project will improve reliability

Reliability is assured when customers can obtain the supplies for which they have contracted. PennEast has failed to identify an enduring reliability issue in the region served. For customers of firm pipeline capacity, including local gas distribution companies in this region, analysis shows that there is currently far more than enough firm capacity to meet customers' needs -- even during peak winter demand. "In total, there are 49.9% more resources available to meet peak day demand from local gas distribution companies in the region than is needed."[13]

For customers who have contracted for interruptible service, reliability is an economic decision and depends heavily on the forecasted frequency of service interruptions. The Eastern Interconnection Planning Collaborative issued a report in July 2015 that describes several approaches for improving reliability of electric generation and mitigating pipeline constraints, "for low frequency, short duration constraints resulting in the non-scheduling or interruption of gas-fired generation." [14] The economics of two primary methods identified in the EIPC study, dual fuel and purchasing natural gas from LNG facilities, were analyzed in greater detail by Skipping Stone.[15] This analysis shows that the PennEast project is not a cost-effective solution. "Based on our analysis of

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[13] See "Analysis of Public Benefit Regarding Penn East Pipeline", at 7-9, attached hereto as Exhibit A (Study commissioned by The New Jersey Conservation Foundation to evaluate whether PennEast will lower costs to consumers and to examine unserved demand for firm capacity.).
[14] Eastern Interconnection Planning Collaborative, Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios and Gas-Electric System Interface Study ("Gas-Electric Report") (July 2, 2015), http://www.eipconline.com/phase-ii-documents.html.
[15] See Exhibit A at 9-11.

alternative costs, one can readily see that it is highly unlikely that an electric generator will choose to bear the fixed cost burden of the firm pipeline capacity and would be economically better off choosing oil or LNG for the few days each year of high, coincident, gas demand."[16]

2. PennEast also fails to demonstrate that its project will reduce costs, and current data and analysis show the opposite -- that it will increase costs for consumers or customers

Data show, contrary to PennEast claims that it will lower costs, that a) Marcellus prices will escalate when new pipeline capacity comes online, and in fact, have already started to do so; and b) the cost differential in the region served by PennEast will shrink, with or without PennEast. For several years, Marcellus natural gas prices have been trading "well below the Henry Hub national benchmark price because of the area's high gas production and limited pipeline takeaway capacity." [17] But building PennEast creates additional capacity, which economists expect will raise, not lower, Marcellus natural gas prices.[18] Now, "[n]ew pipeline investment is expected to increase takeaway capacity from the low cost Marcellus/Utica shale and reduce regional surpluses and increase gas prices by 2018."[19] This occurs because the "spread between Henry Hub and Marcellus natural gas prices narrows as pipeline capacity grows."[20] "New pipelines are already allowing larger amounts of gas to travel from the Marcellus to end users, with the spot price spread

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[16] Id at 4.
[17] U.S. Energy Information Administration, Natural Gas Weekly Update (Jan. 7, 2016), http://www.eia.gov/naturalgas/weekly/archive/2016/01_07/index.cfm.
[18] See id; see also Exhibit A at 12-15.
[19] Public Service Enterprise Group, Edison Electrical institute 2015 Financial Conference (2015), https://www.sec.gov/Archives/edgar/data/81033/000119312515370394/d77337dex99.htm.
[20] See U.S. Energy Information Administration, Natural Gas Weekly Update (Jan. 7, 2016), http://www.eia.gov/naturalgas/weekly/archive/2016/01_07/index.cfm.

between Henry Hub and Leidy Hub decreasing over the last year. The spread has been slashed by more than half in the past 12 months, to 69 cents/MMBtu, as of Feb. 19, from $1.74/MMBtu as of Jan. 29, 2015."[21]

Moreover, existing natural gas prices are already at a low point, with New Jersey prices being amongst the lowest in the nation.[22] Thus, PennEast's assertion that the project is needed because it will lower costs is contrary to both the facts in this particular case and also the economic reality in the natural gas market.

Importantly, FERC Commissioners are concerned with protecting captive, rate-paying customers of competing pipelines from price increases. PennEast adds significant excess capacity to the market in eastern Pennsylvania and New Jersey;[23] as shippers on PennEast reduce their contracts on competing, legacy pipelines, the impact will be to increase, rather than decrease costs to gas customers in the region. Costs will increase for two reasons. First, rate-payers currently recoup significant value from reselling excess capacity on the secondary capacity market. This value would plummet if PennEast's capacity were to come online. Second, if rates are raised on existing pipelines to recover lost revenue, existing rate-payers would be exposed to higher costs.[24] As set out in greater detail in Part III below, FERC must examine this regional economic data.

3. PennEast fails to demonstrate unmet demand to support its project

[21] SNL Financial, "Mega-projects linked to Appalachian shale top list of planned pipelines," by Arsalan Gul, February 25, 2016, attached hereto as Exhibit B.
[22] EIA.gov, State Historical Residential Natural Gas Prices, http://www.eia.gov/dnav/ng/xls/NG_PRI_SUM_A_EPG0_PRS_DMCF_M.xls
[23] Exhibit A at 8-9 "In total, there are 49.9% more resources available to meet peak day demand…"
[24] See Exhibit A at 12-15.

To demonstrate demand-side need for its project, PennEast relies on rudimentary analysis, conclusory statements, self-commissioned studies, circular reasoning, and precedent agreements with its own subsidiary companies. These cannot serve to "develop whatever record is necessary" for FERC to conclude that the PennEast project's benefits outweigh its adverse impacts.[25]

First, PennEast makes sweeping claims of demand-side need based upon a single winter price spike in gas during the winter 2013/2014.[26] PennEast's conclusion that this particular winter price spike justifies the PennEast expansion does not stand up to economic analysis.[27] Most electric generation customers do not purchase firm capacity and choose a more cost-effective strategy to meet their needs.[28] Other regions that have conducted an economic analysis of natural gas demand have come to this very conclusion. For example, the Massachusetts Attorney General's office commissioned an independent regional economic analysis to determine whether there were less harmful alternatives than greenfield pipeline construction to meet the state's energy needs. Even though there were serious physical constraints to the existing natural gas pipeline system, that study revealed that new pipeline construction was the least economical way to meet regional need.[29] Moreover, as it stands, analysis of gas flows within PJM during the Polar Vortex event

[25] See Certificate Policy Statement at 61,749.
[26] PennEast R.R. 1 at 1-5–1-7.
[27] See Exhibit A at 5.
[28] See Gas Electric Report
[29] See Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas, Analysis Group, Inc. (Nov. 2015) ("Even under a 'stressed system' scenario, there are cheaper, less carbon intensive ways [than additional new natural gas pipelines] to ensure electric reliability, like energy efficiency and demand response, that are less risky for ratepayers."), attached hereto as Exhibit C; See also "Solving New England's Gas Deliverability Problem Using LNG Storage and Market Incentives," Skipping Stone (2015), attached hereto as Exhibit D.

showed that some pipelines never reached full flow capacity. [30] Since that winter, FERC and PJM have implemented policies that have fundamentally changed and improved the coordination of natural gas and electricity in the PJM region.[31] These improvements were put to the test in the harsh winter of 2014/15 and enabled the system to maintain reliable operations.[32]

Further, PennEast's application is full of conclusory statements as to market demand.[33] Such conclusory statements do not reflect the reality of New Jersey's and Pennsylvania's economic situations. For Pennsylvania, there is a negligible deficiency of natural gas.[34] It is also a net exporter of natural gas.[35] A further indication that New Jersey's current supply is sufficient to meet demand, New Jersey has some of the lowest natural gas prices in the entire nation.[36] In fact, in April, 2015, it had the lowest residential natural gas rates in the entire nation.[37] Finally, a recent study indicated that the PennEast pipeline would result in a 53% surplus beyond current demand in Southeast PA and NJ. [38]

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[30] See Exhibit A at 4.
[31] "Expert Analysis Shows Reforms Made After Polar Vortex Already Meet Grid Reliability Concerns," New Jersey Conservation Foundation, March 9, 2016, attached hereto as Exhibit E.
[32] Id.
[33] See e.g., PennEast R.R. 1 at 1-2 ("The Project was developed in response to market demands in New Jersey and Pennsylvania")
[34] Pennsylvania Public Utility Commission, Pennsylvania Gas Outlook Report 2014 at 28-29 (2014), http://www.puc.state.pa.us/NaturalGas/pdf/Gas_Outlook_Report-2014.pdf
[35] EIA.gov, International & Interstate Movements of Natural Gas by State (2014), https://www.eia.gov/dnav/ng/ng_move_ist_a2dcu_SNJ_a.htm.
[36] EIA.gov. State Historical Residential Natural Gas Prices (2015), https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_m.htm
[37] EIA analysis indicating that New Jersey has the lowest gas prices in the nation during April 2015 (2016), http://www.eia.gov/dnav/ng/xls/NG_PRI_SUM_A_EPG0_PRS_DMCF_M.xls.
[38] Labyrinth Consulting Services, Inc., Professional Opinion on the Proposed PennEast Pipeline Project (June 18, 2015).

PennEast also relies upon self-generated "evidence" of consumer benefits documented in a study that PennEast itself commissioned.[39] This study "fails to examine actual pipeline contracts and available resources to meet peak demand in determining whether PennEast is, in fact, needed to meet demand."[40] In fact, using Concentric's own demand data, Skipping Stone's analysis shows that "there are 49.9% more resources available to meet peak day demand from local gas distribution companies in the region than is needed…."[41] In the absence of real external evidence of market demand, PennEast's self-commissioned studies cannot be relied upon by FERC as proof of public benefits; the conflict of interest is clear.

PennEast also relies on circular reasoning to argue that long-term projections demand its project be built: that because natural gas consumption is predicted to increase in future decades, the PennEast project is consistent with consumer demand.[42] This argument does not stand up to basic logic. Even if increased gas consumption is predicted, it does not follow that such an outcome is in the public convenience and necessity, as required for NGA certification.[43]

Finally, PennEast relies on precedent agreements with twelve gas shippers as prima facie evidence on market demand.[44] Six of these twelve shippers, or their parent, sister, or

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[39] See PennEast R.R. 1 at 1-5 (citing Concentric Energy Advisors, Estimated Energy Market Savings from Additional Pipeline Infrastructure Serving Eastern Pennsylvania and New Jersey (2015)).
[40] See Exhibit A at 7.
[41] Id. at 9.
[42] See PennEast R.R. 1 at 1-5–1-6.
[43] Cf. Julia Frayer & Marie Fagan, Maine Energy Cost Reduction Act: Cost Benefit Analysis of ECRC Proposals 6, 32, 41 (2015), prepared for Maine Public Utilities Commission (finding that increase in natural gas supply to Maine would not be in public interest, despite predicted rate decreases and existence of private contracts for gas supply).
[44] PennEast R.R. 1 at 1-2 to 1-5.

subsidiary companies, fully comprise the ownership of PennEast.[45] As noted by FERC, precedent agreements must be considered among many factors as evidence of project need:

> Rather than relying only on one test for need, the Commission will consider all relevant factors reflecting on the need for the project. These might include, but would not be limited to, precedent agreements, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market.[46]

Indeed, these precedent agreements alone are evidence primarily of the interests of PennEast's owners and shippers in the project, and not market demand.[47]

PennEast cannot demonstrate that the project is based on new demand. PennEast's construction would displace supply from existing legacy pipelines and result in elevated costs for other pipeline shippers. FERC has a duty to protect the interests of "captive customers," and ratepayers by keeping their costs down.[48] Were FERC to rely on PennEast's empty claims with respect to public need, such reliance would violate the Natural Gas Act's legal requirements. Moreover, any finding made by FERC as to public demand for natural gas should be made and acted upon through a process of regional gas supply planning, and not through purely isolated decisions that miss the forest for the trees.[49]

B. PennEast's Application Considers an Improperly Narrow Set of Interests

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[45] See id. at 1-3; FERC Docket No. CP15-558, Accession No. 20150925-5028, Application of PennEast Pipeline Company, LLC for Certificates of Public Convenience and Necessity and Related Authorizations ("PennEast Application") at 6–7.
[46] Certificate Policy Statement at 61,747.
[47] See Exhibit A at 20.
[48] See Certificate Policy Statement at 61,743 (stating that FERC's certificate policy should "protect captive customers").
[49] See infra part III.

PennEast's burden is not a light one; after demonstrating public need for its project, a pipeline applicant must "develop whatever record is necessary . . . for the Commission to be able to find that the benefits to the public from the project outweigh the adverse impact on the relevant interests."[50] Determining whether the public convenience and necessity are met inherently requires FERC to balance factors that go beyond the narrow private interests of a section 7 project's beneficiaries. This is reflected in FERC's certification policy, which provides that "the Commission will consider the effects of the project on all the affected interests; this means more than the interests of the applicant, the potential new customers, and the general societal interests."[51] Moreover, under section 7 of the NGA, FERC necessarily cannot determine whether the "public convenience and necessity" require a pipeline project, while considering only specific private interests.[52] In properly weighing public benefits against adverse impacts, FERC must consider such public interest factors as:

- preserving ecosystem services provided by wetlands and other natural features along the pipeline route;
- safeguarding ratepayers from stranded infrastructure costs;
- ensuring the pipeline project is consistent with the long-term development of energy supply, including clean energy resources, in the project region; and
- as discussed in part I.C below, broad environmental and public health impacts of gas extraction, shipping, and combustion.

However, in its project application before FERC, PennEast describes the purpose and need for its project in reference to particular private interests: natural gas shippers, utilities, electric generators, and energy users to be served, as well as fleetingly to local

[50] Certificate Policy Statement at 61,749.
[51] Id at 61,747
[52] See 15 U.S.C. § 717f(e).

economic interests during project construction.[53] The interests of this narrow set of private parties are insufficient for full consideration of "all the affected interests" under FERC's own certificate policy or of the NGA's mandate to consider the "public convenience and necessity."[54]

To properly consider all affected interests and balance the public benefits and adverse impacts of the PennEast project, FERC must consider local jobs and consumer interests in clean energy development, including renewables, efficiency, and conservation, that may be lost as an opportunity cost of natural gas build-out.[55] FERC must also consider broad *public* interests, including those interests in ecosystem health, clean air, clean water, and a balanced atmosphere that may be affected by increased fossil fuel extraction, shipping, and combustion enabled by the PennEast project.[56] Yet PennEast's application includes only a cursory review of energy efficiency and renewables as alternatives to its project.[57] FERC must consider true regional costs of stranded assets from overbuilding, as the energy sector moves forwards to reach its goals of lower emissions, and environmental sustainability. PennEast's application is therefore inadequate, and should be rejected.

C. PennEast Fails to Fully Consider Environmental Impacts, Which are Residual Adverse Effects Relevant to the Public Convenience and Necessity

[53] SeePennEast R.R. 1 at 1-2 to 1-6.
[54] Id.
[55] Union of Concerned Scientists. The Natural Gas Gamble: A Risky Bet on America's Clean Energy Future (2015), www.ucsusa.org/naturalgasgamble.
[56] See infra part I.C.
[57] *See generally* FERC Docket No. CP15-558, Accession No. 20150925-5028, Resource Report 10 ("PennEast R.R. 10") at 10-3–10-6.

PennEast also fails to fully account for broad and lifecycle environmental impacts that properly bear upon FERC's task to balance "the evidence of public benefits to be achieved against the residual adverse effects."[58] FERC must consider these grounds in assessing PennEast's application. In deciding whether to issue a certificate of public convenience and necessity, FERC is charged with making a broad public interest determination.[59] FERC's certificate policy describes relevant factors as: "the enhancement of competitive transportation alternatives, the possibility of overbuilding, the avoidance of unnecessary disruption of the environment, and the unneeded exercise of eminent domain." [60] Under FERC practice, certain environmental interests not considered in the course of economic balancing "may need to be separately considered in a certificate proceeding."[61] However, even while environmental review proceeds concurrently with FERC's economic balancing, environmental factors are still relevant to FERC's ultimate "public convenience and necessity" determination.[62] To hold otherwise would be to deny that FERC considers adverse public effects of environmental degradation to be relevant to the public convenience and necessity.

To be sure, courts have established limits to the types of public interest considerations within FERC's purview—for example, by finding employment discrimination by regulated entities to be outside the scope of federal energy regulation

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[58] Certificate Policy Statement at 61,745.
[59] See 15 U.S.C. § 717f(e); Columbia Gas Transmission, LLC v. 1.01 Acres, More or Less in Penn Twp., York City., Pa., 768 F.3d 300, 331 (3rd Cir. 2014) ("A key Congressional goal in enacting the NGA [was] to have FERC balance the competing public interests involved. . . ."); see also Certificate Policy Statement at 61,737 (describing FERC's certificate policy as designed to "determin[e] whether there is a need for a specific project and whether, on balance, the project will serve the public interest")
[60] Id.
[61] Id at 61,747.
[62] See Certification of New Interstate Nat. Gas Pipeline Facilities, 90 FERC 61128, 61397–98 (2000) (clarifying Certificate Policy Statement).

statutes.[63] Nevertheless, certain considerations are squarely within the scope of those directives given to FERC by Congress. Consider FERC's own description of its mandate:

> Under the NGA, the Commission is charged with furthering the public interest in authorizing the construction and operation of interstate natural gas pipelines. . . . As Congress, the Commission, and the courts have interpreted it over the decades, this mission includes, among other things, the assurance of adequate supplies of natural gas to consumers, and the assurance of adequate competition among suppliers to cut costs and improve market conditions for the benefits of consumers. It also includes factors as diverse as considerations of clean air and other environmental benefits, and the energy security of the nation.[64]

Courts have also described environmental considerations as within FERC's scope.[65] Within the boundaries of FERC's regulatory directives, the Commission has leeway to fully consider environmental protection and conservation of natural resources as factors affecting the public convenience and necessity.[66]

However, Penneast fails to adequately consider various pipeline impacts relevant to the present and future public convenience and necessity, including:

- greenhouse gas emissions and air quality impacts associated with methane and volatile organic compound emissions in the extraction and shipping of natural gas on the proposed pipeline;

- greenhouse gas emissions and air quality impacts associated with the combustion of natural gas shipped by the proposed pipeline; and

- groundwater contamination and land use impacts associated with hydraulic fracturing used to extract shale gas to be shipped using the proposed pipeline.

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[63] See NAACP v. Fed. Power Comm'n, 520 F.2d 432, 441 (D.C. Cir. 1975) (holding that "Congress has not charged the [Federal Power] Commission [FERC's predecessor] with advancing all public interests, but only the public's interest in having the particular mandates of the Commission carried out").
[64] Guardian Pipeline, L.L.C., 94 F.E.R.C. 61269, 61948 (2001).
[65] See, e.g., NAACP, 520 F.2d at 441 (describing "the conservation of natural resources" as within FERC's ambit, and noting that "[i]t has . . . been held that environmental considerations are the proper concern of the Commission").
[66] See NAACP v. Fed. Power Comm'n, 425 U.S. 662, 670 n.6 (1976) (upholding D.C. Circuit decision and noting that "the Commission has authority to consider conservation, environmental, and antitrust questions").

These impacts must be considered as specifically applicable to PennEast's application, and as as applicable to regional energy development.[67]

There is some argument to be made that such environmental impacts are in fact "economic" impacts that should be considered specifically in the course of FERC's economic balancing. Yet whether in the course of economic balancing,[68] or through the additional layer of environmental balancing,[69] these public environmental impacts must be weighed: they are highly relevant to the public interest, but PennEast fails to address them. FERC cannot determine that the public convenience and necessity *require* the PennEast project to built, without adequate consideration of such factors that are eminently material to the public convenience and necessity as clean air, clean water, land preservation, and climate systems. However, PennEast fails to adequately examine these impacts.

D. Having Failed to Establish Public Need, or Other Public Benefits, and Ignoring Consideration of Adverse Impacts, PennEast's Application Necessarily Fails to Demonstrate that Public Benefits Could Outweigh its Adverse Effects

Section 7 of the NGA does not contemplate FERC as a simple gatekeeper. Rather, as set out in detail above, FERC must find that the public interest is "required" by the project.[70] As FERC itself describes its certification process:

> After the applicant makes efforts to minimize the adverse effects, construction projects that would have residual adverse effects would be approved only where the public benefits to be achieved from the project can be found to outweigh the adverse effects.[71]

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[67] See infra part V.
[68] See Certificate Policy Statement at 61,745.
[69] Id.
[70] 15 U.S.C. § 717f(e).
[71] Certificate Policy Statement at 61,747.

Yet here, PennEast presents a deficient application that fails to consider "all the affected interests," and that fails to adequately demonstrate public need for additional gas. In weighing what scant public benefits remain on the table, against significant adverse effects, including the project's expected contribution to long-term and widespread environmental problems, FERC should deny PennEast's application as not required by the public convenience and necessity.

II. PENNEAST FAILS TO PROPERLY SET FORTH PROJECT PURPOSE AND NEED UNDER NEPA

As set forth above, the PennEast project requires a "certificate of public convenience and necessity" under section 7 of the NGA.[72] FERC's issuance of such a certificate will generally be a major federal action significantly affecting the environment, triggering the requirement for FERC's preparation of an environmental impact statement ("EIS") under NEPA.[73] Among NEPA's required EIS components is a statement of purpose and need.[74] FERC guidelines set forth expectations for project applicants as to information to be provided to FERC to inform the Commission's preparation purpose and need statements.[75]

PennEast falls short under NEPA by impermissibly limiting the project's statement of purpose and need. FERC cannot be limited to considering the interests of the beneficiaries of the project, and even more specifically, FERC cannot be limited to

[72] 15 U.S.C. § 717f(c)(1)(A).
[73] See 42 U.S.C. § 4332(C); 18 C.F.R. § 380.6(a). FERC has committed to preparing an EIS for PennEast.
[74] 40 C.F.R. §1502.13.
[75] See FERC, Guidance Manual for Environmental Report Preparation ("2002 E.R. Guidance") at 3-6 (2002).

considering the interests of PennEast and its shippers. For these reasons, FERC should reject the PennEast's application.

A. PennEast's Stated Project Purpose and Need are Improperly Limited to the Interests of the PennEast Project's Beneficiaries

In setting forth a purpose and need statement in an EIS, an agency may neither be so narrow as to unreasonably foreclose all but one alternative, nor may it be so broad that "an infinite number of alternatives would accomplish [the stated] goals and the project would collapse under the weight of the possibilities."[76] Courts have explained that the scope of a purpose and need statement must track relevant congressional intentions with respect to the proposed federal action.[77]

As set forth in part I above, in approving a pipeline application under section 7 of the NGA, FERC must conclude that the proposed project "is or will be required by the present or future *public* convenience and necessity; otherwise such application shall be denied."[78] And because FERC must make a broad public interest determination in considering a section 7 certificate application, the purpose and need statement in the corresponding EIS must encompass broad public interest goals that track FERC's directive under section 7 of the NGA.

[76] Citizens Against Burlington, 938 F.2d at 196.
[77] Id. (stating that an agency should "take into account the needs and goals" of applicants, but that "[p]erhaps more importantly," an agency should consider relevant congressional intentions). Cf. HonoluluTraffic.com v. Fed. Transit Admin., 742 F.3d 1222, 1230 (9th Cir. 2014) (upholding purpose and need statement where "[t]he stated objectives compl[ied] with the intent of the relevant federal statutes").
[78] 15 U.S.C. § 717f(e) (emphasis added).

However, as currently written, PennEast's application frames the purpose and need of the PennEast project only with respect to its expected direct beneficiaries: natural gas shippers, utilities, electric generators, and energy users to be served, as well as to local economic interests during project construction.[79] But environmental review of a section 7 project under NEPA may not be limited to these narrow purposes and needs alone, where FERC's ultimate decision under the NGA must be in the broad public interest. As described in part I.A above, the "public convenience and necessity" does not refer only to those members of the public who will directly benefit from a section 7 project, nor does a section 7 project exist in a vacuum. PennEast's purpose and need statement under NEPA must therefore track FERC's broad mandate to make decisions in the public interest, in order that alternatives to the project may fully be considered.[80] Because PennEast frames its project purpose and need too narrowly, PennEast's purpose and need submission to FERC is deficient under NEPA.

B. PennEast's Stated Project Purpose and Need are Even More Improperly Limited to the Interests of PennEast and its Partners

While PennEast claims that there is both business-side and user-side benefit to the project, it improperly relies on a narrow set of private interests (including PennEast's own interests), failing to actually establish end-user *demand*. Indeed, as noted in part I.A.3 above, PennEast improperly infers public demand from its precedent agreements, and by relying on its own self-affirming evidence and statements as to consumer-side need.[81]

[79] See PennEast R.R. 1 at 1-2 to 1-6; see also supra I.B.
[80] See Citizens Against Burlington, 938 F.2d at 196.
[81] See also PennEast R.R. 1 at 1-2 to 1-6.

Therefore, PennEast's purpose and need statement only genuinely encompasses narrow business interests. But PennEast's and shippers' interests alone are insufficient for a purpose and need statement in NEPA review of a NGA section 7 project. As noted in the foregoing subpart, purpose and need statements must track the congressional purposes behind whatever authority is directing the federal agency in its instant action. Therefore, where a section 7 determination requires that public convenience and necessity be satisfied, a purpose and need statement must go beyond the narrow purposes of the private interests driving the project. In some cases, courts have specifically explained that the scope of a purpose and need statement cannot be framed around the private motivations of a permit applicant, at least where an agency's directive includes broader public interest considerations.[82] Under the NGA, FERC is required to find that the public interest is served by the project. Accordingly, the purpose and need statement in an EIS for a section 7 project must adequately encompass public interests. To the extent that conclusory assertions, self-interested studies, and self-serving precedent agreements are the only evidence as to the demand-side purpose and need of the project,[83] the public interest is left out of the equation, leaving only the narrow private interests of shippers and PennEast as within the project's purposes. This renders PennEast's submissions deficient under NEPA, which requires FERC to define project purpose and need such to include those interests to

[82] See, e.g., Nat'l Parks & Conservation Ass'n v. Bureau of Land Mgmt., 606 F.3d 1058, 1072 (9th Cir. 2010) (invalidating purpose and need statement where the agency "adopted [the applicant's] interests as its own to craft a purpose and need statement so narrowly drawn as to foreordain approval"); see also Simmons v. U.S. Army Corps of Engineers, 120 F.3d 664, 669 (7th Cir. 1997).

[83] See supra part I.B.III. To the extent that the larger context in the region's energy development has been ignored, see infra part III.

be considered in FERC's underlying NGA decision--and under section 7 of the NGA, FERC must consider the public convenience and necessity.

III. FERC MUST EXERCISE ITS EXISTING AUTHORITY UNDER THE NATURAL GAS ACT TO REQUIRE REGIONAL GAS PLANNING, SO IT MAY FACTUALLY DETERMINE WHETHER PENNEAST'S CERTIFICATE IS REQUIRED BY THE PRESENT OR FUTURE PUBLIC NECESSITY, CONTRARY TO PENNEAST'S CONTENTION THAT FERC MAY EXAMINE THIS PIPELINE CERTIFICATE IN A VACUUM

A. The Natural Gas Act Requires Regional Planning

To approve the construction of a pipeline project under section 7 of the NGA,[84] FERC must find that the proposed project "is or will be required by the present or future public convenience and necessity."[85] Where a project will have adverse impacts, FERC conducts an "economic test" wherein "the evidence of public benefits to be achieved" are balanced against the "residual adverse effects" of the project.[86]

In conducting this economic balancing, FERC cannot reasonably find that the present or future public convenience and necessity require a pipeline project, while assessing only a single pipeline's localized positive and adverse effects in isolation. Natural gas distribution is inherently regional in nature, and the public interest cannot be

[84] 15 U.S.C. § 717f
[85] 15 U.S.C. § 717f(e).
[86] Certificate Policy Statement at 61,745. See also supra part I.

effectively safeguarded through the piecemeal, ad hoc approvals of individual pipelines in a vacuum, without coordinated planning to ensure that pipeline proposals fit within long-term, regional plans.

Further, FERC cannot properly rely on the opportunistic applications of individual pipeline companies acting alone, to ensure that the public convenience and necessity require a given project. Individual pipeline companies may stand to profit from the development of a particular pipeline,[87] even where the public interest would be maximized through more coordinated regional development. Under current practice, operators compete for customers, who may then allow contracts to expire on existing pipelines, resulting in more pipelines than may be needed to satisfy actual demand.[88] Such an approach violates the Natural Gas Act: under the NGA, pipeline approvals must track the requirements of the public interest, not the requirements of private interests.

Moreover, FERC may not properly rely on precedent agreements between a pipeline company and gas shippers who own, or who are affiliated with owners of that pipeline to demonstrate that a particular pipeline best meets public need in the area to be served. This allows for self-dealing: gas shippers may see an opportunity to profit, and effectively manufacture "evidence" of public need for that project by signing shipping contracts with themselves.[89] FERC should not recognize such self-dealt precedent agreements as definitive/or substantial evidence of public benefit in the "public

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[87] Id at 20.
[88] See Kunkel, Cathy, Institute for Energy Economics and Financial Analysis, "A Note of Caution on Zeal Around More U.S. Gas Pipelines. ("One result of an unplanned approach is that the pipeline capacity companies have proposed dwarfs the amount of gas expected . . . . The cost of that underutilized infrastructure would largely be borne by the rate-paying public.").
[89] Exhibit A at 20.

convenience and necessity" certification process—evidence of a particular opportunity to profit is not evidence that a particular pipeline is in the best interests of the region being served.

Regional planning in pipeline development would help ensure that pipelines are built in a way that is required by the public convenience and necessity, and address the market failure that occurs when shippers and pipeline companies have a financial incentive to propose "uneconomic" projects. In the electric transmission context, FERC exercises its authority to require public utility transmission providers to coordinate electricity transmission planning and share costs for new electricity transmission capacity.[90] It directs transmission planning to be done at the regional level rather than state level, reducing collective action problems and thus increasing cost efficiency.[91] It does this via Order 1000, which followed Order 888 and Order 890, requiring public utility transmission providers to provide open access to facilities and conduct open and transparent regional planning.[92] This approach was upheld as a legitimate exercise of FERC's preexisting authority under the Federal Power Act.[93]

In order to properly perform the economic analysis under FERC's certificate policy, as set out in Part I above, and in order to ensure that the public convenience and necessity require the construction of particular pipelines, FERC should exercise its analogous

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[90] Federal Energy Regulatory Commission, Order No. 1000 - Transmission Planning and Cost Allocation (Nov. 9, 2015), http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.
[91] Federal Energy Regulatory Commission, Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, http://breakingenergy.sites.breakingmedia.com/wp-content/uploads/sites/2/2011/08/FERCOrder1000Presentation.pdf
[92] Id.
[93] S. Carolina Pub. Serv. Auth. v. F.E.R.C., 762 F.3d 41 (D.C. Cir. 2014).

authority under the Natural Gas Act,[94] and ensure coordination in the development of a regional pipeline network.[95] Collectively, these operators would be able to determine the actual demand for natural gas and associated infrastructure. Under this process, pipeline companies would be directed to build the appropriate amount of pipelines, in appropriate locations, to satisfy the demand in a cost efficient manner and allocate the costs of the pipelines appropriately. This process would not require FERC to pick winning and losing pipeline proposals but would direct the industry to the appropriate amount of capacity and the least damaging routes for projects.

In fact, FERC's record of approving every pipeline project it considers demonstrates that absent such an order, it will continue to fall short of fully implementing the statutory requirement to determine which projects are necessary. First, FERC has authority over the construction of new pipeline facilities. As Intervenors explain above, the statutory standard for approving new gas pipeline projects is that the project must be "required by the present or future public convenience and necessity."[96] Because the development of a particular pipeline may produce impacts that affect regional consumers, and because consumers in a region will benefit from a coordinated approach to gas pipeline development, the Natural Gas Act requires FERC to assess whether current regional natural gas needs are being met and whether coordination may better suit public convenience and necessity such that new projects are "required" or not. A coordination-focused analysis such as those performed under Order 1000 would delineate when projects actually are

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[94] 15 U.S.C. § 717f(a).

[95] The language of 16 U.S.C. §§ 824, 824d, and 824e (Federal Power Act §201, 205, and 206), which firmly establish FERC's authority to require regional transmission planning under Order 1000, are closely tracked by 15 U.S.C. §§ 717, 717c, and 717d (Natural Gas Act §1, 4, and 5) respectively.

[96] 15 U.S.C. § 717(f).

required by public convenience and necessity, and when they are merely duplicative and may not be required in light of better regional planning.[97]

In a market such as this one, where precedent agreements involve affiliates, and LDC involvement distorts the regular market signals, and allows the costs of pipeline construction to be borne by the ratepayers, FERC must engage in a broader analysis in order to fulfill its mandate under the Natural Gas Act. As it did with Order 1000, FERC can better fulfill this statutory mandate by issuing a corresponding order under the Natural Gas Act, and engage in regional and interregional planning, coordination, and cost allocation. FERC cannot certify the PennEast project until such regional planning is underway, allowing FERC to adequately safeguard the requirements of the public convenience and necessity.

B. NEPA Requires Consideration of Regional Development

As set forth in part II.A above, a purpose and need statement under NEPA must track an agency's congressional directives in making the underlying decision. Because FERC must consider regional gas development in certifying section 7 projects, as shown above, FERC must accordingly include regional interests in a purpose and need statement[98]

FERC's "hard look" under NEPA requires it to examine aspects of regional economic analysis of need, including changes in scheduling and delivery, demand response, efficiency, renewables, oil-fired generation, and purchasing gas from LNG

[97] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49842 (Aug. 11, 2011) (to be codified at 18 C.F.R. pt. 35) (pincited at the Commission's determinations for its authority to promulgate the transmissions planning and cost allocation reforms).
[98] See Citizens Against Burlington, 938 F.2d at 196; see also HonoluluTraffic.com, 742 F.3d at 1230.

facilities as alternatives to new construction.[99] Here, PennEast fails to include regional energy development interests in its purpose and need submission to FERC, further making PennEast's application deficient under NEPA.

In addition, NEPA requires that federal agencies analyze both the direct and indirect effects of applicable federal actions.[100] "Direct effects . . . are caused by the action and occur at the same time and place."[101] "Indirect effects . . . are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[102] Because the certification of a given pipeline will affect the course of pipeline development in a region overall, FERC must, in conducting NEPA review for a pipeline project, analyze applicable impacts of not just the particular project, but also impacts of regional pipeline development to the extent it is indirectly affected by a pipeline's construction. PennEast fails to do so here.

IV. HAVING UNDULY NARROWED ITS PORTRAYAL OF PROJECT PURPOSE AND NEED, PENNEAST THEN FAILED TO PROPERLY EXPLORE ALTERNATIVES

A. PennEast's Artificially Narrow Construction of Project Purpose and Need has Precluded a Hard Look at any No-Build or an Alternative Energy Solution

The project purpose and need statement serves to set the parameters of the alternatives analysis of a DEIS, insofar as alternatives are assessed in part according to

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[99] See also EPA Comments on the Draft Guidance Manual for Environmental Report Preparation for Applications Filed Under the Natural Gas Act, dated 1/19/2016, from USEPA NEPA Compliance Division Director Karin Leff, to FERC Secretary Kimberly Bose at 1 ("[W]e recommend FERC request the applicant provide information regarding the purpose and need for the proposed project in the context of the broader natural gas supply market."); see also Exhibit A at 10-11.
[100] 40 C.F.R. § 1502.16(a)–(b).
[101] 40 C.F.R. § 1508.8(a).
[102] Id.

their likely achievement of project purposes.[103] Moreover, CEQ regulations require EISs to "[r]igorously explore and objectively evaluate all reasonable alternatives," including a no action alternative,[104] and that EISs "[i]nclude reasonable alternatives not within the jurisdiction of the lead agency,"[105] Accordingly, FERC regulations require that project applicants submit an analysis of alternatives to any proposal, including a no action alternative, and "demonstrate how environmental benefits and costs were weighed against economic benefits and costs, and technological and procedural constraints."[106] Specifically as to a no action alternative, FERC guidelines instruct project applicants to "[d]escribe the effect of any state or regional energy conservation, load-management, and demand-side management programs on the long-term and short-term demand for the energy to be supplied by the project," and to "[d]iscuss energy alternatives in sufficient detail to convincingly present the advantages or disadvantages of natural gas relative to oil, coal, electricity, and other alternative fuels readily available in the project area," including "relative impacts on air quality, . . . relative transportation impacts . . ., and relative environmental and economic impacts associated with the construction of natural gas-based versus alternative fuel-based facilities."[107] Moreover, CEQ and FERC regulations both require the consideration of alternatives in EISs, including a no action alternative (in this case: no pipeline).

PennEast's application is also fundamentally flawed insofar as it conflates demand for natural gas with underlying demand for energy. Energy demand can be met with

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[103] See 2015 Draft E.R. Guidance at 4-13; see also Webster, 685 F.3d at 422.
[104] 40 C.F.R. §1502.14(a), (d).
[105] 40 C.F.R. §1502.14(a)
[106] 18 C.F.R. § 380.12(l).
[107] 2002 E.R. Guidance at 3-106.

substitutes such as energy conservation and efficiency, measures that are more cost-effective than supplying additional fuel.[108] Energy demand may also be met with renewable energy, which has shown to generate more jobs than corresponding use of conventional fuels.[109] Clean energy options such as efficiency, conservation, and renewables, also carry the benefit of reduced environmental impacts.

PennEast's cursory review of clean energy options fails to adequately explain why these alternatives do not also meet the alleged energy supply shortage.[110] PennEast's analysis dismisses a no-action alternative as essentially futile, in that shippers "would likely pursue alternate natural gas transportation projects that could potentially result in similar environmental impacts."[111] PennEast is essentially threatening that its affiliates and partners will ignore the environmental impacts of their activities notwithstanding FERC's certification decision. PennEast also glosses over energy efficiency as a means of meeting energy demand, noting that "[e]nergy conservation has been successful in some areas"[112] However, PennEast neglects to substantively discuss why conservation is not a preferable alternative, except to state without evidence that efficiency measures will not eliminate the need to construct new pipelines. Finally, PennEast engages in only a cursory analysis of renewable energy alternatives, characterizing them as ill-suited for the eastern U.S., insufficient to substitute for certain uses of natural gas, and producing environmental

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[108] See International Energy Agency, Energy Efficiency Market Report 2015 at 107–08 (2015).
[109] See generally U.N. Industrial Development Organization & Global Green Growth Institute, Global Green Growth: Clean Energy Industrial Investments and Expanding Job Opportunities (2015) (finding also that energy efficiency generates more jobs than do conventional fuels).
[110] See generally PennEast R.R. 10 at 10-3–10-6.
[111] Id. at 10-4.
[112] Id. at 10-5.

impacts of their own.[113] PennEast's dismissive, superficial analysis of clean energy alternatives fails to establish that any public demand for energy that may exist in Pennsylvania and New Jersey, is somehow confined to demand for gas—and not clean energy substitutes that may carry fewer adverse impacts.

PennEast's application too narrowly defines demand in terms of *natural gas* demand, rather than underlying demand for energy. For consumers, natural gas is in most cases a means to an end. In order for a New Jersey gas or electricity ratepayer to maintain a given indoor air temperature, or to achieve a given level of refrigeration, computer or television use, etc., the ultimate outcomes are the same regardless of the particular input mix of natural gas, renewable energy, or energy efficiency. There are of course differences between these energy sources with respect to price tag, environmental impacts, and other factors that may affect the welfare of the ratepayers themselves as well as the general public—and that is what the alternatives analysis is for. To the extent that any FERC DEIS adopts PennEast's unduly narrow articulation of purpose and need, constraining it to only natural gas demand, it would fail to satisfy NEPA, because the resulting alternatives analysis would be rendered inadequate.

Yet to whatever extent the PennEast project purpose and need is framed specifically in natural gas terms, as PennEast has done in its application, adopting a DEIS would fail to include a robust comparison of the environmental impacts, including life cycle impacts, under the proposed project versus clean energy alternatives. Indeed, PennEast's

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[113] Id. at 10-6.

application itself includes only a cursory review of energy efficiency and renewables.[114]

PennEast's analysis:

- dismisses a no-action alternative as essentially futile, in that shippers "would likely pursue alternate natural gas transportation projects that could potentially result in similar environmental impacts," *id.* at 10-4;

- glosses over energy efficiency as a means of meeting energy demand, *id.* at 10-5 (noting that "[e]nergy conservation has been successful in some areas" without substantively discussing why it is not a preferable alternative, except to state without evidence that efficiency measures will not eliminate the need to construct new pipelines); and

- engages in only a cursory analysis of renewable energy alternatives, characterizing them as ill-suited for the eastern U.S., insufficient to substitute for certain uses of natural gas, and producing environmental impacts of their own.[115]

Meanwhile, PennEast's analysis does not include:

- lifecycle environmental impacts of natural gas infrastructure buildout, including from extraction and combustion;

- local and sustained employment opportunities associated with clean energy development;

- cost savings associated with energy efficiency; or

- continuing price drops of renewable energy.[116]

As discussed above, FERC's DEIS may not adopt a similarly cursory and dismissive approach to clean energy. Under NEPA, this would be a clear failure to

[114] See generally Penn East R.R. 10 at 10-3–10-6.
[115] Id at 10-6.
[116] See, e.g., National Energy Technology Laboratory (U.S. Dept. of Energy), Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction and Delivery in the United States (2011); U.N. Industrial Development Organization & Global Green Growth Institute, Global Green Growth: Clean Energy Industrial Investments and Expanding Job Opportunities (2015); International Energy Agency, Energy Efficiency Market Report 2015 (2015); International Renewable Energy Agency, Renewable Power Generation Costs in 2014 (2015).

"[r]igorously explore and objectively evaluate all reasonable alternatives,"[117] resulting from a deficient purpose and need statement framed centrally around natural gas demand.[118][119] Energy demand can also be met with renewable energy, which has shown to generate more jobs than corresponding use of conventional fuels.[120]

B. Project Need has Been Defined so Narrowly that Even FERC has had to ask PennEast to Consider Different Receipt Points and Line Alterations in Order to Properly Consider Alternative Routes

Although Intervenors believe that a proper analysis of project need would reveal that PennEast is unnecessary, if FERC were to move forward with a DEIS and consider alternative routes to this narrowly proposed pipeline project, it must require data sufficient to support an analysis of the environmental harms from various route alternatives**.** Such route alternatives ought not to consider the receipt points as fixed, and should include looping to available lines, increased compression and other shipping and receipt points.

V. CONSTRUCTION OF PENNEAST WOULD CAUSE SIGNIFICANT ENVIRONMENTAL HARM, WHICH FERC MUST CONSIDER TOGETHER WITH SIMILAR PROJECTS ADVERSELY IMPACTING THE SAME RESOURCES, IN THIS DEIS SO THAT IT CAN PROPERLY BALANCE HARM AGAINST ANY VERIFIED PUBLIC NEED

PennEast argues that the various concurrent regional pipeline proposals are not

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[117] 40 C.F.R. §1502.14(a) (providing that such alternatives include those courses of action outside the decision-making agency's jurisdiction)

[118] See Simmons v. U.S. Army Corps of Engineers, 120 F.3d 664, 666 (7th Cir. 1997) ("If the agency constricts the definition of the project's purpose and thereby excludes what truly are reasonable alternatives, the EIS cannot fulfill its role.").

[119] See International Energy Agency, Energy Efficiency Market Report 2015 107–08 (2015), https://www.iea.org/publications/freepublications/publication/MediumTermEnergyefficiencyMarketReport2015.pdf

[120] See generally U.N. Industrial Development Organization & Global Green Growth Institute, Global Green Growth: Clean Energy Industrial Investments and Expanding Job Opportunities (2015) (finding also that energy efficiency generates more jobs).

"connected" actions, and, almost as an afterthought, notes that the projects are not cumulative or similar actions. This scant treatment reflects the dearth of support that exists for PennEast's notion that FERC does not need to consider the impacts from these similar, cumulative actions within the confines of a single EIS. To assess PennEast's potential environmental impacts, NEPA's implementing regulations require FERC to examine both "[c]umulative actions," defined as projects with "cumulatively significant impacts," as well as "[s]imilar actions, which when viewed with other reasonably foreseeable or proposed agency actions, have similarities that provide a basis for evaluating their environmental consequences together, such as common timing or geography."[121]

Here, FERC must examine the cumulative impacts of the following similar actions within the PennEast EIS: (1) Constitution pipeline; (2) Columbia East Side Expansion; (3) Garden State Expansion; (4) Leidy Southeast Expansion; (5) Atlantic Sunrise; (6) NorthEast Supply Link; (7) Tennessee Gas Pipeline; (8) Pilgrim Pipeline; (9) Diamond East; (10) Southern Reliability Link; (11) South Jersey Gas; (12) Marc-1; and (13) Marc-2. In order to properly calculate the environmental costs of this proposed project, FERC must assess the cumulative costs from the other similar projects in its draft EIS. These cumulative impacts include, but are not limited to: (1) greenhouse gas emissions, (2) permanent harm to rare (special concern, threatened and endangered species), (3) wetland degradation and losses, (4) interior forest habitat degradation or conversion to non-forest habitat, and (5) water quality degradation.

A. PennEast's Proposed Pipeline Would Cause Increased Greenhouse Gas

[121] 40 C.F.R. § 1508.25(a)(2), (3).

Emissions in an Already Non-Compliant Area

Contrary to PennEast's assertion in its proposed answer, the draft EIS must calculate greenhouse gas emissions from its proposed project.[122] If one were to rely upon PennEast's unsupported (and herein discredited) assertion that there is unmet demand, and that its project would therefore not displace legacy pipeline capacity, then the project itself will necessarily cause additional greenhouse gas emissions, which PennEast must analyze. But if upon analysis of the data Intervenors and others have submitted, FERC determines that there is not unmet demand for this gas capacity, it must still examine the greenhouse gas emissions from the natural gas production, transport, and combustion associated with this project. EPA, in commenting on FERC's treatment of GHG effects from proposed pipelines, stated that FERC has made, "[I]n our view, an incorrect determination that no methodology exists to determine how an individual project's incremental contribution to GHG would translate into physical effects on the global environment…."[123] EPA further asserted that FERC should "include emissions associated with the production, transport, and combustion of the natural gas," in addition to "GHG emissions from the construction and operation of the project."[124] PennEast's assertions to the contrary are unsupported both by NEPA, and by the USEPA's determinations that FERC must consider the very analyses that PennEast would have FERC ignore.

B. The PennEast Project Would Cause Irreversible Harm to State Rare (Special Concern, Threatened and Endangered) Species

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[122] Proposed Answer of the PennEast Pipeline Company, FERC Docket #CP15-558, Document Accession #20151113-5247 at 21-32.

[123] See EPA Comments on the Draft Guidance Manual for Environmental Report Preparation for Applications Filed Under the Natural Gas Act, dated 1/19/2016, from USEPA NEPA Compliance Division Director Karin Leff, to FERC Secretary Kimberly Bose at 2.

[124] Id.

1. Long-tailed Salamanders would be imperiled by implementation of PennEast

Constructing the proposed PennEast pipeline project would cause irreversible, adverse impacts to the long-tailed salamander, a New Jersey threatened species.[125] This species has documented habitat in multiple places along the proposed route, and potential habitat along significant stretches of the route. In fact several of the waterbodies crossed by the proposal were listed as non-degradation waters as a result of actual usage by the species as well as documented habitat.[126] Importantly, only a small percentage of the route has been surveyed, and these populations were not found by PennEast -- rendering its environmental data inaccurate and misleading as to potential environmental costs. In addition, even along the small portion of the route that has been surveyed, as demonstrated by the population that PennEast *missed*, many other existing populations may simply not have been documented sufficiently, because this fossorial species is difficult to find and requires more than a cursory survey effort.[127]

Despite this limited effort by the applicant, Intervenors note that Dr. DeVito reports on a population of long-tailed salamander (Eurycea longicauda) that was documented in 2015 on the Little Nishisakawick Creek, a Category 1 stream, in Holland Township, NJ.[128] The observations were made both above and below the proposed pipeline crossing near milepost 88.4.[129] The Holland Township Natural Resource inventory also indicates that this species is known to occur in Holland Township.[130] Again NJDEP listed this water as a

[125] See Report of Dr. Emile DeVito, submitted herein as Exhibit G.
[126] 2003 N.J. Regulations 15970 (2003).
[127] Id.
[128] See Exhibit G at pp. 2-6.
[129] Id. p. 3.
[130] Highlands Environmental Resource Inventory for Township of Holland, p. 20.

category one in part because of "sightings of the threatened long-tailed salamanders."[131] Additionally, many of the proposed crossings of headwater streams in other locations along the proposed pipeline route also present potential long-tailed salamander habitat.[132]

PennEast's current pipeline route will bisect this threatened species' existing documented habitat. The stream and wetland crossing method proposed by PennEast for this steeply sloped forested location will be open-cut and will also require a 75 foot swath through the forested wetlands bordering the stream, and a 125-135 foot swath of clearing through the forested riparian zone, which consists of both upland and wetland habitat elements. Since the Nishisakawick Creek is an antidegradation stream that requires a 300 foot wide riparian zone, these impacts are extremely significant because they will not only devastate the salamanders' forest habitat but result in the degradation of the creek.[133]

PennEast's approach to addressing impacts to this species and its habitat is to simply institute a timing restriction and conduct more surveys. Yet more surveys and timing restrictions will do nothing to maintain the habitat of this imperiled species. The proposed pipeline route would also directly adversely impact the C-1 streams -- of which there are 49 crossings -- as well irreversibly damage 95 wetland complexes, and remove upland forest canopy, which would further fragment the salamander's already scarce habitat. This project would constitute a significant impact on the habitat of this species, in violation of New Jersey's laws designed to protect against precisely such an outcome.[134]

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[131] 2003 N.J. Regulations 15970 (2003).
[132] Id.
[133] These salamanders are especially valuable to their wetlands habitat, and therefore their presence results in a wetlands designation of exceptional value.

[134] N.J.A.C. 7:7A-7.2.B3 and 7:13-10.6(D)

FERC is required to assess these environmental impacts under NEPA, rather than deferring them to other agencies.[135]

2. PennEast would also negatively impact populations of the endangered Red shouldered hawk

Red shouldered hawk provides an excellent example regarding why the impacts of forest fragmentation should not be trivialized and that the proposed PennEast project will serve to significantly degrade the natural resources of Hunterdon and Mercer Counties. Increased competition from forest fragmentation has nearly decimated the red shouldered hawk.[136] Linear pipeline projects such as PennEast open canopy and fragment forests, enabling red tailed hawks to displace or kill red shouldered hawks.[137] There may be as few as twenty breeding pairs of red shouldered hawk left in New Jersey.[138] And PennEast acknowledges that the proposed project will fragment the habitat of the red-shouldered hawk.[139] PennEast further acknowledges that in several related cases, habitat fragmentation has led to declines in breeding populations and increased competition. Ibid.

In fact, forest fragmentation favors habitat generalists, such as great horned owls, which are voracious predators of the endangered red shouldered hawk.[140] Thus, in New Jersey, despite "best management practices," and "mitigation" during the proliferation of

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[135] See supra I.C.
[136] See Exhibit G at 7.
[137] Id. at 8.
[138] See Exhibit G at 6-9.
[139] Resource Report 3, Appendix 3B-2.
[140] Id. p. 8.

linear projects, this imperiled species continues to decline.[141] And the red-shouldered hawk is just one of many species that contribute to the diversity and well-being of the interior forests of Hunterdon County and Mercer County. PennEast acknowledges the ecological significance of these forests.[142] PennEast proposes to permanently clear hundreds of acres of these forests.[143] This clearing will destroy the ecosystem of the forest interior, and will pose a grave danger to the red-shouldered hawk.

The proposed forest clearing will not just damage the habitat of the red-shouldered hawk, but also the habitats of many of the birds and animals that the red-shouldered hawk preys upon, including blue jays, frogs, voles, squirrels and chipmunks.[144] A similar population of red-shouldered hawks in southern Michigan suffered from habitat fragmentation about two decades ago.[145] Due to increased competition resulting from the altered habitat, that population of red-shouldered hawks was ultimately replaced by another species. Ibid. Habitat fragmentation can also expose the nests of red-shouldered hawks to new predators.[146] When red-shouldered hawks can no longer protect their young, evidence indicates that they may abandon the region entirely.[147]

In sum, the proposed project will cause fragmentation of the habitats of many forest interior species, including the red-shouldered hawk. This habitat fragmentation will disrupt their food chain, force increased competition, and invite new predators. A number of peer-reviewed studies of the fragmentation of habitats for other populations of

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[141] Id. pp. 8-9.
[142] See Resource Report 3, p. 3-27.
[143] Id. at p. 3-47.
[144] Resource Report 3 pp. 3-37 to 3-39.
[145] Exhibit G at 6-7.
[146] Id. p. 7.
[147] Ibid.

red-shouldered hawks, detailed in Exhibit G, showed that habitat fragmentation ultimately caused the abandonment or extirpation of those populations. Clearly, such adverse impacts as habitat fragmentation are not capable of mitigation, and FERC must account for this harm in any weighing of environmental costs of PennEast against specious “benefits.”

C. Approving the PennEast Project Would Also Result in Adverse Impacts to Wetlands and Riparian Areas.

FERC must include wetlands impacts when weighing the environmental costs against any verified public need. PennEast has yet to provide site-specific wetlands data from which FERC or other agencies could determine what the actual environmental impacts would be, nor has it provided plans for how it would avoid such impacts. Moreover, the proposed route continues to shift, rendering a true accounting of environmental costs extremely difficult. However, given that the proposed route crosses 95 wetlands complexes, and C1-designated high quality streams 49 times, the resulting sedimentation from construction alone would: (1) damage populations of benthic invertebrates[148] and fish species, filling in interstices between rocks and gravel on the stream bottom with sediment; and (2) change the porosity and composition of surrounding hydric and riparian soils through disturbance, compaction, and sedimentation.[149]

Under the best of construction conditions, even implementing “best management practices,” these impacts occur throughout the construction site and propagate downstream. Inevitably, with 49 stream crossings, rainfall events will cause additional, unexpected, and overwhelming high water flow rates and erosion conditions at many of the stream

[148] The primary food source for long-tailed salamanders. Exhibit G, at 6.
[149] Id.

crossings. The hydro-geology of these tributaries of the Delaware River -- often steep ravines with fractured bedrock -- is noted for the incredibly flashy nature during rainfall events. No construction practices are capable of successfully controlling the sediment loads that will occur at many of these stream locations. Stream and wetland habitat degradation through soil compaction, erosion, and siltation will be permanent and irreversible. Such impacts cannot be successfully mitigated, either on or off-site.

Even if massive expenditures were employed to remove sediment, repair erosion, and re-create stable streambank and stream-bottom conditions, the losses to rare floral and faunal elements would be irretrievable and irreversible. These permanent impacts to public trust resources are, in fact, <u>not</u> permitted on conservation lands, nature preserves, and other lands held in the public trust.

Contrary to PennEast's assertion that there will be no permanent wetland loss from construction of the Project, conversion of palustrine forested wetlands and palustrine scrub/shrub wetlands into palustrine emergent wetlands represents a significant loss -- and the environmental reality of 'temporary disturbances' is that they become permanent.[150] Allowing such losses becomes even more egregious when one considers that they are contemplated on preserved lands. PennEast almost appears, in fact, to have specifically targeted preserved land, because of the tremendous overlap between the route and these critical lands.

It is vital for FERC to understand that these lands were not selected for preservation without reason -- and many of these preserved lands possess uniquely important wetland,

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[150] <u>See</u> PennEast (Resource Report 2) ("For temporarily disturbed wetlands, restoration and revegetation following completion of construction will be performed in place, in kind with the appropriate wetland plantings.")

riparian and upland habitats, including habitat for rare, threatened and endangered species. And while, in general, the theory behind compensatory wetland mitigation is to attempt to replace (as fully as possible) the functions and public benefits of lost wetlands, when it is used as a justification for finding no significant impact to preserved lands, FERC must examine this proposition with an extremely critical eye.[151] But New Jersey regulations currently lack an objective method to assess unique habitat quality.[152] Preserved lands can function as a proxy for a standardized scoring system. In New Jersey, they typically contain rare remnant natural communities and house special concern species that are subject to very narrow habitat requirements. PennEast's one-size-fits-all mitigation mentality cannot substitute for accurate assessment of extant flora and fauna, particularly on these preserved lands. Moreover, under 40 C.F.R § 230.40, many of these preserved land areas within the PennEast pipeline route are further defined as sanctuaries and refuges and thus considered to be Special Aquatic Sites. PennEast has done little to nothing to

[151] Careful application of the 404(b)(1) guidelines, for example, can expressly protect these special areas by acknowledging that adverse impacts to such preserved lands may not be mitigable. For example, the Chicago District of the US Army Corps of Engineers (USACE) "has identified that mitigation cannot mitigate impacts to all sites. The USACE considers that "the functions and values of high quality areas may be considered to be un-mitigatable under the 404(b)(1) Guidelines" and that "impacts to these areas will not typically be permitted." Examples of these areas include but are not limited to; endangered and threatened species habitat, lands with high-quality plant communities, streams with natural channels and stream segments of high biological value and areas providing habitat for uncommon animals or breeding habitat." [Chicago District Permitee Responsible Mitigation Requirements, revised October 2009] These are the very qualities that led to the selection of these preserved lands as critical to preserve in an untampered condition.

[152] For example, the application of a floristic quality index (FQI) provides an accurate, objective method to identify rare and unique habitats that are un-mitigatable and irreplaceable. This method has been used to identify natural areas, facilitate comparisons between sites, and perform long-term monitoring of remnant natural quality and of habitat restoration. It can be used to characterize rare habitats and identify those sites with plant communities that are too unique to be impacted and replaced. The FQI is a biotic or content based index based on a numerical score called the Coefficient of Conservatism (C). The underlying scientific basis for the FQI is that plant species differ in their tolerance to the type, frequency, and amplitude of disturbance and that plants exhibit a varying degree of fidelity to remnant natural habitats.

show that it has made any realistic attempt to avoid unmitigable impacts to unique preserved lands, sanctuaries and refuges located along the route.

D. Interior Forest Habitat Destruction

PennEast's portrayal of its pipeline route as minimally harmful because it is in some areas co-located along existing rights of way at best displays a genuine ecological misunderstanding of the existing habitat along the route crossings, and at worst, is intentionally misleading as to the amount of harm the project would inflict. New Jersey has a number of interior forest habitat species that have suffered steep decline over the last decade, leading to their listing as rare (state special concern, threatened or endangered). These listings have increased as more pipelines have been built because the type of harm from these linear projects -- loss of forest interior -- simply cannot be mitigated, either on-site or off-site. Once these forests are opened to sunlight, increased invasives, increased predation and temperature changes alter their fundamental ecological characteristics.[153]

Every natural gas pipeline project that FERC has certificated in the past decade, has been given that regulatory approval because FERC has made the finding under NEPA that any environmental harm would be mitigated.[154] In fact, FERC has approved 100% of natural gas pipeline applications in this region that it has considered. Yet, rare species continue to be listed as threatened and endangered, and there is virtually no data revealing that mitigation efforts have even resulted in the stabilization or increase in a species or

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[153] Both the long-tailed salamander and the red shouldered hawk are included in the listed of "New Jersey's wildlife species of greatest conservation need that depend upon forests." See New Jersey Department of Environmental Protection, New Jersey Statewide Forest Resource and Assessment Strategies (2010), http://www.state.nj.us/dep/parksandforests/forest/docs/NJFSassessment.pdf.

[154] See e.g., Transcontinental Gas Pipe Line Company, LLC, 149 FERC ¶ 61,258 (2014); Tennessee Gas Pipeline Co., LLC, 139 FERC ¶ 61,161 (2012), Order on remand, 153 FERC ¶ 61,215 (2015).

public trust resource at risk. In fact, the monitoring required where mitigation has taken place is short-term, insufficient, lacks the sensitivity to determine actual success, and in virtually every case the monitoring ends before actual conclusions can be drawn. Typically, monitoring ends when a threshold vegetation cover is attained, and shortly thereafter the mitigation and restoration sites are overrun with alien, invasive species, or hydrologic parameters fail to be maintained or attained, resulting in complete failure of the mitigation or restoration attempts in the long-term. Regulatory construct does not translate into environmental reality.

E. Water Quality Degradation

As described more fully in Exhibit G, and in Sections V(B)(1) and V(C) above, implementation of PennEast would degrade water quality in C-1 designated streams, failing to meet the legally required antidegradation standards. PennEast's Resource Reports simply note that the pipeline will cross numerous Category 1 antidegradation streams and that in order to "reduce potential and overall impacts, the majority of streams will be crossed using dry construction technology."[155] But PennEast provides no detail from which FERC could reasonably assess the true environmental costs to those streams from this project's construction, as they discard all impacts as "temporary."

Importantly, PennEast states that "[i]n-stream construction across waterbodies may cause both direct and indirect impacts to fish habitat, fish resources, and other aspects of

[155] "Category one waters" means those waters designated in the tables at N.J.A.C. 7:9B-1.15(c) through (i), for protection from measurable changes in water quality based on exceptional ecological significance, exceptional recreational significance, exceptional water supply significance or exceptional fisheries resource(s) to protect their aesthetic value (color, clarity, scenic setting) and ecological integrity (habitat, water quality and biological functions). See N.J.A.C. 7:9B-1.15.

aquatic ecology. In-stream pipeline construction could remove vegetation and habitat, temporarily increase sedimentation and turbidity in the water column, increase the potential for streambank erosion, temporarily disturb streambed foraging areas, and temporarily increase the potential for fuel or chemical spills."[156] PennEast further indicates that blasting of stream bottom with explosives may be necessary, but summarily notes that "[i]mpacts [to aquatic resources] from construction-related sedimentation and turbidity will be limited to short-term, temporary disturbances..."[157] Thus, PennEast's own resource reports catalog impacts to these C-1 antidegradation streams, indicating that there will be construction related turbidity and sedimentation, and that potential impacts to aquatic biota are anticipated. PennEast also indicates that after blasting habitat and refugia will be limited to areas upstream and downstream of the work area -- simply another way of stating that habitat in the blast area will be eliminated.

In fact, the simple action of clearing the land, regrading and smoothing the pipeline right of way ("ROW"), compacting and altering the physical structure of the native soils within the ROW, and replacing forest with ground cover will increase the amount of stormwater runoff generated during each storm event.[158] Based on TR-55 runoff coefficients (USDA, 1986), even for the best drained soils (hydrologic soil group A), the increase in the runoff coefficient value when converting woods to lawns, ranges from 30%-50%. The impacts associated with this increase in runoff will likely be greater on steeper sloped lands that have been recently as they will be more difficult to stabilize.[159]

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[156] Resource Report 3 p. 3-11.
[157] Id. p. 3-90.
[158] Exhibit G at 5-6.
[159] Ibid.

Moreover, the presence of compacted soil in the corridor have reduced capacity for recharge and will thus further increase runoff.[160] All of these construction related issues will lead to an increase in the mobilization and transport of pollutants and an increased opportunity for overall soil erosion.[161]

Peterson (1993)[162] found a greater number and depth of pools in corridors than in adjacent areas and attributed this to the greater density of streambank vegetation which caused the stream to scour substrate instead of eroding stream banks. This response to the removal of riparian forest was more recently illustrated by research done of 16 streams in eastern North America by the Stroud Water Research Institute (1993). This study showed that riparian deforestation causes channel narrowing, which reduces the total amount of stream habitat and ecosystem per unit channel length and compromises in-stream processing of pollutants and that wider forested reaches had more macroinvertebrates, total ecosystem processing of organic matter, and nitrogen uptake per unit channel length. Peterson (1993) also reported that the removal of tree canopy on new ROWs increases stream insolation during the short term, but within two years the areas are bordered by dense shrubs and emergent vegetation and water temperatures are not significantly greater when compared with upstream forested reaches.

Perennial streams in this area are mostly streams in which their hydrology is derived from groundwater discharge. The shallow groundwater sources and flow paths that are essential to maintaining the hydrology of the headwater streams is given no consideration in the resource reports. The diminishment of flow related to the modification

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[160] Ibid.
[161] Ibid.
[162] Referenced scientific literature will be submitted to Docket CP15-558 under separate cover.

of groundwater flow paths can modify the hydrology of sensitive headwater streams and thus constitute a conflict with their antidegradation designation. FERC must also consider climate change within this context, when calculating environmental costs from impacts to antidegradation streams due to the increased frequency of extreme precipitation anticipated for New Jersey.[163] These larger precipitation events will alone cause problems such as stream bank erosion and increase sediment loading -- without pipeline construction. Thus, it is important to consider that it would only take one such low frequency storm event to occur during site construction to create a massive erosion problem similar to that experienced during construction of Tennessee Gas's Northeast Upgrade. Increased turbidity, sedimentation, erosion, habitat loss from water quality degradation and loss of benthic communities would add up to a tremendous environmental cost on the NGA and NEPA balance sheets -- with no countervailing public benefits.

VI. AN EVIDENTIARY HEARING IS NECESSARY BECAUSE THE INFORMATION PENNEAST HAS PRESENTED TO FERC IS HIGHLY QUESTIONABLE

Given that PennEast's claims are either unsubstantiated or based on data that Intervenors and others have demonstrated to be misrepresented, FERC must now hold an evidentiary hearing in order to independently assess the credibility of data entered into this docket. While FERC generally has discretion whether to hold an evidentiary hearing, it must hold one when there are "genuine issue[s] of material fact" that "may [not] be

[163] See Georgetown Climate Center, Understanding New Jersey's Vulnerability to Climate Change (2014), http://www.georgetownclimate.org/sites/www.georgetownclimate.org/files/understanding-new-jerseys-vulnerability-to-climate-change_0.pdf.

adequately addressed on the written record."[164] Indeed, such issues are impossible to resolve on a written record when, as is the case here, "motive, intent, or credibility are at issue or there is a dispute over a past event."[165] PennEast's numerous unsubstantiated claims raise significant credibility concerns that can only be addressed through a trial-type proceeding.

A. PennEast's Economic Claims Must be Subject to Rigorous Cross-Examination, Given the Contradictory Data and Analysis Contained in This Record

In particular, PennEast's claims about the pipeline's economic impacts are grounded upon suspect and opaque methodology, and have now been soundly refuted in this record. As detailed in Part I above, PennEast makes conclusory and misleading statements in its attempt to establish need for the pipeline. While PennEast alleges that the project "was developed in response to market demands in New Jersey and Pennsylvania," it provides no data to support this purported demand-side need.[166] FERC itself has recognized that increased pipeline capacity in recent years has resulted in the Northeast becoming a net exporter in 2015, which suggests that existing pipelines already exceed local demand.[167]

PennEast points to a single winter price spike—an anomaly in contrast with an overall downward trend in price—as its basis for demand-side need, but Intervenors have already provided analysis showing that this price spike was not the result of insufficient

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[164] Minisink Residents for Environmental Preservation and Safety v. FERC, 762 F.3d 97, 114 (D.C. Cir. 2014) (quoting Cajun Elec. Power Coop., Inc. v. FERC, 28 F.3d 173, 177 (D.C. Cir. 1994)).
[165] Union Pacific Fuels, Inc. v. FERC, 129 F.3d 157, 164 (D.C. Cir. 1997).
[166] PennEast R.R. 1 at 1-2.
[167] See 2015-2016 Winter Energy Market Assessment: Item No. A-3 at 7-8 (Oct. 15, 2015), https://www.ferc.gov/market-oversight/reports-analyses/mkt-views/2015/10-15-15-A-3.pdf.

pipeline capacity.[168] Moreover, recently implemented electric market reforms such as "Supply Assurance Programs" further obviate the need for additional supply during peak winter periods.[169] But even if there were unmet market demand, PennEast's analysis remains entirely deficient in assessing the economic value of alternatives to natural gas, such as the demand-side cost savings associated with the continuing price drops and energy efficiency of renewable energy.[170] These all raise questions about the veracity of PennEast's assertions that the company should be compelled to answer.

PennEast's economic expert, Econsult, similarly makes unsupported claims about the economic impact of the pipeline. According to the Goodman Report submitted by Intervenors, "The PennEast Analysis has not provided adequate documentation of the methodology used in its economic modeling, making it impossible to understand how the company developed its employment estimates."[171] Not surprisingly, there are inconsistencies between the Direct Onsite Construction Jobs that the project allegedly will create and the Total Jobs that will, as a result, be supported. Moreover, Econsult does not provide a definition of what constitutes a job or the duration of the 12,160 temporary jobs supported, both of which make it impossible to "evaluate with certainty the employment benefits estimated for the Project."[172]

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[168] See Exhibit A at 5.
[169] Id. at 17.
[170] See Exhibit A at 5 ("The Commission should institute a full evidentiary proceeding with discovery and cross-examination to determine what demand is being met by the proposed pipeline and whether less disruptive and more cost effective alternatives exist to meet such demand.")
[171] Ian Goodman and Brigid Rowan, Expert Report on the Penneast Pipeline Project Economic Impact Analysis for New Jersey and Pennsylvania at 21-22 (Nov. 4, 2015), http://njconservation.org/docs/PennEastEconomicReport.pdf, hereinafter known as the "Goodman Report."
[172] Id. at 42.

The Goodman Report concludes, as a result, that PennEast and Econsult overstate the number of jobs that will be created by approximately two-thirds or more.[173] This is especially troubling because such methodological failures stand in contrast with Econsult's previous practices. As the Goodman Report notes, Econsult was also hired to conduct economic analysis for the Mariner East pipeline project. However, "the job numbers for Mariner East are expressed in FTEs. Therefore Econsult is familiar with this best practice in employment impact analysis, but chose not to present the PennEast job numbers in this standard and meaningful manner."[174] Econsult's deliberate decision to present misleading data warrants intense scrutiny of both its motivations and the role that PennEast played in encouraging such omissions.

B. PennEast's Environmental Data and Claims Must Likewise be Subject to Rigorous Cross-Examination, Given the Contradictory Data and Analysis Contained in This Record

PennEast's environmental data are either inaccurate, or remain incomplete. For example, PennEast has portrayed any environmental impacts from the 49 proposed C-1 stream crossings as capable of mitigation. This assertion, which is directly contradicted by overwhelming scientific literature documenting the failures of mitigation to compensate for wetlands disturbances and loss, for interior forest habitat disruption, and for water quality preservation, should prompt FERC to examine this issue in an evidentiary, trial-type hearing. Decades-long regulatory reliance on "best management practices" has failed to protect New Jersey from ongoing wetlands destruction, species and habitat loss, and water quality degradation. And despite the occasional, partial success of decades-old mitigation

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173 Id. at 33.
174 Id. at 21.

projects, today those same mitigation projects would not succeed given the overwhelming proliferation of invasive species and cumulative habitat losses. The negative impacts on plant communities were most pronounced in those areas with greater initial diversity and quality vegetation, as they were found to be the most susceptible to degradation.[175] All study sites in the pipeline corridor experienced compaction and lower soil moisture inside the pipeline corridor. In addition, NJDEP prepared a document entitled Freshwater Wetlands Mitigation that evaluated the status of 90 select freshwater wetland mitigation sites around the State of New Jersey and determined that, between 1988 and 1999, wetland mitigation practices were not effective in meeting NJDEP's requirements. The report indicated that less than one out of every two acres of proposed mitigation resulted in achieving a freshwater wetland. This shocking statistic clearly illustrates why simply appending conditions to a certificate of public convenience and necessity that require compliance with state permits and regulations does not fulfil FERC's task of assessing the true adverse impacts from proposed projects.

Given this documented record of mitigation failures attendant with natural gas pipeline projects, at some point, the absolute fallacy of the ability to compensate for the adverse impacts from pipeline construction and operation must be cast aside in favor of environmental reality.[176] Granting Intervenors' request for an evidentiary hearing would provide a forum for FERC to assess the true environmental costs of PennEast, and provide

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[175] See Erik R. Olson and James. M. Doherty, The legacy of pipeline installation on the soil and vegetation of southeast Wisconsin wetlands, Ecological Engineering 39:53-62 (2012) (finding that soils within pipeline corridors had higher bulk density, lower depth to refusal, and lower soil moisture).

[176] For reference to actual pipeline impacts and violations, see Stop the Pipeline, What FERC Says Should Happen vs What Actually Happens (2015), http://dec.stopthepipeline.org/what-ferc-says-should-happen-vs-what-actually-happens/

it with a credible basis for fulfilling its Natural Gas Act and NEPA mandates to weigh such costs against any verifiable public benefits.

C. PennEast's Numerous Misrepresentations, Both in the Record and in its Interactions With Affected Homeowners, Significantly Undermine its Credibility

The record still remains unbelievably incomplete, and worse -- rife with misrepresentations as to its contents. Given that PennEast's application was submitted in September 2015, and given that both FERC and NJDEP have repeatedly requested that PennEast submit critical missing information, this alone should provide FERC a sound basis for suspending its review. For example, on March 1, 2016, the Delaware Township Committee noted that "PennEast has not contacted the relevant historical organizations as it claimed in its letter dated December 14, 2015.[177]

Unfortunately, here, PennEast has complemented its misrepresentations in the written record with an abject indifference to the law when surveying the proposed route of the pipeline. PennEast surveyors have repeatedly entered private and public lands without permission. In a letter to Intervenor NJCF dated August 11, 2015, PennEast even acknowledged that its agent had entered NJCF property to conduct native bat surveys, despite the fact that NJCF had expressly denied PennEast permission to enter its property. [178] While PennEast chalked up the incident to "mistake," the credibility of its claim is belied by numerous allegations of trespass in Pennsylvania and New Jersey.[179]

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[177] Letter from Delaware Township to FERC (Mar. 1, 2016), FERC Docket #CP15-558, Accession Number 20160309-0046.
[178] Letter from PennEast to New Jersey Conservation Foundation (Aug. 11, 2015), attached hereto as Exhibit F.
[179] See, e.g., Sallie Graziano, State Police Respond to Call About PennEast Surveyors, NJ.com (Oct. 2, 2015, 3:12 PM), http://www.nj.com/hunterdon/index.ssf/2015/10/hunterdon_land_trust_responds_to_trespass_by_penne.html;

In response, rather than respect the privacy and property rights of homeowners, PennEast has instead, despite its assurances to the contrary, engaged in aerial surveying along the proposed pipeline route.[180] Affected municipalities and private landowners have already raised concerns about the impact of repeated, low-flying aircraft. In a letter to the PennEast Pipeline Company, Delaware Township in Hunterdon County, N.J. asked that the company provide advance notice of such overhead flights: "This is a rural, farming community. Overhead planes and helicopters alarm residents. They terrify livestock, especially horses."[181] PennEast representatives have continued to deny, however, the use of aerial surveys,[182] despite the fact that the Federal Aviation Administration has confirmed the operation of helicopters, at least on one occasion, "on behalf of the PennEast Pipeline Project for the purpose of aerial survey along the proposed pipeline route."[183] Finally, PennEast has ignored, and continues to ignore, residents' concerns on both sides of the Delaware River.[184]

VII. CONCLUSION

PennEast's repeated bad faith attempts to engage honestly with affected communities in New Jersey and Pennsylvania, coupled with the baseless and misleading claims in its submissions to FERC, reflect a complete disregard for FERC procedures,

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Jim Dino, Residents Accuse Gas Pipeline Surveyors of Trespassing, Standard Speaker (Jan. 13, 2016), http://standardspeaker.com/news/residents-accuse-gas-pipeline-surveyors-of-trespassing-1.1994626.

[180] See Letter from FAA to Jacqueline Evans (Jan. 14, 2016), attached hereto as Exhibit H.

[181] Letter from Delaware Township Committee to PennEast Pipeline Company (Nov. 28, 2015), FERC Docket #CP15-558, Accession Number 20151207-0081.

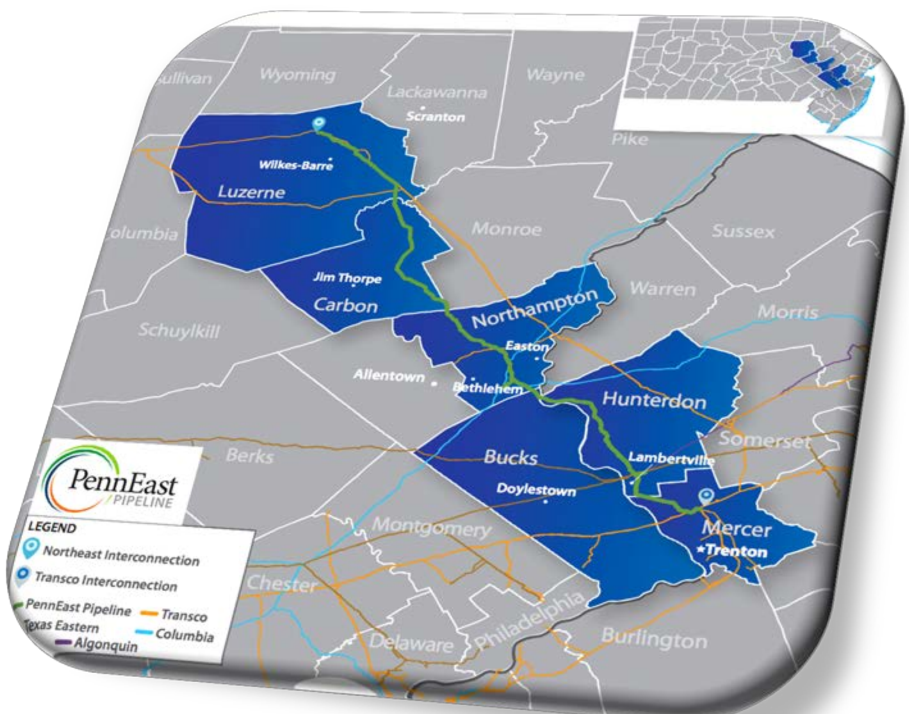
[182] See transcript of Conversation between Jacqueline Evans and Jeff England of UGI , attached hereto as Exhibit I.

[183] Exhibit H, Letter from FAA to Jacqueline Evans (Jan. 14, 2016).

[184] *See, e.g.*, Letter from Lower Saucon Township to PennEast (Feb. 19, 2016), FERC Docket #CP15-558, Accession Number 20160309-0045 ("A number of Lower Saucon Township residents have . . . express[ed] dismay that PennEast Pipeline Company is not responding to their questions and concerns about the pipeline. These include residents whose property will be impacted by the proposed route of the pipeline. . . .")

policies, and the laws from which those derive. This record now contains documentation directly contradicting the PennEast's project's economic and environmental underpinnings, as well as demonstrating the mendacity of PennEast's public representations as to data collection and results. And where PennEast has failed to update its application to reflect changing market conditions, such indifference for data accuracy provides another reason to convene an evidentiary hearing as the appropriate vehicle to properly assess this application, should FERC continue to entertain it. Only rigorous cross-examination at an evidentiary hearing can illuminate the unacceptable lengths to which PennEast will go to obtain approval for this project, and allow FERC to meet its legal obligations under the Natural Gas Act and NEPA.

Analysis of Public Benefit Regarding PennEast Pipeline



Author: Greg Lander

For

The New Jersey Conservation Foundation

SkippingStone

www.skippingstone.com

March 9, 2016

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Table of Contents

Executive Summary

In evaluating the PennEast application, FERC Commissioners will seek to determine whether the application to build new pipeline capacity provides evidence of public benefit. This study evaluates a central claim in the application – that PennEast will lower costs to consumers. This analysis also examines unserved demand for firm capacity and evaluates two alternatives for meeting peak demand needs of electric generation customers, thereby ensuring reliability of electric generation.

Our major conclusions are as follows:

1. **Local gas distribution companies in the Eastern Pennsylvania and New Jersey market have more than enough firm capacity to meet the needs of customers during peak winter periods.** Our analysis shows there is currently *49.9% more capacity than needed to meet even the harsh winter experienced in 2013 (the Polar Vortex Winter)*[1].

2. **Providers of gas-fired electric generation can meet their need for electric reliability more cost-effectively by using either dual fuel or natural gas from LNG facilities.**

   Natural gas pipelines are typically fully utilized between 10 and 30 days a year. Building a pipeline that is only fully utilized for a short period of time is not a cost-effective way to provide reliable electricity. Electric generation customers prefer to purchase supplies using interruptible contracts[2], knowing that they may not be able to obtain gas supplies during peak demand periods. Under pressure to improve electric reliability, such customers now have to choose between contracting for firm supply from new pipeline capacity, such as PennEast, or choose an alternative to natural gas. A common alternative is to switch to oil-fired generation when natural gas is not available; a second is to purchase natural gas from LNG facilities.

   Based on our analysis of alternative costs, an electric generator would bear a higher fixed cost burden by choosing to meet peak demand through firm pipeline capacity and would be economically better off choosing oil or LNG for the few days each year of high electric demand.

3. **PennEast will add significant excess capacity to the market in Eastern Pennsylvania and New Jersey.** Shippers representing almost 40% of capacity stated in the application that they intend to shift their gas supplies from existing competitor pipelines to PennEast, leaving excess and unutilized capacity on other pipelines.

4. **The impact of PennEast may well be to increase, rather than decrease, costs to gas customers. Analysis shows that rate-paying consumers of local gas distribution companies (LDCs) bear the greatest risk of increased costs regardless of whether they are on PennEast or competing pipelines.** Customers of the LDC shippers subscribing to PennEast will pay the full cost of annual service for only

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[1] Concentric Energy Advisors' (Concentric) report for PennEast used peak sendout figures for this period.
[2] Interruptible transportation contracts are contracts under which no fixed charges are incurred, rather charges are only incurred when and to the extent the contract is actually used to deliver gas.

a few days of effective usage per year. Customers served by LDCs on competing pipelines are likely to suffer financial losses in two ways. First, as PennEast adds 1 billion cubic feet per day of capacity to the market, the value of existing capacity in the secondary market will collapse, shrinking by as much as 50 to 90%. Our analysis of transactions on two competitor pipelines shows that the loss of benefit to ratepayers, just on those two pipelines, could be between $130 to $230 million each year. Second, as customers shift contracts from existing pipelines to PennEast, FERC rules permit those pipelines to file for rate increases on remaining customers to recover lost revenues. Resulting rate increases could expose ratepayers to additional costs of over $50 million per year – just on these two pipelines.

5. **PennEast claims of potential savings for gas consumers or electric generation customers are based on faulty assumptions and analysis.** The price spike experienced during the Polar Vortex is unlikely to be repeated and does not alone justify the addition of new pipeline capacity. PennEast claimed benefits that are not based upon future projections of gas prices and do not take into account 8.1 billion cubic feet per day of infrastructure scheduled to ramp up in 2017. PennEast does not address evidence that similar price spikes did not occur in Winter 2014/2015 or the introduction by PJM and NEISO of important Supply Assurance Programs that reduce dependence on constrained natural gas pipelines during peak demand periods.
6. **FERC should not rely on non-arms-length transactions as a foundation for finding market need.** Owners of PennEast contracted for 74.2% of total capacity. FERC Commissioners have a special responsibility to protect rate-paying customers. For PennEast, 38.9% of the capacity is held by local gas distribution companies whose parent firms will benefit from their ownership of PennEast, and whose customers – rate-payers – are at risk of paying for unneeded capacity for 15 years.
7. **In the case of PennEast, the precedent contracts signed by local distribution companies are not arm's length and should not be relied upon for a finding of public convenience and necessity.**
8. **The Commission should institute a full evidentiary proceeding with discovery and cross-examination to determine what demand is being met by the proposed pipeline and whether less disruptive and more cost effective alternatives exist to meet such demand.**

Section I – Study Overview

Skipping Stone was asked to review the proposed PennEast Pipeline and provide its opinion of the potential utilization of the incremental capacity into the geographic region, and what that might mean for electric generation customers. Understanding that the choice faced by electric generation firms would require an analysis of the cost and benefits of purchasing firm capacity on a new pipeline compared to other options, we also provide indicative cost-benefit analyses of two alternatives. Skipping Stone was also asked to examine possible financial motivations of the Sponsor/Shippers of PennEast as an alternative explanation for the purpose of the project.

This review is based on our examination of documents from the PennEast Pipeline LLC FERC Certificate Application CP15-558 and publicly available natural gas industry data and documents.

The application makes a number of assertions about the project purpose as follows:

> "to bring lower cost natural gas produced in the Marcellus Shale region in eastern Pennsylvania to homes and businesses in New Jersey, Pennsylvania, New York and surrounding states."
>
> " with the additional pipeline capacity, energy consumers throughout eastern Pennsylvania and New Jersey would have realized over $890 million in reduced energy costs in the winter of 2013-2014 . Further, without additional natural gas infrastructure providing the region increased access to the abundant dry natural gas reserves located in the eastern Pennsylvania production area, similar price spikes and correspondingly, the potential savings offered by the PennEast Project, could be anticipated in the future. Thus, the PennEast Project is expected to bring annual energy cost savings and significant economic benefits to the Pennsylvania and New Jersey economies."

The assertion that PennEast will produce <u>annual energy cost savings</u> requires looking at a number of salient factors, including:

1) What is the demand that PennEast is purporting to serve, is there unmet demand for year-round, firm capacity in the subject region, and related to that, what would be the utilization rate of such incremental capacity into the subject market.[3] And at such utilization rate, what would be the effective per-unit cost of such incremental capacity at indicative utilizations?
2) Is firm, year-round capacity a cost-effective solution to meet electric generation customers' needs during peak winter periods?
3) What might be offsetting costs to any potential savings?

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[3] In this regard, Skipping Stone assumes that the utilization rates of other lines serving the subject market are or remain the same and that utilization of the PennEast line comes from displacement of peak-shaving resources and electric generation. Even if PennEast were to be higher utilized than the estimated utilizations used in this memorandum, such higher utilization of PennEast would come at the expense of utilization of other pipelines serving the market. Thus, for economic analysis of the effective per unit cost of the added capacity, Skipping Stone assumes for these purposes that in the aggregate, PennEast would serve load unmet by existing natural gas pipelines (i.e., load met by LNG, or oil-fired electric generation).

4) Are the potential savings predicated on repeats of unusual circumstances?
5) Have there been developments in electric and gas markets subsequent to the filing of the PennEast application which undermine the assumptions that must be made in order for there to be future savings associated with the incremental capacity proposed to be provided by PennEast?
6) In light of potentially questionable demand, what financial motives might underpin the Sponsor/Shippers' decision to seek permission to construct a new natural gas pipeline.

Section II – Unserved Demand for Pipeline Capacity and Analysis of Cost-Effective Alternatives

Can LDCs Meet Needs for Firm Pipeline Capacity?

To evaluate whether current pipeline capacity is sufficient to meet current and future demand from LDCs and other customers requiring firm capacity in the Eastern PA, NJ region, it is important to identify the Peak Day demand from LDCs in the region and compare it to Total Peak Day Resources available in the region. The Concentric Energy Advisors report, sponsored by PennEast, fails to examine actual pipeline contracts and available resources to meet peak demand in determining whether PennEast is, in fact, needed to meet peak demand.

We utilized information provided by Concentric about LDC demand in the region from Table 2: "Eastern Pennsylvania and New Jersey LDC Summary Operating Statistics."[4] Information for each LDC is reproduced below in Table 1 as columns (a), (b), (c), and (d) representing Local Distribution Companies (LDCs), Number of Natural Gas Customers, 2013 Retail Sales Volumes (Mcf) and Peak Day Sendout (Mcf), respectively.

To properly calculate current Peak Day Resources it is important to include not only LDC held pipeline capacity and LNG sendout capability, but to also include winter pipeline subscribed capacity levels of retailers[5] serving load in eastern PA and NJ, end-users and electric generators with contracts to locations in the same geographic area[6] and capacity held by producer marketers into this same geographic area[7]. Rows 13 and 14 provide the contracted winter pipeline capacity for these two categories of pipeline capacity holders. For both

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[4] Sources: EIA Form 176, Annual 1307(f) Filing materials, State LDC Filings, and information provided by LDCs.

[5] Here, retailers are those marketers that explicitly serve residential and commercial load in the geographic area and have pipeline FT contracts with firm primary delivery points in the subject geographic area. Note these entities can be distinguished from wholesale Producer-Marketers because these retailer entities in these markets and others have capacity releases from LDCs that carry the indicator that they are serving retail load under one or another "retail choice programs" of LDCs.

[6] With respect to electric generators' capacity, Skipping Stone excluded subscribed winter pipeline capacity level contracts that were for lateral capacity only as these lateral capacity(ies) only entitle the electric generators to move gas under these agreements from one end of the lateral to another.

[7] This type of capacity contract is often referred to as "producer-push" capacity where the capacity comes into the geographic area often (but not always) to pooling points from which it can be purchased for delivery to actual delivery locations within the geographic area.

categories, note that capacity held by shippers to New York points or to pipelines leaving New Jersey, such as Algonquin, was excluded.

We include additional information in columns (e)[8], (f) and (g).

- Column (e) shows these same entities' 2015 Contracted Winter Pipeline Capacity levels in their eastern PA and NJ service locations[9]
- Column (f) provides publicly available LNG vaporization capacity in the same geographic area (including proposed) and
- Column (g) shows Total Peak Day Resources (which is the total of columns (e) and (f))[10]

Table 1. Analysis of LDC Demand in Eastern Pennsylvania and New Jersey

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		No. of Natural Gas Customers	2013 Retail Sales Volumes (Mcf)	Peak Day Sendout (Mcf)	2015 Contracted Winter Pipeline Capacity	2015 LNG Vaporization (Mcf)	2015 Total Peak Day Resources
	Eastern Pennsylvania						
1	UGI Utilities	357,408	116,675,523	654,050	494,607	202,500	697,107
2	UGI Penn	163,796	56,733,872	416,488	218,490	0	218,490
3	PGW	498,694	73,229,988	616,000	304,892	225,000	529,892
4	PECO	498,843	85,834,449	759,594	551,834	161,700	713,534
5	Subtotal	1,518,741	332,473,832	2,446,132	1,569,823	589,200	2,159,023
	New Jersey						
6	PSEG	1,790,240	453,524,804	2,973,000	1,894,994	64,000	1,958,994
7	NJNG	501,595	67,616,570	690,415	525,604	170,000	695,604
8	SJG	359,732	58,997,922	495,056	404,871	75,000	479,871
9	SJR Proposed					250,000	250,000
10	Elizabethtown	278,871	52,732,119	440,148	302,435	24,000	326,435
11	Subtotal	2,930,438	632,871,415	4,598,619	3,127,904	583,000	3,710,904
12	Concentric Regional Total	4,449,179	965,345,247	7,044,751			
13	Retailers, End-Users & Power Gen w- Eastern PA & NJ Capacity				940,095	0	940,095
14	Producer/Marketers w-Eastern PA & NJ Capacity				3,748,500	0	3,748,500
15	Regional Totals			7,044,751	9,386,322	1,172,200	10,558,522

[8] Skipping Stone used 2015 Winter Contracted Capacity because this is the level of capacity to which the PennEast capacity is additive. In addition, it represents the level of capacity that exists (and would exist) absent PennEast and that would be utilized to meet repetitive peak send-outs of the magnitude of those experienced in 2013.

[9] Note that Skipping Stone excluded from such subscribed winter pipeline capacity level contracts that were for lateral capacity only as these lateral capacity(ies) do not entitle the entity(ies) to receive more gas but rather are means of moving gas under these agreements from one end of the lateral to another.

[10] Note that Skipping Stone did not include propane-air resources of any of the entities in the Total of Peak Day Resources.

The above analysis shows that currently subscribed pipeline capacity alone exceeds the Concentric identified entities' peak day sendout by over 33% (Line 15 column (e) divided by Line 15 column (d)). Including these entities' LNG resources increases deliverability resources to 10,558,522 (Mcf per day). The purpose of LNG resources is to provide a local distribution company with additional supplies during peak demand periods that are more cost-effective than the purchase of additional firm pipeline capacity. In total, there are 49.9% more resources available to meet peak day demand from local gas distribution companies in the region than is needed, according to Concentric's own demand data (Line 15 column (g) divided by Line 15 column (d)).

If PennEast is not needed to supply the needs of LDCs in the region, then is the additional supply of 1 billion cubic feet per day of pipeline capacity actually necessary, and for what purpose?

Is Firm Pipeline Capacity Cost-Effective for Electric Generation Customers?

The Concentric study analyzes demand for electric generation, which is typically provided either by contracts for interruptible capacity or by means of bundled (transportation capacity and gas) sales at the generators' delivery points out of the gas network[11], rather than by generator-held contracts with pipelines for firm capacity. That said, the report nevertheless argues that additional capacity is needed for electric generation and to prevent "price spikes."

The period of greatest demand for natural gas is that period of "coincident demand," when gas demand for home heating (provided by LDCs) and for electric generation are both high. In the eastern PA, NJ region coincident demand occurs during winter cold spells. If the demand that PennEast might serve is the coincident demand of natural gas for heating and electric generation in the winter-period, then one has to ask two related questions:

- What is the duration of this coincident demand?
- What is the most economical means of meeting such coincident demand?

Recent studies by EISPC, ICF, ENERGYZT and Skipping Stone[12] have all identified that the period of this coincident demand is from 10 to 30 days, and may increase to 45 days by 2020 and 60 days by 2030. The following analysis calculates the cost of capacity for 10, 20 and 30 days, and includes calculations for 45 and 60 days for completeness.

Is Dual Fuel a Cost-Effective Alternative?

To assess the most economical means of meeting this very short period of peak-period coincident demand, we compare the costs of relying on firm pipeline capacity with a well-known alternative, the use of dual fuel for electric generation. First, we calculate the cost of providing

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[11] These delivery points out of the gas network are either at direct-to-plant pipeline points or are points on LDC systems where the generator can receive gas from the LDC.

[12] EISPC "Study on Long-Term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection" September 2014
ICF "Options for Serving New England Natural Gas Demand October 22, 2013
ENERGYZT "Analysis of Winter Reliability Solutions for New England Energy Markets August 2015
Skipping Stone "Solving New England's Gas Deliverability Problem using LNG Storage and Market Incentives" September, 2015

pipeline capacity that is fully utilized only between 10 and 60 days per year. We then compare this cost with the equivalent cost of using fuel oil rather than natural gas. This analysis also assumes that because the pipelines in the subject geographic area are fully subscribed from their production locations to their market locations, then electric generation customers, to get such capacity for natural gas during coincident peak demand days, would require incremental firm pipeline capacity that cannot be interrupted during such periods of peak demand.

The all-in cost is the effective cost to a power generator reserving capacity year-round[13] that is only needed from 10 to 60 days per year[14]. To illustrate, Skipping Stone provides the analysis shown in Table 2. This analysis is based on two assumptions that can be adjusted: The 100% Load Factor Pipeline Cost (assumed to be $.50/Dth/Day); and the Winter Gas Cost (using the estimated 2019/2020 winter gas cost published by NYMEX in Feb-2016).

Table 2. Analysis of All-in Cost of Capacity

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
100% Load Factor Pipeline Cost	Days Per Yr	Annual Cost/Dth /Day of Capacity	Equivalent Days of 100% load Factor Use /Yr	Cost of Pipeline Capacity per Dth used	Winter Gas Cost	All-in Delivered Cost per Dth used	Dth/Gal	Equivalent $/Gal
$0.43	365	$156.95	10	$15.70	$2.90	$18.60	0.139	$2.58
$0.43	365	$156.95	20	$7.85	$2.90	$10.75	0.139	$1.49
$0.43	365	$156.95	30	$5.23	$2.90	$8.13	0.139	$1.13
$0.43	365	$156.95	45	$3.49	$2.90	$6.39	0.139	$0.89
$0.43	365	$156.95	60	$2.62	$2.90	$5.52	0.139	$0.77

Calculation of All-in Comparative Costs for Fuel Oil

How does the total cost of using natural gas to meet peak load, available only through year-round firm capacity, compare with the cost of using No.2 fuel oil?

First, we evaluate the cost of contracting for firm pipeline capacity for a given number of peak days. Column (c) shows the annualized cost per Dth per day of capacity[15]. Column (d) varies

[13] This same all-in cost calculation would also apply to an LDC displacing some amount of LNG vaporization capacity with year-round pipeline capacity. This occurs when the LNG vaporization and LNG storage capacity is utilized to an extent such that it makes economic sense to add an increment of pipeline capacity and then "grow into" that pipeline capacity again relying on LNG for needle peaks until overall load growth and winter period demand once again makes anther incremental pipeline capacity addition economical..

[14] The reason that such capacity may only be needed by a power generator from 10 to 60 days per year is that there is sufficient otherwise un-used existing capacity all but those days when the coincident demand from electric generation and heating load exceeds existing pipeline capacity. See also Concentric report Page 18 where it discusses price spikes when demand is greater than 8 Bcf/d into the subject market which according to Figure 11 on page 17 occurred some 15 times during the Polar Vortex winter of 2013/2014.

[15] The annual cost per Dth per day presents what the cost for one Dth on one day would be if one Dth per day of capacity was reserved for a year and only used on one day to receive the one Dth.

the number of equivalent days of 100% load factor, or days of peak usage. Ten days of full use is equivalent to 5 days of full use and 10 days of 50% use. The all-in cost of capacity per Dth (assuming a cost of $0.43 per Dth per day of reservation and 10 days of use during times of peak load) has an effective capacity cost of $15.70 per Dth used. At 30 days of peak load, the all-in capacity cost drops to $5.23. To calculate the all-in cost of use, we add the cost of gas during the winter period, $2.90 per Dth, for a total delivered fuel cost of $18.60 per Dth used.

Column (i) shows the price per gallon for fuel that results in an equivalent cost per Dth for the natural gas alternative. For peak demand of 10 days, the natural gas alternative would be the lower cost alternative if the cost of No.2 fuel oil is $2.58 per gallon or higher, equivalent to $108.56 per barrel of oil. For peak demand of 30 days, the natural gas alternative would be the lower cost alternative if the cost of No.2 fuel oil is $1.13, equivalent to $47.47 per barrel of oil.

It should be noted that this 10 to 60 days of peak demand analysis is for illustrative purposes to show that even a pipeline that has a daily transportation rate of as little as 43 cents can result in very high effective costs in use unless it is utilized much more than 60 days – i.e., the existing gas system is constrained on that many or more days.

Based on this basic analysis of alternative costs, one can readily see that it is highly unlikely that a generator will choose to bear the fixed cost burden of the pipeline capacity and would be economically better off choosing oil as fuel during the few days of coincident demand each year.

Calculation of All-in Comparative Costs for LNG

In addition to the oil alternative, securing additional LNG deliveries at locations downstream (i.e., north and east) of the NJ/PA demand centers, as well as from existing LNG facilities within the NJ/PA geographic area cited by the Concentric report, are likely to be even less expensive as a supply alternative. Of note here, any additional LNG that is vaporized at Northeast LNG facilities, such as Eastern MA or New Brunswick, Canada, can make supplies traveling to the Northeast on various pipelines available instead for delivery into the NJ/PA region. This is because the LNG resources would physically serve the New England market thereby enabling supplies otherwise bound for New England to remain in the NJ/PA market and serve demand there. As a result, additional capacity would become available on one or more of the major pipelines connecting the NJ/PA demand centers to New England, such as Texas Eastern, Transco, Tennessee or Columbia to Algonquin (or Maritimes and Northeast).

Because of the current substantial excess of worldwide LNG, future LNG supplies are currently priced at $6.00 to $8.00 per Dth vaporized into New England markets. At these prices, LNG supplies are likely to clear the market lower than the above modeled oil prices in Table 2. Customers can arrange LNG supplies in advance of the winter period and ensure that the inventory is either in the LNG tanks or on the floating storage and regasification ships during the winter period. LNG inventory is arranged in advance in much the same way as pipeline capacity is reserved in advance, except subscription terms are typically year to year and for use of existing facilities do not require multi-year commitments.

Section III – Potential for Increased Costs to Captive Customers on Competing Pipelines

The FERC Commissioners are concerned with protecting consumers from excessive rates. We analyzed the potential impact of additional capacity on captive customers of competing pipelines with particular regard for the likely impact on rate-payers. Shippers who own capacity on competing pipelines are likely to suffer two negative impacts, or offsetting costs, as a direct result of the addition of the substantial 1 Billion cubic feet per day incremental capacity proposed by PennEast.

Shippers will encounter two sources of increased costs:

1) As the total supply of capacity increases, the value of secondary market capacity is likely to decline, particularly if demand is largely unchanged over the vast majority of the year (i.e., all but the highest 10 – 60 demand days per year).[16] Thus, shippers who own existing pipeline capacity and seek to resell unused capacity into the secondary capacity market **will suffer a loss of value**.
2) Non-renewal or turnback of subscriptions on existing lines could lead to cost-shifting to captive customers of such lines at the next rate case. The risk of non-renewal is significant, as several PennEast Shippers stated in the PennEast application that they plan not to renew portions(s) of their existing legacy capacity portfolios. In addition, other shippers may find that they are able to rely on excess capacity as a consequence of the addition to the market of the PennEast capacity and also choose to not renew. The revenue lost from such turnbacks will ultimately be re-distributed to the pipelines' remaining shippers.

What is the Impact of PennEast on Secondary Market Capacity Values?

Since there is no evidence of significant increased demand for the 40% of capacity purchased for in-state New Jersey use, the increased supply from PennEast will add to the total supply of pipeline capacity in the region and lead to significant underutilized capacity.

The secondary market enables shippers to find buyers for their unneeded capacity by means of either capacity release transactions and/or Asset Management Agreements[17] (AMAs). As a result of excess capacity, secondary market values related to capacity release and AMAs could drop dramatically.

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[16] The reductions in secondary market values impact any firm capacity holder with a less than 100% load factor use of their capacity which sells their unused capacity to others during period of low use. These secondary market purchasers pay the capacity holder for their firm rights. To the extent a particular geographic area is flooded with new capacity, the secondary market values drop to near zero because the supply greatly exceeds the demand. Specifically, it is generally LDCs that sell unused capacity and use large percentages (usually 80% or more) of these secondary market revenues to reduce rates paid by their firm sales customers (ex. residential and commercial customers).

[17] Asset Management Agreements are agreements where a purchaser agrees to provide capacity management services (and often gas supply) and pay the holder of firm capacity often large sums of money to gain control of their capacity in return for agreeing to use a limited amount of that capacity to meet the needs of the selling party while using the balance to make other sales to other parties. These AMAs are effectuated through capacity release transactions in the secondary market.

In particular, for the purposes of this memorandum, Skipping Stone studied capacity release transactions[18] on two pipelines in the subject geographic area: Texas Eastern Transmission (TETCO) and Transcontinental Gas Pipe Line (Transco). The period studied was 2015. The transactions analyzed were those where the capacity terminated in the same eastern PA and NJ geographic area as that discussed in the Concentric study for PennEast.

Skipping Stone found for these two pipelines that the value of traded capacity was in excess of $250 Million in 2015. The aggregated dollars, quantities and average rates for the two lines' 2015 transactions are set forth in the two tables that follow.

Table 3. Texas Eastern (TETCO) Traded Capacity[19]

TETCO 2015 Capacity Release Quantities, Rates and Value			
Eastern PA and NJ locations	**Annualized Daily Equivalent Traded (Dth)**	**Avg Rate per Dth/Day**	**Dollars Realized 2015**
From M2 and into M3	1,398,127	$0.3415	$174,292,476

[18] The transaction types studied were releases from capacity holders to acquiring shippers that were done outside of those done to enable retail choice. Under retail choice many LDCs release capacity at pipeline maximum rates (regardless of capacity values) to marketers that have contracted to serve firm customers on the LDCs' systems. These transactions do not reflect competitive pipeline capacity market conditions and therefore were eliminated so as not to overstate the value of released capacity in the subject markets. In addition, in those cases where no price was provided under an AMA transaction, the average price for the similar capacity was used.

[19] TETCO presents the values of their trades on a segment and point basis so Skipping Stone provided just the segment values (i.e., the values of capacity to get gas into M3 which is the eastern PA and NJ zone from the adjacent M2 area which is the western PA and OH zone) as those would be the values most impacted by an incremental 1 Billion Cubic feet (1,000,000 Dth/d) of capacity into their M3 zone serving eastern PA and NJ. Transco on the other hand reports the values for their trades on a point-to-point basis so the value of getting to a market area point from supply areas is that which would be impacted.

Table 4. Transcontinental Gas Pipe Line (Transco) Traded Capacity

Transco 2015 Capacity Release Quantities, Rates and Value				
ST	County of Delivery	Annualized Daily Equivalent Traded (Dth)	Avg Rate per Dth/Day	Dollars Realized 2015
NJ	Camden	2,000	$0.3050	$222,650
NJ	Essex	215,924	$0.1761	$13,879,181
NJ	Gloucester	104,589	$0.1430	$5,459,521
NJ	Mercer	208,184	$0.3453	$26,238,007
NJ	Middlesex	264,000	$0.2130	$20,524,680
NJ	Union	1,274	$0.0200	$9,300
PA	Monroe	152,459	$0.2553	$14,204,015
PA	Montgomery	167,962	$0.1135	$6,958,227
PA	Philadelphia	42,691	$0.1683	$2,622,767
Totals and Average		1,159,083	$0.2130	$90,118,348

Within the subject market area, the Annualized Daily Equivalent Traded[20] quantity on the two pipelines was approximately 2.55 Billion cubic feet per day. The impact of adding another 1 Billion cubic feet to the same market, an amount roughly equivalent to a 40% increase in regional capacity, would likely crush these values; potentially by as much as 50-90% depending on time of year and other factors. Thus, the PennEast pipeline is likely to put at risk the value of existing capacity, which recently traded for $260 Million per year in secondary market transactions. The greatest volume of existing capacity is held by local gas distribution companies, and ratepayers receive 80% of the value of such resale transactions. These ratepayers are captive customers of the LDCs served by existing pipelines and would suffer a significant financial loss if excess capacity were to be approved by FERC Commissioners.

Notably, this loss of benefit to ratepayers in the subject market would be experienced every year and we estimate could be between $130 Million and $230 Million, or averaging $180 Million each year until such time as the regional demand increase sufficiently to make use of the incremental capacity.

What is the Impact of Non-Renewals of Subscribed Capacity on other Pipelines?

With the addition of the incremental capacity associated with PennEast into the subject market, shippers with contracts expiring in the near to medium term (3 to 10 years from now) would be able to either forgo renewal and rely on the existence of the capacity or be able to negotiate substantial discounts.

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[20] Annualized equivalent means if there were two trades, one of 1,000 Dth/d for a year and another for 365,000 Dth/d for a day, the Annualized Daily Equivalent of each would be 1,000 Dth/d and the total of the two would be 2,000 Dth/d.

We evaluate the potential impact of non-renewals on customers of Texas Eastern (TETCO) and Transco pipelines. The rates on TETCO and Transco for capacity to Eastern PA and NJ run on average between $0.52 and $0.67 per Dth/day. To illustrate, we calculated the impact if half of PennEast capacity, or 500,000 Dth/d, were to go unsubscribed on existing pipelines. At the average of the two rates above (~$0.595), the result would be a loss of over $108 Million per year between the two pipelines.

FERC rules permit affected pipelines to file for rate increases on remaining customers to seek to recover lost revenues. This could mean that the same ratepayers facing a potential loss of secondary market benefits could see a substantial portion of the costs of a rate increase as well. Moreover, like the cost of lost secondary market benefit, the cost of increased rates would be a cost they would bear every year.

Even if Pennsylvania and New Jersey ratepayers were forced to absorb **only half** of the potential lost revenues of $108 Million, this conservative estimate shows that ratepayers could be asked to pay an additional $50 Million a year.

Section IV – Factors that Diminish Possible Future Savings Suggested by Concentric

Are Potential Savings Due to a Repeat of Polar Vortex Circumstances Likely?

Concentric cites the 2013/2014 market disruptions coincident with the Polar Vortex as a measure of savings that could have been realized had PennEast been in service at that time.

Concentric appears to be justifying the build of a pipeline purely on the basis of a past price experience, one that notably did not occur in either the 2014/2015[21] nor in prior winters. So, the likelihood of reoccurrence is lower than assumed by Concentric. Concentric should, in any case, reduce their estimate of "potential savings" based on the likelihood of a reoccurrence of the conditions that would create such savings.

Furthermore, any calculation of potential savings should also include potential additional costs that would be borne by ratepayers holding capacity on competing pipelines. The costs, as calculated above, could range from $180 to $280 Million a year (averaging possibly $230 Million a year).

In addition, potential savings are reduced or even wholly eliminated as additional pipeline capacity comes online. Several other projects are slated to come on line before or around the same time as PennEast might come on line. If this occurs, the price depression facing producers with trapped gas supplies will largely be or have been abated. As recently reported by Barclays Bank[22], "Almost 8.1 Bcf/d of infrastructure in the Northeast region has been fully subscribed and is scheduled to ramp up in 2017." Barclays goes on to state "[m]ost of the 2017 pipeline projects are in the southwestern portion of the Marcellus and Utica shales[23], which potentially could strengthen price points," meaning that once the trapped production has outlet to market, the currently favorable pricing will dissipate, if not fully evaporate.

Pipelines should be planned to address longer-term conditions and trends, rather than as a response to a single event, since planning and construction of pipeline capacity takes several years. In order to have been in service by the winter of 2013 PennEast would have had to have started its development process somewhere around the 2008/2009 period. The gas price situation at that time was wholly different from the price situation today, and five years from now the price situation will be wholly different from today's, with or without PennEast.

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[21] Notably the winter of 2014/2015 was colder and had colder days than the Polar Vortex winter of 2013/2014.

[22] See Natural Gas Intelligence March 03, 2016 "Barclays Reduces 2016 NatGas Price Outlook and Sees Breakout in 2017"

[23] These projects largely involve east to west capacity additions and pipeline flow reversals to the south and west. This means that these now trapped supplies will soon have choices of markets and will flow to the most favorably priced market, whereas absent these additions, producers have few choices and compete with one another to gain access to the limited NE market, namely the subject geographic area identified by Concentric.

Are Potential Savings Impacted by Recent Electric Market Reforms?

In the past two years, both PJM and NEISO have instituted market rules which heavily incentivize generators to have fuel during peak critical periods[24]. Skipping Stone will refer to these market rule changes as "Supply Assurance Programs."

Notably also, in the short-run NEISO has instituted its Winter Reliability Program where it pays generators to have fuel oil and/or LNG in tanks ready to be used to assure such critical winter period fuel supplies are available for generation. In New England this has had the effect in both of the past two winters (2014/15 and 2015/16) of greatly dampening price spikes. In turn, price spikes in the subject geographic area have also been dampened, as the pipelines running through eastern PA and NJ also either continue north and east or supply pipelines running into New England.

Under the Supply Assurance Programs, both PJM and NEISO have auctions that create price signals and payments to generators. While significant dollars are to be paid to generators under these Supply Assurance Programs, they are amounts that are far short of amounts required to cover year-round firm transportation on interstate pipelines. As a result, anecdotally and to Skipping Stone's knowledge, gas-fired generators have either opted to install dual fuel capability, arrange for peaking LNG supplies, or make firm supply call arrangements with large wholesale players to backstop their commitments.

The likely ongoing impact of these developments is that the scrambling for supply that led to the enormous price spikes experienced during the period covered by the Concentric report are much less likely to occur in the future. Thus, it is increasingly likely that price spike avoidance, a claimed attribute of a proposed PennEast Pipeline, has in large part already, and enduringly, been addressed. To the extent, then, that the potential for future price spikes have been largely avoided by such market rule changes, the supposed benefits from such avoidance have already been realized – without the proposed presence of PennEast to do so.

[24] In PJM this market rule change is known as "Capacity Performance" and in NEISO the market rule change is referred to as "Pay for Performance".

Section V – Weak Public Benefit but Strong Financial Incentives

Given the lack of evidence from the LDC Sponsor/Shippers of their systems' load growth, as well as certain LDC Sponsor/Shippers' statements made regarding replacing some of their currently contracted interstate capacity with proposed new-build PennEast capacity, questions arise as to what could be the driver behind such a project.

Generally pipelines are proposed and built to meet known demand, such as when LDCs sign-up for expansion to serve new territories or replace over-reliance on winter-peaking resources. Pipelines can also be proposed to meet the needs of Producers who seek to move gas from capacity constrained supply areas to liquid market locations. From our review of the documents, the PennEast Pipeline is proposed to serve neither demand from LDCs nor supply from Producers.

What then is a possible motivating genesis for PennEast?

Is Return on Capital a Motivating Factor?

A potential motivator might be a rather simple one: namely, a vehicle for the LDC Sponsor/Shippers to replace dollars collected from ratepayers and sent to third-party unaffiliated interstate pipelines, with dollars collected from ratepayers and paid to themselves – or rather paid to the affiliated, non-regulated, companies owned by the same corporate shareholders as the regulated LDC signing the contracts.

Under an LLC structure such as that of PennEast, the owners (called unit-holders) are generally entitled to distributions of cash net of direct expenses and retained working capital. Direct expenses of new pipelines are both Fixed and Variable. Fixed Expenses can be simplified into the categories of a) interest payments, b) overhead, c) maintenance expenses and d) Non-income taxes (ex. property taxes and franchise taxes). Variable expenses, such as the costs of running compressors and those related to transporting gas, are collected from customers as they transport gas and do not meaningfully figure into the profits of pipeline owners. Thus, for the purposes of this analysis they will be disregarded.

In addition, Pipeline LLCs typically have a 50% Equity and 50% Debt capital structure. Below is a simplified but typical structure for the annual revenue of a pipeline and how it is generally put together.

Assuming an initial capital cost of $1.2 Billion, at the LLC level, investors would put in $600 Million and banks would finance the other $600 Million. For these purposes, Skipping Stone will assume an annual interest rate of 5%. Generally, pipelines then seek to get rates that will generate revenue based upon an annual percentage of total capital that is between 8% and 10% more than their interest rate (i.e., 13% to 15%) and apply that percentage (i.e., revenue level) to total initial capital cost (i.e., the $1.2 Billion). Assuming the lower level, 13% applied to the $1.2 Billion would mean that the pipeline would seek rates that recovered $156 MM per year. Once pipelines have determined their desired revenue level they then design their rates. In our simplified example, applying that revenue level to a pipeline with 1 Bcf per day (1,000,000 Dth/d) of capacity yields daily rates per the below.

Table 5. Simple Economic Structure of Pipeline Revenue Derivation

	Dollars ($M)	Typical Pctg.	Annual Revenue ($M)	Capacity (Dth/d)	100% LF Rate ($/Dth/d)
Assumed Interest Rate		5.0%			
Typical delta to Int Rt%		8.0%			
Upfront Costs					
Total Capital Cost	$1,200	13.0%	$156	1,000,000	$0.4274

Then, there are costs that are deducted from the pipeline's revenues which in the case of LLC structured pipelines result in distributable cash – otherwise considered return to the investors. A typical illustrative revenue, cost and distributable cash[25] structure of a new-build LLC Pipeline is set forth below.

Table 6. Typical LLC Pipeline Revenue, Cost, and Distributable Cash Structure

	Applicable Dollars for Pctg ($M)	Typical Pctg.	Annual ($M)	Capacity (Dth/d)	Cost Component in Rate
Annual Revenue			$156	1,000,000	$0.4274
Annual Costs					
Total Capital Cost Financed		50.0%			
Interest Cost	$600	5.0%	$30	1,000,000	$0.0822
Typical Annual Costs as Pctg of Total Capital Cost					
Operations & Maintenance	$1,200	1.0%	$12	1,000,000	$0.0329
Non-income taxes	$1,200	2.5%	$30	1,000,000	$0.0822
Overhead	$1,200	2.0%	$24	1,000,000	$0.0658
Total Annual Cost	$1,200	8.0%	$96	1,000,000	$0.2630
			Annual Cash ($M)		**Portion of Rate to Investor Cash**
Distributable Cash	$1,200	5.0%	$60	1,000,000	$0.1644

In addition, it is often the case that entities that form LLC Pipelines also double leverage their invested capital. This generally means that while the LLC gets 50% of its total capital cost as equity (in the case above $600 Million), the LLC Members then finance often as much as 50% of that equity contribution at their respective corporate levels. If this were to be the case with all of the LLC members of the LLC Pipeline, then their total equity cash investment would be just

[25] Note that Distributable Cash is on-going once the pipeline has established what it considers sufficient Working Capital Reserves, usually on the order of 2-4% of Total Capital Cost.

$300 Million and assuming they financed their other $300 Million at the same 5% (for an annual cost of $15 Million) then the return on equity to those partners would be $45 Million ($60 Million of cash minus $15 Million of interest) on a $300 Million cash investment. This would mean that those entities would possibly be seeing a 15% return on their cash investments.

The potential 15% return on capital is a very healthy one indeed in this overall economic environment. It is quite possible that this level of financial gain is a very strong motivator behind the proposed PennEast Pipeline.

Do Non-Arm's-Length Commitments Demonstrate Market Need?

Since the restructuring of the US Natural Gas Pipeline Industry in the mid 1990's, the Federal Energy Regulatory Commission (FERC) has had a policy of relying on contracts to pay for new pipelines and expansions of existing pipelines as evidence of market need sufficient to find such construction was in the "public convenience and necessity." A finding that a project is in the public convenience and necessity is what is required for the FERC to both grant eminent domain and to justify any construction of interstate facilities. That said, for most of the past 20 years since it established its policy of reliance on contracts as evidence of market need, those contracts were almost always between un-related parties – they were arm's-length contracts.

That previously prevailing fact is not the case with respect to 74.2% of the capacity and ownership of PennEast. In fact most of the Shippers, that is, the contracting parties on whom FERC typically relies as evidence of market need, are owners with a distinct financial interest in the existence of the pipeline and the returns it will provide. Moreover, assuming the LDC shippers are able to have their PennEast Contracts paid for by those LDCs' ratepayers, one has to question whether the FERC can continue its policy of relying on contracts as evidence of market need, the foundational aspect to a finding of public convenience and necessity.

This cannot be overstated or overemphasized.

If non-arm's-length contracts, possibly motivated by financial gain to affiliates of the shippers, are properly scrutinized then there may be *no market need* for a large proportion of the PennEast capacity upon which a finding of public convenience and necessity can rely. Instead, it may be that rather than a market need, there is purely a shareholder return "need" which should not be sufficient to grant a certificate of public convenience and necessity.

Section VI – Conclusion

As discussed in this memorandum, given all of the following:

1) The potentially evident low percentage utilization;
2) The likely existence of lower cost potentially less disruptive alternatives[26];
3) The likely negative impacts on ratepayers who presently benefit from secondary market transactions to reduce their energy costs;
4) The possible negative impact on LDC ratepayers due to turnback of capacity and/or non-renewal of capacity due to a potential glut of capacity;
5) The likely elimination of favorable pricing for gas in the supply area of the proposed line owing to other known developments;
6) The inappropriateness of relying on past events rather than modeling and forecasting future events based upon known changes as a justification for an action as large as adding a Billion cubic feet of incremental pipeline capacity to a limited geographical area;
7) Recent changes in Electric market rules which may have already eliminated the conditions that gave rise to the price spikes of the past;
8) The likely inappropriateness of reliance on non-arm's-length transactions as a foundation for finding market need; and finally,
9) The fact that most of the sponsors of the proposed line are the regulated utility-shippers' unregulated affiliates that are likely committing ratepayer dollars to provide equity returns that will be realized by the unregulated affiliates;

the Commission should institute a full evidentiary proceeding with discovery and cross-examination to determine what demand is to be met by the proposed pipeline and whether less disruptive and more cost-effective alternatives exist to meet the demand determined from such evidentiary proceeding.

[26] Especially alternatives relying on greater utilization of existing LNG facilities to meet short duration peak demands

Thursday, February 25, 2016 2:45 PM ET Exclusive

Mega-projects linked to Appalachian shale top list of planned pipelines

By Arsalan Gul

Natural gas pipeline operators are pouring billions of dollars into interstate pipelines to move Appalachian shale production to markets across the country.

Three of the most expensive natural gas transportation projects under development, for instance, plan to move Marcellus and Utica production to three different areas: New England, the Midcontinent, and the Southeast.

Those three projects, the Atlantic Coast Pipeline, the Northeast Energy Direct project, and the Rover Pipeline project, are part of nearly 70 million Dth/d of interstate natural gas pipeline capacity projects under development in the United States as of Feb. 19, according to an S&P Global Market Intelligence analysis. The bulk of the projects under development, nearly 50 million Dth/d of capacity, are in the announced or early stage of development.

US gas pipeline projects by estimated year in service

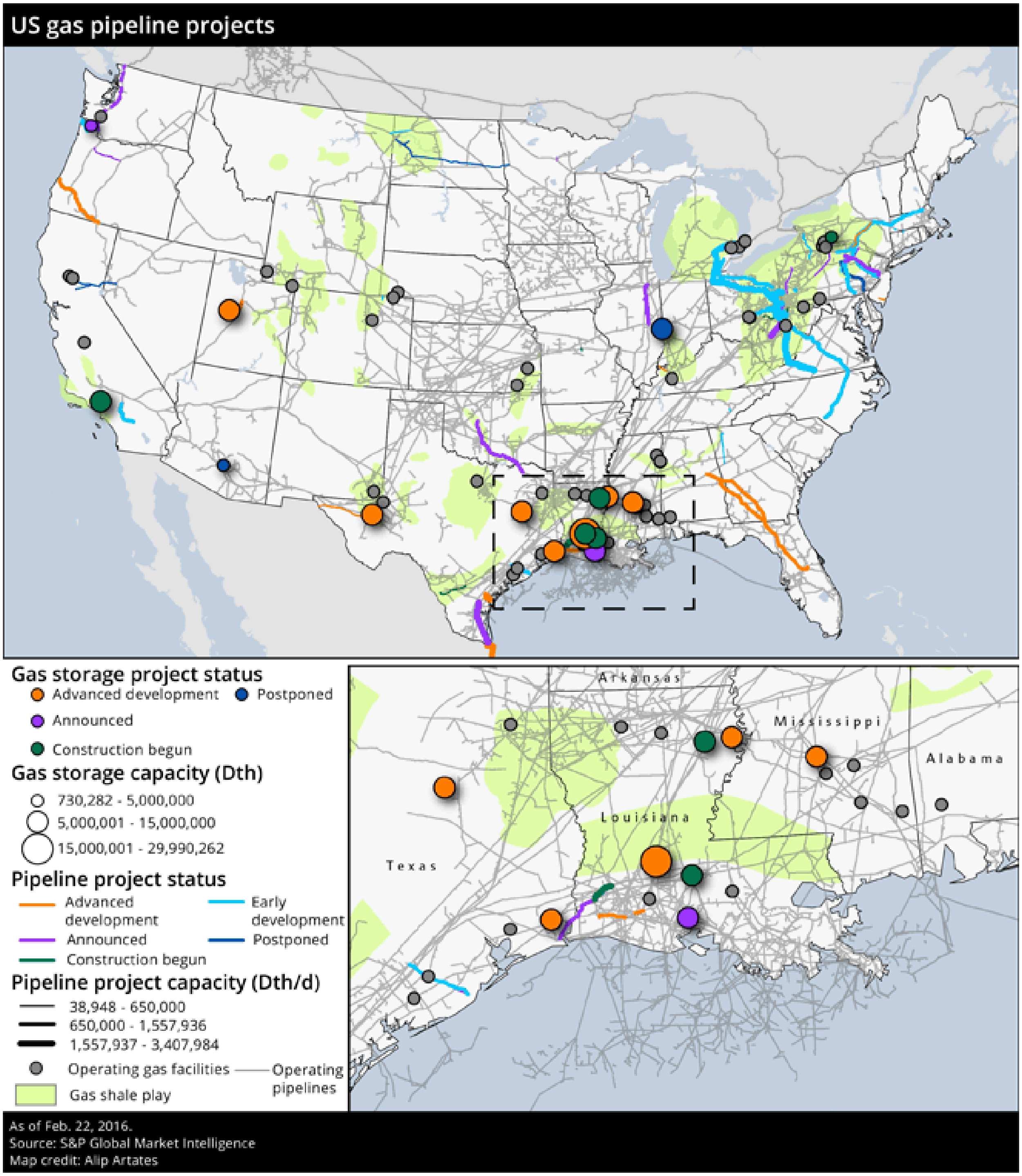
	Development status (Dth/d)					
Year in-service	Announced	Early development	Advanced development	Construction begun	Postponed	Total
2016	0	1,826,507	1,115,876	2,802,744	0	5,745,127
2017	2,862,707	11,355,799	4,189,299	1,200,000	0	19,607,805
2018	8,374,539	11,411,881	4,310,614	0	0	24,097,034
2019	614,113	778,968	623,174	0	0	2,016,255
2020	2,044,791	0	0	0	0	2,044,791
2021	3,844,791	0	0	0	0	3,844,791
2022	3,407,984	0	0	0	0	3,407,984
2024	0	0	0	0	243,427	243,427
Unknown	**2,035,560**	**654,752**	**778,968**	**584,226**	**3,209,932**	**7,263,438**
Total	**23,184,485**	**26,027,907**	**11,017,931**	**4,586,970**	**3,453,359**	**68,270,652**

Data includes pipeline projects longer than 10 miles.
As of Feb. 19, 2016.
Source: S&P Global Market Intelligence

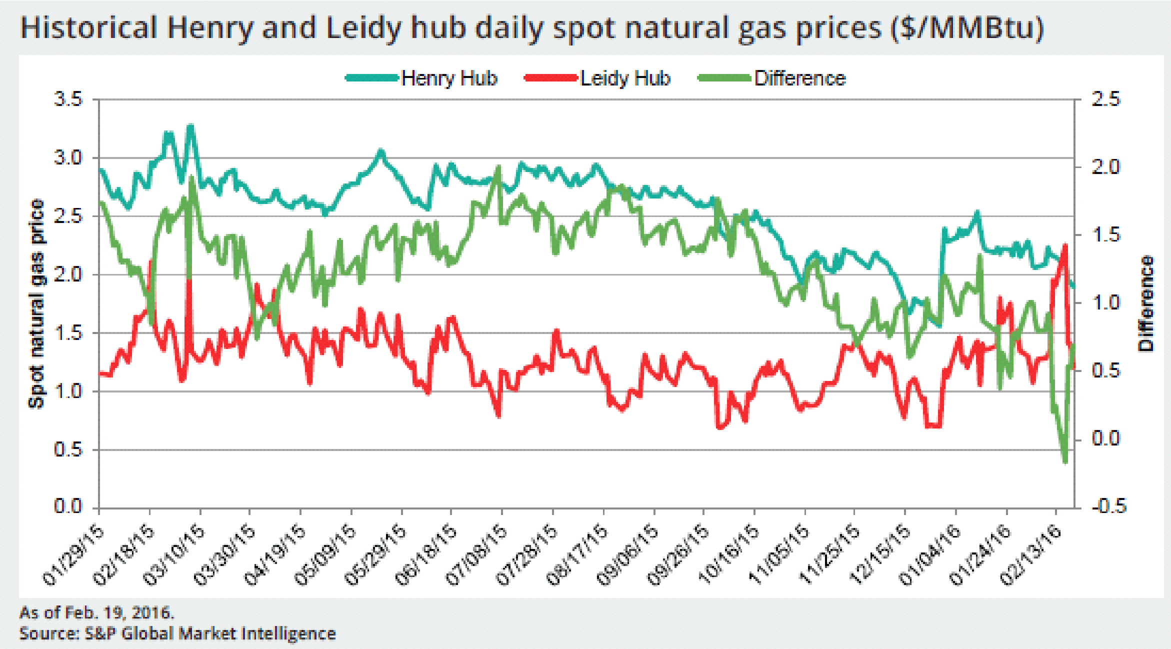
While many projects are in earlier stages of development, much of the capacity is expected online within the next three years. Approximately 72%, or 49.4 million Dth/d out of the total 68.3 million Dth/d planned pipeline capacity is expected to be completed by the end of 2018. The year 2018 will be big year of changing gas flows, with 24.1 million Dth/d of planned capacity expected in-service that year.

S&P Global begins coverage of an announced project when the owner submits a prefiling with FERC. The project is then moved to the early development phase when the owner files a FERC certificate application and is subsequently upgraded to advanced development when FERC grants the certificate. When a FERC order to initiate construction is issued, the project will be marked as under construction. A project is updated to completed status when FERC issues an order to commence operation.

The projects under development span the country, but are concentrated around new production in Appalachia, and new demand centers in the Gulf Coast and Southeast, as those regions gear up for LNG exports and increased reliance on natural gas for power generation and industrial processes.



New pipelines are already allowing larger amounts of gas to travel from the Marcellus to end users, with the spot price spread between Henry Hub and Leidy Hub decreasing over the last year. The spread has been slashed by more than half in the past 12 months, to 69 cents/MMBtu, as of Feb. 19, from $1.74/MMBtu as of Jan. 29, 2015.



Those spreads will likely continue to narrow as time goes on, given the money being spent to move Marcellus supplies. Atlantic Coast Pipeline LLC, owned by Dominion Resources Inc., AGL Resources Inc., Piedmont Natural Gas Co. Inc., and Duke Energy Corp., is the interstate pipeline project with the highest estimated construction cost for projects expected to be online before the end of 2018, totaling $5.1 billion.

Construction on the 1.5 million Dth/d pipeline is set to begin in the second half of 2016 and is expected to be in service by 2018. The project will move supply out of Appalachia, originating in West Virginia and running through Virginia and to southern North Carolina.

Northeast Energy Direct has the second highest estimated construction cost of pipelines coming online before the end of 2018, totaling $5 billion between two phases. The project is owned by Kinder Morgan Inc.'s Tennessee Gas Pipeline Co. and has two sections, the Market Path and the Supply Path.

The Market Path component is scalable up to about 1.27 million Dth/d of capacity with an estimated cost of $3.3 billion. It would run from Wright N.Y., to beyond Dracut, Mass. The Supply Path is scalable up to 1.17 million Dth/d of capacity with an estimated cost of $1.7 billion, and would start from the heart of the Marcellus production area to Wright. The pipeline is needed for the baseload of both LDCs and power generation, according to the Kinder Morgan East Region Natural Gas Pipelines President, Kimberly Watson

The Rover pipeline project, owned by Energy Transfer Partners LP's ET Rover Pipeline Company LLC is the third largest project by estimated construction cost estimated to come online before the end of 2018, totaling an estimated $4.4 billion. The pipeline will be designed to deliver about 3.2 million Dth/d from the Marcellus and Utica regions to Michigan and other markets. On Nov. 9 Rover pipeline requested FERC for an expedited approval so that they could start construction on the project by June or July 2016. The company told FERC that the project would help alleviate the regional bottleneck of production.

Pipeline projects by estimated year in service and capacity (Dth/d)

Project	Owner	Capacity (Dth/d)	State from	State to	Estimated year in-service	Mileage	Development status	Estimated Construction Cost ($000)
Cameron Pipeline Expansion Project	Cameron Interstate Pipeline	2,268,744	LA	LA	2016	21	Construction begun	286,514
Ohio Valley Connector	Equitrans LP	1,168,452	WV	OH	2016	36	Early development	300,000
Constitution Pipeline Project	Cabot Oil & Gas Corp.; Piedmont Natural Gas Co.; Capitol Energy Ventures Corp.; Williams Partners LP	650,000	PA	NY	2016	124	Advanced development	683,000
Northern Access 2016 Project	National Fuel Gas Supply Corp.; Empire Pipeline Inc.	497,000	PA	NY	2016	97	Early development	451,000
Algonquin Incremental Market (AIM)	Spectra Energy Partners LP	342,000	NY	MA	2016	38	Construction begun	971,551
Western Kentucky Lateral	Texas Gas Transmission LLC	223,953	KY	KY	2016	23	Advanced development	81,000
Rock Springs Expansion	Transcontinental Gas Pipe Line	192,000	MD	PA	2016	11	Construction begun	79,500
Lebanon West II (Replacement)	Dominion Energy	130,000	PA	OH	2016	10	Advanced development	120,000
Connecticut Expansion	Tennessee Gas Pipeline Co.	70,107	NY	CT	2016	14	Early development	85,700
South Jersey Pipeline	South Jersey Gas Co.	58,423	NJ	NJ	2016	22	Advanced development	90,000
Southern Indiana Market Lateral	Boardwalk Pipeline Partners LP	53,500	KY	IN	2016	30	Advanced development	95,000
Clarksville Gas and Water Natural Gas Interconnect Pipeline Project	Texas Gas Transmission LLC	52,000	KY	TN	2016	21	Early development	19,600
Loudon Expansion	East Tennessee Natural Gas LLC	38,948	TN	TN	2016	10	Early development	NA
Rover Pipeline Project	ET Rover Pipeline Co. LLC	3,164,557	WV	MI	2017	711	Early development	4,400,000
Cheniere Corpus Christi Pipeline Project	Cheniere Energy Inc.	2,190,847	TX	TX	2017	23	Advanced development	NA
Leach XPress	Columbia Pipeline Group	1,460,565	PA	OH	2017	160	Early development	1,750,000
Nexus Pipeline	DTE Energy Co.; Enbridge Inc.; Spectra Energy Partners LP	1,460,565	OH	MI	2017	250	Early development	2,000,000
Prairie State Pipeline	AGL Resources; Tallgrass Development	1,460,565	IL	IL	2017	140	Announced	NA
Gulf Trace	Transcontinental Gas Pipe Line	1,200,000	LA	LA	2017	8	Construction begun	300,000
Magnum Gas Header Pipeline	Magnum Gas Storage	1,168,452	UT	UT	2017	62	Advanced development	NA
Florida Southeast Connection(Southern Pipeline Project)	NextEra Energy Inc.	973,710	FL	FL	2017	126	Early development	537,000
MARC II Pipeline	Central New York Oil & Gas Co.	973,710	PA	PA	2017	31	Announced	250,000
PennEast Pipeline	AGL Resources; New Jersey Resources Corp.; South Jersey Industries Inc.; PSEG Power LLC; Spectra Energy Partners LP; UGI Energy Services	973,710	PA	NJ	2017	114	Early development	1,000,000
Atlantic Sunrise Expansion/Central Penn	Transcontinental						Early	

North	Gas Pipe Line	850,000	PA	PA	2017	56	development	NA
Atlantic Sunrise Expansion/Central Penn South	Transcontinental Gas Pipe Line	850,000	PA	PA	2017	122	Early development	NA
Sabal Trail	Sabal Trail Transmission LLC	830,000	AL	FL	2017	500	Advanced development	3,000,000
Nueva Era	Howard Energy Partners; Grupo Clisa	584,226	TX	NA*	2017	190	Early development	NA
Dalton Expansion Project	Williams Cos. Inc.; AGL Resources	436,222	GA	GA	2017	111	Early development	471,900
Revolution Pipeline	Energy Transfer Partners LP	428,432	PA	PA	2017	100	Announced	NA
Bakken Header Supply Lateral	Northern Border Pipeline Co.	287,244	ND	ND	2017	64	Early development	NA
Sunbury	UGI Energy Services	200,000	PA	PA	2017	35	Early development	161,000
New York Bay Expansion	Williams Partners LP	115,000	NJ	NJ	2017	0.2	Early development	130,000
Mountaineer XPress	Columbia Pipeline Group	2,629,017	WV	WV	2018	165	Announced	1,800,000
Nueces – Brownsville Pipeline	Comision Federal de Electricid	2,531,646	TX	TX	2018	150	Announced	1,550,000
Sur de Texas – Tuxpan (Marino) gas pipeline	Comision Federal de Electricid	2,531,646	TX	NA*	2018	497	Advanced development	3,100,000
Mountain Valley Pipeline	NextEra Energy Inc.; EQT Corp.; WGL Holdings Inc.; Vega Energy Partners	1,947,420	VA	WV	2018	300	Early development	3,500,000
Atlantic Coast Pipeline/ Southeast Reliability Project	AGL Resources; Piedmont Natural Gas Co.; Duke Energy Corp.; Dominion Energy	1,460,565	WV	NC	2018	550	Early development	5,100,000
Dominion Supply Header	Dominion Resources Inc.	1,460,565	PA	WV	2018	39	Early development	500,000
Oregon LNG Pipeline	LNG Development Co.	1,460,565	OR	WA	2018	87	Early development	NA
Coastal Bend	Gulf South Pipeline Co.	1,382,668	TX	TX	2018	65	Early development	720,000
Northeast Energy Direct Pipeline (Market Path)	Tennessee Gas Pipeline Co.	1,265,823	NY	MA	2018	246	Early development	3,300,000
WB XPress	Columbia Pipeline Group	1,265,823	VA	WV	2018	29	Early development	850,000
Northeast Energy Direct Pipeline (Supply Path)	Tennessee Gas Pipeline Co.	1,168,452	PA	NY	2018	174	Early development	1,700,000
Sooner Trails Pipeline Project	NextEra Energy Inc.; Southern Star Central	1,168,452	OK	TX	2018	250	Announced	NA
Pacific Connector Gas Pipeline	Williams Cos. Inc.; PG&E Corp.; Veresen Inc.	1,000,000	OR	OR	2018	230	Advanced development	1,800,000
Diamond East Project	Transcontinental Gas Pipe Line	973,710	PA	NJ	2018	50	Announced	800,000
Cameron Access	Columbia Gulf Transmission LLC	778,968	LA	LA	2018	34	Advanced development	309,900
Washington Expansion Project	Northwest Pipeline LLC	750,000	WA	WA	2018	140	Announced	NA
Eastern System Upgrade	Millennium Pipeline Co LLC	200,000	NY	NY	2018	8	Announced	NA
North Mist Expansion	Northwest Natural Gas Co.	121,714	OR	OR	2018	13	Announced	NA

NA = not available
* U.S.-Mexico natural gas pipeline project.
Data includes pipeline projects longer than 10 miles with an estimated year in-service before 2019.
As of Feb. 19, 2016.
Source: S&P Global Market Intelligence

Product Tips

To find more details about U.S. natural gas pipeline projects, go to the natural gas project development page.

Bryan Schutt contributed to this article.

Power System Reliability in New England

Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas

<u>Analysis Group, Inc.</u>

Paul J. Hibbard

Craig P. Aubuchon

November 2015

Acknowledgments

This Report presents a review of winter electric resource needs in New England and compares the potential ways to meet those needs, considering both ratepayer cost and regional carbon emissions. This is an independent report by Analysis Group, Inc. (AGI) on behalf of the Massachusetts Office of the Attorney General (AGO), with funding from the Barr Foundation.

Throughout the project, AGI received input from the Office of the Attorney General, a Study Advisory Group comprising a wide spectrum of the region's electric and gas industry stakeholders (listed on the next page), and Dr. Jonathan Raab of Raab Associates (who facilitated the Advisory Group process). The authors wish to thank the Barr Foundation, the AGO, the Study Advisory Group, and Dr. Raab for their input on the analysis presented in this report. The authors also would like to recognize the significant contributions of Pavel Darling, Christopher Llop, Justin Metz, and Dana Niu of AGI for their assistance with this project.

The analytic method, views and observations described in this study, however, are solely those of the authors, and do not necessarily reflect the views and opinions of AGI, the Office of the Attorney General, Dr. Raab, or any members of the Study Advisory Group.

About AGI

AGI provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 700 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, and Beijing.

AGI's energy and environment practice is distinguished by expertise in economics, finance, market analysis, regulatory issues, and public policy, as well as significant experience in environmental economics and energy infrastructure development. The practice has worked for a wide variety of clients including energy producers, suppliers and consumers; utilities; regulatory commissions and other public agencies; tribal governments; power system operators; foundations; financial institutions; and start-up companies, among others.

Study Advisory Group

The Attorney General's Office and AGI would like to thank the Advisory Group (listed below) for their invaluable feedback and input. The Advisory Group members served as a sounding board for the AGO and AGI throughout the modeling process. However, all of the modeling related decisions (including the modeling framework, assumptions, data choices, analysis, and conclusions) are the sole responsibility of the authors using their best professional judgment. Listing the Advisory Group members is not indicative of their concurrence or support for anything contained in this Report, and they may disagree with inputs, analysis, and observations set forth in it.

Study Advisory Group Members, Listed Alphabetically by Organization

Peter Shattuck (Acadia Center)
Bob Rio (Associated Industries of Massachusetts)
Greg Cunningham (Conservation Law Foundation)*
N. Jonathan Peress (Environmental Defense Fund)*
James Daly (Eversource)
Tony Scaraggi (LNG Importers)
Michael Altieri (Massachusetts Executive Office of Energy and Environmental Affairs)
Charlie Harak (National Consumer Law Center, Inc.)
Marcy Reed (National Grid Massachusetts)
Dan Dolan (New England Power Generators Association, Inc.)
Peter Rothstein, Janet Besser (alternate) (Northeast Clean Energy Council)
Sue Coakley (Northeast Energy Efficiency Partnerships, Inc.)
Tom Kiley (Northeast Gas Association)
Cynthia Arcate (PowerOptions)
Marc Hanks (Retail Energy Supply Association)
David Littell (The Regulatory Assistance Project)

*shared seat

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I. EXECUTIVE SUMMARY

Context

The New England region currently relies on natural gas to produce 44 percent of its net electricity needs and its total generating capacity, a figure that could exceed 50 percent by 2024.[1] Our region's dependence on natural gas for electricity generation raises concerns about the reliability of electricity supplies during winter peak conditions, when the region's interstate pipeline system is largely committed for heating needs. It also raises concerns about costs. In years when there are frequent constraints with high utilization on interstate pipelines, prices within the region for spot purchases of natural gas often spike, leading to cost increases for electricity consumers. As generation from new, efficient natural gas plants drives down the output from legacy coal, oil, nuclear, and older natural gas generating facilities, the region may in the future become even more reliant on natural gas fired generation to meet peak electric demand. Increased reliance on natural gas and gas-fired generators that operate without firm natural gas transportation capacity has led to concerns about whether, on the coldest winter days, the region will have enough generating resources to maintain system reliability. As a result, some have suggested that additional gas pipeline capacity is needed in the region for power system reliability and price benefits.

At the same time, this transition away from legacy coal, oil and older natural gas units and towards new, efficient natural gas plants has driven down the greenhouse gas (GHG) emission intensity of the system and lowered total GHG emissions, consistent with regional policies. As discussed further in this Report, however, this trend is not sufficient to meet the region's long-run climate objectives.

Study Purpose

The Massachusetts Attorney General's Office retained Analysis Group, Inc. (AGI) to conduct an independent assessment of the region's power system out to 2030 to determine the following:

1. *Could the region experience power system "deficiencies" – periods during peak winter demand when the electric system may not be able to meet peak electric demand?*
2. *If any such deficiencies are identified, what is the full suite of practical options for maintaining power system reliability – particularly during winter months – including but not limited to electric ratepayer funding for natural gas infrastructure?*

Then, considering the practical options identified for maintaining power system reliability:

3. *What would be the relative costs to electric ratepayers associated with these options – both to implement the options and as a result of how they affect wholesale electric prices?*
4. *To what extent do various options help achieve or impede New England states' obligations and goals with respect to GHG emission reductions?*
5. *What other factors not captured in the quantitative analysis are relevant for consideration?*

[1] ISO-NE, Resource Mix. Available: http://isone.org/about/what-we-do/key-stats/resource-mix.

This Report systematically reviews these questions to gain an understanding of whether the current system can maintain reliability and what the economic costs and benefits (to electric ratepayers) and GHG emission implications would be of either staying the course or pursuing a new path to meet the region's energy needs.

The purpose of this Report is to provide New England's policymakers and stakeholders with an independent and transparent assessment of the potential benefits and drawbacks associated with the various approaches to addressing the region's dependence on natural gas for electricity generation. We recognize that this is but one of many studies related to the region's dependence on natural gas, and that all studies require forecasting and judgment on highly variable and uncertain future market conditions. It is incumbent on policy makers and stakeholders to consider carefully the purpose, analytic method, and outcomes of all such analyses.

Study Method

Our analysis is focused on the New England region, reviewing system conditions through 2030. We forecast the need for gas-fired generation to meet the region's electrical load requirements in each year and compare that to a forecast of available natural gas supply, after subtracting out firm demand for gas by local gas distribution companies. Combined, we use these forecasts to estimate any potential "deficiencies" – or periods when the electric system may not be able to meet peak electric demand given constraints in natural gas transportation capacity. We model a "base case," which reflects severe winter conditions, the capability of non-gas fired generation, and market incentives that increase the availability of generation to help meet peak electric demands. We also model "stressed system" scenarios that assess the impact of varying increases (over our base case assumptions) in dependence on natural gas for electricity generation that may arise due to changes in the electric generation resource mix.

We then identify several "solution sets" that represent different approaches to meeting any identified reliability needs going forward, including market-driven ("status quo") solutions, natural gas pipeline expansion, and energy efficiency/renewable energy investments. We compare the solution sets from the perspective of electric ratepayers, reviewing both the up-front costs to implement the solutions and the potential benefits of the solutions due to their impact on wholesale energy market prices. We also compare the solutions with respect to their impact on states' abilities to meet GHG reduction obligations and targets.

Additionally, we review two "infrastructure scenarios" that involve the development of natural gas or transmission infrastructure projects that are either larger and/or brought into service earlier than needed to meet power system reliability. These scenarios capture a wider range of impacts above and beyond just electric reliability needs.

We carry out our analysis from a conservative reliability planning perspective – namely, with every judgment and assumption we err on the side of overstating the need for electricity generation, and understating the level of resources available to meet that need.

Key Findings

Under the base case analysis, power system reliability can and will be maintained over time, with or without additional new interstate natural gas pipeline capacity.

New England's existing market structure, including recent changes to address reliability during challenging system conditions at the time of winter peak demand, will provide the resources and operational practices needed to maintain power system reliability. The region will continue to rely on natural gas as the dominant fuel of choice, but we find that under existing market conditions there is no electric sector reliability deficiency through 2030. This result reflects both the declining long-term forecast of peak winter demand and the increasing availability of new non-gas resources, including dual-fuel capable units that can generate on oil during peak winter periods.

Under the stressed system sensitivities we modeled, power system reliability deficiencies emerge by the winter of 2024/2025.

We also modeled the impact of an increase (over our base case assumptions) in dependence on natural gas for electricity generation. We assume approximately 1,200 megawatts (MW) of additional non-gas fired capacity retirements (beyond our base-case assumptions) are replaced with gas-only resources, and further assume that approximately 20 percent of existing oil-fired resources in the region do not have oil at the time of winter peak demand (this represents approximately 1,800 MW of generation). Under this stressed system scenario, an electric reliability deficiency of approximately 1,675 MW arises in 2024, growing to approximately 2,400 MW in 2029/30. From the perspective of natural gas transportation capacity, this deficiency is the equivalent of approximately 0.42 billion cubic feet per day (Bcf/d). There are 26 hours of deficiency spread out over 9 total days, with only 2 days and 4 hours with a total deficiency greater than 2,000 MW in the 2029/30 winter in any scenario.

To meet this stressed system deficiency need, we considered five "solution sets" that could plausibly emerge given economics and currently-known technological capabilities, and/or that are specifically under consideration by the region's states and stakeholders. The impact of each solution set depends on how it affects price setting in wholesale power markets and also the required costs to implement each solution set. Each solution set also affects the ability of the region to meet its climate goals going forward. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies.

Dual-fuel and/or Firm Liquefied Natural Gas (LNG) Solution Sets

Absent any action by states, electricity markets would likely meet any deficiency need through the addition of dual-fuel capability at existing facilities, and/or by contracting for LNG.

New England has significant potential new dual-fuel capability at existing gas-only resources, and underutilized LNG storage and vaporization capacity that could be relied on by gas-fired generators. Absent any action by states to promote alternative solutions, reliability will most likely be maintained through a combination of these resources. This pathway may continue to experience periods of elevated winter prices, but will also require the least cost investment from ratepayers. Specifically, these two "market outcome" solution sets reviewed – involving the conversion of gas-only generation to dual-fuel capability, or the specific contracting on a multi-year basis of storage and delivery as needed of LNG by or for electricity generators – involve minimal up-front investment by consumers. Instead, these solutions would increase costs to the owners of generating assets to meet capacity and energy market obligations, and associated implementation costs would partly or fully flow through to ratepayers over time through existing wholesale market mechanisms.

Market-based solutions fail to offer outcomes consistent with the climate change programs and goals of the New England states.

These market outcome solution sets offer trajectories of GHG emissions that exceed the region's potential GHG reduction objectives. This level of excess potentially represents a failure to meet the region's climate goals and could increase GHG emission-reduction compliance costs for electric ratepayers over time.

Additional Natural Gas Pipeline Capacity Solution Set

The construction of additional natural gas pipeline capacity could address the identified stressed system deficiency, provided such capacity was fully reserved for delivery to electricity generators under coincident winter peak conditions for heating and electricity generation.

Long-term investment in firm interstate pipeline capacity would enable sufficient gas-fired electricity generation to meet winter peak needs under the stressed system scenario. Specifically, the reservation of approximately 0.3 Bcf/d or more by 2024, with an incremental 0.12 Bcf/d for a cumulative total of 0.42 Bcf/d or more by 2029 would be sufficient, provided the capacity is guaranteed for delivery to electricity generators at the time of winter peak, and could not be diverted (e.g., to meet unexpectedly high heating needs of natural gas local distribution company (LDC) customers).

Investment in new interstate pipeline capacity generates significant wholesale electricity price benefits but would require up-front and long-term ratepayer commitments.

Increasing natural gas transportation capacity in New England would lower wholesale electricity costs by lowering natural gas prices at times when the interstate pipeline system would otherwise face greater constraints, and thus higher natural gas price basis differentials. The annual average price suppression benefit is likely large enough to exceed the annualized cost to implement the solution set. However, this solution set places up-front costs and risk on ratepayers through significant long-term commitments to pay for the associated infrastructure.

The pipeline solution fails to offer outcomes consistent with the climate change programs and goals of the New England states.

The pipeline solution set offers a trajectory of GHG emissions that exceeds the region's potential GHG reduction objectives. This level of excess potentially represents a failure to meet the region's climate goals and could increase GHG emission-reduction compliance costs for electric ratepayers over time.

Energy Efficiency (EE), Demand Response (DR), and Renewable Energy (RE) Solution Sets

Increased investment in various combinations of EE, DR, and RE resources could address the identified stressed system deficiency, provided actions were taken to increase such investments beyond existing programs and their current trajectories.

There are many options to meet any identified deficiency need through expanded investment in EE, DR, and RE (through distant low-GHG resources transmitted across existing or new transmission capacity). We modeled three solution set combinations: 1) EE and DR sufficient to meet the need; 2) EE with imports of distant low-GHG energy using existing transmission lines, and 3) EE with imports of distant low-GHG energy using new transmission lines. The cost of low GHG imports reflects the fact that the capacity and energy must be guaranteed to be available at the time of, and for the duration of, winter peak conditions in order to address the region's reliability needs.

Investment in EE/DR represents the best solution from the perspective of ratepayer costs.

Sustained investment over time in EE and DR, above and beyond investment currently committed and expected due to existing state policies, has the greatest potential net consumer benefit. Further, this solution set represents a lower-risk pathway for ratepayers, since it involves flexible annual investments that can be altered over time in response to changing expectations around natural gas supply and demand, EE/DR technology development and resource cost, power system demand growth, and the addition and attrition of electric generating resources. That is, this effort also offers the potential to meet long term climate goals beyond 2030 with lower up-front capital investments. However, increased EE installations would require sustained commitment and action by New England states over the next decade.

Increased EE combined with new transmission and/or commitments to purchase firm capacity from distant low-carbon resources generates significant potential electricity price benefits but also involves significant ratepayer up-front investment obligations.

An EE solution set that includes the transmission of low-carbon and/or renewable resources to New England markets instead of DR could generate substantial wholesale electricity price savings, to the extent that imports displace higher-priced marginal generating resources. However, in order to represent a solution to meet reliability deficiency needs, such imports would need to be backed by firm capacity commitments, including delivery at the time of winter peak. The cost of such a capacity commitment, if combined with the cost of transmission investments, could exceed the electricity price suppression benefits associated with this solution. While imports of low-carbon resources that are not backed by firm commitments may be more economic and help the region meet climate goals, they do not represent a solution to any winter reliability need.

EE combined with firm imports of distant low-carbon resources on new or existing transmission lines provides the greatest benefits from the standpoint of GHG emissions.

Meeting winter system reliability deficiency needs through EE and firm imports of low carbon resources would achieve significant reductions in the emissions of GHG associated with electricity generation in the New England region relative to the status quo outcome. It would also provide increased flexibility to meet longer-term climate policy targets.

Infrastructure Scenarios

"Infrastructure scenarios" – involving major pipeline or transmission investments sooner and/or larger than needed to address reliability needs – amplify the impacts of similar solution sets.

In addition to reviewing solution sets designed to address the reliability need, we reviewed major infrastructure investments in natural gas transportation capacity that is larger and sooner than needed and transmission capacity that comes into operation sooner than needed. These infrastructure scenarios demonstrate cost, risk, electricity price, and GHG emission impacts that are similar in nature but larger in size than the pipeline and transmission solution sets sized and timed to address stressed system deficiencies.

Summary of Observations

Based on our analysis, we find that power system reliability will be maintained with or without electric ratepayer investment in new natural gas pipeline capacity. This outcome is consistent with the current and expected future conditions facing our region. New England has maintained reliability through cold winter conditions over the past few years, and going forward, the regional grid operator forecasts declining peak demand for electricity during winter months.[2] Further, recent changes to wholesale markets provide strong financial signals for resource developers and operators of existing assets to ensure unit reliability during periods of winter scarcity. In short, the combination of declining demand and the success of new market initiatives will likely accomplish intended results: power system reliability will be maintained going forward, including at the time of winter peak demand. However, the region may want to consider pathways that provide additional certainty of meeting identified deficiencies that may exist under a "stressed system" perspective.

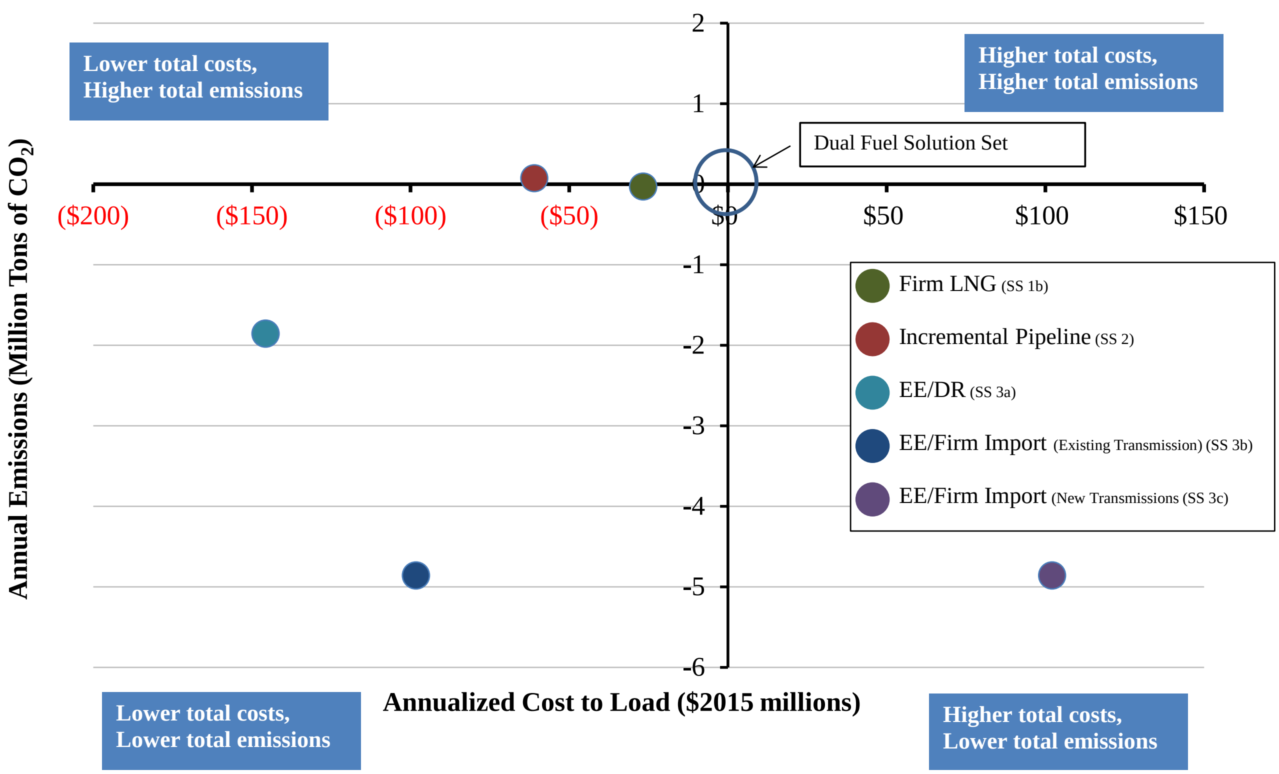
Importantly, the different solution sets that meet the stressed system deficiency vary in fundamental ways from both ratepayer cost and climate policy perspectives. Certain options offer long-term price reducing benefits, but require major up-front investments by ratepayers; others require more measured investments, but also provide fewer price reductions for consumers. Thus there may be additional value that should be attributed to the "incremental" approaches to address the stressed system deficiency. This is particularly true given our finding that, under our base case assumptions, we find no deficiency over the forecast horizon.

This option value may also be important given the region's GHG goals and commitments. With little to replace in the way of higher-emitting resources, solution sets that continue our growing dependence on natural gas for electricity generation do not appear sustainable relative to our region's and our Nation's evolving GHG emission reduction requirements and goals. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies. In contrast, solution sets that fail to do so could require more significant investments at a later date.

[2] ISO-NE Capacity, Energy, Load and Transmission (CELT) Report, System Planning, May 1, 2015.

As Figure ES1 (below) shows, only the EE/DR and EE/Firm Import (Existing Transmission) solution sets solve the stressed system reliability deficiency in a way that both reduces ratepayer costs and reduces GHG emissions relative to the current market outlook of relying on dual-fuel capability. Both the pipeline solution set and the firm LNG solution sets can reduce total ratepayer costs but do not reduce total GHG emissions. Finally, a solution set that includes EE and the firm import of distant low-GHG energy over new transmission lines provides substantial GHG emission reduction benefits, but would lead to a net increase in total ratepayer costs after accounting for both the cost of firm energy supply and new transmission capacity. In general, however, imports without a firm capacity commitment may be available at a lower cost, which could help the region meet its climate goals independently of a focus on reliability needs.

Figure ES1: Annualized Cost and Emission Impacts, By Solution Set ($2015 mil)



Infrastructure scenarios that are larger and/or installed sooner than needed to meet the deficiency amplify the impacts of similar solution sets, but do not change the relative ranking of each option. These infrastructure scenarios demonstrate cost, risk, electricity price, and GHG emission impacts that are similar in nature but larger in size than the pipeline and transmission solution sets.

II. INTRODUCTION AND PURPOSE

A. Emerging Challenges to Winter Power Supply

New England generating capacity additions and operations are governed by the administration of competitive wholesale markets for capacity, energy, and ancillary services. Recent changes to those markets are expected to provide incentives to ensure that generation capacity is available to meet system needs every hour of the year. Nevertheless, the wholesale market construct has two features that have been the focus of significant analysis and policy deliberation in recent years: (1) resource attrition (i.e., from nuclear, coal, and oil-fired capacity) and addition of gas-fired capacity are increasing the region's reliance on power plants using natural gas as the primary fuel, and (2) to date, most natural gas power plant owners have not found it in their financial interest to purchase much firm natural gas transportation capacity for power plant operations. In light of these two features of wholesale market operations, there is concern that under some scenarios the region could have insufficient generating and demand resource capacity available to meet electric system needs, and/or that system constraints lead to high prices, particularly under cold winter conditions with periods of high natural gas demand from all sectors (especially for home heating demand).

Over the past couple years, a number of states in New England have taken steps to evaluate whether *electric* utilities should be allowed to collect in rates costs associated with the forward procurement of new interstate *natural gas* pipeline capacity on a firm basis.[3] In order to take this step, regulators should be convinced that this type of market intervention is needed to address potential power system reliability risks, and represents a prudent investment for the life of the asset. Beyond reliability, states may also consider whether such an investment would lower overall costs for electricity ratepayers, or otherwise be in the public interest.

Reviewing our dependence on natural gas is warranted for several reasons. Local resources for the supply of electricity are limited in New England, particularly at the time of winter peak demand. The only significant indigenous fuels for electricity generation in the region – biomass, hydro, wind, and sunlight – are restricted by resource availability and/or output variability. The contribution of local and renewable resources to annual energy requirements is significant, has substantial potential for expansion, and continues to grow. However, reliability concerns are tied more to the certainty of resource availability at the time of the winter system peak, or under unpredictable stressed system conditions, than to the magnitude of annual energy production. For example, there are only limited opportunities to increase hydro resources within New England, and at the time of winter peak solar capacity is generally not available and wind resource output is an unpredictable function of weather. As a result, the reliable

[3] This includes Massachusetts, Maine, Connecticut, and New Hampshire. Relevant studies include MA (D.P.U. Docket 15-37), ME (Maine Energy Cost Reduction Act, 35-A M.R.S. §1904-(2)), CT (Public Act No 15-107), and NH (NH PUC Docket IR 15-124). In addition, the New England States Committee on Electricity (NESCOE) also reviewed the issue in a series of reports in 2012 and 2013. See B&V (2013).

operation of the electric system in New England under system peak conditions remains heavily dependent on the timely delivery and/or storage of fuels from outside the region for nuclear and fossil-fuel (coal, oil, and natural gas) power plants.

Several of the more “traditional” resource options have their own set of challenges, with implications for the overall level of reliability of fuel supply and electricity generation. The two resource types with the most reliable fuel storage for long-run operations – nuclear and coal-fired generation – face economic and regulatory hurdles to continued operations and have experienced substantial retirements in recent years. Specifically, persistent low energy market prices, and the increased variable costs or need for incremental capital investment associated with emerging safety and emission control requirements, are putting pressure on continued participation by these resources in regional electricity markets.[4] Further, there are major economic and regulatory impediments to the siting new nuclear or coal-fired resources in the region; in fact, no one has filed for review of new nuclear or coal resources under ISO-NE’s interconnection review procedures.[5]

The remaining resources – generating capacity fueled by oil, natural gas, or both (dual-fuel) – require fuel imported from outside New England, and are subject to limitations on the ability to store such fuel for long-run operations. Continuous oil-fired operation at many units is constrained by both limited on-site tank capacity (with the need for potentially frequent replenishment of fuel) and in some cases annual operating limits based on applicable air regulations. Similarly, natural gas-fired capacity is dependent on contemporaneous fuel delivery on an as-needed basis through the region’s interstate pipeline system.[6]

The continuous increase in natural gas capacity and its share of regional generation is creating dependence within New England on natural gas for electricity generation throughout all hours of the year. From 2000 to 2014, the region’s reliance on natural gas for energy generation increased from 15 to 44 percent, largely replacing coal- and oil-fired generation.[7] Over the same time period, the region added approximately 12,000 MW of gas-fired generating capacity, with all other resource types combined adding just over 2,000 MW.[8] Further, there is little reason to believe this trend will diminish anytime soon. Natural gas dominates the ISO-NE interconnection queue for baseload or cycling resources, representing over 7,000 MW and approximately 62 percent of all interconnection queue resources. Most

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[4] Recent wholesale electricity market rule changes (discussed below) are designed to significantly improve the economics of existing capacity resources. Nevertheless, in October 2015, Pilgrim announced its intent to retire by 2019 (and possibly as early as 2017), due in part to the need for new capital investments in response to NRC regulations.

[5] See, for example, the ISO-NE Interconnection Request Queue, available: http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue.

[6] Some of the region’s gas-fired capacity is connected to the distribution networks of the natural gas local distribution companies.

[7] ISO New England, *2015 Regional Energy Outlook*, (hereafter “2015 REO”), page 15.

[8] 2015 REO, page 18.

of the remainder – nearly 3,700 MW (36 percent) – are wind resources whose capacity value is set at a fraction of nameplate capacity.[9]

ISO-NE has conducted significant due diligence over the past five years on the potential impact of our dependence on natural gas on power system reliability. In response, ISO-NE and the region have enacted a comprehensive suite of electricity market reforms to address the issue, affecting virtually every market (energy, capacity, reserves/ancillary services),[10] creating better alignment between the timing of transactions in the natural gas and electricity markets, and establishing clear and frequent lines of communication between power system and pipeline operators, particularly during times of high demand. These changes should fundamentally alter the economics and reliability of power system operations under severe winter conditions, providing the necessary financial signals for enhanced availability and the reliable operation of existing resources, as well as longer-term investment in new resources to enhance the resilience of power system operations during winter peak conditions.

ISO-NE has expressed confidence that the suite of market changes it has promoted will provide the necessary financial incentives for reliable operations at all times of the year on a fuel neutral basis.[11] Yet ISO-NE has also promoted the potential benefits of new natural gas transportation infrastructure to address reliability and energy pricing needs.[12] And while most of the New England states are committed to letting competition in the electricity sector determine the path of infrastructure development and electricity pricing, the states are now actively considering (through legislation and/or regulatory action) options to pursue pipeline infrastructure contracts paid by electricity customers to address winter electric system reliability and cost challenges, and to have electric distribution companies procure large quantities of distant low-carbon resources through long-term contracts in part to help address GHG reduction goals.[13]

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[9] Due to the variable nature of wind generation and the operational performance incentives inherent to New England's capacity market (discussed further below), wind resource capacity value is discounted for reliability planning purposes, and many wind resource owners may choose not to take on capacity supply obligations.

[10] Changes include progressively stronger incentives in the capacity market for reliable operations during periods of peak system needs; more flexibility in the timing and structure of energy market offers to allow for a diverse set of approaches to fuel supply and pricing; changes to amounts procured and pricing in reserve markets providing for substantial additional revenues to generators during times of scarcity; enhanced auditing of generating resource operational capability on all fuels; greater coordination between electric and natural gas system operators; and clarification of the responsibilities of generators that have capacity supply obligations. In combination, these changes represent a fundamentally different and more lucrative structure for ensuring the reliable operation of generating units – including the acquisition of necessary fuel on a timely basis – during winter peak conditions and other times of scarcity.

[11] Testimony of Matthew White on behalf of the ISO, submitted ISO New England Inc. and New England Power Pool, Filings of Performance Incentives and Market Rule Changes; Docket No. ER14-1050-000, filed January 17, 2014.

[12] The Recorder: ISO New England calls for increased gas capacity. Richie Davis, Recorder Staff. January 21, 2015. Published in print: Thursday, January 22, 2015.

[13] See FN 1. In addition, see Appendix 4.

To some extent, the states' efforts reflect the difficult balance between relying on competitive market forces to guide reliable and efficient power system outcomes, but recognizing the paramount importance of preventing power (and natural gas) system reliability failures, and meeting broad-based climate risk mitigation objectives. On one hand, the proper design of the region's wholesale markets for capacity, energy and ancillary services – particularly with recent changes – should allow the market to identify the most efficient, lowest-cost path to maintaining power system reliability in all hours of the year, resulting from competition among a variety of fuel and resource options including pipeline gas, liquefied natural gas, oil and dual-fuel capability, grid-connected and distributed renewables, and demand-side measures. On the other hand, the consequences of missing the reliability and climate objectives are high, and potentially unacceptable from a public policy perspective: if markets cannot or do not provide proper and timely financial incentives, the potential economic, health and public safety impacts of having insufficient resources and infrastructure to meet peak demand can be severe.[14]

B. Purpose of the Study

The Massachusetts Attorney General's Office (AGO) hired AGI to conduct an independent region-wide assessment of potential regional power system reliability needs and solutions and to analyze potential future resource outcomes comparing cost and GHG emission impacts. Specifically, we review:

- Could the region experience power system "deficiencies" – periods during peak winter demand when the electric system may not be able to meet peak electric demand?
- If any such deficiencies are identified, what are the full suite of practical options for maintaining power system reliability – particularly during winter months, including but not limited to electric ratepayer funding for natural gas infrastructure?
- What would be the relative costs to electric ratepayers associated with these options – both to implement the options and as a result of how they affect wholesale electric prices?
- To what extent do various options help achieve or impede New England states' obligations and goals with respect to GHG emission reductions?
- What other factors not captured in the quantitative analysis are relevant for consideration?

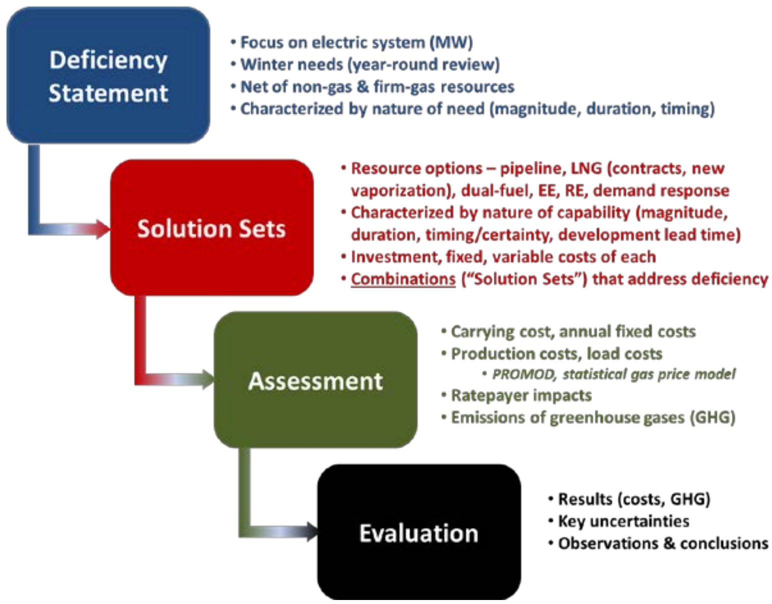
The purpose of our review is to provide information and data to help New England's policymakers and stakeholders consider the potential benefits and drawbacks of various approaches to addressing our region's dependence on natural gas for electricity generation. We recognize that this is one of many studies related to the region's dependence on natural gas, and that all studies require forecasting

[14] ISO-NE and stakeholders in effect recognize this balance in the implementation of the temporary "Winter Programs." During the interim period while the financial signals of recent and pending market rule changes begin to take effect and grow, ISO-NE has proposed and the region has implemented significant out-of-market actions to secure fuel for reliable system operations, to ensure power system reliability until the full effect of the new market structures is in place.

and judgment on highly variable and uncertain future market conditions. It is incumbent on policy makers and stakeholders to carefully consider the purpose, analytic method, and outcomes of the various analyses. Our analysis is designed to provide data and analysis to support the region's consideration of these issues.

C. Overview of Analytic Method

As noted above, this study's primary purpose is to provide a consistent cost and emission comparison of feasible options for maintaining reliable electric supply through 2030, in consideration of potential constraints on natural gas delivery for electric generation.[15] We focus on options to maintain system reliability in the face of increasing dependence on natural gas for electricity generation – including but not limited to electric company pipeline capacity contracts – and conduct a comparative evaluation of the options from reliability, ratepayer costs and risks, and GHG emission perspectives.



The analysis comprises four basic components, described further in the sections that follow. First, we identify the timing, magnitude, and nature of deficiencies that would exist on the electric system absent new resource development beyond what will otherwise occur in response to ISO-NE Forward Capacity Auctions to maintain resource adequacy. For the deficiency review we analyze and model electric and natural gas system conditions in New England through the year 2030, taking into consideration electric system load and all available resources, with attention to the amount of natural gas transportation likely to be available for electricity generation (particularly during winter months). Second, we identify a discrete number of solution sets that represents various feasible combinations of infrastructure and/or resource options in amounts that (1) are sufficient to address any identified deficiency, and (2) can result from the operation of market outcomes or otherwise be implemented through legislative or regulatory action.[16] Next, we conduct an assessment of the solutions sets including financial/ratepayer analysis, production cost modeling, and a review of GHG

[15] We assume and expect power supply reliability is maintained, even if it is uncertain at this time which resources will emerge to maintain reliability over the forecast horizon. Thus while we use the term "deficiency," we do not mean to suggest or indicate an expectation that the electric system will experience a power supply reliability problem over the forecast horizon.

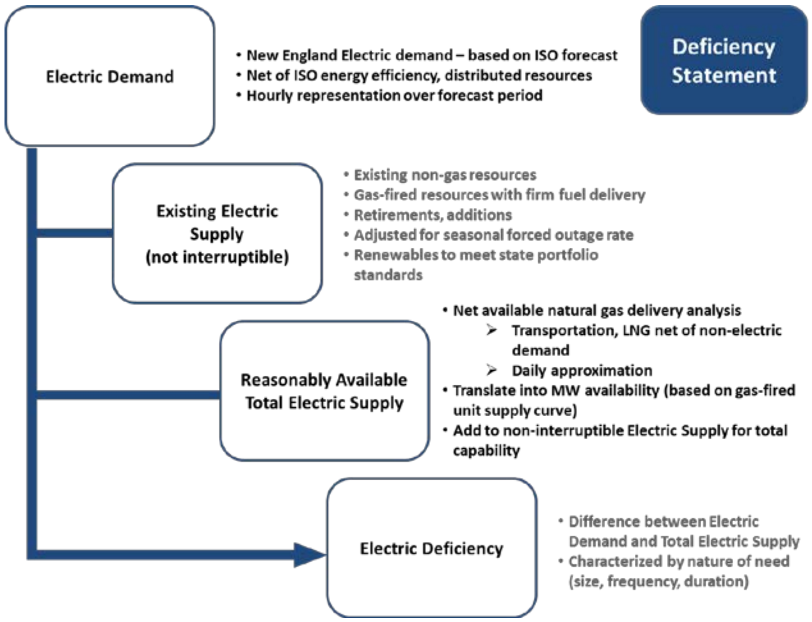
[16] We discuss our screening criteria for "practical" solution sets in Section V.

emission impacts. Finally, we evaluate the results in a comparative analysis of solution sets, identify key uncertainties, and provide observations on the results.

III. POWER SUPPLY DEFICIENCY ANALYSIS

A. Power Supply Deficiency Analysis

To identify the timing and size of solution sets to be evaluated in this report, we first identify a potential deficiency to be met through future resource or infrastructure development. In this context, the term deficiency is not meant to indicate an actual reliability shortfall; instead, it is an estimate for modeling purposes of periods when the electric system may not be able to meet peak electric demand given constraints in natural gas transportation capacity, and thus requiring some combination of additional actions.



In evaluating potential power system deficiencies, we are careful not to construct the analysis in a way that predetermines the conclusion. Specifically, our analysis does not "assume in" a gas supply deficiency by dispatching the electric system *assuming sufficient gas transportation is available in all hours*. This recognizes that whether or not additional interstate pipeline capacity is built (and if so, how much) is not yet known, and that absent additional pipeline capacity there are other ways electric load would be met in constrained hours. Similarly, we do not "assume away" a deficiency by anticipating potential future non-pipeline resource commitments (e.g., firm LNG storage and delivery) or policies (aggressive new renewable, load-shifting, or load-reducing measures or policies). All such potential outcomes are instead configured and evaluated as solution sets to allow for consistent comparison of cost and GHG emission impacts. Thus we adhere in our deficiency analysis to a straight-forward continuation of current market, infrastructure, and regulatory conditions. Under this outlook, the region will continue to rely on natural gas as the dominant fuel of choice, and we include more than 19.5 GW of natural gas fired capacity in 2020 in our base case, representing 52 percent of total system capacity. This total includes 9.6 GW of dual-fuel capacity, with 2.4 GW of that dual-fuel capacity assumed to come on-line after 2019.[17] This total also assumes the retirement of the Pilgrim Nuclear facility in 2019.[18]

Our development of the deficiency statement involves four basic steps: (1) identifying hourly demand for electricity through the modeling horizon; (2) establishing the contribution of non gas-fired supply resources that may be relied upon during cold winter conditions; (3) estimating the quantity of natural gas pipeline capacity that may be assumed to be available for electricity generation on a daily basis across the year, reflecting forecasted LDC pipeline use, and translating this into MW of available generating capacity; and (4) combining these estimates to develop a daily and hourly representation of the total megawatt deficiency of the electric system over the modeling horizon – that is, the amount of electric load that would need to be met through changed operations on the current system, or development of new infrastructure or resources.

Our deficiency calculation is focused on winter peak conditions from a reliability planning perspective. Consequently, the deficiency statement assumes a demand forecast based on extremely cold weather year conditions (e.g., the temperature profile of 2004, one of the coldest years in the past two decades) and coincident high electric load (e.g., the Capacity, Energy, Loads, and Transmission (CELT) 90/10 load forecast, net of existing energy efficiency and photovoltaic (PV) resources).[19] More detail on the steps in our deficiency calculation are summarized in Appendix 1. Below, we describe in more detail two key elements of the deficiency analysis – our derivation of the quantity of natural gas that will be available for electricity generation (in consideration of natural gas LDC demand forecasts and supply plans), and our estimate of the need for natural gas-fired generation on the electric system once all other electric resource options have been considered.

1. Availability of Natural Gas for Electricity Generation

To estimate the total quantity of natural gas available to the electric generation sector, we compare an estimate of forecasted LDC demand for natural gas from interstate pipelines to total available pipeline capacity.[20] First, we assume that the total existing interstate natural gas pipeline capacity is equal

[17] This estimate is in-line with other estimates of dual-fuel capability, including the publicly available totals reported in the ISO-NE CELT (2015) and AGI's review of confidential individual generator data provided by ISO-NE as part of its assessment of the ISO-NE Forward Capacity Market Performance Incentives.

[18] In October 2015, the owners of the Pilgrim Nuclear facility filed a non-price retirement request with ISO-NE.

[19] The 90/10 forecast is based on an expectation that system loads will exceed the forecast only 10 percent of the time. In contrast, the 50/50 load, which is used for resource adequacy planning and in the net Installed Capacity Requirement (ICR), would be expected to be exceeded 50 percent of the time.

[20] We recognize that there are other potential sources of natural gas for electricity generation in addition to interstate pipeline gas, such as supplies sourced from regional LNG facilities. Since these would require forward contracts to procure and ensure LNG is available for electricity generation at the time of winter peak, we do not assume LNG as a resource in the deficiency statement but, rather, assess it as potential solution set.

to 3.95 Bcf/day, based on Energy Information Administration (EIA) State to State capacity data.[21] This includes capacity for Algonquin, Iroquois, Tennessee, Portland Natural Gas, and Maritimes & Northeast Pipelines. We include an additional 0.414 Bcf/day of new capacity in the third quarter of 2016 for the Spectra Algonquin Incremental Market (AIM) Project and the Kinder Morgan Connecticut Expansion Project.[22] Therefore, starting in the 2016/2017 winter, the total capacity of interstate natural gas pipelines is 4.36 Bcf/day.

Next, we develop a forecast of LDC demand for natural gas from interstate pipelines based on the historical relationship between interstate pipeline deliveries to both LDCs and other end-users with historical weather conditions. To do so, we use daily scheduled pipeline and LNG deliveries to LDCs and end-users for the period December 1, 2012 to present using data provided by SNL Financial.[23] We also use the weighted average temperature for the ISO-NE Control Area collected by ISO-NE.[24]

Using this historical data, we then develop the statistical relationship between demand and temperature for the three-year winter periods 2012/13, 2013/14, and 2014/15, as shown in Figure 1. We forecast future gas demand assuming a growth rate for LDC and end-user demand from interstate pipelines of 1.4 percent.[25] We recognized that peak day demands of the LDCs are not fully met through pipeline deliveries, and any peak day demand above this growth rate is met through other resources, such as increased LNG vaporization from regional LNG facilities (e.g. Distrigas) and LNG peak shaving supplies. We assume that these supplies are unavailable to the electric generation sector. Therefore, our

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[21] We note that this assumption is consistent with the 3.7 Bcf/d used in ICF/ISO-NE (2014) and the 3.9 Bcf/d used in B&V/NESCOE (2013). See ICF International. "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II" Prepared for ISO New England, November 20, 2014. Additional detail on our review of LDC supply and demand, and how both may change over the modeling horizon, is presented in Appendix 1.

[22] These projects have received or are pending final FERC authorization. In contrast, we exclude projects that have initiated the FERC pre-filing process or may have precedent agreements with shippers. This includes both the Spectra Atlantic Bridge project, the Spectra Access Northeast project, and the Kinder Morgan Northeast Energy Direct project.

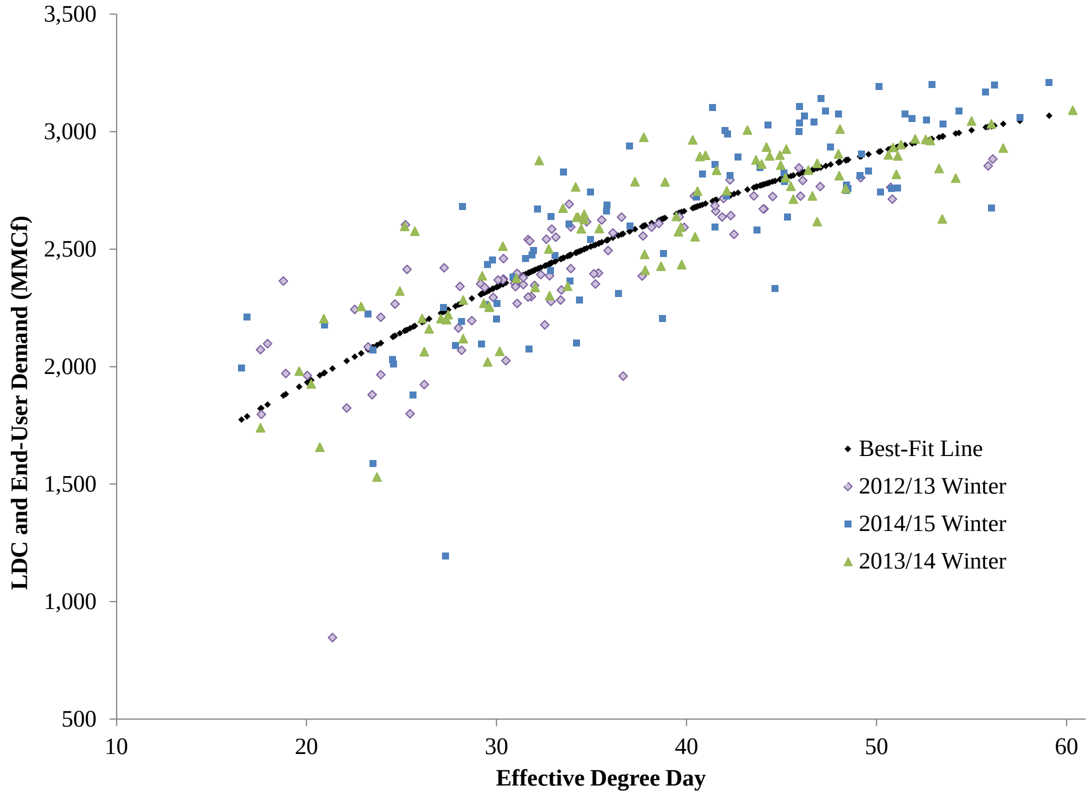
[23] SNL Financial is a data aggregation service that compiles electronic bulletin board data reported by each individual pipeline company. SNL classifies each delivery point based on available contract information.

[24] See ISO-NE, Zonal Information, available: http://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info.

[25] Our estimate is consistent with the long term growth rate used by other recent studies (ICF (2015); Synapse/DOER (2015)). While certain LDCs currently are forecasting higher growth rates, these forecasts typically include demand from end-use customers (as returning capacity exempt customers), which we already separately account for in our estimates. Using a higher LDC growth rate based on current LDC assumptions could double-count end-user demand. On the supply side we exclude incremental supply resources proposed to meet higher growth rate expectations. We assume that any supply additions approved through an LDC resource planning process would be reserved to meet LDC demand above and beyond the quantity forecasted here and unavailable to the electric generation sector. In Appendix 1 we provide a sensitivity that tests both assumptions.

estimate represents a forecast of LDC firm demand for natural gas only from the existing interstate pipeline system.

Figure 1: Historical Relationship of Weather and Gas Demand, 2012-2015

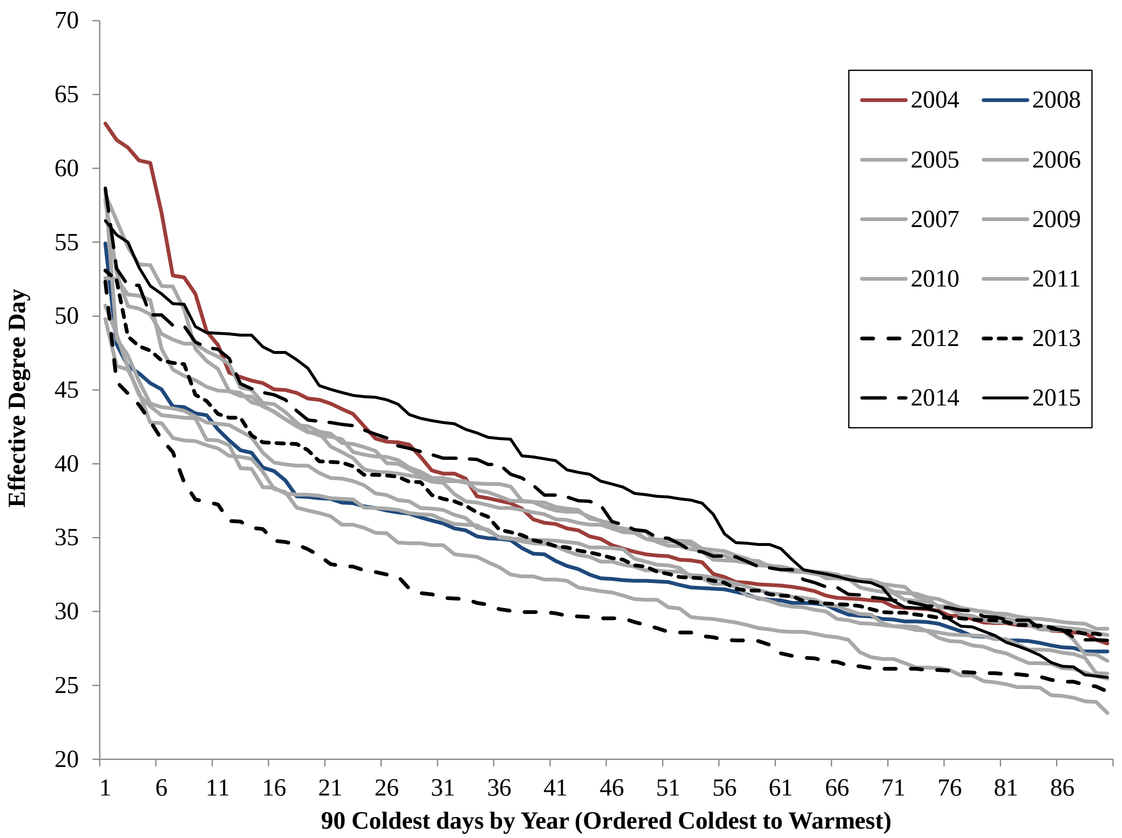


Notes:
[1] Total deliveries are the sum of LDC and End-User demand.
[2] Winter includes December, January, and February.
[3] Effective degree day is defined as 65 degrees Fahrenheit – Temperature.

Using the historical relationship between weather and gas demand Figure 1, we develop natural gas demand forecasts based on both the 2008 weather year (a median winter) and the 2004 weather year (representing a cold weather year, including the coldest day of the past 10 years). As shown in Figure 2, the 2004 year (shown in red) represents far colder winter peak conditions than either of the recent winters in 2012/13 or 2013/14, when New England experienced "Polar Vortex" conditions in late January 2014. This also includes the 2015 year, which experienced a period of sustained cold greater than any previous year.

By combining our estimates for total natural gas pipeline capacity and the daily forecast of natural gas LDC and end-user pipeline demand developed above, we estimate the total hourly pipeline natural gas available to the electric generation sector. Finally, we assume that our daily natural gas availability is fully ratable; that is, the pipeline gas available to electricity generation in each hour is one twenty-fourth of our daily estimate.

Figure 2: Historical Weather Years, 2004-2015



Note:
[1] Weighted average temperature for the ISO-NE control area.
[2] Effective degree day is defined as 65 degrees Fahrenheit – Temperature.

2. Electric Sector Natural Gas Demand

Base Case Deficiency Evaluation

In the second step, we estimate the total quantity of natural gas fired capacity that is needed to meet electric load in every hour, assuming that non-gas fired resources are operable at the time of winter peak conditions (though quantities available are fully reduced by historical seasonal equivalent forced outage rates). We compare this quantity of capacity to the total capacity of gas-fired generation resources that could be dispatched, given the estimated quantity of pipeline natural gas available to the electric generation sector. As a general rule, we use assumptions and data consistent with the ISO-NE planning process.

This estimate requires forecasts for electric sector load and available electric sector generation resources. In order to focus on demand during colder than average winters, we develop deficiency statements using the CELT 90/10 peak load forecast, net of passive demand response and behind the meter solar PV. This forecast reflects load at a level likely to be exceeded only 10 percent of the time. We translate the CELT seasonal peak loads and annual energy forecasts into an hourly load profile and assume that the system will need to carry 2,000 MW of reserves in every hour. [26,27]

Next, we develop a supply curve of available generation resources in each year, taking into account known additions and retirements. We start with the system as it exists today, including known retirements and additions. This includes the recent retirement announcement of the Pilgrim Nuclear facility. Going forward, we assume that all incremental Renewable Portfolio Standard (RPS) requirements are met through in-region wind resources, derated to 5 percent of nameplate capacity with respect to availability during peak periods, consistent with the ISO-NE Transmission Planning Technical Guide (2014).[28] We include all known retirements, based on a review of the current ISO-NE non-price retirement designations and Ventyx default retirements.[29]

With respect to imports, we follow the ISO-NE CELT convention and only include known imports with a firm capacity supply obligation through Forward Capacity Auction (FCA) # 9. That is, we assume – from a resource adequacy and reliability standpoint – that there are only 95 MW of 'firm'

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[26] We developed these hourly load shapes using the Ventyx PROMOD software, a widely used production cost model that simulates the dispatch of the electric generation sector. We describe our use of PROMOD in greater detail in Section V and Appendix 3. Ventyx develops these hourly load shapes based on the historical relationship of hourly data and system annual peak and energy. We reviewed PROMOD's annual load shapes to ensure consistency with monthly and seasonal peaks specified in the ISO-NE forecast.

[27] We recognize that our assumption of needing to carry 2,000 MW of reserves may to some extent be operationally redundant with our application of equivalent forced outage rates on all available resources. This represents an additional conservative assumption on our part, to ensure electric reliability is maintained in all hours.

[28] We recognize that the contribution of such resources at the time of winter peak could be higher than five percent. However, we assume five percent for the deficiency calculation consistent with our approach to evaluating system deficiencies from a reliability perspective.

[29] A full list of unit retirements is included in Appendix 3.

imports in 2019.[30] Existing imports may continue to participate in future capacity auctions, which could continue to provide an important non-gas resource during winter months. Finally, in estimating resource availability at the time of winter peak, we assume that dual-fuel units are available to operate on oil (and have sufficient oil supply), and we derate the total capacity of each resource by historical fuel specific equivalent forced outage rate demand (EFORd) (for dual-fuel capacity we apply the oil-fired EFORd rate).[31] Finally, we include all new resources that have cleared in recent Forward Capacity Auctions and, over the modeling period, add new generic dual-fuel natural gas capacity as needed to maintain at least a 14.3% reserve margin.[32]

Our assumption that existing oil-fired capacity will be available, and new capacity additions will be dual-fuel capable, reflects the outlook that recent market rule changes in New England will provide strong incentives for asset owners to ensure resource availability during potential scarcity hours. These incentives include (but are not limited to) the performance incentive program in the Forward Capacity Market, more flexible (hourly) pricing in the energy market, improved generator auditing procedures, and increased purchases and pricing levels in the reserve market. These market rule changes were designed, in part, to address periods of scarcity associated with potential constraints on the interstate natural gas pipeline system into the region.

With this complete supply curve and load forecast, we estimate the difference between total load and total non-gas fired resources in each hour of each year. This represents the total MW "need" that could be filled by gas-fired capacity. The total reliability deficiency is the difference between this electric sector need (for gas-fired generation) and the total quantity of natural gas fired generation that can be dispatched, given the hourly pipeline natural gas available to the electric generation sector. The deficiency is defined on an annual basis over the modeling horizon by (a) the maximum total magnitude of the deficiency, in MW and Bcf/day of need; (b) the frequency of deficiency events of any size in terms of number of days and number of hours per year; and (c) the duration of deficiency events in terms of the number of consecutive days over which a deficiency exists.

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30 It is unlikely that imports will be as limited in all future years as reflected in this assumption. However, since *in any given year* of the modeling horizon potential import resources could decide to not take on a capacity supply obligation in New England (due, for example, to the exporting region's supply/demand conditions or relative pricing in other neighboring regions' capacity markets), we do not assume they will be available at the time of winter peak, consistent with our approach to evaluating system deficiencies from a reliability perspective. As with other assumptions we have made that may overstate demand or understate supply, to the extent this assumption is wrong we are overstating actual future system deficiencies.

31 This information is provided through the North American Electric Reliability Corporation Generating Availability Data System. See: http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx.

32 We note that this is slightly above the 2018/19 net Installed Capacity Reserve (ICR) requirement of 13.9%, but is consistent with the long-run expected reserve margin forecast in the 2015-2024 ISO-NE Capacity, Energy, Load, and Transmission (CELT) Report.

Stressed System Deficiency Evaluation

In addition to our base-case deficiency evaluation, we also model additional scenarios to explore potential reliability needs in the event that some non-gas fired resources retire or other oil-fired units are otherwise unavailable. These scenarios generally describe conditions in which the electric system experiences an increase in gas demand, greater than that forecast in the base case. This includes limits on the total capacity of oil-fired resources available, and incremental retirements of non-gas fired capacity, as follows:

- Scenario 1: "Oil Unavailable" Scenario: While we expect our reduction of unit capacity for historical seasonal EFORd should to some extent already account for these factors, we make this adjustment in recognition of the fact that units could be unavailable for a number of reasons, including operating limitations under existing air quality permits, available oil supplies during winter events, or generator outages above and beyond historical outage rates. We assume that only existing fuel oil #2 units are available at the time of winter peak, and assume that all other existing resources (fuel oil #6 or unidentified) and other new dual-fuel capacity are available only on gas. This represents approximately 1,800 MW, which is 20 percent of all existing dual-fuel capable units and approximately 40 percent of all dual-fuel units in the future supply stack, including new resources.
- Scenario 2: "Gas-Only" Scenario: We assume the retirement of existing non-gas fired capacity in amounts equal to approximately 1,200 MW, with such capacity replaced by gas-only units (i.e., no dual-fuel capability). This sensitivity reflects, in part, the ability for generators to assume additional risk of non-performance under current pay-for performance rules, which don't formally require dual-fuel capability. In this sensitivity, from a deficiency analysis perspective, *which* units retire is less important than the fact that the retirements be non-gas units, and that the capacity is entirely replaced by gas-only resources. In effect, this represents an absolute increase in the deficiency amounts.
- Scenario 3: "Stressed System" Scenario: A combination of the previous two scenarios.

B. Deficiency Statement Results

We find that under existing market conditions, there is no electric sector reliability deficiency through 2030, and therefore that no additional pipeline gas capacity is needed to meet electric reliability needs (Table 1). New England's existing market structure – including recent changes to address reliability during challenging system conditions (such as at the time of winter peak demand) – will likely provide the resources and operational practices needed to maintain power system reliability. This result reflects both the declining long-term forecast of peak winter demand and the increasing availability of new non-gas resources, including dual-fuel capable units that can generate on oil during peak winter periods. And as described in the previous section, we constructed the base case to include several assumptions that reflect worst-case planning scenario conditions, tending to overstate the "deficiency" beyond normal reliability planning practices.

Nevertheless, it is instructive to understand the vulnerability of the current system to increased system stress, above and beyond that already included in our base case. Under the most stressed scenario, we find that an electric reliability deficiency of approximately 1,675 MW arises in 2024, growing to 2,480 MW in 2029/30, occurring in 26 hours across at most nine days. These 26 hours represent a total energy deficiency of approximately 24,000 MWh over the full winter period in the stressed system scenario. There are only two days and four hours with a total deficiency greater than 2,000 MW in the 2029/30 winter in any scenario.

From the perspective of natural gas transportation capacity, this deficiency is the equivalent of approximately 0.42 billion cubic feet per day (Bcf/d), assuming that capacity must be available on a fully ratable basis and that the deficiency must be met entirely with natural gas fired generation.

In the following sections, we identify solution sets that could be used to meet both the peak deficiency and the duration/frequency. Here, the duration and frequency determines in part how often a given solution set will need to be used. The economic assessment compares this frequency of use with the total annual costs required to implement each solution set. This considers the tradeoffs associated with solutions or other market actions that involve fixed costs required throughout the year, and variable costs and actions that may be available on an as-needed basis.

Table 1: Electric Sector Reliability Deficiency Analysis, 2020-2030

Total Hours with a Deficiency

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	3	4	4	4	4	7
Scenario 3 "Stressed System"	0	0	2	3	10	9	13	15	19	26

Total Days with a Deficiency

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	2	2	2	2	2	3
Scenario 3 "Stressed System"	0	0	1	2	4	4	5	7	7	9

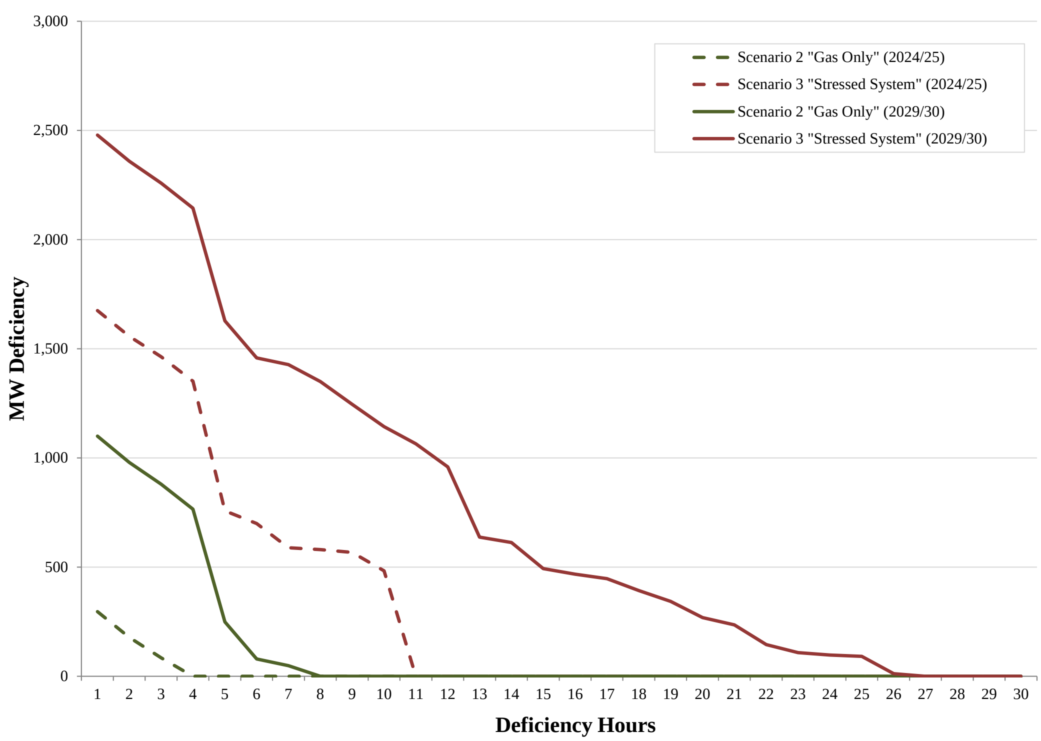
Peak Hour Deficiency (MW)

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	296	576	699	433	743	1,100
Scenario 3 "Stressed System"	0	0	185	435	1,675	1,955	2,078	1,813	2,122	2,479

Peak Hour Deficiency (Bcf/hr)

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0.0021	0.0041	0.0050	0.0031	0.0053	0.0078
Scenario 3 "Stressed System"	0	0	0.0013	0.0031	0.0119	0.0139	0.0148	0.0129	0.0151	0.0176

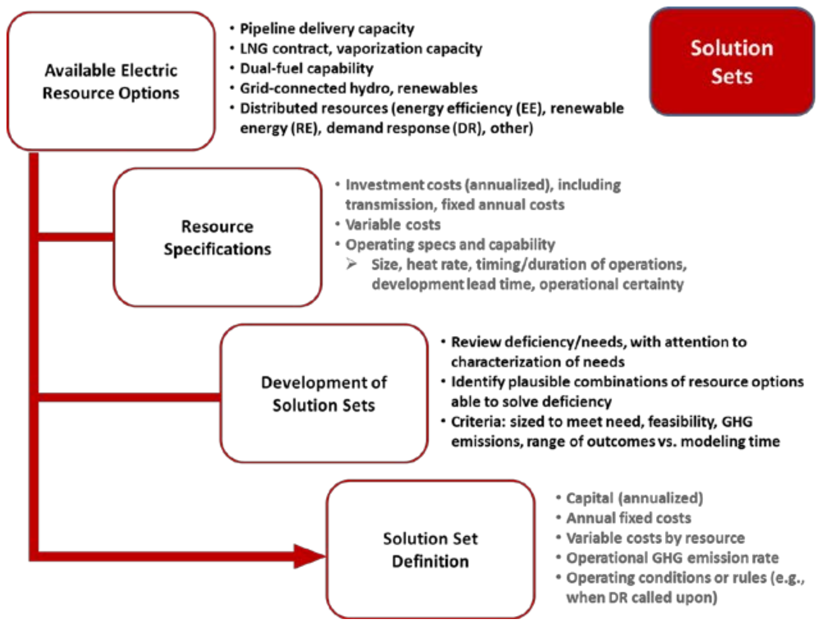
Figure 3: Deficiency Duration Curve (2024-25 and 2029-30)



IV. POTENTIAL ELECTRIC SECTOR PATHWAYS TO ENSURE RELIABILITY UNDER "STRESSED" SYSTEM CONDITIONS

A. Solution Sets

As noted in Section III, we find no deficiency in our base case analysis. Given this conclusion, there is no need to review solution sets as a response to a base case reliability need. Nevertheless, the continued reliance on oil-fired and dual-fuel generation, and possibly other variable solutions such as LNG, will likely continue to lead periodically to high winter prices due to natural gas constraints, and elevated carbon dioxide emissions from oil-fired generation used during winter peak periods. Consequently, while base case conditions do not require any changes from a reliability perspective, our stressed system scenario does identify potential deficiencies. Policy makers and stakeholders may wish to consider the potential cost and GHG emission implications of various solutions that could address the stressed system needs and may have the potential to lower customer costs, lower total GHG emissions, or both.



The fundamental purpose of identifying solution sets to meet the maximum deficiency is to demonstrate feasible options to meet system needs while providing different benefits for customers, through lower energy prices, lower GHG emissions, or both. Our focus is on resources that could plausibly emerge given economics and currently-known technological capabilities, and/or that are specifically under consideration by the region's states and stakeholders.

We develop these "solution sets" as various combinations of electric and/or natural gas resources that could reasonably and practically contribute to meeting the maximum deficiency under the stressed system scenario going forward. We focused on the following threshold requirements and criteria:

(1) Solution sets must, at a minimum, be able to provide or support enough power to satisfy the identified deficiency for the magnitude, frequency, and duration of the deficiency. Specifically, the resource(s) of the solution set must be able to produce or enable firm power output at the time of the most severe winter peak conditions, for as long and as often as needed. This not only limits resources available for the solution sets, it also establishes conditions on solution sets to ensure that the solution set can be counted on to meet the reliability deficiency at the time of winter peak.

For example:

- a three-hour demand response resource cannot satisfy a twelve-hour deficiency;
- solar PV cannot contribute to a deficiency that occurs when it is dark (as is generally the case with winter peak period deficiencies);
- pipeline capacity cannot be counted on unless primary firm transportation rights are guaranteed for electricity generation prior to winter operations;
- a transmission solution cannot be counted on unless backed by a "firm" capacity supply obligation that guarantees availability under winter peak conditions (for example, a contract backed by committed resources such as hydro, wind, or a combination of the two); and
- LNG cannot contribute to a deficiency unless the fuel is previously contracted for, with guaranteed storage, vaporization and pipeline delivery reserved and usable at the time of winter peak conditions.

(2) Solution sets must be feasible and practical from technology, market, and regulatory/policy perspectives, based on reasonable knowledge and expectations in place today. Thus, for example, new nuclear or coal capacity is assumed impractical from economic and siting/permitting policy perspectives; advanced grid-connected battery storage is not specifically considered a solution set alternative given current cost and development expectations; and reducing or shifting demand through advanced demand control technologies and new time-of-use rate structures is not considered given the regulatory and rate design issues that need to be settled before this could become a sizable resource.

(3) Solution sets should be sized and timed to address the identified deficiency. As a general rule, solution sets are assumed to be placed into service when and in amounts needed over the modeling horizon. However, in certain solutions sets where the resource in question is not easily scalable, the full size of the solution needed in the *highest* deficiency year may be assumed in place in the *first* deficiency year (e.g., high-voltage transmission to access distant low-carbon resources), or otherwise may be added generally timed to the deficiency, but in just a couple or few increments (e.g., natural gas pipeline capacity increases or new transmission investments).

We include outcomes that would normally flow from existing competitive market incentives, as well as outcomes that would require legislative or regulatory actions by states (and that have been considered in various forms by states). Below, we describe solution sets grouped into the following categories: (1) market driven outcomes that would likely flow directly from existing market incentives, to ensure fuel delivery security during times of scarcity (i.e., incremental dual-fuel capability and/or firm LNG commitments); (2) incremental pipeline transportation capacity sized at a minimum to meet the identified deficiency and dedicated for electricity generation at the time of winter peak through electric ratepayer funding; and (3) aggressive investment (whether from regulatory policy or technological change) in incremental energy efficiency and other renewable energy.[33]

Each solution set represents an incremental change to the electric generation sector, which will result in an increase in available electric supplies or a decrease in total electric demand. These solution sets include variable options (such as LNG or demand response) which can be called upon only during deficiency hours and also larger fixed options, which would be available both during the winter peak deficiency events and also during all other hours in the year (such as incremental pipeline capacity, new transmission capacity, or increased energy efficiency). Each solution set, therefore, will have a unique impact on total system natural gas utilization, natural gas prices, and the total cost of energy used to serve customers. We discuss these impacts in the next section.

In order to ensure a consistent and comparable analysis focused on electric ratepayers (who would pay for and be the primary beneficiaries of the investments), we conduct the financial analysis with ratepayers responsible for the full cost to implement each solution set, including all fixed and variable costs associated with new investments based on existing cost-of-service principles that also recover return on rate base, depreciation, and taxes. Also, in estimating costs for all solution sets, we assume costs based on current or known information and recent estimates, without presuming increased performance or declining costs for any resource or solution set. We match annualized benefits to annualized costs over the full modeling period and express all values in levelized real 2015 dollars.[34] Additional details on each solution set, including sources and assumptions for costs, are described in Appendix 2.

Market-Driven Outcomes

Solution Set 1(a): "Status Quo" – Dual-Fuel

The first solution set reflects the market-driven evolution of the region's resources that would likely occur absent any major steps taken by states to achieve alternative resource outcomes. This market outlook assumes, in effect, the status quo. We compare all other solution sets to this outlook. It assumes neither any specific non-market actions to fund the development of natural gas pipeline capacity for use by electric generators, nor funding for transmission and/or long-term contracts to acquire distant low-carbon resources with firm winter commitments. Finally, it does not assume any technological breakthrough or change in state policies to increase distributed renewable and efficiency resources in the region beyond current expectations.

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[33] Broadly, this solution set represents increased investment in renewable and other distributed technologies of various types and sizes (grid-connected wind/hydro, energy efficiency, demand response, distributed generation). A solution set focused on energy efficiency represents the likely lowest-cost distributed approach, based on our review of previous studies.

[34] We recognize that solution sets requiring an incremental capital expansion, for either a new transmission line or new incremental gas pipeline, will necessarily have lifetimes beyond 2030 and the end of our modeling period. We do not consider the remainder of ratepayer payments associated with these investments beyond 2030, nor do we consider any potential benefits to the electric generating sector beyond that point. We discuss the implications for these remaining costs further in Section V.

This outlook recognizes that current market incentives are *not* sufficient to cause many power generators to enter into major advanced commitments for firm natural gas pipeline transportation to cover winter peak operations at full output. Instead, and in response to incentives to ensure operation during times of scarcity, market participants would add dual-fuel capability and ensure sufficient alternative fuel is on site to maintain availability at the time of winter peaks. The costs associated with these alternatives are estimated in the assessment phase and compared with other solution set options. This solution option reflects the fact that there is substantial potential capacity for incremental dual-fuel capability within New England, both in the form of reactivating mothballed capability and adding new dual-fuel capability at existing units.

Dual-fuel capability is added at existing units, with annual increases of 500 MW in 2022; 1,500 MW in 2024; and 400 MW in 2026 (for a total of 2,400 MW). Total annualized incremental dual-fuel capacity costs are assumed to be $6,856/MW, based on information identified in Schatzki and Hibbard (2013), and include both annualized capital costs and annual operating costs for fuel and operations and maintenance. Importantly, electricity consumers would only realize incremental costs for this solution if and to the extent that the addition of duel fuel capability on an existing resource affects capacity market prices as a marginal capacity resource, which may in fact be unlikely. Nevertheless, for comparison with other solution sets, we provide dual-fuel costs calculated as the full incremental cost on a cost of service basis, potentially overstating the cost impact of this solution on ratepayers. This solution set is referred to a “Dual-fuel (SS 1a)”.

Solution Set 1(b) – Firm LNG

As an alternative to adding dual-fuel capability, gas-fired power plants could enter into seasonal or annual contracts on a single or multi-year basis for the delivery (prior to winter peak, or timed for winter peak), storage and regasification of LNG, along with firm delivery of the associated gas to existing gas-only generating resources, if and as needed for fuel supply during winter peak conditions. Existing incentives in the region’s wholesale markets could lead generating resources to take this approach to ensure availability and operation during times of winter scarcity absent any specific actions taken by states. Thus we include an LNG option as an alternative market-driven solution set with the maximum amount of assumed LNG capability that is available set to an estimate of the region’s LNG vaporization capacity, net of estimated LDC use.

Consequently, we assume that net deliverable natural gas capacity for electricity generation associated with the regional LNG facilities is limited by what is used by LDCs during winter peak conditions – which we assume to be equivalent to the full Maritimes & Northeast (M&N) pipeline capacity (limiting contributions from Canaport, which is included in the total existing pipeline capacity described above) and a portion of the Distrigas storage and vaporization capacity assumed to be used by LDCs.[35]

[35] Individual LDCs contract for firm capacity from the Distrigas facility, with the intent that required storage amounts are full as of December 1st in each year. ICF/ISO-NE (2014) reports that 20 percent of the LNG received at

LNG storage and vaporization is contracted for in amounts not more than the full shipment quantities needed to meet the identified deficiency. That is, we do not assume that electric generators or ratepayers pay for firm LNG commitments beyond the quantity required to cover the estimated deficiency. This requires total annual volumes at least equal to the cumulative deficiency need across the winter, which we estimate could be covered by one shipment of LNG, or approximately 3 Bcf. It also requires availability of vaporization capacity up to 0.42 Bcf/d on the maximum deficiency day; we estimate that at least 0.5 Bcf/d vaporization capacity from LNG facilities would be available for electricity generation on peak winter days. Information on potential structures for such contract arrangements, including contract terms and fixed annual and variable costs, were provided to AGI by LNG representatives and Environmental Defense Fund. Our estimate of the cost of this solution set is based on a 90-day term charter arrangement, with a demand charge of $200,000, escalated annually with inflation, and variable charges based primarily on Henry Hub pricing plus a processing cost of $3.50 per Dth, shipping costs of $1.50 per Dth, and delivery charges of $0.16/Dth, all escalating annually with inflation. This solution set is referred to as "Firm LNG (SS 1b)".

Incremental Pipeline Transportation

Solution Set 2 – Incremental Pipeline

The incremental pipeline transportation outlook assumes the development and construction of new interstate pipeline capacity in amounts needed to address any potential deficiency through 2030. Given the identified size of need, we make no assumption as to whether this new capacity would be added as new development or as an expansion of existing supplies. It is assumed that the costs associated with any incremental pipeline capacity developed to meet electric reliability needs would be fully collected from electricity ratepayers on a cost of service basis.[36] We assume that the minimum incremental pipeline capacity that would be needed to meet a power system need would be sized to meet the peak hourly deficiency identified in the deficiency analysis. We also assume that a pipeline (expressed in Bcf/d) is available on a fully ratable basis (i.e., the minimum size of a pipeline is equal to 24 times the peak hourly need). We model a solution set sized to meet the deficiency need, and placed in service in increments and in time consistent with the emergence of the need. This solution set is directly comparable to other solution sets designed to meet the identified reliability need.

Distrigas goes to National Grid's greater Boston-area distribution system, and another 10 percent is delivered by truck to off-site LNG peak shaving facilities. Thus, for the purposes of our study, we assume that 70 percent of the total Distrigas facility regas capability (0.5 Bcf/d) is available to help meet any identified electric sector reliability need. For solution set development, therefore, we limit the maximum quantity of LNG available from Distrigas and available as a potential solution set to 0.5 Bcf/day.

[36] As discussed above, the focus of the analysis is on pipeline capacity that could be used to meet identified *electric system reliability* needs. We do not assess whether there is a need for incremental pipeline capacity to meet gas LDC needs, or whether power system needs (or lack thereof) should affect considerations related to development and construction of new pipeline capacity for use by gas LDCs.

In this solution set, 0.3 Bcf/d of new pipeline capacity reserved for electricity generation is added in 2024, in-service for the 2024/25 winter, and 0.12 Bcf/d of capacity reserved for electricity generation is added in 2028, in-service for the 2028/29 winter. We assume that total capital costs for the 0.3 Bcf/day installation are approximately $788 million, with a first year cost of service of $140 million. Costs for the 0.12 Bcf/day installation are assumed to scale linearly by size. This solution set is referred to as "Incremental Pipeline (SS 2)".

Energy Efficiency (EE), Demand Response (DR), and Renewable Energy (RE)

We develop three solution sets that represent an increase in energy efficiency and renewable energy. The first is focused on increases in energy efficiency and demand response in amounts sufficient to eliminate the potential deficiency on the electric system. While there are many renewable and distributed resources available to the electric sector, we limit the first modeled solution set to just EE and DR, since in our judgment this is likely to be the lowest-cost combination of renewable/distributed resources that could address the deficiency.[37] Other solution sets combine EE with the addition of firm imports of low carbon (likely hydropower) resources over existing or new transmission lines.

Solution Set 3(a) – Energy Efficiency and Demand Response

This solution set combines incremental annual energy efficiency investments plus demand response over time as needed to meet the maximum deficiencies annually. By 2030, this amounts to approximately 1,300 MW of winter peak EE[38] and 1,100 MW of DR. We truncate measure lives for all EE measures and programs at ten years, with complete annual installations starting in 2020 and concluding in 2030. This solution set is focused on the likely lowest-cost distributed approach to address identified deficiencies. We assume that incremental EE is available at a cost of $0.067/kWh, and to account for the incremental degradation of EE on a $/kWh basis, we further assume that EE costs increase at a rate of 7.45 percent annually. Our estimate is based on our review of recent filings of actual energy efficiency program data, including the Massachusetts Program Administrators' draft Program filings for 2016-2018 and the Northeast Energy Efficiency Partnerships' Regional Energy Efficiency Database (REED). We index the cost of demand response to recent bids offered into the PJM capacity market.[39] This solution set is referred to as "EE/DR (SS 3a)".

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[37] This is based on our review of the Synapse/DOER (2015) study, which includes the total, incremental quantities of capacity and energy that could be developed for Massachusetts, including appliance standards, energy efficiency (residential, commercial/industrial, and large industrial), and incremental renewables, including landfill gas, anaerobic digestion, biomass, combined heat and power, solar, and on- and off-shore wind.

[38] Load profiles are developed based on historical program administrator data.

[39] We rely on PJM bid data because similar information is not readily available for ISO-NE. See Monitoring Analytics, Independent Market Monitor for PJM, "Analysis of the 2017/2018 RPM Base Residual Auction." October 6, 2014, Table 18.

Solution Set 3(b) – Energy Efficiency and Firm Imports (Existing Transmission)

This solution set combines annual energy efficiency investments plus firm winter delivery commitments from low-carbon resources, in amounts sufficient to meet the annual deficiencies over time. By 2030, this amounts to approximately 1,300 MW of winter peak EE, with 1,100 MW of firm winter capability added in 2020. This solution set assumes that imports are delivered using existing transmission capacity. We assume that, in order to meet reliability needs, this interconnection would need to be accompanied by a firm capacity supply obligation equal to the full capability, and a commitment to ensure firm delivery of the capacity at the time of winter peak. We assume that the cost of firm capacity during winter peak is equal to the levelized cost of new hydroelectricity capacity, based on recent levelized cost of electricity EIA data. This solution set is referred to as "EE/Firm Imports (Existing Transmission) (SS 3b)".

Solution Set 3(c) – Energy Efficiency and Firm Imports (New Transmission)

Solution Set 3(c) is the same solution set as 3(b), except imports are delivered assuming new transmission capacity is required. We assume that new transmission capacity for 1,100 MW costs an additional $1.4 billion. This solution set is referred to as "EE/Firm Imports (New Transmission) (SS 3c)".

Table 2: Summary of Solution Sets

Solution Set	Description	Key Assumptions
Market Driven Outcomes		
SS 1a: Dual-fuel Capacity	Annual increases of 500 MW in 2022; 1,500 MW in 2024; and 400 MW in 2026.	• Annualized costs of $6,856/MW
SS 1b: Firm LNG Capacity	Firm delivery of LNG dedicated for electricity generation with a 5-year contract and rolling renewals; Annual contract quantity available in increments of 3 Bcf.	• Contract includes daily demand charge and variable costs indexed to Henry Hub, plus relevant adders
Incremental Pipeline Capacity		
SS 2: Incremental Pipeline	Incremental capacity added incrementally to meet need; 0.3 Bcf/day in 2024 and 0.12 Bcf/d in 2028.	• Costs indexed to proposed pipelines, maximum reservation charge of $39/dth-month • Total capital costs of $788 million, first year costs of $140 million (0.3 Bcf/d) • Costs represent full cost of service, including return on equity, taxes, and depreciation
Energy Efficiency, Demand Response, and Renewable Energy		
SS 3a: Energy Efficiency and Demand Response	Total of 1,300 MW peak winter Energy Efficiency by 2030, with 950,000 MWh installed annually, 2020-2030. Total demand response of 1,100 MW by 2030.	• Total lifetime costs of $0.067/kWh, including all incentives and participant costs • Demand Response costs indexed to recent capacity market bids
SS 3b: Energy Efficiency and Firm Imports (Existing Transmission)	Same EE as SS 3a, plus an additional 1,100 MW of firm imports of distant low-carbon energy. We present total ratepayer costs two ways: assuming imports use existing transmission lines (with no incremental cost) and assuming imports require new transmission capacity.	• Firm imports priced at the levelized cost of new hydropower capacity, using EIA data, $4.3 billion for 1,100 MW capacity facility
SS 3c: Energy Efficiency and Firm Imports (New Transmission)		• Incremental new transmission capacity (SS 3c) available for $1.4 billion, including all cost of service obligations

B. Infrastructure Scenarios

In addition to solution sets that meet the above criteria, we separately consider two infrastructure "scenarios" that are larger than needed to meet the deficiency and/or installed as the maximum total need in the first modeling year (e.g., installed before the identified need). This includes both a natural gas pipeline and a transmission scenario. These infrastructure scenarios model extensions of the reliability solution sets, and allow us to consider potential economic and ratepayer impacts beyond the scope of the current study. In order to avoid confusion, we review the results of these scenarios separately, since they are not comparable to the solution sets (i.e., not "fitted" to the identified reliability need). The purpose of analyzing infrastructure investments made earlier and/or larger than necessary is to explore the potential range of cost and emission impacts to ratepayers. Both infrastructure scenarios are assumed to be in-service in 2020, with immediate and comparable reductions in the volatility of natural gas prices at Northeast trading hubs.

Infrastructure Scenario 1 – Larger and Earlier than Necessary Gas Pipeline

We model the incremental addition of a 0.5 Bcf/day pipeline, where the full amount of capacity is reserved for electricity generation. The pipeline is added in 2020, in-service for the 2020/21 winter. Total capital costs for the 0.5 Bcf/day installation are approximately $1.3 billion, with a first year cost of service of $233 million. This scenario is referred to as "Larger Pipeline (IS 1)".

Infrastructure Scenario 2 – Earlier than Required Transmission Investment

Similar to the larger/earlier than required pipeline, we also model a transmission infrastructure scenario which considers the full addition of the 2,400 MW of new capacity in 2020. This is more directly comparable to a natural gas infrastructure scenario which is also sized above the reliability need. Both scenarios recognize the lumpy nature of infrastructure investments and consider the potential for more immediate price suppression benefits. This scenario involves the one-time addition of 2,400 MW of firm winter commitments in 2020. We assume that new transmission capacity for 1,100 MW costs $1.4 billion consistent with the EE/Firm Imports (New Transmission) (SS 3c) solution set, with the remainder (1,300 MW) delivered over existing transmission lines at no incremental cost. The cost of firm energy commitment backed by new hydropower is based on the same costs as the EE/Firm Imports (Existing Transmission) (SS 3b) and the EE/Firm Imports (New Transmission) (SS 3c) solutions, scaled to meet the full 2,400 MW need. This scenario is referred to as "Earlier Transmission (IS 2)".

V. ASSESSMENT

A. Method

Each solution set has a unique impact on total system natural gas utilization, natural gas prices, cost of implementation, the total cost of energy used to serve customers, and GHG emissions.

To compare the impact of solution sets on electric ratepayers in a consistent manner, we take two steps. First, we estimate the total potential up-front cost to ratepayers to “implement” each solution set, with a consistent focus on the annual costs likely to be incurred by ratepayers associated with solution set resources. This includes, for example, an estimate of the cost of service for firm pipeline investments, new transmission, contracts for capacity with distant low-carbon resources, LNG storage/vaporization, or annual costs for incremental EE/DR. We evaluate these costs for each solution set using consistent financial assumptions, and translate them into annualized costs that would be collected from electricity consumers over the forecast horizon.

However, the impact on electricity consumers is not limited to annual costs to implement solution sets. Since each solution set has a unique impact on the marginal price of electricity due to changes in the anticipated dispatch of system resources, each solution set also leads to a unique annual cost to the region’s ratepayers for electricity market purchases. Consequently, in the second step we carry out production cost modeling through 2030 for each solution set, including an integrated gas-electric model to simulate the impacts of each solution set on natural gas prices, in order to establish the total cost to load to meet electric sector needs over the forecast horizon. The production cost modeling is also used to identify annual total system emissions of CO_2 in order to inform our evaluation of each solution set from the perspective of states’ GHG reduction goals and obligations.

The total cost to electric ratepayers combines the results of steps one and two. Specifically, we combine the annual costs to implement each solution set with its impact on total cost to load using production cost modeling results, in order to establish the total annual cost to the region’s electricity consumers associated with each solution set. As described earlier, in our view there is a “status quo” outcome that is likely to occur absent any specific or extraordinary legislative or regulatory action taken by states – namely, a market-driven outcome involving the addition of dual-fuel capability on some portion of the region’s existing gas-only generating resources. To clearly compare the different impacts of each solution set using consistent methods and metrics, and relative to status quo outcomes, we compare each solution set to the Dual-fuel (SS 1a), market-driven dual-fuel capability solution set, on the basis of total annual cost to electric ratepayers and GHG emissions.

In the previous section, and in more detail in Appendix 2, we summarize our estimates of annual ratepayer implementation costs. In the next section, we summarize our approach to the production cost modeling approach. Appendix 3 provides greater detail on modeling inputs, methods, and assumptions.

Production Cost Modeling

We use the PROMOD production cost model to simulate the economic dispatch of generators used to meet system load in every hour of the year over the full ten year period, 2020 to 2030. PROMOD is a widely accepted and commonly used model. The PROMOD simulation engine considers the full mix of available resources and minimizes the total cost to load based on economic and operational criteria, subject to system transmission/operational constraints. To do so, it dynamically solves for the locational marginal price (LMP) in every hour on a zonal basis. LMPs reflect both the system load in each zone and the costs of the marginal (or last) unit required to meet demand in that hour. In ISO-NE, natural gas units were the marginal unit, setting LMPs, approximately 70 percent of the hours in 2014.[40] In our base case market outlook, natural gas continues to be the dominant fuel, and natural gas units provide more than 54 percent of all generation throughout the modeling period. Across all scenarios, natural gas provides at least 48 percent of all generation.

Our PROMOD runs for solutions sets reflect distinct expectations regarding the price of delivered natural gas. Since the New England system relies so heavily on natural gas to provide both baseload and peak generation, the price of delivered natural gas is a key driver in determining the total cost to load for New England ratepayers. In previous winters, high natural gas prices, driven in part by increased demand from the electric generation sector, led to increased electricity costs for electric sector ratepayers during winter periods. Going forward, natural gas prices will continue to reflect changes in the underlying supply and delivery of natural gas to local trading hubs. The "basis differential" – that is, the difference between delivered natural gas prices in New England and the price of natural gas supplies (typically, at Henry Hub) – will continue to reflect the balance of available supply/transportation, and the total demand for delivered gas in Northeast markets. During periods of winter peak demand, delivered natural gas prices will continue to reflect the impact of high utilization of existing natural gas infrastructure in the region.

Each solution set identified in section IV is designed to meet the peak hour deficiency, under the most stressed system scenario. These solution sets are designed to meet the identified need through some combination of increasing total available electric supplies or by decreasing total electric sector demand. Either effect – an increase in available supplies or a decrease in total demand – will potentially lower natural gas prices. To ensure the production cost modeling reflects these changes, we separately model natural gas prices for each solution set.

Our baseline natural gas forecast reflects the current outlook for delivered natural gas prices to the Algonquin and Dracut City Gates, based on futures contracts out to 2022.[41] Beyond 2022, we assume that monthly prices continue to grow at the two year compound average growth rate observed in the futures prices.[42] This allows for growth in the underlying commodity price of gas, as observed at Henry Hub, and for growth in the monthly basis differentials observed at Algonquin and Dracut. Over the modeling period, delivered natural gas prices at the Algonquin City Gates increase from a low of

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[40] ISO New England's Internal Market Monitor, 2014 Annual Markets Report, May 20, 2015, Figure 2-17.

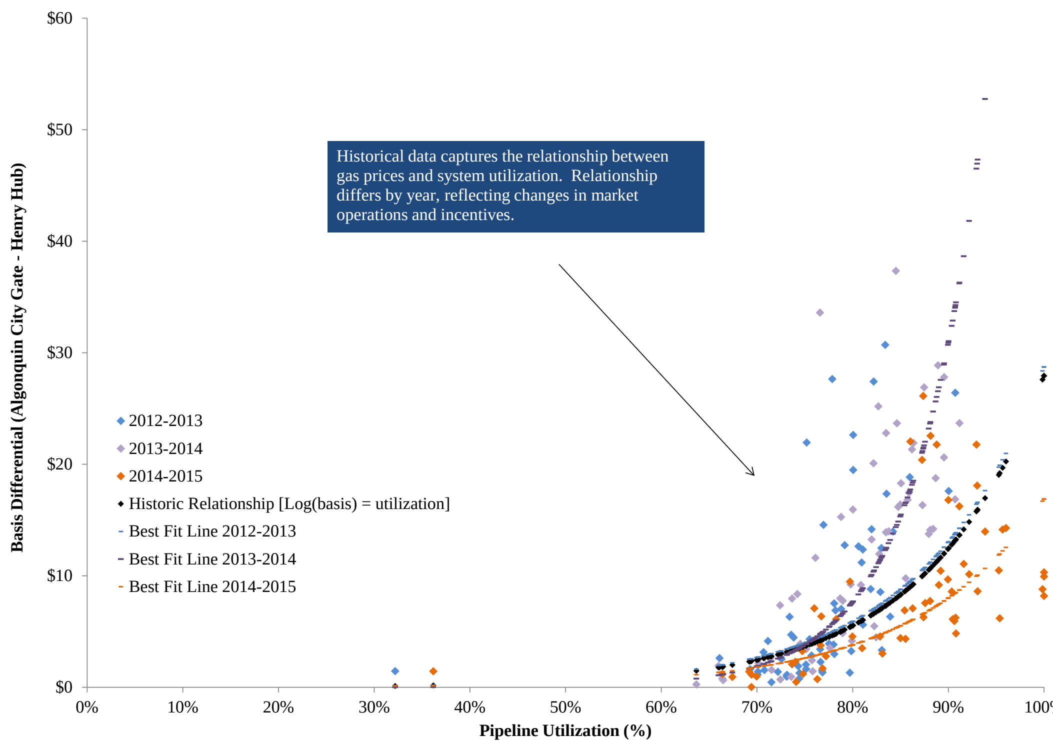
[41] We rely on futures prices as reported by OTC Global Holdings and reported by SNL Financial.

[42] This growth rate is approximately 4 to 5 percent for all months.

approximately $8.00/MMbtu in winter 2020 to a high of $11.50/MMbtu in winter 2029/30 and in the base case, continuing to reflect high winter basis differentials relative to the Henry Hub forecast.

To model the impact of each solution set on natural gas prices, we examine the historical relationship between pipeline utilization and the basis differential between the Algonquin City Gate and the Henry Hub price series for the previous three winters. As shown in Figure 4 gas prices in the most recent year (despite being a very cold year) remained lower at similar levels of utilization, as compared to 2012/13 and 2013/14. This relationship may reflect a number of factors that will continue to be in place going forward, including greater use of LNG and increased oil-fired capacity (in part due to the ISO-NE winter reliability program), and greater coordination between the electric and natural gas sectors. We develop our forecast of future gas prices based on the historical relationship between gas prices and system utilization. This method is consistent with several previous studies. First, we estimate the statistical relationship between gas prices and pipeline utilization, based on the relationship in each winter (2012/12, 2013/14, and 2014/15). This relationship captures the non-linear relationship between pipeline utilization and prices – for example, reducing utilization from 95 percent to 90 percent has a greater impact on prices than a similar five percentage point reduction, from 80 percent to 75 percent (see Figure 4). The utilization-price relationship begins to moderate at approximately 80 percent utilization.

Figure 4: Pipeline Utilization and Natural Gas Prices, Winters 2012-2015



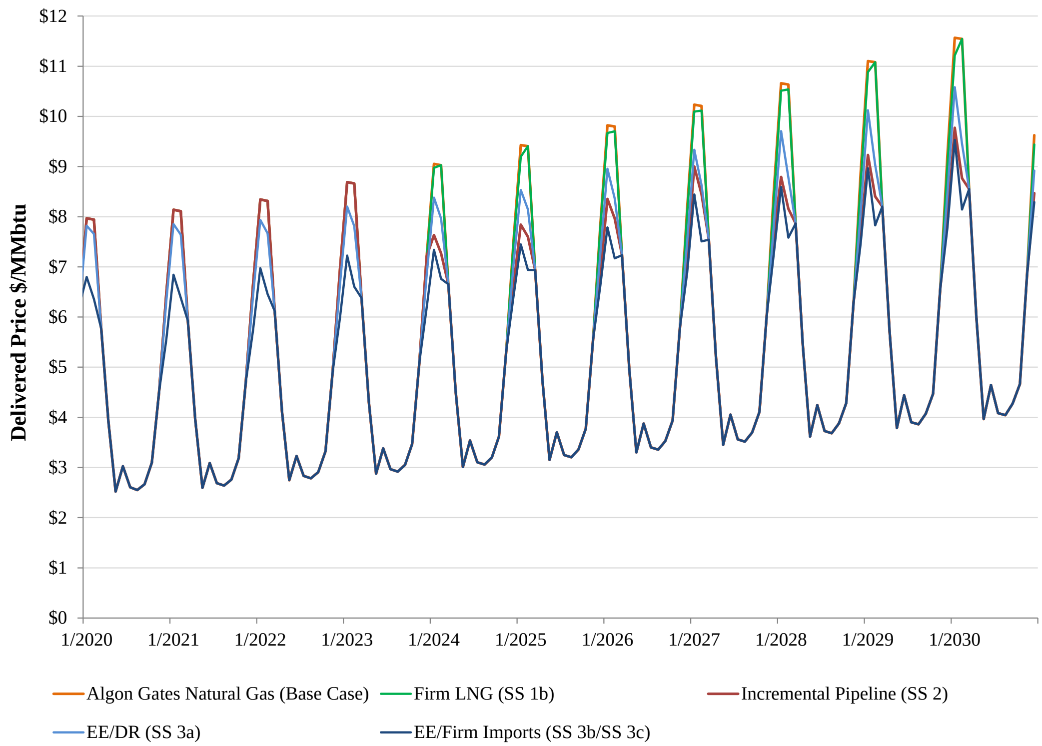
Notes:
[1] Daily utilization is based on the sum of LDC, End-User and Power Plant demand divided by system capacity.
[2] Basis differentials are the difference between Henry Hub and the Algonquin City Gate.

Next, for each solution set, we then estimate the change in daily utilization (relative to the status quo Dual-fuel (SS 1a) market outlook) that would be expected for either an increase in total capacity (both Firm LNG (SS 1b) or Incremental Pipeline (SS 2)) or a decrease in total demand from the electric sector[43] (EE/DR (SS 3a), EE/Firm Imports (Existing Transmission) (SS 3b), EE/Firm Imports (New Transmission) (SS 3c)). Using the relationship illustrated in Figure 4, we translate the estimated change in utilization into a percent change in natural gas prices, relative to the existing market outlook for natural gas prices.[44] The final natural gas price curves for each solution set are illustrated in Figure 5. These gas price curves reflect the fixed and variable nature of the different solution sets. Solution sets that include energy efficiency, which is assumed to be added incrementally in each year, decline in price gradually each year. In contrast, the addition of incremental transmission and natural gas capacity has more immediate and permanent reductions in natural gas prices.

[43] For this purpose we assume that energy efficiency or imports displace marginal natural gas fired generation with a 7,600 Btu/kWh heat rate. Further, we assume that variable LNG supplies are available during identified deficiency days, and do not impact prices in every day of the month.

[44] We estimate the change in utilization and corresponding percent change in prices for each day in the winter modeling period. We assume that variable solution sets – like firm LNG or demand response – only impact gas prices during identified deficiency days. Solution sets in operation for every hour are assumed to reduce utilization on all days. As a final step, we estimate the monthly percent change in natural gas prices as the weighted average of the estimated daily changes. This monthly change represents the final input to the production cost model, and captures the expected change in prices relative to the original market outlook.

Figure 5: Forecasted Natural Gas Prices, By Solution Set



Finally, to develop our comparison of solution sets, we use PROMOD to model the impacts of each solution set – including the gas price forecast from Figure 5 – on the dispatch of power system operations and outcomes. Here, the difference between each simulation and our market outlook scenario represents the direct incremental impacts of a given solution set on the power system. These simulation runs otherwise maintain the same inputs, in terms of power plants available to be dispatched and their operational characteristics.

Our use of a production cost model also allows us to estimate the locational marginal price, total generation, and GHG emissions. Both measures account for the hourly dispatch of resources to meet system load. Importantly, this dispatch captures these aggregate impacts for every hour in every year of the modeling period. We use these outputs, in combination with the estimated solution set costs identified in Section IV.A, to quantify the total change in ratepayer costs and GHG emissions between solution sets.

B. Results

In this section we provide the results of our cross-sectional analysis of the impacts of solution sets designed to address the stressed system deficiency. Results are presented as differences relative to the market driven outcome (Dual-fuel (SS 1a), with respect to (1) annualized changes in total costs to electric ratepayers (including both electricity prices and implementation costs) and annualized changes in total emissions, (2) the annual trajectory of GHG emissions and regional climate goals, and (3) additional factors relevant to each scenario. We also provide the results of our infrastructure scenarios: Larger Pipeline (IS 1) and Earlier Transmission (IS 2)).

1. Annualized Ratepayer Impacts – Total Costs and GHG Emissions

Solution Sets

The cost to electric ratepayers in New England associated with the solution sets evaluated here would include either up-front and annual investment and fixed costs or contract obligations in order to make the solutions happen. This could include cost-of-service recovery for long-term investments or contractual obligations for natural gas pipelines, transmission lines, or contracts for firm winter capacity (e.g., from distant low-carbon resources); it could also include annual or market costs for incremental dual-fuel capability, reservation costs for deliverable LNG, or annual investments in EE and DR capability. Absent such commitments up front, one cannot assume that the resource would be available to meet power system needs at the time of winter peak demand, and thus such resources would not represent solutions from the perspective of power system reliability.

The costs to electric ratepayers for each solution set also depends on how operation of that solution set affects price setting in wholesale power markets. As noted earlier, certain solution sets are targeted to and may only operate during the time of deficiency need (e.g., Dual-Fuel (SS 1a), Firm LNG (SS 1b)), and thus only affect power system prices in limited hours throughout the year. Others, such as Incremental Pipeline (SS 2), and EE/Firm Imports (SS 3b/SS 3c), have the potential to affect power system prices in a much larger number of hours throughout the year.

At the same time, costs to electric ratepayers for each solution set also depend on how operation of that solution set affects the ability of the region to meet its climate goals going forward. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies. We present the GHG emission trajectory of each solution set immediately following results for ratepayer costs.

Table 3: Evaluation of Electric Reliability Solution Sets, Annualized Impacts

Negative Dollar Values represent lower costs than the Market Outlook Dual-fuel (SS 1a)
Negative Emissions represent a decrease in GHG emissions relative to Market Outlook Dual-fuel (SS 1a)

Solution Set	[1] Cost of Energy (Cost to Load)	[2] Cost to Implement Solution Set	[3] = [2] + [1] Total Ratepayer Impact	GHG Emissions (million metric tons)
Market Outlook				
Firm LNG (SS 1b)	-$45	$18	-$27	-0.03
Incremental Natural Gas Capacity				
Incremental Pipeline (SS 2)	-$127	$66	-$61	0.08
Energy Efficiency, Demand Response, and Renewable Energy				
EE/DR (SS 3a)	-$247	$101	-$146	-1.86
EE/Firm Imports (Existing Transmission) (SS 3b)	-$502	$404	-$98	-4.86
EE/Firm Imports (New Transmission) (SS 3c)	-$502	$604	$102	-4.86

Notes: All values for Table 3 and Figure 6 are presented in levelized, real $2015, millions, unless otherwise noted. Pipeline emissions include an estimate for in-region GHG emissions from fugitive methane leaks.

With this in mind, our analysis of ratepayer costs in the present study is specifically focused on identifying the net impact of both the implementation costs of each solution set and the resulting impact to electricity market costs to load. The results, shown in Table 3 and Figure 6, may be described and summarized as follows:

- All impacts are relative to the status quo Dual-fuel (SS 1a) solution set; thus, in Table 3 and Figure 6 all results represent *differences* from the status quo solution outcome. It is useful to note that in these estimates we assume that the implementation cost of the market outlook dual-fuel solution set – namely the cost of converting gas-only capability to dual-fuel capability – would be completely paid by electric ratepayers.

- Firm contracts for the storage and delivery of LNG-based gas as needed during winter peak conditions (SS 1b) – represents the lowest implementation cost solution set, which would cost ratepayers $18 million more per year than the dual-fuel solution set. This solution would also reduce electricity market costs to load by roughly $45 million, leading to net annual ratepayer savings of approximately $27 million per year. This solution set would lead to a slight decrease in emissions over time (0.03 million metric tons annually) relative to the dual-fuel solution set.

- Incremental Pipeline (SS 2) capacity sized to meet the deficiency would deliver substantial price suppression benefits to the region, amounting to approximately $127 million in savings per year.

Since the cost to implement this solution would be approximately $66 million per year, the net impact on ratepayers would be a net savings of approximately $61 million annually, relative to the status quo outcome. This solution leads to an increase in GHG emissions of 0.08 million metric tons per year relative to the dual-fuel solution set due to an increase in total fossil fired generation.

- The EE/DR (SS 3a) solution set provides the lowest total cost solution accounting for changes in both energy and implementation costs and would save ratepayers approximately $146 million per year, relative to the dual-fuel option. The $146 million savings (relative to the dual-fuel solution set) include reductions in electricity market costs of $247 million per year and annual costs of $101 million to install EE measures. This solution set lowers total annual emissions by 1.86 million metric tons per year.
- The EE/Firm Imports (Existing Transmission) (SS 3b) solution would provide annual ratepayer benefits of roughly $98 million per year relative to the dual-fuel solution set. While the EE/firm Imports (existing transmission) solution produces far greater annual energy market savings ($502 million per year), the estimated cost to procure capacity and energy on a firm basis year-round significantly cuts into electricity market savings.[45,46] This solution set lowers total annual emissions by 4.86 million metric tons per year, the largest reduction among all solution sets.
- And if instead, the same set of incremental firm winter imports required new transmission capacity (SS 3c), total ratepayer costs would be $102 million per year higher relative to the dual-fuel solution. A solution involving new firm imports would also reduce annual emissions by 4.86 million metric tons per year.

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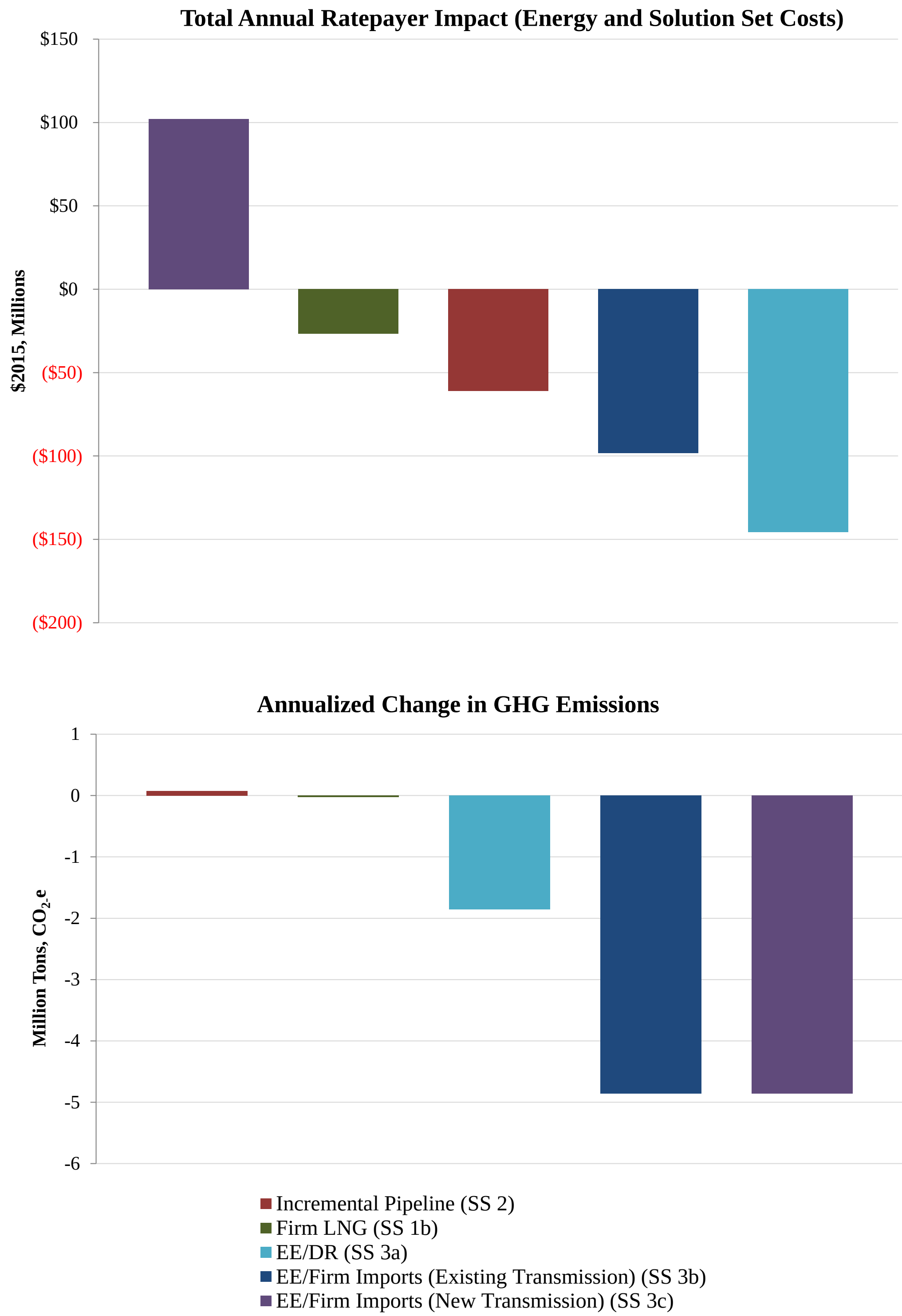
[45] As discussed in Section IV, we estimate the costs of such a contract at the estimated levelized cost of new hydroelectric generating capacity, based on Energy Information Administration analysis. That is, we assume that to provide a firm winter delivery contract, the seller would need to construct new capacity to back such a contract, or otherwise compensate the provider (or the provider's ratepayers) at the cost of service value of the capacity now committed to the New England region. The same consideration applies to infrastructure scenario 2.

[46] If the seller of capacity/energy under such a contract either planned to or were contractually obligated to be a price taker in the region's forward capacity market, there could in theory be capacity market price suppression benefits in addition to the estimated energy market price suppression benefits. However, consistent with New England's buyer-side mitigation market rules, it is unlikely that such a contract would qualify as a state-exempt resource, or be allowed to reduce the clearing price for capacity in forward capacity auctions. The same consideration applies to the transmission solution sets and infrastructure scenarios. We discuss the implications for dynamic market interactions in greater detail in Section V.B.3, below.

Figure 6: Evaluation of Electric Reliability Solution Sets, Annualized Impacts

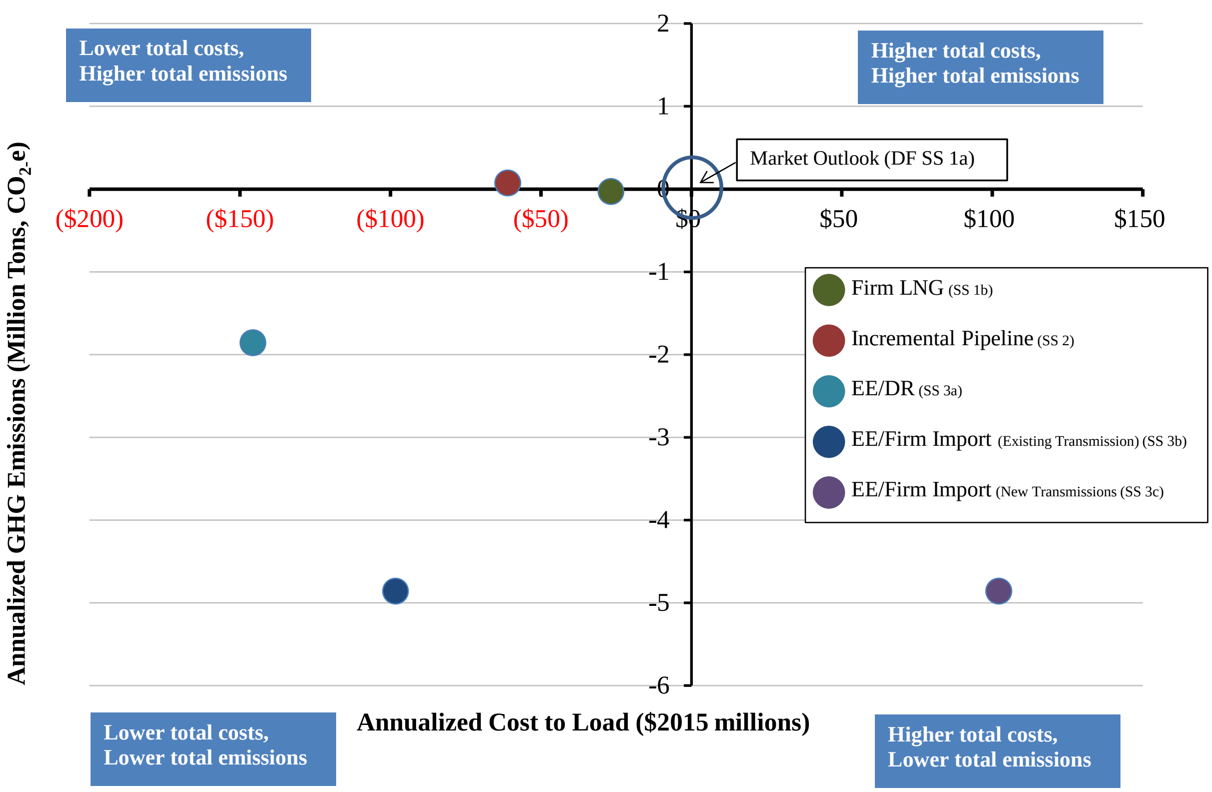
Negative Dollar Values represent consumer savings relative to market outlook Dual-fuel (SS 1a)
Negative Emissions represent a decrease in GHG emissions relative to market outlook Dual-fuel (SS 1a)



These solution sets present a wide range of both ratepayer impacts and GHG emissions impacts. As illustrated in Figure 6, only the EE/Firm Import (Existing Transmission) (SS 3b) solution ranks in the top two of all solution sets from both an annualized cost and annualized GHG emission benefit. Other solution sets present a wider range of performance on these two key metrics. EE/DR (SS 3a) provides the greatest cost savings, and the third greatest GHG reductions. Incremental Pipeline (SS 2) capacity provides the third highest ratepayer cost savings, but represents the worst option in terms of achieving regional GHG requirements.

As Figure 7 shows, only the EE/DR and EE/Firm Import (Existing Transmission) solution sets solve the stressed system reliability deficiency in a way that both reduces ratepayer costs and reduces GHG emissions relative to the current market outlook of relying on dual-fuel capability. In contrast, both the pipeline solution set and the firm LNG solution set can reduce total ratepayer costs but do not reduce total GHG emissions. Finally, a solution set that includes EE and the firm import of distant low-GHG energy over new transmission lines provides substantial GHG emission reduction benefits, but would lead to a net increase in total ratepayer costs after accounting for both the cost of firm energy and new transmission capacity. In general, however, imports without a firm commitment may be available at a lower cost, which could help the region meet its climate goals independently of a focus on reliability needs.

Figure 7: Annualized Cost and Emission Impacts, By Solution Set



Note: Pipeline solutions include an estimate for incremental in-region GHG emissions from fugitive methane leaks.

Infrastructure Scenarios

Meeting the reliability need through an earlier and/or larger than necessary infrastructure solution would lead to larger price suppression benefits for the region's electric ratepayers than a pure reliability focused solution. This is true of both the Larger Pipeline (IS 1) and Earlier Transmission (IS 2) infrastructure scenarios. These large investments in new infrastructure also carry immediate and long term cost implications, which must be balanced against these more immediate benefits. The results of these scenarios are presented in Table 4 below.

Meeting the deficiency completely through firm contracts for 2,400 MW of year-round transmission capacity and energy with provider(s) of distant low-carbon resource(s) in 2020 (Earlier Transmission IS 2) represents a scenario that meets the full deficiency in the first year of service.[47] This scenario generates by far the greatest total energy cost savings, of almost $576 million per year. However, the cost of the scenario, including contract costs plus the cost of new transmission, significantly exceeds this ratepayer benefit, leading to a net annual ratepayer *cost* of $284 million per year more than the status quo solution set.[48] However, the Earlier Transmission (IS 2) infrastructure scenario yields the largest and most sustained reduction in annual GHG emissions.

Similarly, the Larger Pipeline (IS 1) would generate total annual energy cost impacts of $309 million per year, against an annual carrying charge of $176 million, leading to net ratepayer benefits of $133 million per year. This scenario assumes that new pipeline capacity is added in 2020 and is fully available to the electric generation sector on a firm basis. This scenario assumes the greatest reduction in total basis differentials, which provide net ratepayer benefits each year that the pipeline is in-service. As discussed below, this scenario also creates a long-term obligation on ratepayers, which remains even if the value of the asset diminished or is limited for any reason, including the evolution of GHG reduction goals and obligations. It would also lead to the largest total GHG emissions of all solutions evaluated in the report, including market outlook Dual-fuel (SS 1a) solution. Lower gas prices result in greater fossil fired generation, which displaces both dual-fuel-oil-fired generation and imports of other economic energy resources located outside of ISO-NE. This could include the displacement of resources in neighboring regions, including gas, wind, or hydro imports. To the extent that greater in-region gas fired generation displaces gas fired generation from other Regional Greenhouse Gas Initiative (RGGI) states, it may not increase total RGGI emissions.

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[47] In contrast, solution sets that include EE/Firm Imports (SS 3b/SS 3c) are still phased in over time to meet the peak need.

[48] It should be noted that the price suppression benefits estimated for solution sets involving distant low-carbon resources (SS 3b/SS 3c/IS 2) may largely exist even if there is no firm contract for capacity, or full capacity costs to acquire this resource. This is because even without a firm capacity commitment, these resources could deliver inframarginal energy in many, if not most, hours of the year. However, absent the firm commitment and firm backing of reliable capacity, such a resource could not be counted on at the time of winter peak conditions, would have zero or near-zero value from the standpoint of winter reliability needs, and could not be considered a solution to a winter reliability deficiency.

Table 4: Evaluation of Infrastructure Scenarios, Annualized ($2015 million)

Negative Dollar Values represent consumer savings relative to market outlook Dual-fuel (SS 1a)
Negative Emissions represent a decrease in GHG emissions relative to market outlook Dual-fuel (SS 1a)

Scenario	[1] Cost of Energy (Cost to Load)	[2] Cost to Implement Solution Set	[3] = [2] + [1] Total Ratepayer Impact	GHG Emissions (million metric tons)
Incremental Natural Gas Capacity				
SCENARIO (IS 1) - Larger Pipeline (Sized Above Reliability Need)	-$309	$176	-$133	0.20
Incremental Transmission Capacity				
SCENARIO (IS 2) - Early Transmission (New and Existing Transmission Capacity, Firm Imports, 2,400 MW cumulative)	-$576	$860	$284	-6.65

2. Emissions of GHG Relative to States' Electric Sector Emissions Obligations and Objectives

Every New England state has made commitments to address the social, economic and environmental risks of climate change through binding CO_2 emission limits on the electric sector, state GHG reduction targets, and/or long-term multilateral commitments to achieve substantial reductions in GHGs over time.[49] Most recently, the New England Governors' (NEG) and Eastern Canadian Premiers (ECP) adopted a non-binding goal to reduce regional GHG emissions by at least 35-45 percent below 1990 levels by 2030.[50] In addition, EPA's Clean Power Plan (CPP) will result in binding obligations to reduce emissions of CO_2 from the power sector in all states nationwide.[51] Consequently, the GHG

[49] In Massachusetts, for example, the Global Warming Solutions Act (GWSA) established targets and requires the State to reduce total GHG emissions by 25 percent below 1990 levels by 2020 and 80 percent below 1990 levels by 2050. The GWSA includes GHG emissions from buildings, electric power generation, transportation and land use, and non-energy emissions, which considers plastics, solid waste, and other refrigerants. Reductions in the electric generation sector are estimated to provide approximately one third of all reductions anticipated in the 2020 plan; these include increased renewables and long-term contracts, including hydropower, retirements of older coal fired generation, and increased energy efficiency. See Commonwealth of Massachusetts "Global Warming Solutions Act 5-year Progress Report", December 30, 2013, Table 1. The plan estimates that 7.7 percent of all reductions will come from the electric power sector. This represents 28 percent of all reductions estimated in Table 1.

[50] Resolution 39-1 Concerning Climate Change, available: http://www.coneg.org/negecp.

[51] Vermont is currently not subject to control requirements under the CPP. The CPP establishes declining and final state GHG emissions goals beginning in 2022 and allows for multi-state compliance plans (including the use of regional programs like RGGI).

emission impacts of different solutions sets evaluated in this Report represent real and meaningful long-term impacts on consumers.

We evaluate GHG emission impacts of different solution sets using the metric of total emissions of CO_2 in New England as a proxy for considering the potential impact of each solution set's GHG trajectory on the difficulty and cost of meeting binding commitments and/or achieving states' long-term GHG goals.[52] In addition, we identify and discuss ways in which different solution sets may lead to GHG emissions outside the New England region or otherwise affect New England states' abilities to meet GHG reduction targets over time.

Each solution set represents a unique path forward with respect to GHG emissions. Figure 8 presents solution set emissions trajectories, where total annual GHG emissions in each scenario represent all in-region fossil fuel (and other carbon resources, such as biomass) generation based on the relevant PROMOD electric sector simulation. These emissions are compared to a projection of RGGI electric sector requirements, assuming that the current allowance cap continues to decline by 2.5 percent in each year after 2020.[53] The results may be described and summarized as follows:

- Each solution set includes declining emissions over the full study period, but by 2030 no single reliability solution would meet this projected RGGI target, even assuming all incremental RPS goals are met.[54]
- Under the market outlook Dual-fuel (SS 1a), natural gas continues to provide almost 50 percent of total generation, with continued reliance on oil-fired generation during winter months (amounting to more than 1,500,000 MWh by 2030).[55] This solution set fails to meet projected regional climate goals.

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[52] Under existing RGGI and potential future RGGI or CPP binding obligations, the New England states participate in an electric sector mass-based control program, with geographically broad trading of emission allowances among affected sources. In this context, the metric of actual CO_2 emissions may be viewed as indicative of the ultimate cost of allowances, and thus ratepayer cost of compliance. That is, while we do not attempt in this Report to forecast the impact of emission levels on marginal allowance prices, solution sets that lead to regional electric sector emissions exceeding the states' collective RGGI or CPP allocation or emission standards are likely to place upward pressure on allowance prices, marginal unit wholesale price offers, and ultimately costs to electric ratepayers.

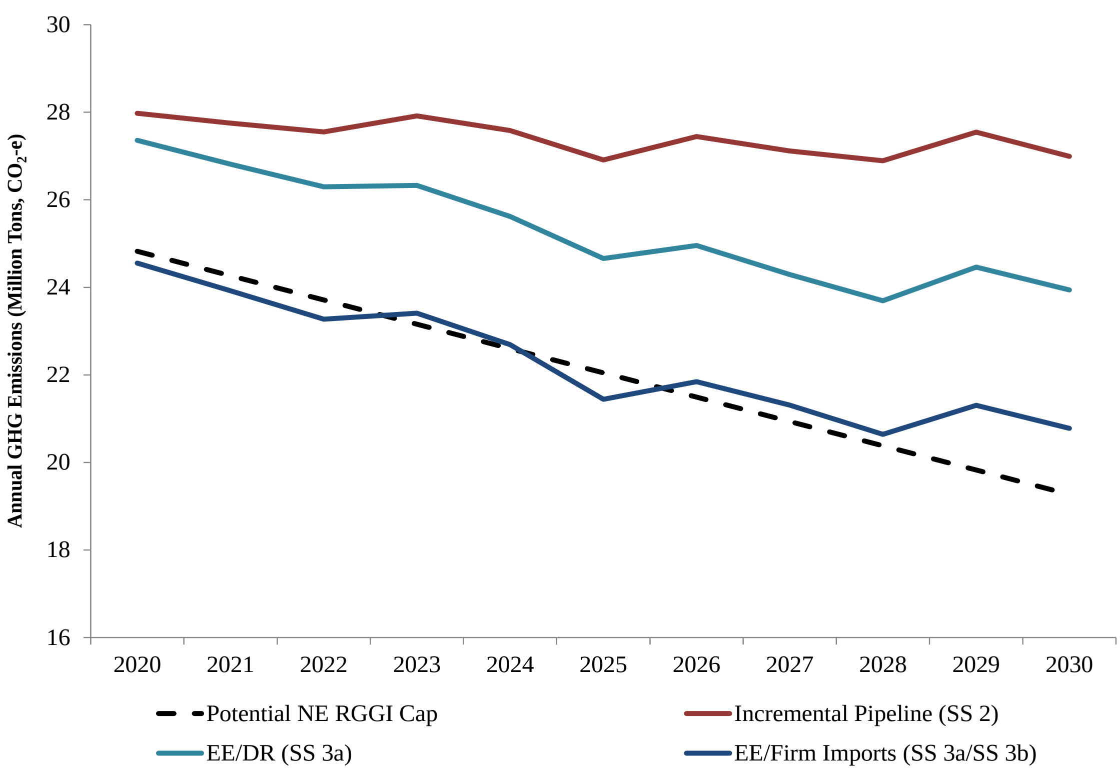
[53] In 2020, the total RGGI cap is 78 million short tons of CO_2. This cap includes the 6 New England States, plus New York, Maryland, and Delaware. Historically, New England's share of the regional cap has been approximately 35 percent. As described in Appendix 4, we found that RGGI emission targets are more stringent than assumed reductions from the electric sector as specified in GHG action plans and are also below the state targets set forth in the CPP.

[54] As discussed in Appendix 2, we assume a static CO_2 price that increases in real terms by 2.5 percent each year. That is, we do not model the potential dynamics of increasing CO_2 prices in response to any potentially binding constraints.

[55] For comparison, New England used oil for approximately 1,540,000 MWh in the 2013/14 winter. See Brandien, P. "ISO-NE Cold Weather Operations, Federal Regulatory Commission." April 1, 2014.

- The Firm LNG (SS 1b) solution set offsets a portion of the status-quo oil-fired generation, leading to a marginal reduction in oil-fired generation. Nevertheless, this solution set fails to set a carbon emission path consistent with long-term obligations and goals.
- The Incremental Pipeline (SS 2) solution set displaces the need for higher emitting oil-fired generation, but it also increases total fossil fired generation: gas fired generation meets 55 percent of total system load by 2030, an increase of almost 3 GWh (4 percent) in total generation relative to the market outlook (DF SS1a) solution set. Similar to the Firm LNG and dual-fuel solution sets, the incremental pipeline fails to meet projected regional climate goals.
- The EE/DR (SS 3a) solution set leads to meaningful reductions in natural gas-fired generation and would allow for gradual reductions in overall carbon emissions associated with the electric power generation sector. However, this solution set is still insufficient to meet climate goals throughout the full forecast horizon.
- Adding firm contracts for distant low/zero-carbon resources (instead of DR, which has a de minimis impact on CO_2 emissions) to EE solution sets significantly improves GHG trajectory outcomes. The EE/Firm Import (SS 3b/SS 3c) solution sets produce an immediate and long-term reduction in total CO_2 emissions in every year of the study period, and lead to the largest total reduction in in-region carbon emissions. While these solution sets still do not fully achieve the projected RGGI target for 2030, they lead to emissions that are more consistent with projected climate goals.

Figure 8: Annual GHG Emissions and Potential ISO-NE Climate Goals



Notes:

Pipeline emissions include an estimate for in-region GHG emissions from fugitive methane leaks. Emissions for Dual-fuel (SS 1a) and Firm LNG (SS 1b) are excluded for clarity; both solution sets report annual emissions that are within 0.15 million metric tons of the Incremental Pipeline (SS 2) solution set.

The estimates in Figure 8 include an estimate for the potential in-region GHG emissions associated with fugitive emissions of methane on the pipeline transportation system for the incremental portion of natural gas use in the Incremental Pipeline (SS 2) (and also included in the Larger Pipeline (IS 1) infrastructure scenario). Using assumptions based on industry standards for pipeline, compressor and meter/regulation station losses, we find that these fugitive emissions could contribute an additional 0.47 million metric tons of CO_2-equivalent GHG.[56] Our estimate also does not include any GHG impacts associated with an increase in in-region natural gas consumption for residential needs. Specifically, in addition to gas-fired generation emissions and fugitive emissions from interstate pipelines, increases in natural gas consumption in the New England region could increase overall GHG emissions associated with CH_4 releases due to natural gas production, processing, and transport outside the New England region, as well as GHG emissions due to increased operation of compressor stations. This assumes that New England demand does not displace demand from other regions, which may be unlikely given the policy objectives of the CPP.

Finally, it should be noted that solution sets involving incremental firm capacity from distant low-carbon resources (SS 3b/SS 3c) could involve the development of new large hydro generation facilities, which also have potential GHG implications not accounted for in our analysis. Specifically, new dams inundate reservoir basins, which induces further decomposition of biomass and can lead to an increase in total GHG emissions, attributable to the facility's development. Recent research by Hydro Quebec found that these emissions are highest during the two to four years immediately following reservoir construction, and, on a CO_2-equivalent basis, can exceed the emissions of new gas fired generation before moderating and reaching levels consistent with existing lakes in later years.[57] To date, existing climate policies and renewable portfolio standards (which mostly exclude large hydropower facilities from eligibility) do not consider net emissions of large scale hydro imports, and any estimated net emissions

[56] These estimates assume a 21x global warming potential of CH_4 over a 100 year time frame, consistent with Massachusetts facility reporting guidelines. Recent estimates from the IPCC updated this value to 28x that of CO_2 for a 100 year timeframe and 84x the GWP for CO_2 for a 20-year timeframe. (Intergovernmental Panel on Climate Change AR5, Chapter 8, 2013).

[57] Teodoru et al. (2012) estimated the net CO_2 emissions associated with the construction of the 485 MW Eastmain-1 reservoir in the James Bay region of Northern Quebec, Canada, accounting for the pre-construction carbon footprint of the landscape and the actual measurements from the reservoir surface after inundation. They found that the net CO_2 equivalent emission rate for a new hydro dam in a boreal forest landscape could exceed the emissions of a new natural gas combined cycle unit over the first few years of the asset's life, and projected they would then decline to less than half of the assumed emissions of a NGCC over the remaining 100-year life of the hydro facility. Hydro Quebec supported and participated in the development of this study as part of a net greenhouse gas emission study. See http://www.eastmain1.org/en/index.html.

would depend on the unique site conditions of each reservoir site.[58] Over the long term, however, these net impacts may be considered under the joint climate plans formed by the New England Governors/Eastern Canadian Premiers (NEG/ECP), or to the extent they are considered by other regions, the price of long term import contracts may reflect the higher cost of meeting in-region climate risk reduction goals.

In contrast, imports that do not require a firm commitment could be based on other resources, including wind (on and off-shore) or existing hydro facilities. These resources could be used to meet regional climate goals, potentially at a lower cost than the firm commitment included here. However, this would not address a potential winter reliability need from a firm planning perspective and are not included here.

3. Market Interactions and Other Risk Factors

The sections above focus on quantifiable ratepayer cost and regional GHG emission impacts associated with different solution sets designed to address the identified reliability deficiency. In this section, we review and summarize qualitatively key factors to consider when evaluating the consumer and policy impacts of potential future outcomes. These factors are related to the competitiveness of wholesale markets and impacts on producers and social welfare; the impacts on the customers of natural gas LDCs; and the risks associated with different solution sets from the electric ratepayer perspective. Table 5 contains a high-level summary of a number of important additional qualitative considerations.

Interaction with competitive wholesale markets – In our assessment we specifically model the interaction of solution sets with wholesale market economic commitment and dispatch and the associated changes to energy market pricing and emissions. However, wholesale markets involve a more complicated and dynamic interplay between factors that cannot be fully captured in a production cost modeling of the electric system. This includes the potential impact of differences in energy market net revenues for producers and how producers may respond in turn, through their development of offers to provide capacity and ancillary services. It also includes the potential long-run impact on wholesale market competition that could arise from different approaches to addressing potential reliability deficiencies. An assessment of specific legislative or regulatory actions must carefully consider the balance between market competition, resource outcomes, and ratepayer risks.

The fundamental purpose of states moving to a competitive market structure was to remove the investment risk previously incurred by regulated utilities and borne by ratepayers, and to put that risk in the hands of those best able to manage it – namely, the competitive market participants that operate in both the electric and natural gas markets. While electricity markets remain relatively new, they have evolved rapidly, with the evolution of market design focused on achieving a structure that provides the

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[58] In contrast, MA does require an analysis of the net lifecycle emissions that account for the "temporal changes in forest carbon sequestration and emissions resulting from biomass harvests, regrowth, and avoided decomposition" associated with Class II biomass facilities. See Renewable Energy Portfolio, MA 225 CMR 14.02.

right signals for market participants to pursue outcomes that represent, in the long run, the most efficient use of society's resources and the lowest possible costs for consumers.

Major long-term investments borne by captive ratepayers may look like a good proposition from the standpoint of short-term ratepayer savings. Indeed, as noted above we find modest ratepayer net benefits across a number of solution sets involving various forms of state-sponsored investment in resource outcomes (e.g., subsidization of natural gas pipelines, transmission, contract capacity, and energy efficiency/renewable resources). But intervention in markets should be carefully weighed against the risk that such actions can seriously interfere with competitive market dynamics by changing the relative prices of competing resources, artificially suppressing prices and producer revenues, and impeding the free entry and exit of current and future market participants. While in a limited short-run analysis such actions may look necessary and/or beneficial, in the long run they are also likely to interfere with competition, reduce market efficiency, and increase all-in consumer prices for energy, capacity and ancillary services.

Another consideration relates to our focus on *ratepayer impacts*. Since the context for our analysis is states' current consideration of having electricity consumers pay for natural gas infrastructure, we quantify in the Report differences in solution set impacts on electric ratepayers, or changes in "consumer surplus." When considering long-term ratepayer investments, this is generally the standard by which public utility commissions evaluate competing alternatives – namely, the total costs, risks, and benefits borne by the *ratepayers* who will be responsible for the cost burden of the investment or commitment in question. However, evaluating the broader efficiency of market outcomes should also consider the potential impact on *producer surplus* – that is, the impact on producer profits over time – with the ultimate goal of maximizing the combination of producer and consumer surplus, or total social welfare.

The solution sets evaluated in this Report would change the underlying economics of participation in wholesale markets by producers and affect the revenue flows to many market participants in both electric and natural gas industries. For example, investments in energy efficiency or natural gas pipelines would reduce energy market costs for consumers, but would also reduce revenues and profits for producers, and change revenue streams (positive and negative) for other participants in electricity and natural gas markets (e.g., energy efficiency providers and natural gas shippers/marketers/pipeline owners). Similarly, contracted capacity for an interconnection to a neighboring region could significantly suppress wholesale market prices, increasing revenues and profits to some producers (e.g., the owners of hydro assets backing power sales), and decreasing revenues and profits to other producers (e.g., owners of in-region generating assets).

The ultimate impact on total social welfare of all consumer and producer impacts is difficult to establish (and is beyond the scope of this Report), since over time the cost reductions and producer revenues lost in the energy market would be at least partially offset by increases in other markets, such as the forward capacity, reserve, and ancillary services markets, as generating asset owners increase offers to ensure economic viability, or otherwise retire and force new entry earlier than otherwise would occur. In short, reductions in total social welfare that arise from projects supported by non-market actions may discourage or otherwise displace projects that would have been more cost effective in the long run.[59]

Interaction between electric and natural gas ratepayers – Many natural gas LDCs contract with third parties for management of their natural gas supply and transportation assets, with the goal of maximizing the value of those assets. These arrangements often include a sharing of revenues among the portfolio managers, natural gas LDC shareholders, and LDC ratepayers. The addition of natural gas capacity that would in effect be owned by electric ratepayers and dedicated for use by electricity generators would increase available transportation capacity, and thereby decrease or eliminate the value of natural gas LDC assets that are often sold off for use by electricity generators; this would lower rebates to LDC ratepayers, and lower revenues to LDC shareholders and portfolio managers. That is, if electric companies hold firm capacity for use by electric generators, then it is unclear who will remain in the market to purchase large quantities of capacity release from other firm shippers. In fact, by securing firm capacity for electric generators, the resale capacity of LDC firm transportation rights will likely be lower, representing a net cost to natural gas ratepayers. Conversely, the electric ratepayer firm transportation assets may also have resale value, and allow through such resale a reduction in the cost obligation borne by electric ratepayers for the firm pipeline commitments. We expect, however, that this value may be minimal since the addition of electric ratepayer-funded transportation capacity would dramatically reduce the value of such capacity in many or most hours of the year. However, estimating the impact of such capacity resale by transportation asset owners (LDCs and electric ratepayers) is beyond the scope of this Report.

Ratepayer risk – Our financial analysis of different solution sets applies the same financial assumptions and approaches to ensure comparability and uses consistent decision rules related to the timing of the investments. The goal of structuring our analysis in this way was to present the ultimate impact on electric ratepayers using a consistent cost metric – namely, the expected total annual costs to electricity consumers, considering both the expenditures needed to implement the solutions and the annual impact on total energy market costs to load. All of our analyses evaluate impacts over the full forecast period (i.e., through 2030) on a net present value basis and then use these results to identify an annualized ratepayer impact.

While we believe this is the most fair and consistent approach to compare ratepayer impacts across solution sets, it does mask some important differences in the risk profiles of different approaches, and/or in the potential value (or lack thereof) associated with solution sets throughout and beyond the forecast horizon. As noted in Table 5, there are some significantly different risk profiles across solution sets; differences that are a function of the "lumpiness" of implementation costs, and the ability to adjust spending/implementation as new information becomes available over the forecast horizon.

Specifically, solution sets can be loosely grouped into "one time" and "incremental" approaches to addressing potential winter peak deficiencies. On the one hand, pipeline and transmission/capacity

[59] See Initial Comments of the Office of the Attorney General, in Re: D.P.U. 15-37, filed June 15, 2015, Section III.B.2.

additions (in both solution sets and infrastructure scenarios) require major one-time[60] investments and associated long-term ratepayer commitments that cannot be reversed if events do not proceed as expected, or if a change in winter demand or in supply technology options suggests an alternative path going forward.[61] In contrast, the other solution sets either have a minimal up-front cost impact on ratepayers (e.g., the Dual-fuel (SS 1a) and Firm LNG (SS 1b) solution sets), or in the EE/DR (SS 3a) solution set require ratepayer commitments that can vary (increase or decrease) each year as new information becomes available related to the magnitude of need and/or cost of various solution set options (i.e., changes in the cost of efficiency measures and programs, or renewable/distributed alternatives). While we have not attempted to quantify it in this Report, there may be a meaningful option value that should be attributed to the "incremental" approaches to address the stressed system deficiency. This is particularly true given our finding that, under our base case assumptions, we find no deficiency over the forecast horizon.

This option value may also be particularly important given the suite of GHG goals and commitments. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies. In contrast, solution sets that fail to do so will require more significant investments at a later date. It is also important to note that these climate commitments were made, in part, with a consideration for the wide range of public health, economic, and environmental benefits associated with reduced GHG emissions and a recognition of the many other externalities associated with fossil fuel generation, though a full review of such externalities is beyond the scope of this Report.

[60] The EE/Firm Imports (SS 3b/S 3c) solutions require up-front commitments to contract for firm winter capability backed by resources that can deliver at the time of winter peak, and potentially one-time commitments to construct and pay for any transmission needed to deliver such capacity to load. The Incremental Pipeline (SS 2/IS 1) solutions also require major up-front commitments, either on a one-time basis (in the infrastructure scenario) or in two separate pieces (in the solution sized to the stressed system deficiency).

[61] We realize that in theory regulatory commissions could disallow recovery of a portion or all investments made for new interstate pipeline capacity, transmission infrastructure, and/or capacity contracts. However, in practice we expect and assume that the costs associated with any of these solutions would be deemed prudent at the time of investment, and cost recovery would be pre-approved or largely assured through up-front regulatory findings.

Table 5: Risk Factors and Other Considerations Associated with Solution Sets

Solution Set	Other Considerations
Market Driven Outcomes	
SS 1a: Dual-fuel Capacity ("Status Quo")	• No up-front investment and requires no action on the part of legislatures or regulators • Dual-fuel upgrade costs may not be passed on to consumers (unless upgrade cost affects marginal capacity market prices), costs borne by producers represent a reduction in profits • Relying on oil during winter peak periods has only limited impact on winter gas prices; when oil prices are low, economic oil-fired generation can reduce on-site inventories leading into stressed winter conditions • Air quality permits often restrict total hours of oil-fired operation, though restrictions generally allow more hours of operation than needed to address winter peak reliability needs • Operation time at units will be limited by the quantity and size of oil storage tanks, ability to switch from gas to oil, and ability to replenish supplies, which can be challenging during extreme cold periods
SS 1b: Firm LNG Capacity	• No up-front costs to consumers; implementation costs reflected in energy market prices on as-needed basis • LNG use targeted to deficiency may have only limited impact on winter delivered gas prices • Creates flexibility with respect to intra-annual operations and allows for 5 year lead time for renegotiation or pursuit of alternative solution sets if needed • Contract prices and terms are untested at this point; firm commitments remain dependent on contract language and financial penalties; imports constrained by global price risk, global supply production risk • Prices would ultimately be set by few suppliers with limited competition
Incremental Pipeline Capacity	
SS 2: Incremental Pipeline:	• Major up-front investment creates long-term ratepayer cost obligation; obligation remains even if use or value of assets diminish or is limited for any reason (e.g., evolution of GHG reduction goals/obligations) • Increased certainty of solution set once approved; known in-service date allows for accountability and tracking of progress made by a single entity • Mechanism to guarantee firm transportation for electricity generation at winter peak is unknown • Increased capacity reduces or eliminates the value of existing capacity release benefits, which may lead to a net loss for gas ratepayers, LDC shareholders, and portfolio managers • Increased in-region flows may be used to serve other markets or LNG exports, potentially increasing pipeline utilization and reducing or eliminating price suppression benefits • Faces significant siting and regulatory challenges, potential local property value impacts and non-GHG environmental impacts • May increase GHG outside New England, and an associated increase in natural gas production and consumption would also increase non-GHG environmental impacts
Energy Efficiency, Demand Response, and Renewable Energy	
SS 3a: Energy Efficiency and Demand Response	• Up-front investment is annual, and can be adapted on an annual basis in consideration of actual need and changes in technology, policy and cost factors; actual technologies/programs relied on could adjust in response to technology and cost breakthroughs • Requires a sustained commitment by states for investment, likely over many years; absent a commitment the EE/DR solution cannot be counted on to meet deficiency in later years • Realization could be limited by ability to ramp up resources and providers; full suite of benefits are not immediately available • Requires robust monitoring and verification to ensure expected winter peak impacts are being realized • Annual costs are not certain – could either grow or decline in later years
SS 3b/c: Energy Efficiency and Firm Imports (existing and new transmission)	• (See above in SS 3a regarding EE) • Major up-front investment creates long-term ratepayer cost obligations; ratepayer obligation remains even if use or value of assets diminish or is limited for any reason • Must guarantee and price firm winter/year-round capacity; otherwise, cannot be counted on to address deficiency; availability and cost of a firm winter deliverable product is unknown

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VII. GLOSSARY

ACO	Annual Contract Quantity
AGI	Analysis Group, Inc.
AGO	Massachusetts Office of the Attorney General
AIM	Spectra's Algonquin Incremental Market pipeline project
Basis differential	The difference between delivered natural gas at trading hubs and the Henry Hub
Bcf	Billion cubic feet: a unit of natural gas
CELT	Capacity, Energy, Loads, and Transmission: ISO-NE annual planning document
CH_4	Methane
CO_2	Carbon dioxide
CPP	Environmental Protection Agency Clean Power Plan
Deficiencies	Periods when the electric system may not be able to meet peak electric demand
DOER	Massachusetts Department of Energy Resources
DR	Demand Response
Dth	Dekatherm: a unit of natural gas
ECP	Eastern Canadian Premiers
EE	Energy Efficiency
EFORd	Equivalent Forced Outage Rate on Demand
EIA	US Energy Information Administration
EPA	US Environmental Protection Agency
FCA	Forward Capacity Auction
FSRU	Floating Storage and Regasification Unit
GHG	Greenhouse gas emissions
GWSA	Global Warming Solutions Act
ICF	ICF International
ISO-NE	Independent System Operator of New England
LDC	Local distribution company, used for natural gas
LMP	Locational marginal price
LNG	Liquefied natural gas
M&N	Maritimes & Northeast Pipeline
$MMTCO_2e$	One million metric tons CO_2 equivalent
MW	Megawatts: a unit of power
NBP	United Kingdom’s National Boundary Point
NED	Kinder Morgan's Northeast Energy Direct pipeline project

NEEP	Northeast Energy Efficiency Partnership
NEG	New England Governors
NYISO	New York Independent System Operator
PFP	ISO-NE Pay-for-Performance Program
PJM	Pennsylvania, Jersey, Maryland Interconnection
PROMOD	An industry-standard electric market simulation model marketed by Ventyx
RE	Renewable Energy
REED	Northeast Energy Efficiency Partnerships Regional Energy Efficiency Database
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization

VIII. APPENDICES

1. Deficiency analysis

In this appendix, we provide additional detail on the deficiency analysis, specifically with respect to the methodology used to forecast natural gas demand and additional sensitivities of the key results presented in Table 1.

Availability of Natural Gas for Electricity Generation

As described in Section III, we relied on daily scheduled pipeline and LNG deliveries to LDCs and end-users for the period December 1, 2012 to present using SNL Financial,[62] and the weighted average temperature for the ISO-NE Control Area collected by ISO-NE.[63] Figure A1 below shows the total demand and capacity for the period January to March 2015, and highlights that during peak periods, the system is fully constrained, with total scheduled deliveries net of LNG sendout (shown here as negative demand) approaching total pipeline capacity. Here, we rely on scheduled deliveries during the timely nomination cycle. Under the timely nomination cycle, natural gas is scheduled for delivery by 12:30 pm the day before. That is, the timely nomination gives the greatest assurance to shippers (including both LDCs and generators) that they will receive their nominated capacity. This assurance is necessary under a strict reliability perspective, since it is only the capacity not nominated by firm shippers during the timely cycle that is available to electric generators on an interruptible basis the following day. Other nomination schedules include the evening cycle (by 7 pm the day before, for delivery by 10 am the following day) and the intraday nomination cycles (which allow for nomination and delivery during the same day). Not considered here is the challenge of electric-gas coordination, and the simple fact that the natural gas day and electric generation day operate on different time schedules. We note that greater coordination by the gas and electric sectors has alleviated and can continue to alleviate potential constraints. For example, in recent winters, ISO-NE has advanced the day-ahead market timeline to allow for more time to procure gas and has maintained regular communications with gas pipeline operators.[64]

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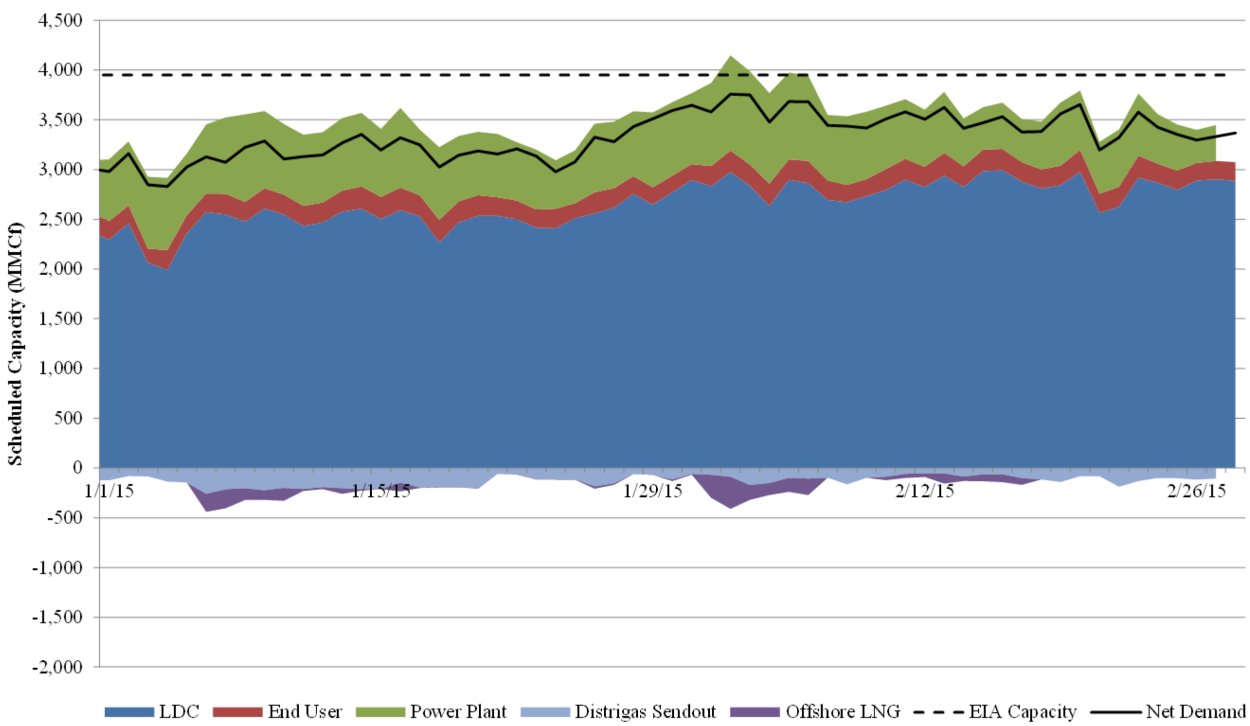
[62] SNL Financial is a data aggregation service that compiles electronic bulletin board data reported by each individual pipeline company. SNL classifies each delivery point based on available contract information.

[63] See ISO-NE, Zonal Information, available: http://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info.

[64] See Callan, W. ISO-NE Winter 2014/15 Review. Electric/Gas Operations Committee (EGOC) Teleconference, June 29, 2015. Available: http://www.iso-ne.com/committees/industry-collaborations/electric-gas-operations.

Figure A1: Scheduled Natural Gas Demand and Total Capacity, ISO-NE System

January – March 2015



Notes:

Total deliveries are the sum of LDC's, end-user, and power plant deliveries. LNG deliveries to the natural gas system are reflected as a reduction in total deliveries, instead of an increase in total capacity. Total capacity is based on EIA state to state data for existing interstate pipeline gas capacity.

Consistent with ISO-NE/ICF (2014), we developed a daily forecast of natural gas demand from LDCs and end-users based on the historical relationship between demand and weather. We developed two separate forecasts – one for winter conditions (defined as any day from December through February of each year, with total temperature less than 65 degrees Fahrenheit) and one for non-winter conditions (defined broadly as all days with temperature greater than 65 degrees Fahrenheit). The statistical relationship in Figure 1 of Section III is defined by Equation 1. Equation 2 provides the non-winter relationship.

$$\textbf{\textit{Equation 1}}: \ \textbf{\textit{Projected LDC Interstate Pipeline Demand in MMCf}}\ (\textbf{\textit{when temp}} < \mathbf{65^{\circ}}\ \textbf{\textit{F}}) \\ = \left(\mathbf{878 + 60.6 * \textit{EDD} - 0.4 * \textit{EDD}^2}\right) * (\textbf{\textit{Year}} - \mathbf{2015})\text{\^{}}(\mathbf{1.4\%})$$

$$\textbf{\textit{Equation 2}}: \ \textbf{\textit{Projected LDC Interstate Pipeline Demand in MMCf}}\ (\textbf{\textit{when temp}} > \mathbf{65^{\circ}}\ \textbf{\textit{F}}) \\ = (\mathbf{905 - 0.53 * \textit{EDD}}) * (\textbf{\textit{Year}} - \mathbf{2015})\text{\^{}}(\mathbf{1.4\%})$$

Our use of the 1.4 percent growth rate, while consistent with recent studies, does not necessarily align with recent estimates for peak design day demand growth as filed in certain LDC long term supply plans. However, there are several important differences between our assumed growth rate of demand from existing pipelines and the *overall* growth rate of LDC demand. These differences include demand from capacity exempt customers, demand met by incremental supplies not available to the electric generation sector, and demand from power plants served by LDCs. We described these key differences in Section III, but provide additional detail here.

First, we apply the 1.4 percent growth rate to both LDC and end-user demand. We obtain historical data for these two sectors separately; end-users are defined as large (typically commercial/industrial) customers that connect directly to the interstate pipeline, typically before the city gate. Recent LDC filings have included plans that account for the return of some capacity exempt customers.[65] While this represents an increase in LDC forecasted demand, it is not a net increase in total demand for the system. These growth rates reflect, in part, growth for the LDC portfolio which includes new LDC customers and are not necessarily limited to new growth for all natural gas users. Because these capacity exempt customers are already captured in our end-user definition, a higher LDC-specific growth rate would double-count their forecasted take from the interstate natural gas pipeline system. Put another way, we assume that both LDC demand and end-user demand grows by 1.4 percent.

Second, our use of a lower growth rate reflects a more narrow view of incremental demand from the existing and approved interstate pipelines used in our base case deficiency statement. That is, this growth rate does not reflect incremental demand that could or will be met from new facilities or from LNG resources that are unavailable to meet electric sector demand.

We have made no assumption for how LDCs will meet incremental new demand, above this 1.4 percent growth rate. To do so would require, in part, an assessment of the cost and benefits of all possible supply strategies. Therefore, for the purpose of estimating incremental gas available to the electric generation sector, we assume that neither the incremental demand nor the associated incremental supplies to meet that demand are available to, or otherwise affect, the electric generation sector.[66]

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[65] For example, National Grid included returned capacity-exempt load of 41,080 MMBtu/day in 2015/16 and beyond. Subtracting this demand from total firm design peak day would lower the estimated compound annual growth rate during this period from 2 percent to 1.6 percent. See National Grid, Long-range Resource and Requirements Plan, DPU Docket 15-36, Revised Forecast as filed July 10, Response to Information Request DPU-1-5, at page 18 and Table G23-D (Revised).

[66] This includes the recent precedent agreements for new pipeline capacity with the Kinder Morgan Northeast Energy Direct (NED) pipeline. It also includes National Grid's most recent petition of approval for five new LNG contracts. These include a nine year contract with GDF Suez at the Distrigas facility, and agreements for new incremental liquefaction facilities. Because we are primarily concerned with LNG supplies to help meet a peak reliability deficiency in 2025 or later, we assume that contracted capacity at the Distrigas terminal becomes available to the electric generation sector. We do not include new LNG capacity from the proposed liquefaction facilities, which would be used to meet LDC peak design day demand. These new facilities would access the Algonquin pipeline at the current site in Providence, Rhode Island and the Tennessee pipeline at an undisclosed

Third, our estimates of historical demand at LDC city gates will necessarily include demand from the electric power sector served by those LDCs. This fact suggests that we will understate the total quantity of gas available to the electric generation sector and over-state the potential reliability deficiency.

However, as a sensitivity to the results presented in Table 1 of Section III, we also evaluated potential system deficiencies assuming that total natural gas demand from LDCs and end-users grows at compound annual growth rate of 2.2 percent over the life of the study and that the system adds 0.5 Bcf/day of incremental pipeline capacity – to meet LDC needs – in 2020. This capacity is not reserved for the electric generation sector and is only available on an interruptible basis throughout the winter months. We find that the peak deficiency in the stressed system case, considering both a higher growth rate and new capacity to serve that demand, is actually lower than the peak deficiency presented in Section III (see Table A1). This means that our definition of solution sets to meet a potential deficiency are robust to potential assumptions of higher LDC growth rate that could be met by new LDC supplies.

Table A1: Electric Sector Reliability Deficiency Analysis Sensitivity, 2020-2030

Assuming 2.2% growth in LDC/End User Demand and Incremental 0.5 Bcf/d LDC capacity in 2020

Total Hours with a Deficiency

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	2	4
Scenario 3 "Stressed System"	0	0	0	0	4	5	5	5	12	17

Total Days with a Deficiency

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	1	2
Scenario 3 "Stressed System"	0	0	0	0	2	2	2	2	5	6

Peak Hour Deficiency (MW)

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	173	764
Scenario 3 "Stressed System"	0	0	0	0	450	940	1,266	1,017	1,552	2,143

Peak Hour Deficiency (Bcf/hr)

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	0.0012	0.0054
Scenario 3 "Stressed System"	0	0	0	0	0.0032	0.0067	0.0090	0.0072	0.0110	0.0152

Notes:

Includes the same assumptions described in Section III.

location in Massachusetts. See Joint Testimony of Elizabeth D. Arangio and John E. Allocca, Exhibit NGRID-EDA/JEA-1, D.P.U. 15-129, page 6, filed August 20, 2015.

2. Solution Set Costs

Each solution set described in Section IV represents an incremental change to the electric generation sector, which will either increase the total availability of fuel for natural gas and/or dual-fuel fired generation or decrease total electric demand during winter peak hours. These solution sets include variable options (such as Firm LNG (SS 1b) or demand response (as part of EE/DR SS 3a)) which can be called upon only during deficiency hours and also larger fixed options, which would be available both during the winter peak deficiency event and during all other hours in the year (such as Incremental Pipeline (SS 2) capacity, or EE/Firm Import (SS 3b/SS 3c) capacity). Each solution set, therefore, will have a unique impact on total system natural gas utilization, natural gas prices, and the total cost to load. We describe the impact of each solution set on natural gas prices in this Appendix.

We assume that ratepayers are responsible for the full cost to implement each solution set, including all fixed and variable costs associated with new investments based on existing cost-of-service principles that also recover return on rate base, depreciation, and taxes. Costs for each solution set are expressed in annualized terms, and in the assessment phase, we match annualized benefits to annualized costs over the full modeling period.[67] When appropriate, nominal costs are converted to real costs assuming a 2.5 percent inflation rate. All values are annualized over the period 2020 to 2030 in level-real terms assuming a 7 percent private discount rate.

Additional details on sources and specifications for solution set costs are described below.

Market-Driven Outcomes

Solution Set 1(a): "Status Quo" – Dual-fuel

Under the ISO-NE Pay-for-Performance (PFP) program, resources that clear in the forward capacity auction (starting with FCA #9 for deliverability in 2018/2019) will receive base capacity payments, and during periods of scarcity, resources that perform well will receive additional payments while those that fail to perform or perform poorly will receive a significant penalty charge. This places the financial risk (or benefit) of scarcity performance on individual generators and provides for an additional incentive to resources to increase unit reliability during periods of potential fuel shortage. This could include incremental dual-fuel capability or non-interruptible gas supply arrangements. The PFP program will be phased in over seven years and will not be fully available until 2025.

As described below, first, we develop our base case outlook for natural gas and dual-fuel capacity using the Ventyx simulation-ready data for the ISO-NE and Eastern Interconnection region, with adjustments to potential retirement dates and new additions based on our review of relevant planning documents published by ISO-NE. Second, we use a generic resource adequacy capacity market model and add new dual-fuel capable resources over time, in quantities sufficient to meet reliability requirements. We include more than 19.5 GW of natural gas fired capacity in 2020, representing 52 percent of total

[67] We recognize that solution sets requiring an incremental capital expansion, for either a new transmission line or a new incremental gas pipeline will necessarily have a lifetime beyond 2030 and the end of our modeling period. We do not consider the remainder of ratepayer payments associated with these investments, nor do we consider any potential benefits to the electric generating sector in years after 2030.

system capacity. This capacity includes 9.6 GW of dual-fuel capacity, with 2.4 GW of that dual-fuel capacity assumed to come on-line after 2019.[68]

Under the existing market outlook, generators have incentives to perform during periods of peak winter demand, and to do so during periods of natural gas shortage or price spikes. However, individual units may be unavailable during winter peak for several reasons, such as generator outages beyond the assumed average EFORd, operating limits for total emissions, or limits on fuel availability and deliverability in generator storage tanks. They may also be unavailable as the full effectiveness of PFP is phased in over the seven year period. To account for this uncertainty, and as part of our stressed system deficiency statement scenario, we assume that all new dual-fuel capacity and all fuel oil #6 capacity is unavailable at the time of winter peak. This represents 20 percent of all existing dual-fuel capable units and approximately 40 percent of all dual-fuel capacity in our assumed future supply stack.

In the dual-fuel solution set, we add sufficient quantities of dual-fuel capability at existing resources to meet the deficiency. This includes 500 MW in 2022; 1,500 MW in 2024; and 400 MW in 2026 (for a total of 2,400 MW). The 2013 AGI review of the ISO-NE FCM PFP found that increased investment in dual-fuel represented the most cost effective investment, and that more than 11,000 MW – including 4,000 MW of mothballed capacity at existing dual-fuel units – was available.[69]

Based on that finding, we estimate that the total cost for the dual-fuel solution set can be met by existing resources with under- or unutilized capability, and total annualized incremental dual-fuel capacity costs are assumed to be $6,856/MW, consistent with that study, adjusted for inflation. These costs include both annualized capital costs and annual operating costs for fuel and operations and maintenance. Importantly, electricity consumers would only realize incremental costs for this solution if and to the extent that the addition of duel fuel capability on an existing resource affects capacity market prices as a marginal capacity resource, which may in fact be unlikely. Nevertheless, for comparison with other solution sets, we provide dual-fuel costs calculated as the full incremental cost on a cost of service basis.

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68 This estimate is in-line with other estimates of dual-fuel capability, including the publicly available totals reported in the ISO-NE CELT (2015) and the AGI's review of confidential individual generator data provided by ISO-NE as part of its assessment of the ISO-NE Forward Capacity Market Performance Incentives.

69 Schatzki, T. and Hibbard, P. "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives." September 2013, pages. 4 and 21, also Figure 3.

Solution Set 1(b) – Firm LNG

LNG plays an important role in the natural resource portfolio for ISO-NE customers, including local gas distribution companies (LDCs). It provides a flexible natural gas resource that can be used to meet peak demands, and at the same time, provides a hedge against daily volatility in delivered natural gas prices at New England city gates. In New England, there are two primary sources of LNG available to LDCs: facilities with direct import capability connected into the interstate pipeline system and off-system LNG resources that rely on trucked capacity and are available for peak shaving.

Table A2 summarizes LNG facilities and their known capacities. From an electric reliability perspective, we are primarily concerned with LNG supplies that can be used to provide incremental gas service to the electric generation sector during peak demand periods. Therefore, we assume that all LNG peak-shaving facilities owned and operated by LDCs (45 facilities representing a combined 1.4 Bcf/d capacity) are used to meet residential peak day needs and are not available to meet electric reliability demand.

In contrast, both the Canaport and Distrigas facilities are connected to the interstate natural gas pipeline system. Canaport is located in New Brunswick and interconnected to the Maritimes & Northeast (M&N) pipeline and supports North to South flows into New England. Canaport is one of several sources of natural gas to the M&N pipeline. As described below, we assume that the full capacity of the M&N pipeline (0.833 BCF/D) is available to New England customers in our deficiency statement. Therefore, we do not include any incremental LNG supplies from Canaport in our analysis.

The Distrigas facility, located in Middlesex, Massachusetts and interconnected to the Tennessee Gas Pipeline and Algonquin Pipelines, allows for the back-fill of natural gas into the interstate pipeline system with East to West flows. The Distrigas facility also provides LNG to the Mystic Generating Station, a 575 MW natural gas steam turbine. The Distrigas facility can store up to 3.4 BCF of LNG and can re-gas up to 0.715 BCF on a continuous basis. This represents 4.75 days of total sendout at maximum capacities.

Table A2: Existing Liquefied Natural Gas Capability

Resource	Capacity	Assumption	Solution Set
Canaport	1.3 BCF/Day	Included in the Deficiency Statement, as a supply to the 0.833 BCF/D M&N Pipeline	Not Included in Solution Sets
Distrigas	0.715 BCF/Day	Historical Flows and Back-fill included in Demand Forecast	Non-LDC Capacity available for solution sets
Neptune[70]	0.635 BCF/Day	Out-of-Service; Potentially available at a higher cost, including fees to return to service	Not Available for solution sets
Northeast Gateway			
LNG Peak Shaving	1.4 BCF/Day	Used to meet LDC peak Demand in excess of forecast interstate pipeline demand	Not Available for solution sets

There is little publicly available information on the number or terms of LNG contracts with electric generators. Because LNG typically serves as a swing resource used to meet peak demand, economic theory suggests that LNG prices will typically be bounded by the opportunity cost of either selling LNG into alternative markets or purchasing the next available landed fuel resource, such as natural gas from pipelines or delivered oil for electricity generation. That is, variable costs for LNG supplies can be expected to be the higher of the price of oil or natural gas during constrained periods and high prices. Equally important, the current practice of using LNG as a swing resource includes additional risk that supplies may not be available or otherwise accessible during peak periods for a reliability deficiency challenge. LNG may be unavailable for physical reasons of force majeure, if for example, shipments can't land at an off-shore terminal due to winter storms, or may be unavailable for supply resources, if for example, world prices are higher in other markets which limit production or total U.S. sales.

To develop a comparable solution set for reliability purposes, we include both fixed and variable charges for a quantity of LNG that is fully reserved and guaranteed for delivery to the electric power sector. Information on potential structures for such contract arrangements was provided to AGI by LNG representatives and the Environmental Defense Fund through the Study Advisory Group process and presented to all Study Advisory Group members. They provided two potential contracts, described below.

[70] The Neptune facility received a five year suspension of its operating license from the U.S. Maritime Administration in summer 2013. See LNG World News, "Neptune Suspends LNG Deepwater Port Operations", July 29, 2013.

The first contracting model, (for the Base-Load LNG Solution) is for a land based terminal where the expected maximum deficiency quantity per hour (MHDQ) is converted to an Annual Contract Quantity (ACQ) for the subject year by multiplying such year's MHDQ by 24 (hours in a day) and then by 90 (days in the December 15 through March 15 deficiency period). This methodology substantially overstates the needed quantity (i.e., the Deficiency Quantity compared with ACQ), but the contributing Study Advisory Group members represented that this simplified approach is consistent with other contracts, which sizes the re-gasification need to the peak hour need, analogous to pipeline scheduling practices.

The second Contracting Model assumes a dedicated Floating Storage and Regasification Unit ship (FSRU) and a term charter arrangement for the same 90 day period. Under this second contracting model, the commensurate ACQ is the greater of the Total Deficiency Quantity (determined by the deficiency model) or 3 Bcf (3,000,000 Dth). The 3 Bcf quantity is the approximate capacity of an FSRU ship. To achieve this latter dedication, the FSRU would be chartered for the full period that it was docked at one of the two off-shore receiving facilities. This service could also be provided using the on shore Distrigas terminal with a similar commercial (i.e., demand charge) arrangement. Both options require a per day chartering fee, comparable to a pipeline demand charge (discussed below).

While not considered here, the relevant Study Advisory Group members indicated that potential hybrid entailing a base-load LNG component (i.e., using a land-based terminal) along with an FSRU component are also commercially and physically feasible: for example, a land-based quantity of LNG for the full 10-year period approximately equal to that in the first year of the Base-Load LNG Solution construct followed by FSRU supply as described above across the same period in the same fashion. Such a hybrid solution could achieve both reliability supply needs and more general price moderation or suppression owing to the addition to the New England market.

In recognition of the global dynamics surrounding the supply and demand of LNG, the variable cost component of fuel supplies for each contract is indexed to the highest of three trading hubs. In this model, proposed structure takes the highest of the: a) Henry Hub plus adders (discussed below); b) the United Kingdom's National Boundary Point (NBP) plus shipping to New England; and, c) 14.5 percent of Brent Crude Oil Index (used as the oil benchmark for LNG). At the current outlook of low oil prices, the "higher-of" price is likely to be set by Henry Hub, and oil prices can serve as a "cap" on future LNG prices. The "adders" for the Henry Hub pricing are: a) a 15% pricing adder for natural gas used to power liquefaction (the recognized sales price adder used at the Cheniere LNG export facility on the Gulf Coast); b) the processing cost; and, c) a shipping cost. Processing costs are based on fixed processing charges for subscribers to Cheniere, which are in the neighborhood of $3.50 to $3.60 per Dth of LNG output.[71] The shipping cost is estimated to be $1.50 per MMBtu bringing the processing cost ($3.50) plus shipping ($1.50) to a total estimated adder of $5.00 per MMBtu.

We base our estimate of an LNG solution set using the FSRU contract model described above. This includes a 90-day term charter arrangement, with a daily demand charge of $200,000, escalated

[71] Cheniere Energy, Inc. SEC Filing 8-K, August 2015, pages 24 -26.

annually with inflation, and variable charges using our forecast of Henry Hub pricing plus the indicated processing cost of $3.50 per Dth, shipping costs of $1.50 per Dth, and delivery charges of $0.16/Dth. All variable costs are assumed to escalate annually with inflation.

Incremental Pipeline Transportation

Solution Set 2 – Incremental Pipeline

Pipeline development costs can vary significantly based on a number of important factors, including whether the project is an expansion or a new development; the location and distance of the chosen route, including right of way easements and other land requirements; the total pipeline diameter, capacity and number of compressor stations used to deliver natural gas; and other factors, such as the financing structure used in the development. Here, we do not forecast a specific pipeline solution, but rather, include a generic estimate of pipeline capacity based on our review of recently completed and proposed pipeline developments, with costs expressed both in terms of development costs (on a $/inch-mile basis) and as total ratepayer costs (on a $/Dth-month maximum reservation charge basis). We index total costs to the two most recent announcements for both the Spectra AIM project[72] and the Kinder Morgan Northeast Energy Direct (NED) project and estimate total ratepayer costs using a maximum reservation charge of $39/Dth-month.[73]

Based on this review, we assume that total capital costs for the 0.3 Bcf/day installation are approximately $787.5 million, with a first year cost of service of $140 million. Costs for the 0.12 Bcf/day installation and the 0.5 Bcf/day installation are assumed to scale linearly by size. In practice, actual costs will depend on the specific project chosen, and costs may not scale linearly between capacities.

Energy Efficiency, Demand Response, and Renewable Energy

Solution Set 3(a) – Energy Efficiency and Demand Response

To develop the energy efficiency and demand response solution set, we draw from the energy efficiency capability estimates presented in the Synapse/DOER (2015) study. They estimate that the total incremental potential for appliance standards and residential, commercial, and industrial energy efficiency

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[72] The Spectra AIM project is a 0.342 Bcf/day expansion in New York, Massachusetts, and Connecticut, with a total estimated capital cost of $876 million, a capital recovery factor of 20 percent and a first year cost of service of $175 million, with a maximum monthly reservation charge of $42.58. See Spectra AIM Project, FERC Section 7(b) and 7(c) Application and Public Exhibits, FERC Docket No. CP14-96, February 2014, Exhibit P Tariff and Rates. We note that Synapse/DOER (2015) used the Spectra AIM costs in its analysis, with a linear adjustment to monthly reservation rates assuming 80 percent utilization over a five month period. In contrast, we do not forecast pipeline utilization and prices ahead of time; instead, ratepayers are responsible for the full cost of service, with the total pipeline utilization determined through the electric sector dispatch and modeling results.

[73] This assumes a 30 year depreciation schedule, a 10.4 percent nominal weighted average cost of capital, and recovery of federal and state income taxes.

at the time of winter peak is 590 MW of capacity. We make a simplifying assumption that the total feasible capability of such resources for the ISO-NE region is equal to 2.2 times that of the Massachusetts capability identified by Synapse, based on the portion of end-user load served in Massachusetts relative to the New England region as a whole, for a total of 1,300 MW of winter peak capacity. In contrast to Synapse, we consider this energy efficiency to be incremental to the current ISO-NE CELT forecast, which includes its own estimate of energy efficiency. Conversely, the Synapse estimate presented above is assumed to be incremental to Synapse's own adjustment of the CELT forecast. Their adjustment, which includes additional contributions from EE, is designed to account for uncertainty in ISO-NE's planning approach that may discount total EE contributions to load.[74] Therefore, our analysis does not include or consider any existing energy efficiency which is not already captured in the ISO-NE forecast.

We developed our cost estimate of incremental energy efficiency using the average of the lifetime cost of all planned programs, including incentives and participant costs, as identified in the 2016-2018 Massachusetts Program Administrator draft Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan.[75] Our use of the total lifetime cost allows for an apples-to-apples comparison with other solution sets that also assign the full cost of each solution set to ratepayers. We use these Massachusetts' costs as an approximation for the average cost of incremental EE in the ISO-NE region. The Northeast Energy Efficiency Partnership (NEEP) reports energy efficiency program costs, excluding participant costs, for each state in its Regional Energy Efficiency Database (REED). The load-weighted average cost for all New England states in 2013 is equal to the Massachusetts program cost, which suggests that Massachusetts is a useful proxy for the region as a whole.

In the EE/DR (SS 3a) solution set, the remaining deficiency is met through the use of demand response, which can be called upon by ISO-NE during peak periods to reduce total load. To meet a peak deficiency in 2029/30, we include the cost for an incremental 1,100 MW of demand response at $31.06/MW-day, based on recent PJM capacity auction results.[76] We estimate that this demand response would be called upon in up to 26 hours during the 2029/30 winter.[77]

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[74] ISO-NE assumes an annual increase in program costs of 5 percent, with an additional 2.5 percent inflation, and applies a 10 percent uncertainty adjustment or de-rate to estimated savings reductions in MA, RI, and ME. See Peterson, P. and Fields, S. "Challenges for Electric System Planning: Reasonable Alternatives to ISO-NE's Discounts for Uncertainty." Prepared for E4 Group, July 24, 2015.

[75] This corresponds to the total resource cost in the Program Administrator filings, and it is used by program administrators to determine the cost effectiveness of individual efficiency programs. See Massachusetts Energy Efficiency Guidelines, §3.4, Department of Public Utilities Order 08-50-B, October 26, 2009.

[76] We rely on PJM bid data because similar information is not readily available for ISO-NE. See Monitoring Analytics, Independent Market Monitor for PJM, "Analysis of the 2017/2018 RPM Base Residual Auction." October 6, 2014, Table 18.

[77] Our use of 1,100 MW of DR is not a forecast of the total incremental DR that may be available over the full modeling period. For example, in the 2016-2018 draft resource plan, National Grid indicated a soft commitment to procuring up to 3,637 MW of commercial/industrial demand response over the three year period at a total program administrator cost of $23 million (Massachusetts Joint Statewide Three-Year Electric and Gas Energy

Solution Set 3(b) – Energy Efficiency and Firm Imports (Existing Transmission)

In addition to the EE/DR (SS 3a) solution set outlined above, we also consider a blended solution comprised of both energy efficiency and new incremental imports from hydropower and other new Class 1 renewables which could be used in support of regional climate goals EE/Firm Imports (SS 3b/SS 3c). The imports component of these solution sets is about half of that of amount proposed for procurement under Massachusetts Senate Bill 1965, submitted by Governor Baker in July 2015. Under this bill, utilities could procure up to 18,900,000 MWh of clean energy annually, or approximately 2,400 MW of capacity. If the bill is enacted as proposed, initial solicitations would occur no later than April 1, 2016.

To date, there exists little evidence for the potential cost of a long-term energy contract backed by significant quantities of hydropower or wind energy.[78] The purpose of the current solution set is not to model the potential costs or benefits of SB 1965, but rather, to estimate the potential costs and benefits of using imports to meet a peak winter deficiency need, as defined through our deficiency analysis. To meet this criterion, any imports must be available at the time of winter peak on a firm or guaranteed basis. Our solution set costs reflect that perspective.

The most likely source of firm winter imports will be provided by new hydropower supplied from Hydro Quebec. As a government owned public utility, Hydro Quebec is obligated to earn a return on any investments not used to serve its own customers. Accordingly, it sells power into external markets (IESO, ISO-NE, NYISO, PJM) whenever it is economic to do so, or when the cost of energy is higher abroad than the price it could receive in its own service territory. Going forward, Hydro Quebec will be expected to continue to provide energy when it is economic to do so based on market fundamentals. Because Hydro Quebec is itself a winter peaking system (meaning that it requires the majority of its capacity to meet its own demand), the opportunity cost of selling power during those winter months is higher than during a summer peak. The current analysis does not consider new resources from either New York or other Canadian provinces, although both could be used to provide new incremental import capacity.

As a conservative assumption, we estimate that the contract cost for a firm, long-term commitment of imports at the time of winter peak is equal to the capital cost of a new hydropower facility. This perspective suggests that either a) Hydro Quebec would need to build new hydro resources to back this firm commitment, or b) the opportunity cost of selling that power into the ISO-NE market would at least be equal to the cost it could receive at home. In developing our estimate, we rely on the levelized cost of electricity (LCOE) for new hydroelectric resources as reported by the EIA (2015). This estimate is exclusive of transmission costs and fixed or variable operations and maintenance expenses. Based on the assumed EIA capacity factor (54 percent), cost of capital (6.1 percent real after-tax weighted average cost of capital) and a 30 year asset life, we estimate that the total cost of an additional 1,100 MW of firm capacity would be \$4.3 billion with an annualized cost of \$387 million per year. A 2,400 MW firm commitment of capacity would cost \$9.4 billion, or \$843 million per year. Our use of domestic

Efficiency Plan, 2016-2018, filed April 30, 2015, page 444). Instead, our inclusion of 1,100 MW represents our judgment for the mix of resources that offers the lowest cost distributed resource solution set.

[78] In 2011, Vermont public utilities signed a long-term contract for up to 225 MW of peak electric energy supply from Hydro Quebec at a price of \$58/MWh plus the cost of transmission.

hydroelectric costs represents a conservative estimate of potential costs developed in Hydro Quebec. For example, in its 2013 Annual Report, Hydro Quebec reported total capital costs of $6.5 billion for four generating stations at the 1,550 MW Romaine River facility now under construction, without consideration of the cost of the transmission links required to connect these stations to the Hydro Quebec system. We assume that any new facility is able to provide power throughout the year, consistent with the firm contract, and produce energy at a rate greater than the assumed EIA capacity factor.

We develop two EE/Firm Imports solution sets recognizing that the region has the potential to procure some firm capacity over existing transmission lines. For 2018, approximately 1,500 MW of import capacity cleared in the forward capacity auction and has a capacity supply obligation for 1,017 MW during the winter peak period.[79] Since we do not consider these existing imports in the deficiency analysis (because without a long-term commitment they are not obligated to provide power in any winter over the study period), in the EE/Firm Imports (Existing Transmission) (SS 3b) solution set, we include the potential for existing imports, priced at a long-term firm commitment. In actuality, these resources will likely continue to provide capacity and energy to the New England markets, on a year by year basis depending on economic conditions in other regions. If these resources bid into and clear the FCA, then the true incremental cost to consumers of this resource in any given year may be zero.

Solution Set 3(c) – Energy Efficiency and Firm Imports (New Transmission)

Finally, we model a second EE/Firm Imports (New Transmission) (SS 3c) solution set that includes both the cost of new firm energy and the incremental cost for new transmission to deliver that energy. We assume a total cost for new transmission capacity of $1.4 billion,[80] with a first year cost of service charge of $250 million. This cost is representative of a new 1,100 MW transmission line.

When considering the larger transmission infrastructure scenario, we assume that firm contracts totaling 2,400 MW make use of both existing and new firm transmission capacity. To the extent that a 2,400 MW of firm imports would require two transmission lines over the same distance, our estimate potentially underestimates this cost.

[79] In addition, the HQ-NE Phase II line has an energy import capability of 2,000 MW and a capacity import limit of 1,400 MW. See ISO-NE Regional System Plan, 2015, Table 4-9.

[80] In nominal dollars, this is approximately $1.6 billion for a 2020 in-service date.

Example LNG Term Sheet
(provided by Study Advisory Group members)

FSRU LNG Peak Supply Commercial Format – High Level Term Sheet
Prepared by Skipping Stone (9/30/15)
Purpose:

Core contract terms for ensuring a reliable supply of LNG during peak hours of winter at quantities sufficient to eliminate all projected/modeled hours of deficiency.

Term:

A rolling five years with the sixth year pricing and quantity to be agreed upon before the end of a set Contract Year.

> [To give provide supply certainty to Buyer and demand certainty for Seller, parties would delineate a Contract Year to negotiate and seek agreement on pricing and quantity of service for purchases and sales in the year(s) following the end of the then current 5 year term. Example: Assume initial contract year 1 is the winter of 2016/17 and initial contract year 5 is the winter of 2020/21. By a date certain (prior to the commencement of initial Year 2 (i.e., the winter of 2017/18) the parties agree on pricing and quantity for the 2021/22 contract year. In this way, should the parties be unable to agree on such terms, both parties have 5 years to make other plans and arrangements. Such a structure neither locks both parties into longer than a five year contract at any one time (absent mutual agreement to the contrary) nor (more importantly) forecloses the parties from pursuing other future supply arrangements for more than five years into the future.]

Annual Contract Period:

The Annual Contract Period is from December through March of the succeeding year (absent mutual agreement to the contrary).

Annual Contract Quantity (ACQ):

Parties agree to a minimum quantity of LNG for each subject Annual Contract Period. This is a take-or-pay quantity.

Monthly Contract Quantity (MCQ):

The parties agree that the Annual Contract Quantity is allocated as a percentage across each of the months of December through March of the Annual Contract Period; each an MCQ. Each MCQ is a take-or-pay quantity.

> [Example: 16.66% of the ACQ could be the December MCQ, 33.33% of the ACQ could be the January MCQ; 33.33% of the ACQ could be the February MCQ and 16.67% of the ACQ could be the March MCQ, or such other mutually agreeable, individual, MCQ Amounts such that the total of the individual MCQ's equals 100% of the ACQ.]

Vaporization Schedule:

Parties agree to minimum (if any) and maximum daily vaporization quantities (MinDVQ and MaxDVQ) such that each MCQ is vaporized. In addition, the parties agree on a maximum hourly quantity (MHQ) and hours of MHQ in any given day (subject to MaxDVQ and MCQ limits).

> [Example: The MinDVQ (if any) and the MaxDVQ can be stated as percentages of MCQ. Likewise the MHQ can be set as a percentage of the MaxDVQ.]

Pricing:

For the Initial Five Year Annual Contract Periods the pricing shall the agreed upon at contract signing and shall be based upon the formulae on Exhibit A – Pricing attached hereto and made a part of the Agreement.

Allocation of Price:

The Price per MMBtu for each MCQ of each Annual Contract Period shall be allocated between a Fixed Amount and a Variable Amount by Buyer provided the sum of Fixed Amounts and Variable Amounts equals the ACQ times the Price for each ACQ as set forth in Exhibit A – Pricing. Such Fixed and Variable Amount per MMBtu shall be set by Buyer no later than 3 hours before the close of the NYMEX futures contract for the prompt month.

> [Example: Fixed and variable amounts are set no later than 12:00 noon on the last day of trading for the prompt month futures contract in order that the variable component of the Buyers MCQ is price responsive for Buyer's dispatch purposes.]

Other Terms and Conditions (as appropriate)

3. Electric System Model Overview: PROMOD

The PROMOD Model

PROMOD is an electric market simulation model marketed by Ventyx. PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load. This detailed representation allows the model to capture the effect of transmission constraints on the ability to flow power from generators to load, and thus calculates Locational Marginal Prices ("LMPs") at individual nodes within the system. PROMOD and similar dispatch modeling programs are used to forecast electricity prices, understand transmission flows and constraints, and predict generation output. Ventyx simulation-ready data includes data on Eastern Interconnection network structure, resources, fuel prices, basis differentials, and demand.

We use PROMOD to model the impacts of each solution set on the dispatch of power system operations and outcomes, with the difference between each simulation and our market outlook scenario being the direct incremental impacts of a given solution set on the power system. These two simulation runs otherwise maintain the same inputs, in terms of power plants available to be dispatched, power plant operational characteristics, NO_x and SO_2 allowance costs, baseline load levels, and so forth. The market outlook Dual-fuel (SS 1a) case is benchmarked to actual power system operations in the historical months of the 2012-2014 time period (in New England, New York, PJM). With this as a starting point, several core assumptions (e.g., load levels that change as a result of energy efficiency investments, timing of generic capacity additions, natural gas prices that depend on each solution set) were changed, and the model re-run to simulate the solution set case. As described above, the simulation period covers the ten year period between 2020 to 2030. PROMOD outputs include changes in power plant operations, emissions, prices, customer payments, and producer revenues.

Fuel Prices in the Power Sector

As a starting point, we develop our base case outlook for natural gas prices using futures prices at the Algonquin Hub. These future prices reflect the current outlook for constrained winter months with high basis differentials relative to the Henry Hub price. Second, we assume that all distillate oil, residual oil, and coal prices are based on Ventyx fuel price forecasts.

We assume that these monthly prices represent the average expectation of fuel prices within each month, while recognizing that delivered natural gas fuel prices will be both higher and lower on individual days. These average prices also reflect the ability of dual-fuel capable units to switch from natural gas and burn fuel oil, when it is economic to do so. For example, in the 2013/14 winter, gas prices exceeded oil prices on 57 percent of winter days, with oil units dispatched in economic merit order.[81] At the same time, oil units may also be dispatched out-of-merit if needed to meet electric reliability.

Therefore, we estimate the total quantity of oil-fired and dual-fuel fired generation that would have been dispatched, based on the estimated total natural gas availability, as defined in the deficiency

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[81] Brandien, P. "Cold Weather Operations." ISO New England. Presentation to Federal Energy Regulatory Commission, April 1, 2014, page 14.

statement. This is a necessary step in order to capture the impact of daily variation in fuel prices and the potential for increased costs of oil-fired generation that may be dispatched out of merit for reliability purposes. We do this in three steps. First, we compare the total natural gas fired generation and total natural gas consumption, as dispatched by PROMOD based on the average monthly fuel prices, to the total quantity of available natural gas. Then, using the supply curve for each hour, we estimate the marginal generating unit based on the total cumulative natural gas consumption at the limit of available supplies. All incremental generation (the difference between dispatched natural gas generation and available natural gas generation) is assumed to be met in a cumulative fashion by the most efficient dual-fuel and oil-fired generators remaining in the supply curve. This estimates the total oil-fired generation and the total oil consumption on an hourly and daily basis. Finally, as a third step, we estimate the total "uplift" cost to dispatch this oil-fired generation, as the difference between the monthly natural gas price and the monthly oil price. This cost is added to the total cost to load from the production cost dispatch.

Power Plants: Existing Units, Unit Retirements and Additions

The set of power plants is based on actual plants operating within eastern PJM, NYISO, ISO-NE, Ontario, and MISO. We made changes to this dataset (to reflect unit retirements and power plant additions (e.g., to meet the states' RPS). Unit retirement decisions are based on assumed retirements in the PROMOD generator dataset, which rely on information from Ventyx as of September 2014. Some of these retirements have been adjusted as the result of a review of planning documents published by PJM, NYISO, and ISO-NE, along with press releases. Unit additions listed in PROMOD's generator dataset beyond FCA #9 have not been adjusted. Random generator outages for existing and new units were calculated once using PROMOD's algorithm, and fixed for each case. Similarly, scheduled generator maintenance is held constant between solution set modeling runs. Table A3 and A4 below provide generator retirements and additions reflecting these changes.

Table A3: Unit Retirements

Unit Name	Area	Fuel Type	Capacity (MW)	In-service Date	Retirement Date
Berlin GT 1	ISNE - Vermont	Oil	46	6/1/1972	6/1/2022
Brayton Point 1	ISNE - Rhode Island	Coal	247	8/1/1963	6/1/2017
Brayton Point 2	ISNE - Rhode Island	Coal	249	7/1/1964	6/1/2017
Brayton Point 3	ISNE - Rhode Island	Coal	638	8/1/1958	6/1/2017
Brayton Point 4	ISNE - Rhode Island	Oil	446	12/1/1974	6/1/2017
Cleary 8	ISNE - Massachusetts - Southeast	Oil	26	6/1/1966	6/1/2026
M Street Jet 1	ISNE - Boston	Oil	68	5/1/1979	6/1/2029
Middletown 3	ISNE - Connecticut - Central-Northeast	Dual Fuel	245	1/1/1964	6/1/2024
Montville 5	ISNE - Connecticut - Central-Northeast	Oil	42	1/1/1954	6/1/2020
Pilgrim	ISNE - Massachusetts - Southeast	Nuclear	680	12/1/1972	6/1/2019
Schiller 4	ISNE - New Hampshire	Coal	48	10/1/1952	6/1/2020
Schiller 6	ISNE - New Hampshire	Coal	49	7/1/1957	6/1/2020
South Meadow 11	ISNE - Connecticut - Central-Northeast	Oil	47	8/1/1970	6/1/2020
South Meadow 12	ISNE - Connecticut - Central-Northeast	Oil	48	8/1/1970	6/1/2020
South Meadow 13	ISNE - Connecticut - Central-Northeast	Oil	48	8/1/1970	6/1/2020
South Meadow 14	ISNE - Connecticut - Central-Northeast	Oil	46	8/1/1970	6/1/2020
Vermont Yankee 1	ISNE - Vermont	Nuclear	619	11/1/1972	1/1/2015
West Medway 1	ISNE - Boston	Oil	55	7/1/1970	6/1/2020
West Medway 2	ISNE - Boston	Oil	53	3/1/1971	6/1/2021
West Medway 3	ISNE - Rhode Island	Oil	56	7/1/1970	6/1/2020

Sources:
Ventyx power plants database. ISO-NE non-price retirement requests and determinations.

Table A4: Unit Additions

Unit Name	Area	Fuel Type	Capacity (MW)	In-service Date
Bridgeport Harbor 6	ISNE - Connecticut	Natural Gas	475	6/1/2018
Medway Peaker - NEMA	ISNE - Massachusetts	Natural Gas	200	6/1/2018
Medway Peaker - SEMARI	ISNE - Massachusetts	Natural Gas	200	4/1/2018
Salem Harbor CC1	ISNE - Massachusetts	Natural Gas	692	6/30/2017
Towantic	ISNE - Connecticut	Natural Gas	785	12/1/2018
Wallingford 6/7	ISNE - Connecticut	Natural Gas	90	6/1/2018

Sources:
ISO-NE Forward Capacity Auction Results.

Renewables

RPS MWh targets by state are sourced from Lawrence Berkeley National Labs for PJM and NYISO and from the updated ISO-NE RPS Workbook for ISO-NE. Beginning in 2016, we assume that the region meets 100 percent of its incremental renewable target through in-region wind capacity. We add wind resources assuming a 25 percent capacity factor, based on historical generation identified in the SNL power plant database. Over the full modeling period, this adds approximately 4,000 MW of additional wind capacity. Within the resource adequacy model, we de-rate this capacity to 5 percent of nameplate, consistent with ISO-NE planning standards.

Generic Capacity Additions to Meet Resource Adequacy

After the incremental addition of renewable capacity and retirement of units as discussed above, we analyzed the extent to which each region's capacity satisfied forecasted resource adequacy requirements in each year, based on each region's capacity planning process. In ISO-NE, we assume a long-term reserve margin of 14.3 percent and add new generation in the first year of need in sufficient capacity to meet several years of need. We add new generic natural gas/dual-fuel capable combined cycle and gas turbine plants in each region as necessary to maintain resource adequacy. . The operating characteristics of these new plants are assumed to be the same as recently built natural gas generating units. The units were placed on the high-voltage transmission network in each region to maximize deliverability.

Emissions costs

We developed our base case CO_2 price forecast using the most recent RGGI auction results of $6.02/ton, and assume that prices increase by 2.5 percent in real terms each year, proportional to the decline in the RGGI allowance cap. NO_x and SO_2 allowance prices are based on Ventyx price forecasts.

Load Forecasts

Regional Transmission Operator (RTO) level load forecasts are provided by Ventyx, and based on RTO planning documents. ISO-NE data is based on EE-adjusted load from the 2015 CELT Report. PROMOD hourly load shapes were reviewed and calibrated to ensure consistency with seasonal peak demands identified by ISO-NE. NYISO data is based on EE- and PV- adjusted load from the 2014 Gold Book. PJM data is based on EE-unadjusted load from the 2014 PJM Load Forecast Report.

For the energy efficiency solution sets, total energy savings from each program type were divided among summer and winter on-peak and off-peak hours. This distribution of total savings was based on historical data from the final 2013-2015 Massachusetts Program Administrators report. From these load groupings, hourly state savings for each year were determined and modeled in each zone. Total state load savings were proportionally assigned to constituent service areas based on native load in each area.

4. Greenhouse Gases and Regional Climate Goals

Greenhouse gas emissions levels across all sectors for 1990 are based on state-reported historical emissions estimates. “Current” GHG emissions levels are based on state-reported historical emissions estimates, where available, and on business as usual projections otherwise. These “current” emissions levels reflect 2011 emissions levels, the most recent year of estimates available across the largest number of states, and emissions levels for adjacent years otherwise. Specifically, 2010 emissions levels are used for Rhode Island and 2012 business as usual estimates are used for New Hampshire.

Sector-specific emissions levels are based on explicitly labeled emissions categories, except for building emissions, which when not explicitly labeled are calculated as the difference between total emissions and the sum of non-energy, transportation, and electric-sector emissions.

Greenhouse gas emissions targets reflect state-reported emissions goals, illustrated in Table A5. We converted those goals, which are typically reported as a percentage reduction in emissions from baseline levels, to million metric tons of CO_2-equivalent ($MMTCO_2e$) limits using baseline emissions levels and given percentage reductions. Emissions goals are not available for each New England state in every year of interest, so emissions targets used in this report are based on actual values in available years and linearly interpolated values otherwise.

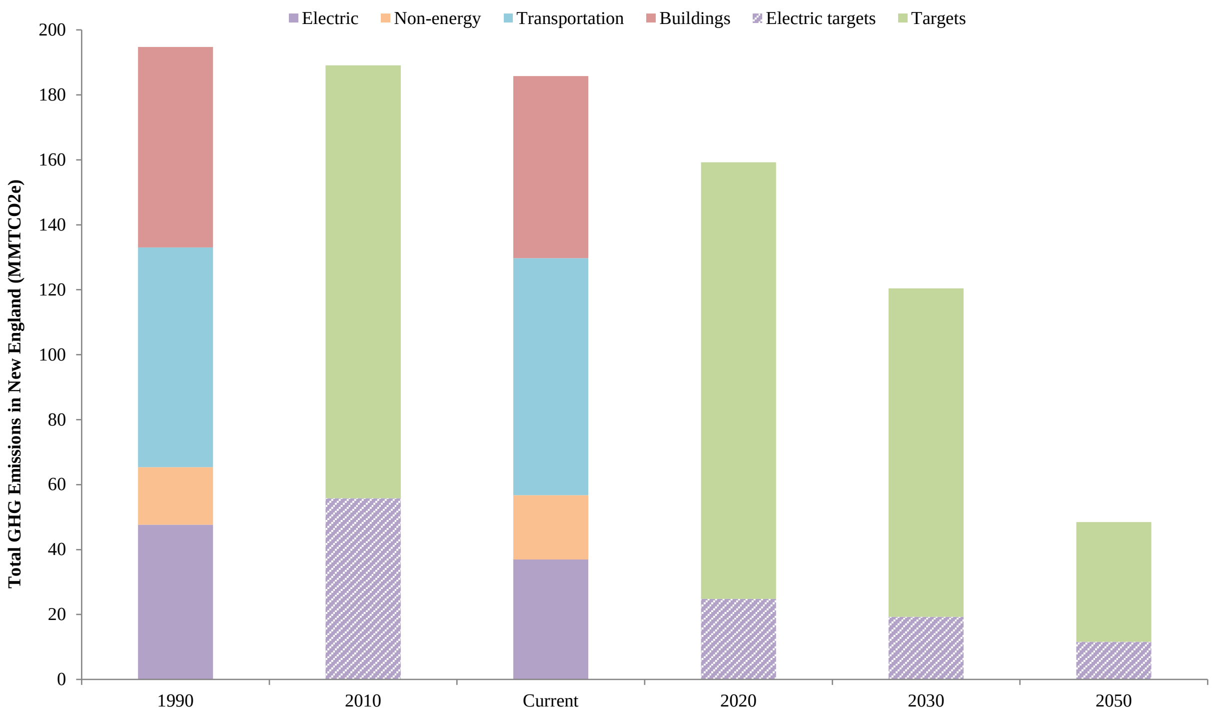
Table A5: Summary of State GHG Goals

State	Title of GHG Emissions Reduction	Type of GHG Emissions Reduction	Date of Adoption	GHG Emissions Milestone
Connecticut	Public Act No. 08-98	Action Plan followed by Legislation	Action Plan: 02/15/2005 Legislation: 10/01/2008	2010: Reduce to 1990 Levels 2020: 10% Below 1990 Levels 2050: 80% Below 2001 Levels
Maine	PL 237	Legislation (Includes Request for an Action Plan)	Legislation: 09/13/2003 Action Plan: 12/01/2004	2010: Reduce to 1990 Levels 2020: 10% Below 1990 Levels
Massachusetts	Global Warming Solutions Act	Climate Protection Plan followed by Legislation	Protection Plan: 05/01/2004 Legislation: 08/01/2008	2020: 25% Below 1990 Levels 2050: 80% Below 1990 Levels
New Hampshire	New Hampshire Climate Action Plan	Action Plan	03/01/2009	2025: 20% Below 1990 Levels 2050: 80% Below 1990 Levels
Rhode Island	RI Executive Climate Change Coordinating Council	Legislation (Includes Request for an Action Plan)	05/01/14	2020: 10% Below 1990 Levels 2035: 45% Below 1990 Levels 2050: 80% Below 1990 Levels
Vermont	Executive Order #07-05	Legislation (Includes Request for an Action Plan)	Legislation: 12/05/2005 Action Plan: 10/26/2007	2012: 25% Below 1990 Levels 2028: 50% Below 1990 Levels 2050: 75% Below 1990 Levels

Source: Individual State Planning Documents

As part of our review, we compared estimated electric sector reductions to an assumed continuation of the RGGI CO_2 emissions caps and the mass based standard for new and existing generation under the Federal EPA Clean Power Plan. We found that assumed RGGI limits are consistent with assumed 2030 electric sector targets imputed from state-level greenhouse gas emissions targets and state-reported GHG action plans and also allow for a trajectory of emissions out to 2050 consistent with full state climate goals . Figure A2 illustrates the total greenhouse gas emissions and targets in New England, with the electric sector represented by the potential RGGI allowance targets.

Figure A2: Total Greenhouse Gas Emissions and Potential Targets, New England



Notes:
1. Emissions goals based on actual values in available years and linearly interpolated values otherwise.
2. Current levels of greenhouse gas emissions are based on 2011 where available and adjacent years where 2011 is unavailable.
3. Buidling emissions, when not explicitly specified on the state level, are calculated as the difference between total emissions and the sum of non-energy, transportation and electric emissions.

Sources used in Appendix 4:

1. "Public Act No. 08-98: An Act Concerning Global Warming Solutions (Global Warming Solutions Act)," State of Connecticut, available at https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm, retrieved on August 19, 2015.

2. "Connecticut Greenhouse Gas Emissions Inventory 2012: Executive Summary," Connecticut Department of Energy and Environmental Protection, available at http://www.ct.gov/deep/lib/deep/climatechange/2012_ghg_inventory_2015/2012_ct_ghg_inventory_final.pdf retrieved on August 27, 2015.

3. "A Climate Action Plan for Maine," Department of Environmental Protection, December 1, 2004, available at http://www.eesi.org/files/MaineClimateActionPlan2004Volume%201.pdf, retrieved on August 19, 2015.

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13. "Summary Level Emissions Report," RGGI, Inc., August 31, 2015, available at https://rggi-coats.org/eats/rggi/index.cfm?fuseaction=search.rggi_summary_report_input&clearfuseattribs=true, retrieved on September 3, 2015.

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Solving New England's Gas Deliverability Problem Using LNG Storage and Market Incentives

Written By: **Greg Lander**

Edited By: **Peter Weigand**

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Executive Summary

For 50 days a year, New England has a gas problem – not enough natural gas is available to meet demand. In the winter of 2013-14 this problem led to dramatic spikes in the price of natural gas and the cost of electricity. How to solve that problem has been the source of political, economic and environmental debate over the past 2 years. One proposed solution is to "flood the market" with new gas via one or more new pipelines, with the multi-billion dollar cost to be borne by electric ratepayers. The other solution, one that the Conservation Law Foundation has promoted, is to maximize the use of existing infrastructure in both the delivery and storage of natural gas. This solution addresses the supply problem during that limited 50 day period in the winter, saves industrial, commercial and residential customers millions of dollars and avoids the need for costly and enormously inefficient infrastructure that will ultimately undermine efforts to meet the challenge of climate change.

As currently managed, New England's natural gas delivery system – its pipelines, storage and import facilities – do not deliver sufficient quantities of natural gas to meet demand during the limited winter peak period. During these peak periods of demand, when high volumes of gas are consumed to simultaneously meet the region's heating and electric power generation needs, management and operation of the current system fails to make the necessary gas deliverable. Numerous corporate and governmental entities are urging a large infrastructure solution: building more pipelines into and across New England to increase regional pipeline capacity. New pipelines, they argue, are needed to address a structural problem of constrained gas supply and the high wholesale energy prices experienced during the winter of 2013-14.

But New England does not have a structural pipeline capacity problem, and not only are new pipelines not the only solution, but they are also the least cost-effective one. For the majority of the year, the region's natural gas system of pipelines and LNG deliverability already operate at less than 50% capacity. On those portions of the 50 coldest winter days each year when the near-simultaneous high demands of regional heating and electric generation loads are not being met efficiently, New England has what in the natural gas industry is considered to be an issue of "deliverability," or the ability to provide a certain quantity of gas to a certain location at a certain time.

Once New England's current gas problem is properly understood as one of deliverability, rather than insufficient "pipeline capacity," the solution that emerges as most efficiently and cost-effectively enhancing deliverability in New England is increasing the use of the region's existing LNG infrastructure.

We reach this conclusion based upon the "cost of use" of each alternative. That is, the cost of new pipeline capacity in an area like New England with a peak-only supply deficiency and where other peak-only supply alternatives already exist must be analyzed on the basis of use. Therefore, when additional deliverability of gas is needed over discrete days of the year rather than on a year-round basis, the overall cost of the pipeline should be measured as a cost on only the days during which it will actually be used to serve the residences and businesses who will pay for it through their gas or electric bills. It should not be measured as artificially spread out across the entire year – the vast majority of which it would not be used or, if used, would cause another already existing asset to go unused.

A cost of use comparison demonstrates that adding additional pipeline capacity is the most expensive and least effective means of addressing New England winter-peak deliverability. The process of building new gas pipelines takes years and does nothing to help us address winter deliverability in the interim. There is also substantial risk that a new pipeline built today will become the ratepayer-funded, stranded cost of tomorrow. Moreover, investing in a new pipeline is unlikely to produce the assumed lower gas prices, as currently stranded Marcellus/Utica gas supply and its artificially low existing prices will more likely rise as numerous planned pipelines to other regions and for export move those prices to that of the Henry Hub. Finally, environmental regulatory regimes, such as the federal Clean Power Plan and existing New England state mandates to aggressively reduce greenhouse gas emissions, create a strong disincentive for any significant increase in natural gas consumption.

For New England, the best means of solving the winter gas issue from a cost of use approach is better utilization of existing natural gas infrastructure and, specifically, existing LNG infrastructure. We call this the Winter-Only LNG "Pipeline" approach. This approach suffers from none of the weaknesses of a year-round pipeline capacity solution.

New England has LNG vaporization capacity both from large import terminals and from LNG storage facilities owned by the local gas distribution utilities or "LDCs." If LDCs were to contract for a baseload level of LNG vaporization during the December 15 - March 15 winter period and for more frequent truck refills of their existing LNG storage facilities, local gas reliability could be maintained while freeing up existing pipeline capacity for sale on the secondary market to power plants.

Not only is this approach technically feasible, a Winter-Only LNG "Pipeline" strategy would provide LNG deliverability throughout New England that would save LDCs and their ratepayers $70 Million a year and as much as $4.4 Billion over twenty years, as compared to a new pipeline proposal. At the same time this strategy would provide peak deliverability that would lower winter wholesale electricity prices on a scale comparable to new pipeline capacity additions. As outlined more fully in Appendix E to this paper, the role that LNG can play in ensuring gas deliverability and driving down spot market gas prices was meaningfully demonstrated in New England in the winter of 2014-2015, when a 4% increase in total gas deliverability from LNG reduced spot gas prices by 43%.

For these reasons, the Winter-Only LNG "Pipeline" outlined in this paper would be less costly and more effective than building new gas pipeline capacity. Such an approach requires a break from the currently prevailing pipeline-centric management and regulation of New England's gas transmission and distribution system. Our alternative approach has the promise to address immediately the problem at hand, and to do so efficiently, effectively and without complex regulation. Consequently, state regulators should direct LDCs to implement the Winter-Only LNG "Pipeline" option immediately. Thereafter, relatively small adjustments can be made to the market incentives and associated reimbursement rules regarding LNG storage and resale—distinguishing the winter period from the rest of the year—in order to make the LNG solution a permanent feature of the New England energy market.

1. Introduction

In New England, as in many parts of the country, natural gas is used to meet residential, commercial and industrial demand for space and water heating, for household appliances and for powering machinery. Gas for these uses is transported from its source via interstate pipelines and purchased on the wholesale market primarily by local gas utilities (LDCs), which in turn sell and deliver the gas on their own pipeline network to their local customers. In New England, where more than 50% of the region's electricity is generated by natural gas-fired electric power plants, the electric sector represents a major consumer of wholesale natural gas.

The baseload supply of natural gas for each of these uses comes principally from a national network of pressurized gas pipelines through which natural gas is transported and sold. LDCs are required by law (as regulated utilities) to ensure that they have sufficient gas supplies to meet their customers' needs. But pipelines are not their only source of natural gas. LDCs serve daily customer need for natural gas with a combination of pipeline gas, LNG provided from their own storage facilities and LNG from large regional LNG-import terminals. They do so because, as a fundamental energy planning principle, pipelines alone are an extremely uneconomic way to meet demand spikes like the system-wide peak demand each winter. This is so because any pipeline capacity, even that needed for such short time purchased (as the result of pipeline regulation and economics) on a 365-days-a-year basis. As a result, a significant percentage of the capacity within any pipeline built to handle peak demand spikes will only be used for a few days each year. Consequently, "pipeline capacity" is not the core metric for LDCs. Instead, gas "deliverability," the ability of a gas company to meet its customers' needs at a given location at a given time, is the critical factor.

Therefore, the "natural gas problem" or "winter energy crisis" that New England faces it is not an issue that revolves around (or can be economically solved by) year-round pipeline capacity, but instead one that centers on gas deliverability on approximately 50 discrete days from mid-December to mid-March.

This paper analyzes this natural gas deliverability issue and recommends an innovative, lower cost solution using existing LNG infrastructure. Over four sections, we:

- Explain New England's current natural gas problem and describe how it is one of winter deliverability rather than of overall pipeline capacity;
- Analyze the technical and economic viability of new large pipelines as a potential solution to the problem of regional winter deliverability;
- Propose an alternative solution, demonstrating that more efficient use of existing LNG infrastructure is not only a technically viable solution to New England winter deliverability but also the quickest and most economical solution; and
- Suggest regulatory changes to facilitate long-term and self-sustaining implementation of the LNG solution.

2. The New England Natural Gas Problem

New England's natural gas problem would most accurately be termed a "50 day on-peak deliverability problem." That is, for some portion of around 50 days per year the near-simultaneous and high demands of regional heating and natural gas for electric generation loads are not being met efficiently. To define this problem, we must understand both the needs of the natural gas system and how gas companies meet these needs.

A natural gas delivery system requires supply to be kept at sufficient pressure at all times as gas leaks and explosions can occur if deliverability (i.e., pressure) is interrupted. LDCs are charged with preventing this catastrophic loss of pressure. With a combination of pipeline capacity, local LDC-owned and operated LNG satellite storage facilities and vaporization capability at large regional LNG terminals, New England's LDCs have a portfolio of resources and contracts to ensure that this does not occur. LDCs use all of these sources of natural gas supply to meet their deliverability requirements, maintaining adequate pressure throughout the system at all times. LDCs plan years in advance to ensure that when their customers turn on their furnaces, stoves, water heaters and factories, the gas – the deliverability - will be there to meet the pressure requirements. LNG and propane resources are essential to this process, since it would be extremely uneconomic for an LDC to meet peak demand with year-round pipeline capacity. We discuss these economic dynamics in section 3.1.

In New England, the long term contractual owners of pipeline capacity are predominantly LDCs. These LDCs are not owners of the pipeline itself, rather owners of the rights to use the capacity *within* the pipeline. Those rights give the LDCs the ability to later purchase, and have delivered, a certain amount of gas per day and within the day, each hour, as needed.

While power plants are also large users of natural gas, they typically don't contract for pipeline capacity. Since there is no regulatory or market rule that power plants must have firm fuel supply, power plants generally rely on excess capacity available when LDCs don't need it to serve their own firm load.[1] This excess capacity is traded on the secondary market, comprised of "capacity release" (release of unused capacity rights) or LDC "off-system" sales.

While pipeline capacity, or the quantity of gas potentially available to a customer from a certain pipeline, is the component that gets the most attention (a fact underlying the large infrastructure solution being advanced by many policymakers), pipeline capacity is only one piece of the entire puzzle that is overall system deliverability. With distribution obligations across wide geographic areas, LDCs cannot rely on pipelines alone. Since any pipeline or proposed additional capacity can only deliver gas to a single location, it can still fail to meet an LDC's deliverability needs if the LDC's loads are in a location far from the LDC's pipeline off-take station or "citygate." Numerous satellite LNG facilities are scattered throughout New England comprising 16.3 Bcf of the total native LDC LNG storage that have historically been used[2] to meet needle peak demands on the LDC's local delivery systems through pressure maintenance and by increasing gas deliverability to, or on, the LDCs' systems.

Skipping Stone has performed quantitative analyses, contained in Appendix A to this paper, indicating that LDC demand during the spring, summer and fall—and for much of the winter—is easily handled by existing infrastructure. Indeed, the peaking on-system LNG resources owned by the LDCs are being used at only 20% of their total storage capacity. This confirms that the problem to be solved is a deliverability and associated supply inventory problem isolated to certain days during the period between December 15 and March 15 ("Deep Winter"). Importantly, our analysis indicates that the combination of existing pipeline and native LNG deliverability exceeds existing LDC sendout on the highest peak days by nearly 10% (see Chart 16 on page A9 of Appendix A).

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[1] There are market rules administered by ISO-New England intended to incentivize or penalize generators for their actual performance during periods of high demand, but unlike the requirements discussed in this paper with respect to LDCs, there are is no requirement that electric generators have guaranteed "firm fuel."

[2] Another reason is New England geology. Unlike the Appalachian producing region to the west with its depleted gas production fields that can be converted to storage fields, or the Midwest with its large aquifers which lend themselves in many cases to water driven gas storage fields, New England has neither of these geological attributes. As a result, natural gas must be liquefied and stored in above-ground tanks, rather than being stored underground as a gas.

The following charts reflect that, under current demand forecasts and in the absence of a deliverability solution, New England can generally expect deliverability shortfalls during the Deep Winter period in the near- to mid-term future (2020 through 2030) with its current pipeline capacity.[3]

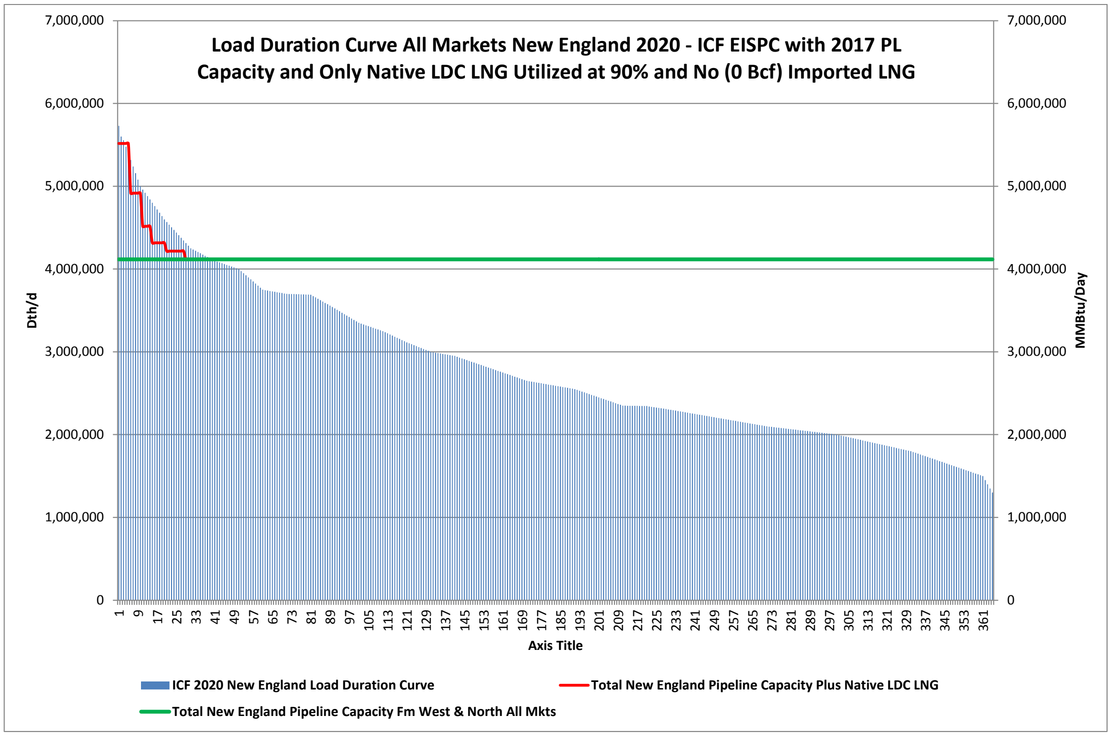

Chart 1: Deep Winter Demand and Supply Shortfall for 2020
Sources: ICF Study, Skipping Stone

[3] For full supporting analysis, see Appendix A. The Demand Duration curve is from the ICF-EISPC/NARUC Study on Long-term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection, September 2014 ("ICF Study"). New England 2017 capacity inventory includes all 2015 existing capacity, plus Spectra's AIM expansion and the Tennessee CT expansion. Skipping Stone modeled native LDC LNG inventory starting at full capacity, but using no more than 90% of that inventory. For purposes of Charts 1 and 2, Skipping Stone did not include any ship-borne LNG, did not increase native LDC LNG inventory by any amount of winter refill from truck-borne LNG loaded at on-shore LNG import terminals despite the fact that most LDCs have some amount of winter refill from truck-borne deliveries. In addition, Skipping Stone eliminated propane deliverability as constrained by propane and storage so as to only consider available sources of natural gas. While LDC propane deliverability is and will most likely remain additive, we excluded it for the purposes of developing a solution to the New England gas problem because of restrictions regarding propane and natural gas mixing ratios and because New England has a relatively low total propane storage inventory capacity.

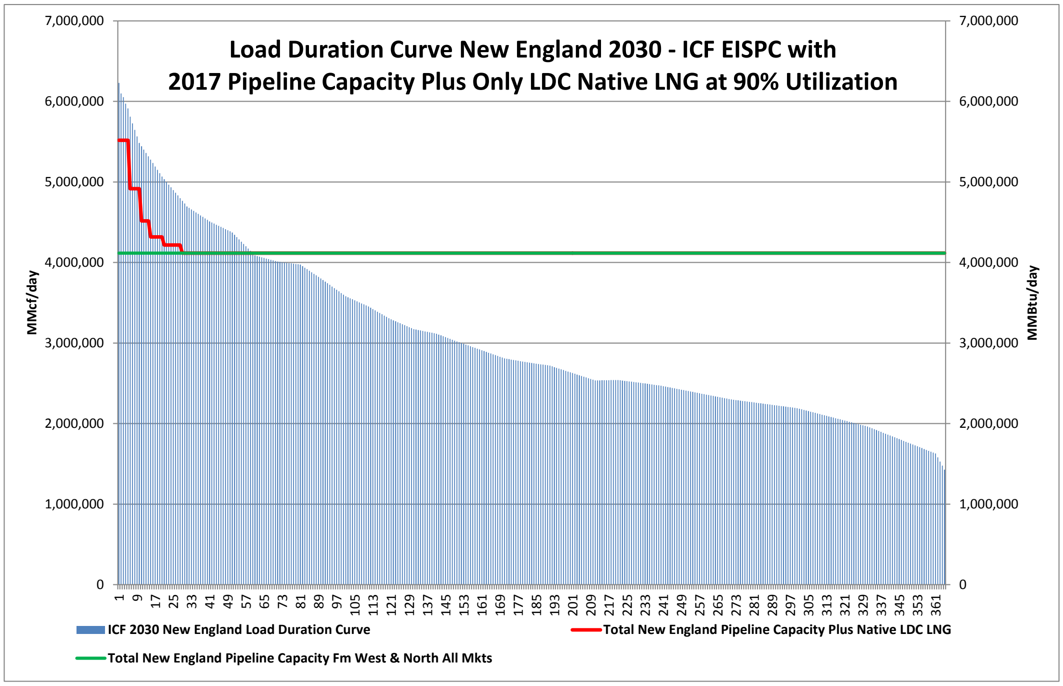

Chart 2: Deep Winter Demand and Supply Shortfall for 2030
Sources: ICF Study, Skipping Stone

As can be seen above and is substantiated in Appendix A, the 2020 and 2030 Deep Winter demand from all markets in New England will exceed 2017 pipeline capacity plus New England native LDC LNG "sendout," that is, the quantity of LNG that LDCs deliver from storage to meet their system load, as provided by the current 16.3 Bcf of New England native LDC storage. The above depictions use 90% of that native LDC storage, or 14.6 Bcf over the Deep Winter period. While this analysis indicates that additional natural gas deliverability will be required in New England for 2020 and 2030, it also reveals that expected shortfalls well into the future will be an issue of peak demand, rather than year-round pipeline capacity.

3. The Large Pipeline Option

There are two principal schools of thought regarding the solution to New England's Deep Winter natural gas deliverability problem: 1) build more pipeline capacity, or 2) increase utilization of existing infrastructure, primarily LNG capacity.

3.1 Pipeline Capacity Economics and Accurate Accounting of Pipeline Capacity Cost

The most important fact to remember about New England's gas problem is that it is a Deep Winter, peak demand deliverability problem, not a year-round capacity crisis. In light of this fact, building more pipelines to provide a year-round supply of gas—whether it is needed or not— is simply not a cost-effective solution.

New pipeline capacity can be cost-effective when used to meet new, year-round demand; however, in New England the highest day of modeled demand each year for all LDCs can be as much as three times that of the average day. Building 365-day pipeline capacity to meet a peak of that magnitude means massive unused capacity for the other 364 days of the year. As is shown in Charts 3 and 4 below, if New England's existing pipelines were designed to meet the total deliverability needed for only one peak day (or more likely for a few hours that day) each year, the recovery of the huge investment in building that infrastructure would make normal natural gas service to businesses and residences fundamentally uneconomic.[4]

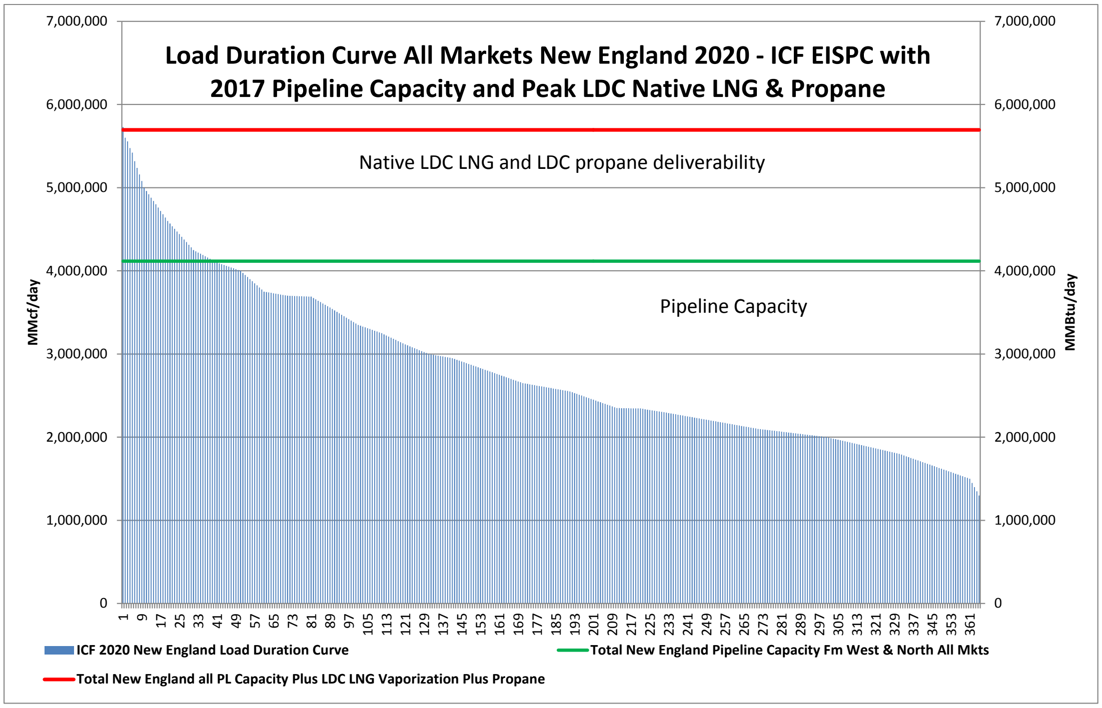

Chart 3: New England Pipeline Capacity plus LDC LNG and Propane Deliverability Overlay for 2020
Sources: ICF Study, Skipping Stone

[4] This is due to the fact that a very large proportion of the pipeline capacity needed only during the peak day, or peak hour, would remain idle the remainder of the year, and those costs would have to be recovered in LDC rates designed largely by spreading fixed costs over average total annual LDC throughput. See Appendix A for further discussion and analysis underpinning Charts 3 and 4.

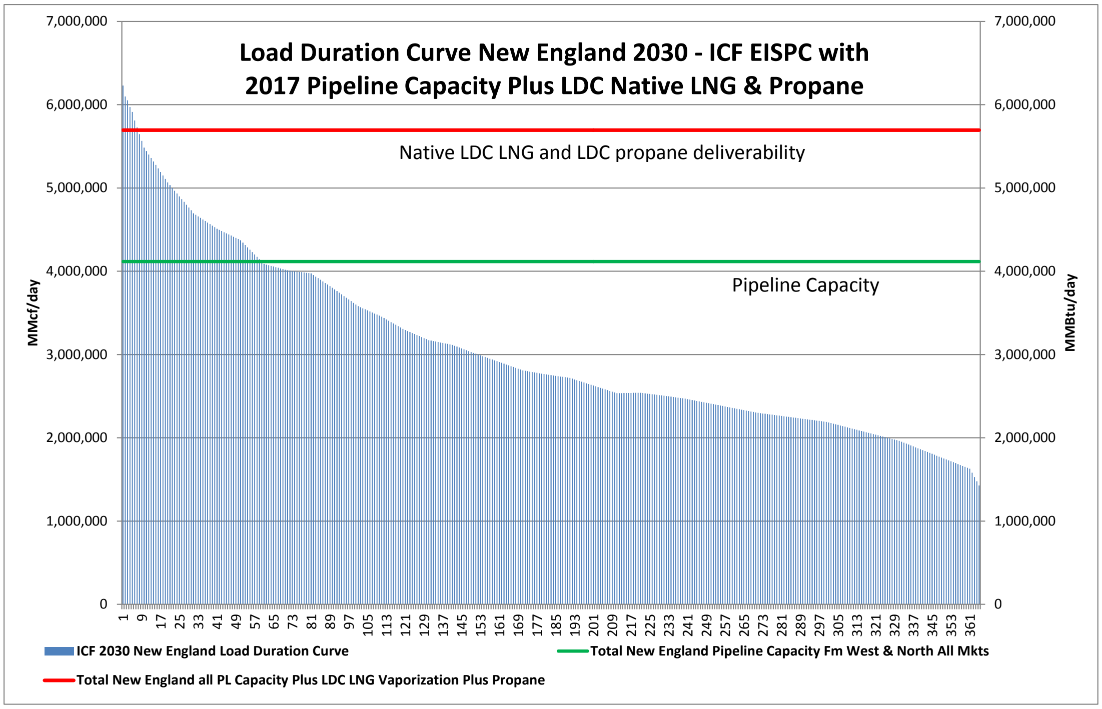

Chart 4: New England Pipeline Capacity plus LDC LNG and Propane Deliverability Overlay for 2030
Sources: ICF Study, Skipping Stone

The same principle applies to a large new pipeline project designed to meet New England's 50-day Deep Winter demand peak. As the following Chart 5 and the associated analysis in Appendix B demonstrate, one 800,000 decatherm per day (Dth/d), equivalent to 0.8 billion cubic feet per day (Bcf/d),[5] pipeline project added to New England's existing system of pipeline plus LDC LNG and propane sources would significantly exceed the region's demand even on the highest 2030 modeled day of the year.[6]

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[5] A dekatherm is a measure of the heat energy, equivalent to 1,000,000 BTUs, or the energy contained in about 1,000 cubic-feet of natural gas.

[6] The Access Northeast Project and Tennessee Gas's Northeast Direct Project each would exceed this size as currently proposed.

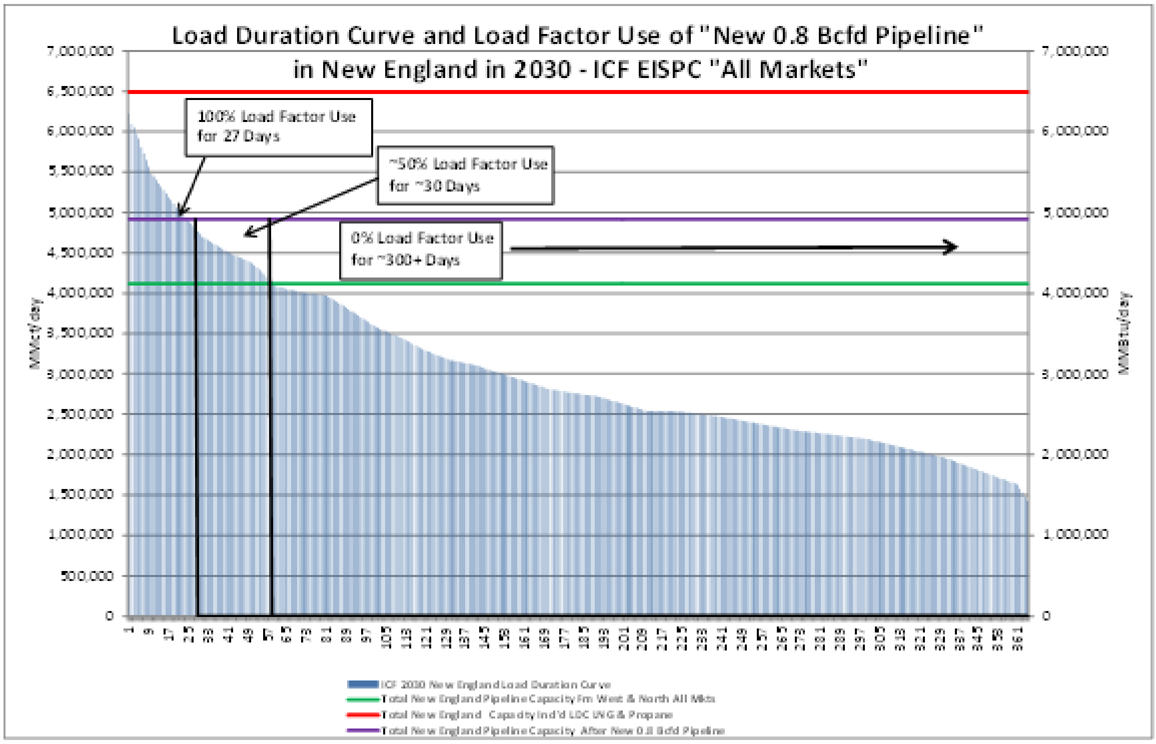

Chart 5: 2030 Load Duration Curve and Load Factor Use of New Pipeline
Sources: ICF Study, Skipping Stone

In order to further understand the costs of permanent, 365-day pipeline capacity built to meet peak day demand, one needs to understand how a pipeline's tariffs define its service obligations and cost recovery through the rates it charges.

Normally, when a utility buys a certain quantity of pipeline capacity for a day, it purchases the right to receive 1/24th of that daily quantity each hour. For example, if a utility needs 1,000 decatherms (or 1 million cubic feet of natural gas) for an hour starting at 7 AM on its highest demand day, it is required to contract for 24,000 Dth on that day in order to ensure that its *one* hourly take of 1,000 Dth is met. Thus, if a utility's peak hour was 1,000 Dth per hour for 5 hours on 10 winter days each year, but its total peak *day* demand for those same 10 days was only 18,000 Dth over each 24-hour period, existing pipeline tariffs would (and in fact do) require the utility to oversubscribe capacity on a daily basis by 133%[7] on those 10 days, which results in an even larger oversubscription the other 355 days a year, when its peak hour might require delivery of 600 Dth and its daily sendout might be 10,000 Dth or less.

Simply put, when you buy pipeline capacity, you buy a daily amount of service for every day of the year over a long, multi-year period.[8]

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[7] 24,000 is 133% of 18,000.

[8] Pipelines could in theory sell services for shorter terms, but in order to get regulatory approval of expansions, and in order to finance such expansions, the terms of pipeline capacity agreements are normally for annual daily capacity over 20 or more years.

3.2 The Amount of Gas Capacity Utilized on the New Pipeline Determines How Much the Pipeline Costs to Ratepayers

Such oversubscription of pipeline capacity to meet short periods of peak demand is hugely expensive. For example, if incremental pipeline capacity costs $1.50 per Dth/d on a year-round use basis, using it for one day would translate into a fixed charge of $547.50 per Dth[9] for that one day's use. However, if you need that 1 Dth only for an hour on that one day, you have to subscribe to 24 Dth/d raising the cost for that one hour of need *24 times* to $13,140—an astonishingly high price to provide enough gas to meet that 1 Dth of demand. That is why New England, which has long experienced very high "needle peak" demands in the winter, has for more than 60 years chosen to meet those needle peaks with LNG vaporization.

If we assume that the economics of base-load pipeline capacity expansions into New England are on the order of the $1.50 per Dth per day[10] quoted above, that equates to approximately $11.00/Dth/day[11] for 100% load factor use to cover the 50 days of Deep Winter for which the service is actually needed. The cost would be approximately $7.30/Dth/day for 100% load factor use if the need were for 75 days of capacity service—and that's before the cost of the gas itself has been factored in.[12]

Even these numbers are extremely conservative, since they assume *100% use* of the new capacity across those 50 or 75 days. That is not, in fact, how incremental pipeline capacity is utilized. Our analysis shows that across the 50 and 75 days of highest load, the load factors would be closer to the 30 - 50% range (or lower) depending on the magnitude of the incremental capacity addition. The larger the capacity addition, the lower the load factor of use across the 50 or 75 days of highest total demand.

Examining typical LDC load curves (i.e., the duration of load across the 50 highest demand days) shows us that, by making the reasonable assumption that existing (already purchased and interconnected) pipeline capacity would be utilized first, the incremental capacity would be used at far lower load factors than 100% across the 50 or 75 highest demand days.[13]

For the purpose of this examination, a 50% load factor of use for a 50-day need costing $11.00 per Dth-day at 100% load factor would translate into a cost of $22.00 per Dth actually used—before adding in gas cost. Likewise, a 30% load factor use of a 75-day need costing $7.30 per Dth-day translates into a cost of $24.33 per Dth actually used—again, before adding in the cost of gas.

Once the cost of gas (an assumed $4.00 for winter gas) is added to the fixed costs associated with those optimistic 50% and 30% load factors, the total delivered cost of service per Dth for those 50 to 75 days

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[9] $1.50 per Dth/d x 365 days/year = $547.50. This is before adding the cost of the Dth of gas moved through that Dth/d of capacity.

[10] This is a valid assumption for planning purposes, derived from: 1) ICF-EISPC/NARUC Study on Long-term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection; September 2014; 2) mid-range of estimated cost range for pipeline capacity from the Maine Public Utilities Commission Review of Natural Gas Capacity Options, February, 26, 2014 from Sussex Economic Advisors; and, 3) Skipping Stone's own knowledge of, and experience with, pipeline construction economics.

[11] $1.50 per Dth/d *365 days/year = $547.50/ year fixed cost; then $574.50 ÷ the 50 days of use = $10.95/Dth/d effective cost across the days used, assuming 100% load factor of use across those 50 days.

[12] $1.50 per Dth/d *365 days/year = $547.50/year fixed cost; then $574.50 ÷ the 75 days of use = $7.30/ Dth/d effective cost across the days used, assuming 100% load factor of use across those 75 days.

[13] For example, over the 50 days of some use, the new capacity (depending on its magnitude) might be 100% used for 10 days in total, and 50% used across another 20 days in total, and 25% use over the remaining 20 days. Therefore its overall use across the 50 days would be the same as 24 days use at 100% (because 50% use over 20 days is the same as 100% use over 10 days and 25% use over 20 days is the same as 100% use over 4 days.) All of which means that the annual load factor (24days@100% and 341 days@0%) is far less than 10%.

ranges from $26.00 to $29.00 per Dth. If we assume a more realistic 10% load factor for 75-day service costing $7.30 Dth/d, the effective cost per Dth delivered for use rises dramatically to $77.00 per Dth.

3.3 The Economics of a "Big New Pipeline" From an Electric Generator's Point of View

The primary discussion around pipeline economics should be centered on the impact it will have on an LDC's ratepayers, because they are the ones who will pay for any pipeline expansions. It is important to also consider the economics of a new pipeline for natural gas-fired electric power plants, since the inability of electric generation to access gas during winter peak can result in sharp needle peaks, as experienced during the "Polar Vortex" winter of 2013/2014.

But for similar reasons, adding new pipeline capacity is inefficient to address the winter needs of power generators. Natural gas-fired power plants providing base-load service year-round can be expected to operate at a load factor of between about 46% and 65%.[14]

In the somewhat optimistic 46% annual load factor power plant example, the fixed cost of pipeline capacity would be nearly $25.00 per MWh produced (assuming the $1.50/Dth/d new pipeline build reservation rate). Adding in the previously used $4.00 cost of gas and assuming a 7,500 Btu/kw heat rate, the cost per MWh delivered to the grid would be nearly $55.00 before recovery of generator capital and operating costs. Note that this $55.00 per MWh price is more than twice that recently reported by ISO-NE for the Spring and early Summer of 2015.[15]

The numbers are even worse for natural gas-fired "peaker plants"[16] which operate, optimistically, only about 10% of the year. For these plants, the per MWh produced cost (with the same pipeline and gas cost economics) would be nearly $265.00/MWh —again before recovery of generator capital and operating costs.

In summary, the economics of a new pipeline make no more sense for a New England gas-fired electric generator operating in the current market than it would for LDC customers.

3.4 Common Assumptions as to the Effect of a New Pipeline on Gas Prices Are Overstated

There are those that suggest that a "new pipeline" will access new supplies – new supplies that will lower the national and regional cost of all gas four or more years from now – when such new pipeline would be in service. This assumes, however, that the gas market four years from now will be the same as it is today. While a full analysis is beyond the scope of this paper, a quick review of what is going to transpire over those intervening years tells us that this assumption is faulty. Even if a big new pipeline were built to New England, the supplies to which it would connect will have other, alternative markets to which they can and may flow. Among those markets are Chicago, Ontario, the mid-Atlantic, the Gulf Coast, Florida and international LNG markets.[17]

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[14] For example, if a power plant were to operate 16 hours a day, 7 days a week, for 20 years (excluding two weeks per year for maintenance down time), its load factor would only slightly exceed 64%, while the same plant operating 16 hours a day for the 5 weekdays per week (not running on weekends and again excluding two weeks per year for maintenance down time) would fall slightly short of a 46% load factor.

[15] http://isonewswire.com/updates/2015/8/11/wholesale-electricity-prices-and-demand-in-new-england-july.html
As a further, note - even if gas cost was only $2.00 per Dth delivered, the all in cost per MWH would still be nearly $40.00/MWH before recovery of generator capital and operating costs. And, as discussed above, in Skipping Stone's opinion such $2.00 gas prices will not persist once all pipeline reversals are complete.

[16] Assuming a 10,000 Btu/kw heat rate.

[17] Chicago is where much of the Rockies Express 1,200,000 Dth/d reversal will bring gas, Ontario is where the NEXUS or the ET Rover lines (each greater than 1,000,000 Dth/d) will go, the US Gulf Coast (including LNG export) is where another 3,000,000 to

Every single pipeline today that has Marcellus /Utica gas supplies attached to it is undertaking low-cost, quick-to-implement, supply-push, flow reversals to take the excess supplies that are currently dampening prices to the markets cited above. Once those reversals occur and the supply is unstranded, prices will no longer be dampened and those supplies will go to the highest priced market.

In addition to flow reversals, other pipelines are in the process of permitting and constructing lines to new unserved areas of the country. The effect of all this activity, in our opinion, will be that instead of the prolific supplies being priced below the Henry Hub (the national pricing point on which all other prices are based), supplies in the Marcellus/Utica will be priced the same as the Henry Hub.[18]

In light of all of this activity to release suppressed Marcellus/Utica supply to other regions of the country why is it that supply-push pipelines have not already 'pushed' to New England?"

The answer is simple – a very high cost of use driven by load factor. Pipeline operators are aware of New England's low load factor and that the region only needs the extra capacity some 50 days a year. As a result, producers do not see the economics of a New England supply-push pipeline working for them. Producers evaluate pipeline projects from a cost-of-use perspective, and the cost to support a year-round project to meet a highly seasonal demand is not a "good bet" for those with other, better alternatives.

4. Rethinking the Problem: The Winter-Only LNG "Pipeline" Solution

Given these stark economics, it is essential that regulators and policymakers consider and compare alternative paths to meeting this short duration Deep Winter peak demand. Essential to this inquiry is a comparison of the pipeline and any alternatives on an "all-in delivered cost of gas used" basis rather than just a "pipeline capacity coverage at all costs" basis. This gas-used basis is the most intellectually consistent comparison from the ratepayers' perspective – and they are the ones who will be saddled with the sunk cost of overbuilt pipeline capacity.

4.1 LNG Can Solve Peak Winter Demand: Quickly, Reliably and Cost Effectively

Our analysis demonstrates that, on an "all-in delivered cost of gas used basis," increased use and better management of New England's existing LNG supply, storage, and delivery infrastructure would be the most readily available, reliable and most cost-effective solution to the region's Deep Winter deliverability problem.

4.1.1 New England Has Adequate LNG Capacity to Meet Winter Peak Deliverability Needs

Our focus in this subsection is the fact that one must have a sufficient supply of LNG to have sufficient associated deliverability.

Investigation has shown that New England has adequate existing LNG vaporization capacity to meet the region's winter peak deliverability needs. Overall, the area has nearly 3 Bcf/d (approximately 3,000,000 Dth/d or 3.0 MMDth/d) of vaporized LNG deliverability, much of which is not fully contracted or utilized at

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6,000,000 Dth/d of capacity on Tennessee, Texas Eastern, Columbia Gulf, and Texas Gas is headed; and, the mid-Atlantic and Florida are where another 3,000,000 to 5,000,000 Dth/d and where Transco's reversal, Spectra's Sabal Trail, Dominion's Atlantic Coast, and EQT's Mountain Valley Pipeline are all headed.

[18] Prices will likely be priced at Henry Hub levels less the variable cost of pipeline fuel (1 to 2%) and usage rates (usually less than 1 cent per Dth) given the elimination of current bottlenecks which cause producers to lower (depress) their prices in order to be selected by shippers controlling capacity to transport gas to markets.

present.[19] That deliverability comes not only from New England's large-scale LNG import capacity, but also from its LDCs own native LNG storage facilities across the region. These facilities were, and to a large extent still are, needed to meet the needle peak demands regularly experienced on LDC local delivery systems both through pressure maintenance at locations far from an LDC's take-station and for increasing deliverability when needed.

One of the many advantages of LNG vaporization in this respect is its "tailored deliverability"—it can be run as needed for either very short or for extended periods of time. Additionally, if more deliverability is needed, vaporizers can be added to the system at relatively low cost in order to provide more hourly and, if needed, daily deliverability.[20] LDCs in New England have historically used their access to stored LNG to meet normal load growth until such time as that growth, in the aggregate, led to increased demand of sufficient *annual* duration to make incremental pipeline capacity additions economically sensible. But that is not, and has never been, the case for New England winter demand. The needle peak winter demand for all LDCs in New England over at least the past 50 years has always exceeded regional supply pipeline capacity. Nevertheless, LDCs have cost-effectively "kept the heat on" each winter by managing their total pipeline plus their LNG supply inventory. This would imply that an LDC's inability to meet peak winter demand should trigger questions regarding the need for better, more prudent resource planning, rather than an assumption that additional pipeline capacity must be required.

4.1.2 Creating a Winter-Only LNG "Pipeline"

LNG deliverability is typically husbanded by LDCs and is not utilized as flexibly, efficiently or effectively today as is technically and economically possible. In order to serve the interests of ratepayers, the LDC's valuable LNG infrastructure (developed at the expense of ratepayers) could be used in conjunction with existing LNG import and vaporization facilities which can refill LDC satellite storage to essentially base-load this otherwise squandered set of capacity assets.

Such repurposing of existing assets would create a winter-only "pipeline" for LDCs (the New England Winter-Only LNG Pipeline) to ensure that the gas system as a whole has the capability to serve other demand (such as electric generation demand) via existing pipeline capacity that would be freed up by the combination of terminal LNG gasification and truck deliveries to existing native LDC LNG storage facilities.

Given the Deep Winter deliverability problem and an analytic view of its magnitude and duration, Skipping Stone studied how to optimize the use of existing pipeline capacity and existing on-system LNG storage and vaporization, as well as how to make better use of existing on-shore LNG terminal storage and vaporization, existing trucking capacity from on-shore terminals, and existing off-shore ship-borne storage and vaporization capability. The resulting analysis follows and shows that existing LNG infrastructure can be used to meet LDCs' firm heating demands on peak days while maintaining reasonable volumes of excess supply available for sale on the secondary market to natural gas electric generators and other spot market consumers.

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[19] The source of New England LNG is imported LNG vaporized into the New England pipeline and distribution systems from two onshore Import Terminals (Distrigas owned by GDF Suez in Everett MA, and Canaport, owned by Repsol in St. Johns, New Brunswick) each with storage and gasification units and two off-shore receiving locations (Neptune, owned by GDF Suez; and, Northeast Gateway, owned by Excelerate) at which special tankers equipped with gasification units can gasify at the anchorage and deliver their natural gas into pipeline facilities serving New England load centers.

[20] Vaporizers are typically coils or loops of pipes running submerged through water baths that are heated to turn the liquid natural gas back into vapor. Addition of vaporizers requires adequate storage availability.

4.1.3 Ensuring a Reliable LNG Supply

In Charts 6 and 7, Skipping Stone shows that by advance contracting, planning and implementation, where cargoes of imported LNG are scheduled together with LDC sendout and with planned winter refills of LDCs' native LNG storage, New England LDCs can both meet their firm heating demands and have excess Deep Winter supply (or excess capacity) available for sale to those markets in New England that do not have firm year round pipeline capacity, such as gas-fired electric generators.

The 2020 All Market Load Duration Curve chart below includes pipeline capacity as it will exist in 2017 and the LDC LNG sendout and storage capacity that exists today, with the addition of vaporized imported LNG and a nominal amount of winter refill so as to maintain inventory for post Deep Winter needle peaks.[21]

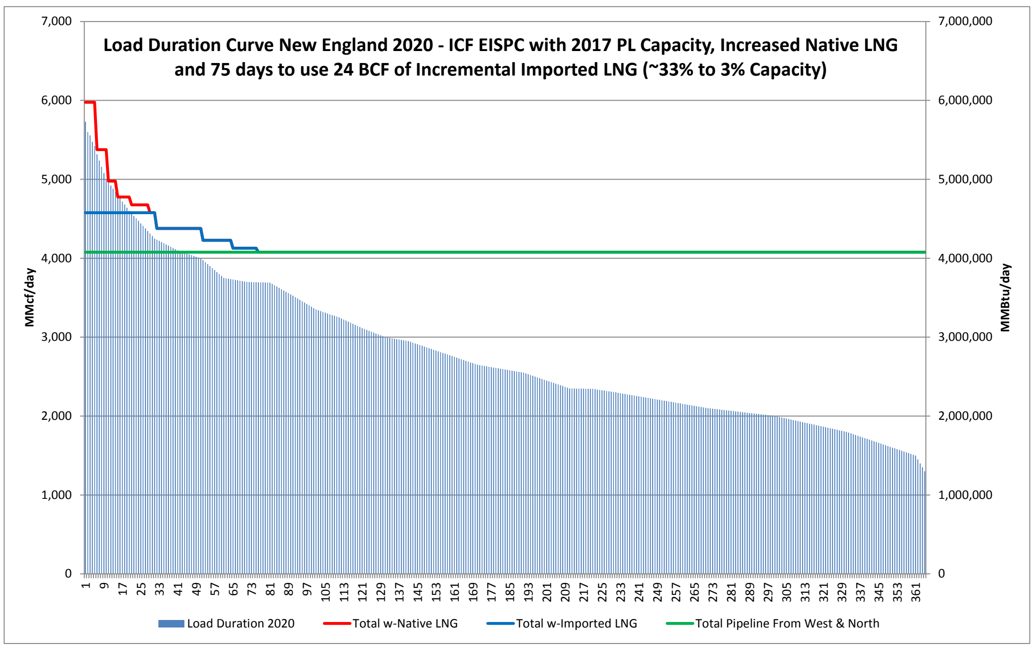

Chart 6: Load Duration Curve New England 2020 75 Peak Days Demand with LNG Overlay
Sources: ICF Study, Skipping Stone

Chart 6 shows that with the addition of approximately eight cargoes of LNG in total over the 90 day Deep Winter period (during which time LNG would be vaporized to meet the 75 highest days of demand) the entire Deep Winter peak demand period can be supplied with some excess capacity to spare.[22] This excess capacity would enable LDCs to release or sell pipeline capacity into the secondary market, supplying natural gas generators and reducing the peak wholesale gas and electric market prices in the New England region and potentially in other regions.[23]

[21] Note that Skipping Stone's analysis here does not include existing propane storage or deliverability which would be additive.

[22] This is the area between the blue line (imported LNG supply and deliverability) and the green line (2017 pipeline capacity). Eight cargoes is ~24,000,000 Dth or ~24 Bcf of vaporized natural gas.

[23] This version of a 2020 New England Winter-Only LNG "Pipeline" scenario excludes truck-borne and concomitant satellite LNG vaporization increases which could be used to further fine tune the 2020 solution set.

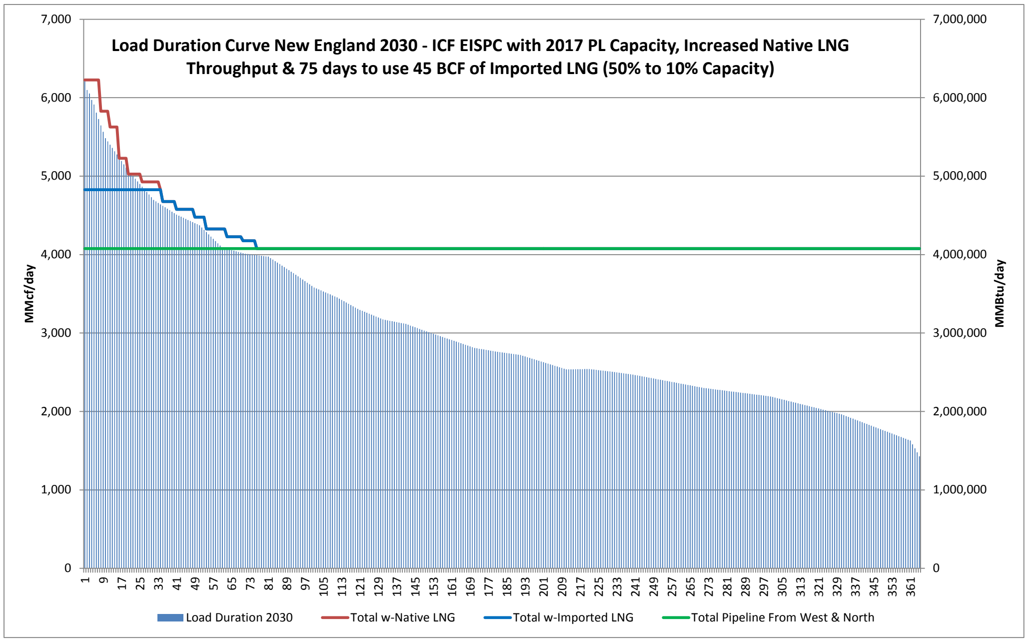

Chart 7: Load Duration Curve New England 2030 75 Peak Days Demand with LNG Overlay
Sources: ICF Study, Skipping Stone

It is important to note that the demand for gas depicted in Charts 6 and 7 reflects a conservative estimate that does not take into account the potential acceleration of renewable energy deployment to meet peak Deep Winter electric power generation needs. Even under this conservative scenario with high demand for natural gas during the Deep Winter peak periods, fifteen cargoes of LNG delivered to Massachusetts' on-shore and off-shore terminals and the Canadian Maritimes' on-shore terminals over the 90 day Deep Winter period would address the forecasted deliverability shortfall in 2030.[24] Planning to meet the same peak deliverability with new pipeline capacity would be wildly uneconomic for New England gas customers, resulting in massive amounts of unused pipeline capacity year-round as discussed in Section 3.1.

In Chart 7, the 2030 New England Winter-Only LNG Pipeline scenario increases throughput by native LDC LNG storage facilities by 6 Bcf over the course of the Deep Winter. This is accomplished by trucking from the on-shore LNG terminal in Everett to the native LDC LNG storage facilities. Several of these storage facilities have multiple truck receiving bays and are rated for up to 40 trucks per day each. National Grid alone is rated for a maximum of 180 trucks per day to its many LNG storage facilities—an amount in excess of the Everett terminal's maximum truck-loading capability.[25] The enhanced native LDC LNG throughput over the 90 days of Deep Winter would entail 6,000 trucks in total.

Given the risk of inclement weather in a New England winter, those deliveries would be scheduled once satellite facilities had drawn down inventory to make room and then could realistically run at the rate of

[24] This is represented by the area between the blue line and the green line; fifteen cargoes at ~ 3Bcf each equal approximately 45 Bcf.

[25] Everett is rated at 100 trucks per day loading capacity and informed Skipping Stone that with procedure modifications could ramp up to as many as 120 trucks per day with no facility modifications. The operator of the facility also notes that it can simultaneously load trucks, vaporize and unload from ships with no impairment of its deliverability to any of its off-takers Algonquin, Tennessee, the Mystic River Power Plant, or National Grid, the LDC whose system is directly connected to the Everett facility.

between 75 and 80 trucks per day during good weather days. While 6,000 trucks over a 90 day period would amount to a per-day loading of approximately 66 trucks per day, when the additional days to ensure driving in better weather conditions are included, it would likely entail moving 75 to 80 trucks per day.[26] This level of truck movement would be in addition to some percentage of the current winter-fill shipments of approximately 1,000 -1,200 trucks per winter.[27] Truck delivery is an enhancement in that it keeps LNG storage inventories at LDC satellite locations at levels sufficient to meet post Deep Winter needle peaks of demand while also meeting Deep Winter demand with vaporization. Alternatively, the enhanced LDC vaporization could be replaced by terminal or floating vaporization instead of truck-delivery from an on-shore terminal.

The LNG business is a logistics business. The most important logistics include coordinated scheduling of ships, pier-side delivery, vaporization and other off-take (such as by truck) to ensure that there is space in storage tanks to receive the cargo of large, ocean-going LNG import ships. Additional logistics for off-shore buoys include having the tankers with on-board vaporization lined up in advance. Fortunately, these logistics are well-known and predictable.

> **Liquefaction**: Putting the proposed 2020 level of LNG delivery from the New England Winter LNG "Pipeline" detailed in Appendix C in perspective against existing and future LNG liquefaction capacity is instructive. By 2020 the U.S. alone will have 9 Bcf/d of liquefaction capacity operating, assuming all currently fully permitted and under construction terminals come online. The 2020 proposal is for 24 Bcf over the 90 day period; 24 Bcf is less than 3 days of U.S. production. In 2030, assuming the same 9 Bcf/d of U.S. production capacity is that which ultimately gets built, the proposed 45 Bcf of New England LNG Winter Pipeline utilizes just 5 days of U.S. production (less than 2% of annual U.S. productive capacity).
>
> **Shipping**: There were 387 LNG Ships active globally at the end of 2013 with another 114 on order, bringing the likely 2020 roster of ships to over 500. New England would need to contract for less than 3% of the ship fleet at peak in 2030 to deliver the required LNG across a time period of less than 25% of the year. Moreover, at the discharge rate anticipated for 2030, each ship would spend on average only 3-5 days in port demurrage or discharging their cargoes.
>
> **Trucking:** With respect to truck delivery economics, for a typical cost of from $0.01 to $0.02 per Dth per truck-mile, round trip,[28] an LDC could move into a mode of continuous vaporization (at far below peak levels) from their facilities. [29] In doing so, the LDC could increase the amount of pipeline capacity freed-up by an amount equivalent to nearly 1,000 Dth/d per truck scheduled per day; all the while maintaining sufficient inventory for the coldest day(s).

[26] This would have the terminal operating at between 66% and 75% of truck loading capacity.
[27] Even if all 1,200 current "winter truck loads" were in the Deep Winter's 90 days, adding 6,000 trucks to that level only brings the total to 7,200 over 90 days or 80 trucks per day on average; an amount still only 60% to 80% of the Everett facility's capability.
[28] Note that this estimated cost per Dth/round-trip truck-mile. is likely with advance, as opposed to emergency, scheduling.
[29] Alternatively, because vaporization is highly flexible, the example of 1,000 Dth/d vaporization could be timed to provide a generator with non-ratable hourly gas to meet fast ramp sub-day demands for gas from load following gas generators.

4.2 The Economics of a Winter-Only LNG "Pipeline" vs. a Large New Pipeline

The bedrock concept of the New England Winter LNG "Pipeline" is to treat, for economic and rate purposes, the offloading, vaporization and truck borne off-takes of LNG in a manner similar to a baseload pipeline — namely, as a fixed cost. By implementing advance planning, regardless of the severity of winter weather, the New England Winter LNG "Pipeline" supplements existing capacity during the coldest weather or frees up capacity for use in other markets during less cold weather. In either event, it is intended to act as an alternative to what would otherwise be an underutilized, very expensive year-round pipeline.

4.2.1 A Real World Cost Comparison

A comparison between a large new gas pipeline and the New England Winter LNG "Pipeline" highlights the differences and advantages of the LNG solution. Our real world example involves an LDC that has entered into a precedent agreement to purchase 160,000 Dth/d of capacity at rates consistent with the indicative rates discussed above on a new interstate pipeline that we will assume has a minimum capacity of 800,000 Dth/d. For purposes of comparison, the LDC *could* contract for just 50 days' worth of 160,000 Dth per day LNG. While the former would cost over $87 Million per year in fixed cost *exclusive* of gas cost, the latter (the cargo of about 2.66 LNG delivery ships), would cost approximately $77 Million, *inclusive* of gas cost[30] and would free-up 160,000 Dth/day pipeline capacity for other uses. Alternatively, the LDC could arrange to vary its takes from a minimum to a maximum over the 90 day Deep Winter period (provided of course that they take the full volume both to make room for ship arrivals and in aggregate over the 90 days) and free up the commensurate amount of pipeline capacity as their takes enable.[31]

In order to facilitate this solution, we recommend that regulators permit LDCs to treat the difference between the landed cost of LNG and the cost of pipeline gas (i.e., $9.59 LNG on average over the 5 year period versus the assumed approximately $3.60 winter-time average pipeline gas price over the same period) the same way they treat pipeline capacity payments: that is, as a fixed cost for accounting purposes.[32]

This accounting treatment would permit "pricing" of the extra LNG above native load requirements at the same level as pipeline gas, which would enable the LDC to sell that gas at a profit to winter buyers such as electric generators who lack pipeline capacity but who need winter gas, thereby further reducing the cost of the total arrangement to ratepayers.[33] The savings from avoided demand charges, without any additional contribution from secondary market sales of the extra gas by LDCs, would be nearly $23 Million per year. Scaling this annual savings for a 160,000 Dth/d portion of an 800,000 Dth/d pipeline up to the full

---

[30] Assumes average landed LNG cost (inclusive of terminal margin) of $9.59/Dth over the first 5 years times the 8 Bcf of supply which equals approximately $76.7 Million per year on average.

[31] Because the gasified LNG comes into the system at the far eastern end of the natural gas system, capacity otherwise needed from the south and west to serve the far eastern end is "freed-up" enabling the pipeline capacity that would have been used to bring gas all the way to the east to be utilized by others both in the east and further west. In its simplest terms, if there is demand for 4 Bcf/d and capacity from the west is 3 Bcf/d, adding 1 Bcf/d into the system at the far eastern end enables the 3 Bcf/d of west to east capacity to serve the remaining 3 Bcf/d of market not served by the 1 Bcf/d (east to west capacity) coming in at the far eastern end of the system.

[32] The economic analysis detailed in Appendix C indicates that the landed price of LNG under this strategy would be in the $9.00-$10.00/Dth range. The LNG cost would include terminal profit.

[33] For example, the difference between the 8.0 MMDth of LNG commitment and the approximately 3.0 MMDth amount of pipeline gas which is actually needed -- the 160,000 Dth per day of pipeline capacity times 50 days use times the approximately 40% overall load factor use across those 50 days -- or the approximately 5.0 MMDth of "extra gas."

capacity of the pipeline would be an annual savings of nearly $115 Million per year or approximately $2.3 Billion over the 20-year life of the capacity contracts associated with a new pipeline**.**

In a more refined example of the Winter-Only LNG "Pipeline," in order to meet its near-term needs, the LDC from our example could contract for 60,000 Dth/day of LNG for 50 days (3.0 MMDth in total, or about 1 ships' worth) to be delivered over the 90 day Deep Winter period. Under this more refined arrangement, the economics are even more compelling. Here, the LDC (who would otherwise have to subscribe to a full 160,000 Dth per day year round as their portion of a big pipeline expansion even though they would not need all of that capacity) could contract in advance via the Winter-Only LNG "Pipeline" strategy for multiple years with volumes starting at 60,000 Dth/d, the amount the LDC actually needs in the early years, and then increase that volume as need increases in subsequent years. In the near-term, much like the prior example, the LDC could arrange to schedule its gasification takes from a minimum to a maximum (again provided they take the full volume) and, by doing so, again free up pipeline capacity in the amount of their LNG takes. In this case, the avoided demand/fixed charges are truly significant.

The fixed cost savings to the LDC over the new pipeline approach, using the same methodology as above, would initially be approximately $70 Million per year per LDC—or initially about $350 Million per year across the New England LDCs that would otherwise have subscribed to the 800,000 Dth/d pipeline. In terms of magnitude, if the single 160,000 Dth/d-subscribing LDC had as many as a million customers, that would equate in Year 1 to a fixed cost savings on the order of more than $70 per customer per year. Table 1 sets forth the economic comparisons discussed above over an estimated 20 Year period. Using the more refined 60,000 Dth/d example, the total fixed cost savings would increase from $2.3 Billion over 20 years to as much as $4.4 Billion over the same period.

	A	B	C	D	E	F	G	H
"New Pipeline"	Example Daily Subscribed Capacity	Days of Subscribed Capacity	Total Qty Pipeline Gas Used	Demand/ Fixed Charges ($/Dth/d)	Demand/ Fixed Charges ($/Yr)	Pipeline Winter Gas Cost ($/Dth)	Gas Cost for Gas Actually Used (C* F)	Total Cost of Gas Actually Used (E + F)
Year 1	160,000	365	3,000,000	$1.50	$87,600,000	$3.24	$9,705,750	$97,305,753
Year 2	160,000	365	3,500,000	$1.50	$87,600,000	$3.46	$12,096,875	$99,696,878
Year 3	160,000	365	4,000,000	$1.50	$87,600,000	$3.61	$14,424,000	$102,024,004
Year 4	160,000	365	4,500,000	$1.50	$87,600,000	$3.70	$16,644,375	$104,244,379
Year 5	160,000	365	5,000,000	$1.50	$87,600,000	$3.81	$19,065,000	$106,665,004
Year 6	160,000	365	5,500,000	$1.50	$87,600,000	$3.95	$21,743,838	$109,343,841
Year 7	160,000	365	6,000,000	$1.50	$87,600,000	$4.05	$24,313,564	$111,913,568
Year 8	160,000	365	6,500,000	$1.50	$87,600,000	$4.15	$26,998,186	$114,598,191
Year 9	160,000	365	7,000,000	$1.50	$87,600,000	$4.26	$29,801,844	$117,401,848
Year 10	160,000	365	7,500,000	$1.50	$87,600,000	$4.36	$32,728,811	$120,328,815
Years 11-20	160,000	365	8,000,000	$1.50	$87,600,000	$4.47	$35,783,500	$123,383,505
Late Years	160,000	365	8,000,000	$1.50	$87,600,000	$5.07	$40,568,079	$128,168,084

	I	J	K	L	M	N	O	P
LNG Pipeline	Daily Peak LNG Deliveribility	Days of Peak Deliveribility	Total Qty LNG (I*J)	Average NE Landed LNG Price ($/Dth)	Total LNG Gas Cost (K*L)	LNG Terminal Charge	Total Cost (M+N)	Fixed Cost Treatment (O-G)
Year 1	60,000	50	3,000,000	$8.28	$24,850,820	$3,000,000	$27,850,820	$18,145,070
Year 2	70,000	50	3,500,000	$8.52	$29,803,818	$3,500,000	$33,303,818	$21,206,943
Year 3	80,000	50	4,000,000	$8.63	$34,528,127	$4,000,000	$38,528,127	$24,104,127
Year 4	90,000	50	4,500,000	$8.65	$38,912,576	$4,500,000	$43,412,576	$26,768,201
Year 5	100,000	50	5,000,000	$8.85	$44,256,446	$5,000,000	$49,256,446	$30,191,446
Year 6	110,000	50	5,500,000	$9.07	$49,899,143	$5,500,000	$55,399,143	$33,655,305
Year 7	120,000	50	6,000,000	$9.30	$55,796,314	$6,000,000	$61,796,314	$37,482,751
Year 8	130,000	50	6,500,000	$9.53	$61,957,157	$6,500,000	$68,457,157	$41,458,971
Year 9	140,000	50	7,000,000	$9.77	$68,391,170	$7,000,000	$75,391,170	$45,589,326
Year 10	150,000	50	7,500,000	$10.01	$75,108,160	$7,500,000	$82,608,160	$49,879,349
Years 11-20	160,000	50	8,000,000	$10.26	$82,118,255	$8,000,000	$90,118,255	$54,334,754

Potential Savings From LNG Pipeline	Avoided Demand/ Fixed Charges @ 160,000 Dth/d (E-P)	Avoided Demand/ Fixed Charges For 0.8 Bcf/d Equivalent
Year 1	$69,454,930	$347,274,650
Year 2	$66,393,057	$331,965,283
Year 3	$63,495,873	$317,479,366
Year 4	$60,831,799	$304,158,993
Year 5	$57,408,554	$287,042,770
Year 6	$53,944,695	$269,723,473
Year 7	$50,117,249	$250,586,247
Year 8	$46,141,029	$230,705,146
Year 9	$42,010,674	$210,053,372
Year 10	$37,720,651	$188,603,257
Years 11-20	$332,652,455	$1,663,262,276
Total over 20 Years	**$880,170,966**	**$4,400,854,832**

Table 1 – Economics of New Pipeline vs. LNG Pipeline

Source: Skipping Stone

Equally important, injections of LNG into the system using the Winter-Only LNG "Pipeline" will have a downward effect on winter spot gas prices equivalent, on a dekatherm for dekatherm basis, to that of new pipeline capacity and the concomitant downward effect on peak electricity prices that are driven by such spot gas prices. As a result, secondary market values for natural gas in the Deep Winter are likely to be somewhat, if not entirely, eroded due to the introduction of the Winter-Only LNG "Pipeline." Indeed, limiting or eliminating these values on peak winter days represents one of the motivations cited by policymakers for solving New England Deep Winter price spike issue in the first place. However, under the Winter-Only LNG Pipeline solution, year-round secondary market values will *not* be eroded to anywhere near the same extent because the existing pipeline capacity will remain the same as that in existence as of 2017.

LNG is a flexible resource. Once it is in the tanks it can be dispatched promptly and, especially when put into the existing pipeline system at "the end of the line," can effectively support non-ratable takes by power plants and other end-users alike. A side benefit of this latter attribute is the fact that this non-ratable service, physically effectuated by means of very responsive vaporization, can bring price signals into the market and inform all gas buyers and sellers of the value of that service. Notably, non-ratable service that is physically firm (and priced accordingly) is one that has economic utility year-round, not just in the winter periods. Skipping Stone believes that once price signals are apparent, having such a service acting as available firm and priced as firm would probably call forth more such service.[34]

5. Incentivizing the Long Term LNG Solution

The New England Winter-Only LNG "Pipeline" solution more efficiently addresses the deliverability issues that cause Deep Winter problems than would a pipeline capacity solution. As the Winter-Only LNG "Pipeline" solution is in the best interests of LDC customers, it can and should be implemented in the short term by regulators directing LDCs to utilize their storage capabilities and to contract for LNG capacity as outlined above and by allowing related costs to be recovered.

In the long term, however, it would be more efficient for LDCs to be incentivized such that the Winter-Only LNG "Pipeline" strategy is more directly in their individual economic interest. As we lay out in more detail in Appendix D, LDCs are currently over-incentivized to contract for pipeline capacity, regardless of whether it would be in their customers' best interest to meet peak demand with a more targeted solution like LNG storage and vaporization. New England's natural gas regulatory structure fails to encourage adequate reliance on market forces to drive the efficient use of LNG storage.

Changes to the regulatory structure to meet this end would greatly enhance the economics of the LNG alternative. This incentive void has resulted in an almost exclusive focus on reliability provided by the combination of pipelines and native LDC LNG storage used historically to meet needle peaks of demand. A reformed regulatory scheme which emphasizes market forces and offers effective incentives and disincentives, would relieve the states of having to continue to use command and control regulation strategies to ensure implementation of the LNG solution.

In short, the combination of addressing the physical natural gas needs and the market challenges would greatly benefit customers and the overall New England economy. In Appendix D, Skipping Stone lays out a roadmap for making these changes.

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[34] Such firm, non-ratable, ramp and load following service could also call forth competitive alternatives such as demand response and battery storage on the electric side to meet the same demand(s) as gas-fired generation could satisfy.

6. Conclusion

Greater reliance on existing infrastructure assets to meet known and future deliverability demand and to ensure reliability, followed by incentive reforms to align the interests of LDCs with their customers can set in motion a new round of energy market innovation. New England has a history of leading the way with respect to electric market restructuring. With the steps outlined in this paper, New England can again lead the way to a better utilized, more responsive gas infrastructure, capable of meeting the challenges that face us now and in the future.

Skipping Stone has proposed a different and less costly means of addressing New England's short-duration and short-term Deep Winter deliverability inefficiencies, as well as any potential long-term shortfall. In short, the New England Winter LNG "Pipeline" is a right-sized solution to the New England gas problem.

Incremental capacity additions to New England's conventional pipeline infrastructure to serve native annual load for LDCs will likely continue to be economic if demand growth occurs, without a large pipeline's detrimental effect of "crushing" secondary market values and imposing uneconomic load-factor costs on ratepayers.

Not only could a planned, scheduled and implemented Winter-Only LNG "Pipeline" eliminate the need for a large new pipeline into New England, the presence of some amount of LNG in New England terminals year-round could also address power generators' needs for non-ratable, quick response supply to support intermittent renewable generation. As most observers and commentators agree, the use of renewable energy in New England is only going to grow. As those renewables grow, baseload natural gas power plants will see ever lower load factors of operation; however, while their annual load factors will continue to decline as renewables' contributions increase, gas-fired generators' peak demands are not likely to be eliminated.

There will be rainy days, dark and snowy winter days, and windless, cloudy, hot and humid, summer days in our future – days when gas-fired power plants will keep electrons flowing, at least over the short to medium term. Meeting that need with the existing natural gas infrastructure used to its optimum in an ever more flexible and responsive degree appears to be a much more economical and efficient path on which the New England Energy Market can travel forward.

About the Authors

Greg Lander, President, Capacity Center

Greg is an expert in natural gas markets, pipelines, market rules and transaction systems. He has participated in many federal and state regulatory proceedings and dozens of gas M&A projects. Greg is one of the co-founders, and the longest serving Board Member, of NAESB.

Peter Weigand, CEO, Skipping Stone

Peter has been a successful entrepreneur in the wholesale and retail gas and electric markets for over 25 years and has held C level positions in several energy and technology companies. He has been recognized as an Entrepreneur of the Year by Ernst & Young, as well as one of the Top 50 Most Influential People in Energy by PennWell.

About Skipping Stone

Skipping Stone is an energy markets consulting firm that helps clients navigate market changes, capitalize on opportunities and manage business risks. Our services include market assessment, strategy development, strategy implementation, managed business services and talent management. Market sector focus areas are natural gas and power markets, demand response, renewable energy, energy technology and energy management. Skipping Stone's model of deploying only energy industry veterans has delivered measurable bottom-line results for over 260 clients globally. Headquartered in Boston, the firm has offices in Atlanta, Houston, Los Angeles and Tokyo.

Skipping Stone owns and operates CapacityCenter.com, the only 24/7/365 natural gas interstate pipeline data center covering all the US pipelines. Its automated services monitor capacity release offers, system notices and deal award information, and streams available transactions and their details as they occur to its customers via email for trading, risk and regulatory compliance, as well as deal origination and valuation purposes. Please visit www.skippingstone.com for more information.

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Appendix A: Quantifying New England's Natural Gas Problem

To better identify and define New England's gas problem in detail, Skipping Stone analyzed a variety of data, including:

- The quantity of gas that gas utilities or local distribution companies (LDCs) deliver to meet their system load ("sendout");
- The patterns of such sendout;
- The gas "load duration curve"(a ranking of LDC sendout) from the highest to lowest amount over the 365 days of a year;
- Indicative LDCs' Gas Year (heating season to heating season) sendout; and
- Projected load duration curves for all uses of natural gas in New England.

Projected Load Curves for All of New England in 2020 and 2030

First we put the problem in perspective by looking at projected total demand for all uses of natural gas in New England. This analysis was based on a study performed by ICF Consulting in 2014 for the National Association of Regulatory Utility Commissioners (NARUC), which produced Charts 8 and 9 below.[35] These charts depict the projected total natural gas load curves for New England for 2020 and 2030 respectively, indicating the volume of demand from each of the various sectors of gas consumers, from the highest to the lowest day of demand during each model year.[36]

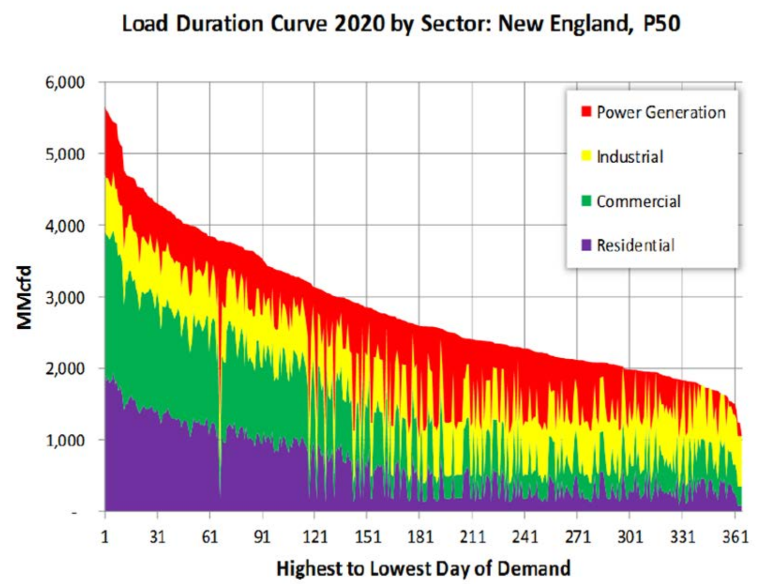

Chart 8: New England, 2020

[35] The 2014 NARUC "ICF Study" can be found at: http://www.naruc.org/Grants/Documents/ICF-EISPC-Gas-Electric-Infrastructure-FINAL%202014-12-08.pdf. NARUC represents the utilities commissions of all fifty states.

[36] Importantly, the 2014 NARUC ICF Study does not make clear in its All Markets load duration curve whether it accounts for the possibility that ISO-New England's "Pay-for-Performance" rules might cause dual-fuel capable generators to burn oil in place of gas during certain peak Deep Winter (the period between mid-December and mid-March) demand periods. If this variable is not factored into the 2014 NARUC ICF Study, that study's depiction of electric demand for gas in New England during high demand winter periods is likely too high.

Source: ICF Study

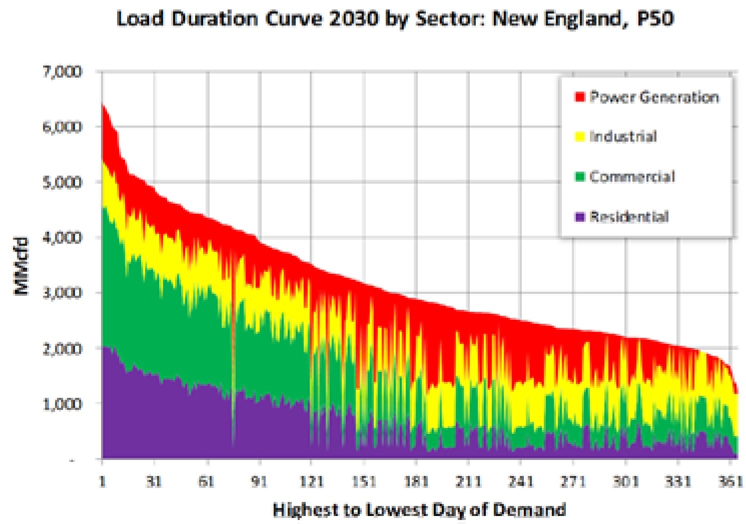

Chart 9: New England, 2030
Source: ICF Study

Using these same 2014 NARUC ICF Study Load Duration Curves, we plotted all New England pipeline capacity held by all shippers.[37] We also added total native LDC LNG storage deliverability and LDC propane storage deliverability. Below in Chart 10 is the Skipping Stone reproduction of the 2014 NARUC Study 2020 Load Duration Curve for all markets with 2017 New England pipeline capacity inventory plus native LDC LNG and LDC propane deliverability overlaid.[38]

[37] This analysis nets out lateral-only capacity and single shipper, multi-pipeline through-haul capacity. Additionally, there is no "capacity" contribution presented in Charts 9 or 10 attributable to or available from any of Massachusetts' on-shore or off-shore LNG terminals and only nominal Canaport/Offshore Nova Scotia deliverability counted under the pipeline capacity category. The Canaport deliverability is estimated to be approximately 200,000 dekatherms per day of the approximately 330,000 Dth/d of firm New England deliveries to (receipts at) Dracut between Portland Natural Gas Transmission (PNGTS) and Maritimes and Northeast (MN&E) delivering to New England from the north and remaining effective for the start of winter 2017.

[38] New England 2017 capacity inventory includes all 2015 existing capacity as noted infra, plus Spectra's AIM expansion and the Tennessee CT expansion.

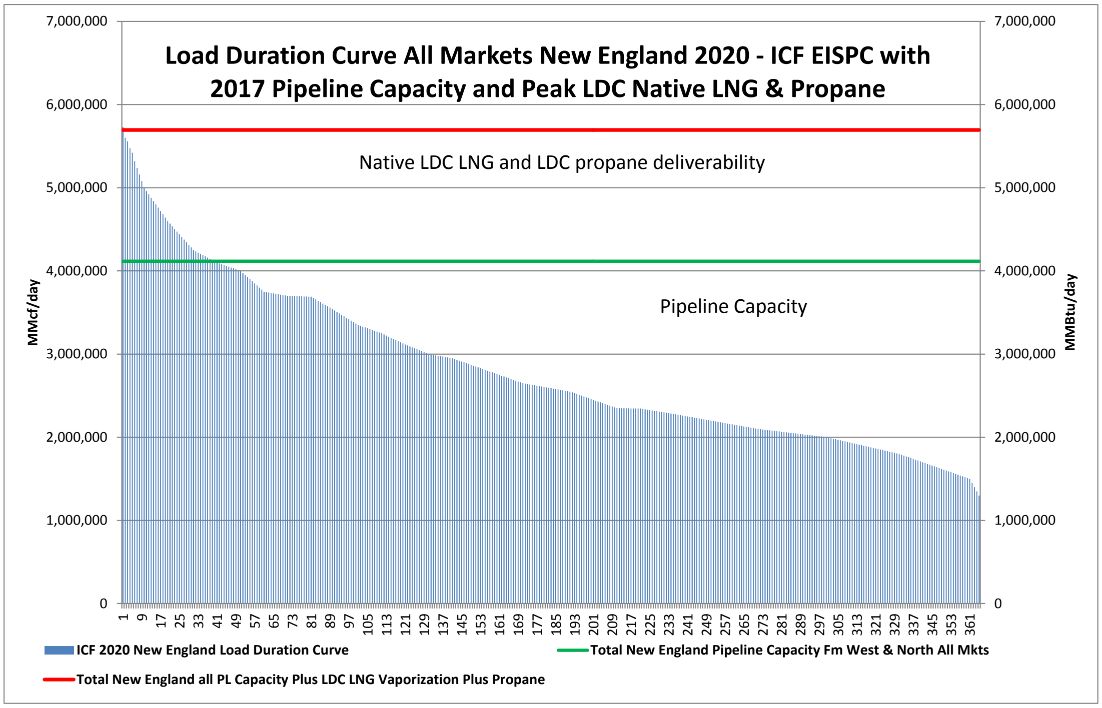

Chart 10: New England Pipeline Capacity plus LDC LNG and Propane Deliverability Overlay for 2020
Sources: ICF Study, Skipping Stone

Chart 11 below is Skipping Stone's reproduction of the 2014 NARUC Study's 2030 Load Duration Curve for all markets with the same 2017 New England pipeline capacity plus native LDC LNG and LDC propane deliverability overlaid.

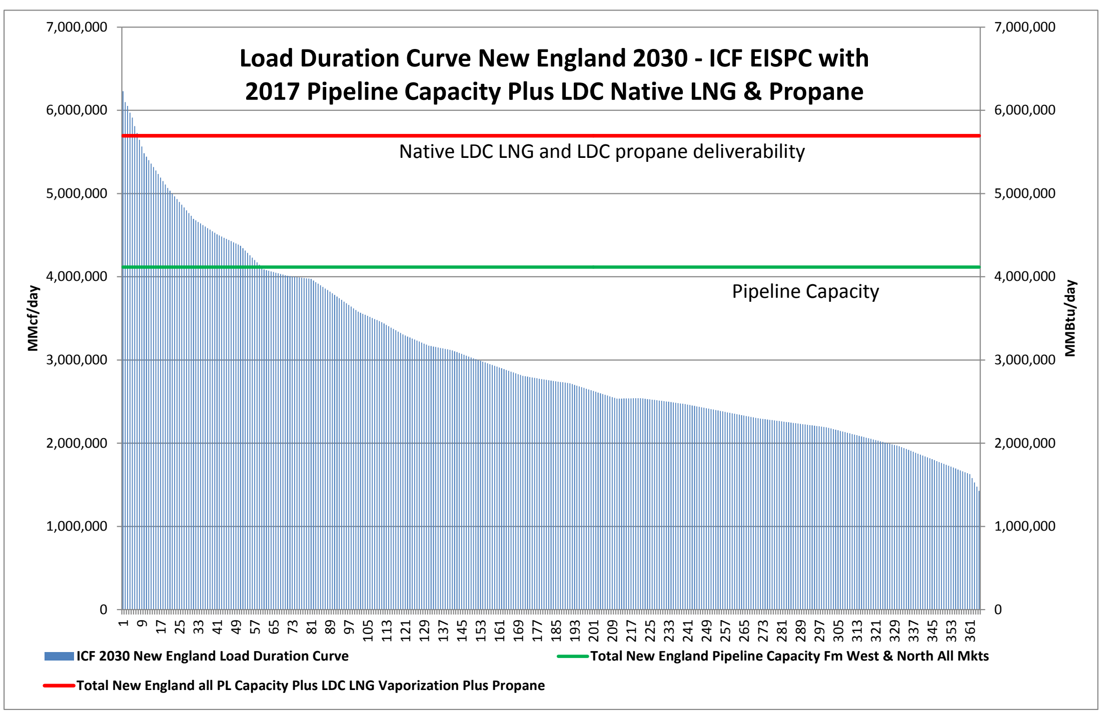

Chart 11: New England Pipeline Capacity plus LDC LNG and Propane Deliverability Overlay for 2030
Sources: ICF Study, Skipping Stone

While the preceding charts depict pipeline plus native LDC LNG and LDC propane deliverability, the duration of the native LDC LNG and LDC propane supply is not capable of annual deliverability at nominal peak deliverability rates as the Charts may imply.

To more accurately depict the contribution of native LDC LNG to meet the 2020 All Markets Load Duration Curve, Skipping Stone created a pro-forma native LDC LNG supply duration curve based upon peak native LDC LNG sendout as limited by current total native LDC LNG storage inventory[39]. That depiction is shown in Chart 12.

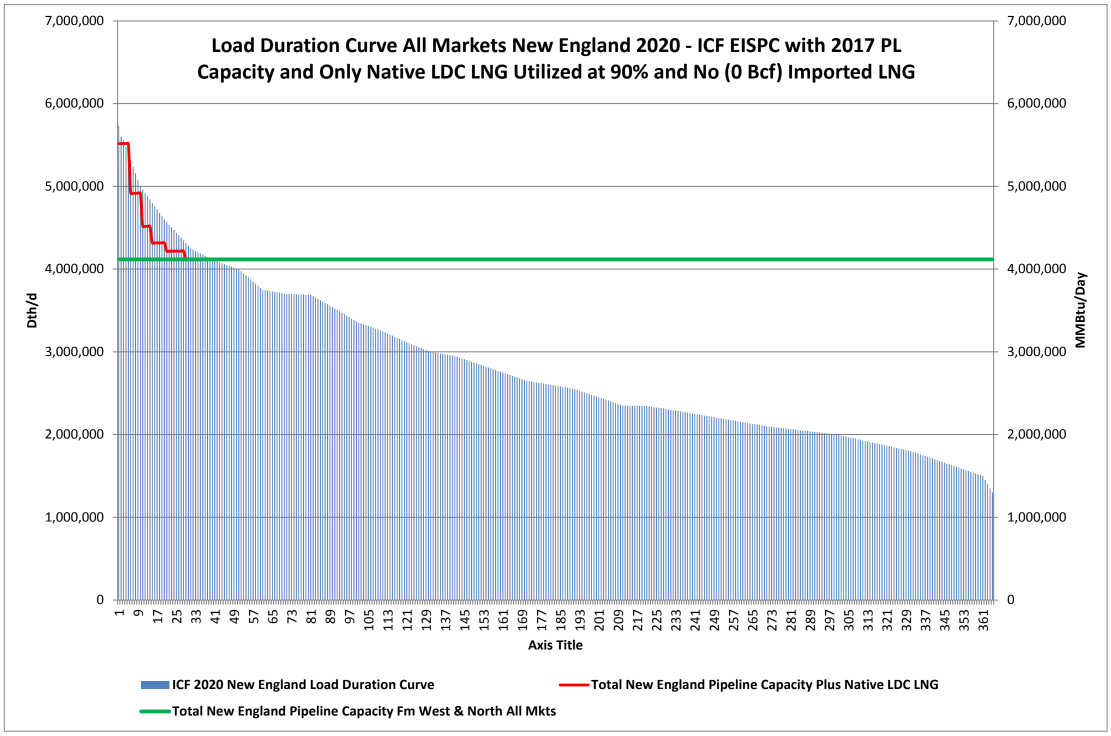

Chart 12: Deep Winter Demand and Supply Shortfall for 2020
Sources: ICF Study, Skipping Stone

The following Chart 13 is the 2030 all markets Load Duration Curve overlaid with the same 2017 pipeline capacity assets and currently existing native LDC LNG supply duration curve (also at 90% utilization) as used in Chart 12.

[39] Skipping Stone modeled that native LDC LNG inventory started at full capacity, but used no more than 90% of that inventory. Skipping Stone did not increase native LDC LNG inventory by any amount of winter refill from truck-borne LNG loaded at on-shore LNG import terminals despite the fact that most LDCs utilize some amount of winter refill from truck-borne deliveries. In addition, Skipping Stone eliminated propane deliverability as constrained by propane and storage so as to only consider all sources of natural gas alone. While LDC propane deliverability is and will most likely remain additive, because of propane and natural gas mixing ratio restrictions and low relative total propane storage inventory capacity, we excluded it for the purposes of developing a solution to the New England gas problem.

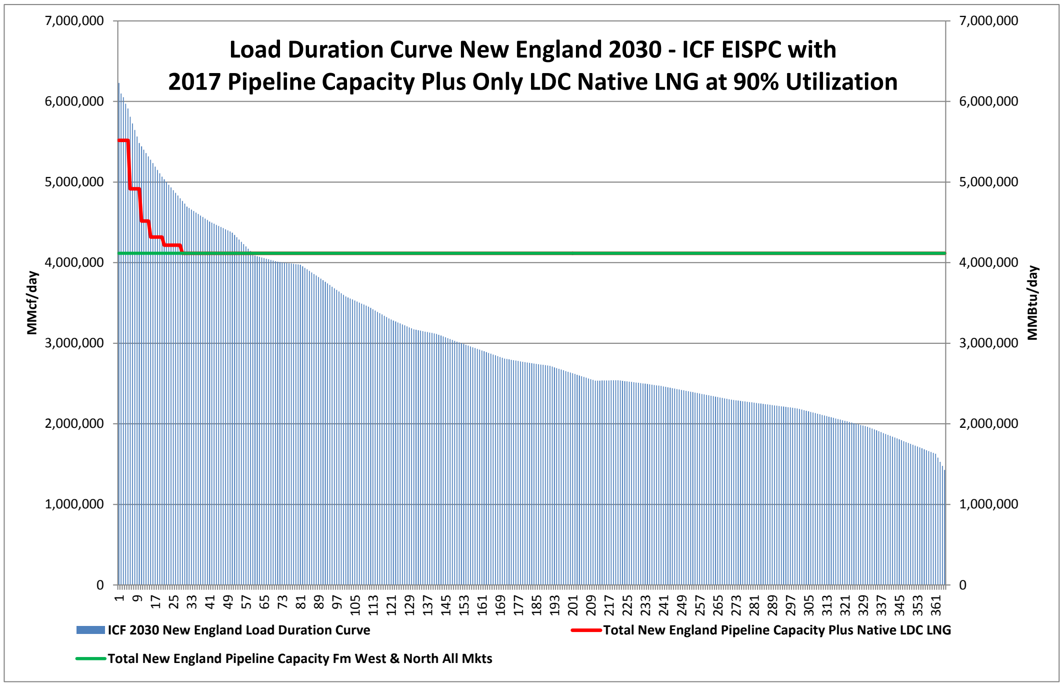

Chart 13: Deep Winter Demand and Supply Shortfall for 2030
Sources: ICF Study, Skipping Stone

As can be seen above, the 2020 and 2030 "Deep Winter" demand (discussed below) from all markets in New England will exceed 2017 pipeline capacity plus New England native LDC LNG sendout as limited by current New England native LDC storage. Current native LDC LNG storage totals 16.3 Bcf. The above depictions use 90% or 14.6 Bcf of that total native LDC LNG storage.

Load Duration & Utility Send Out

While the load duration curve is a concise way of determining load factor utilization of a particular set of capacity and deliverability resources, it does not depict the time period over which that load occurs. The time period is a critical factor that must be considered when re-thinking the role of LNG. To provide insight, a multi-year history and analysis of LDC sendout is required.

To that end, Skipping Stone analyzed 10 years of sendout data for a representative LDC in New England (LDC-1) to determine when its total sendout— its total delivered natural gas—exceeded its pipeline capacity levels, a condition which indicates the LDC's use of its supply of stored LNG.[40] For this indicative LDC-1, the largest in New England, Skipping Stone also inserted a line depicting that LDC's subscribed pipeline capacity.[41] As is typical for northeastern LDCs, the pipeline capacity is far more than its load most of the year and less than its peak load during the winter part of the year.

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[40] Inclusive of pipeline capacity to deliver gas from pipeline storage fields to the LDC's city gate take stations from the pipelines.

[41] For all calculations of subscribed pipeline capacity, Skipping Stone used publicly available pipeline capacity contract postings. These are postings required by the Federal Energy Regulatory Commission (FERC). The Index of Customers is a listing by each FERC regulated entity (i.e., every pipeline and storage operator) of all contracts for transportation and/or storage capacity, which details all locations where and quantities of service provided by each operator. From

The "50 day problem" discussed at the outset of this paper actually occurs during specific days over an approximately 90 day period from December 15 to March 15 of the winter months – a period we are calling "Deep Winter." During the Deep Winter, there are approximately 50 discrete days during which demand exceeds inbound pipeline capacity from the south and west gas production areas.[42]

In that analysis we determined that the earliest calendar day of any gas year that sendout exceeded pipeline capacity levels was November 21 and the latest was March 26.[43] We then looked at the Deep Winter period between December 15 and March 15 of each gas year to determine how many days the LDC's sendout exceeded subscribed pipeline capacity.

In order to ensure that a solution implemented to solve the Deep Winter problem between December 15 and March 15 would also take care of issues occurring on those sporadic "shoulder" days between November 21 and December 15 and between March 15 and March 26, we looked at how often the LDC's sendout exceeded pipeline capacity and the total cumulative amount of sendout in excess of pipeline capacity.

As illustrated in the following chart, what we found was instructive.

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these listings, Skipping Stone identified all LDC capacity contracts, then deducted lateral-only capacity and LDC capacity subscribed on one pipeline to another, which second pipeline delivered to the LDC. This was done so as not to double count pipeline capacity actually available to the LDC. Note also that such postings included delivery capacity from pipeline storage to LDC market locations.

[42] We found only 26 days on which the problem occurred outside of the December 15-March 15 period over the past 10 years. Over that 10 year period the LDC exceeded its pipeline capacity on 19 days in total before December 15 and on 7 days in total after March 15. The maximum number of days in any year before December 15 was 6 and the maximum number of days in any year after March 15 was 4 (they were not in the same gas year – i.e., heating season).

[43] A "gas year", in LDC parlance, runs from November 1 of one calendar year through October 31 of the next. This gas year convention is intended to keep calculations of "heating season" load (occurring between November 1 and March 31) in the same "gas year." This convention is important is because an LDC must plan for having sufficient deliverability as well as inventory for that portion of deliverability coming from native LDC LNG storage, in order to have enough supply in its storage to maintain deliverability across the winter period.

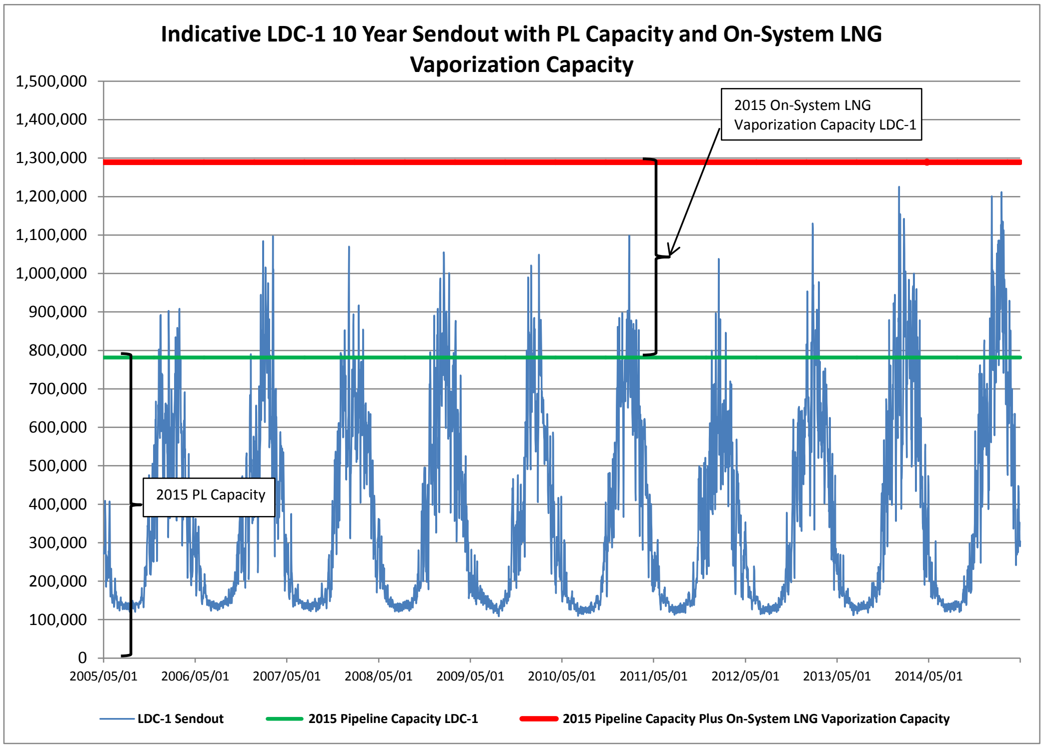

Chart 14: Indicative LDC-1 10 Year Sendout with PL and LDC LNG Capacity
Source: Skipping Stone

In contrast to a downward-sloping load duration curve, an LDC's single calendar year sendout graph is U-shaped, with the highest daily sendout occurring in January and February, dropping in March and April, bottoming out through the summer[44] and then rising again in December. Chart 14 depicts ten consecutive years of sendout. An indicative annual daily sendout of another Massachusetts LDC[45] (LDC-2) for the 2014 calendar year is presented in Chart 15 below, with LDC-2's pipeline capacity and pipeline capacity plus both native LDC LNG and native LDC propane deliverability superimposed as horizontal lines.[46] As is typical for New England LDCs, the contracted pipeline capacity (green line) far exceeds its load most of the year and is sometimes less than its load requirement during the winter part of the year.

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[44] To the extent that LDC does not have gas-fired power plants connected to its system.
[45] (LDC-2) is about one-half the size of LDC-1.
[46] Inclusive of LDC-2's (a) pipeline capacity to deliver gas from storage fields to the LDC's citygate take-stations (the green line); (b) native LDC LNG deliverability and (c) native LDC propane deliverability (both (b) and (c) are represented by the red line).

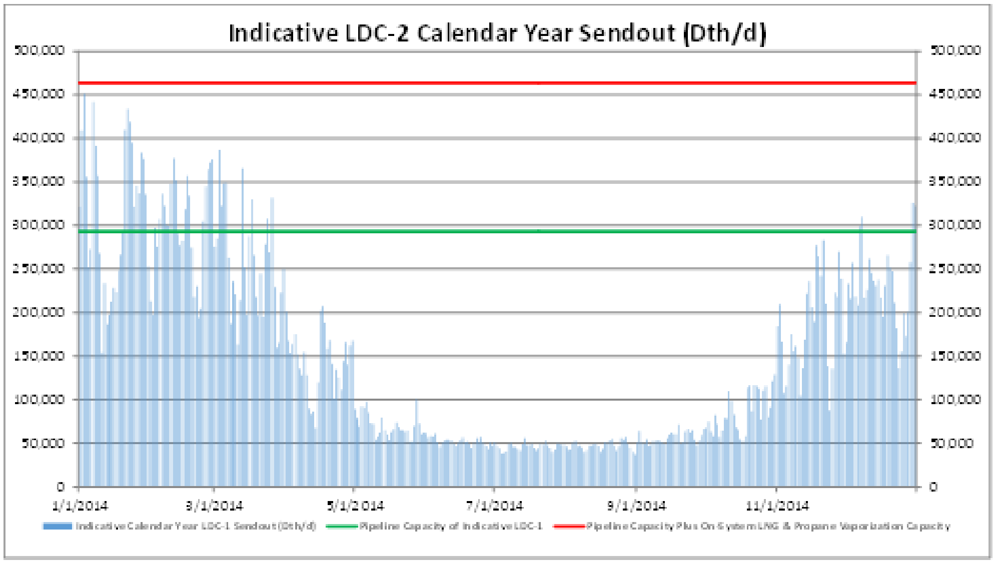

Chart 15: Indicative LDC-2 Calendar Year Sendout
Source: Skipping Stone

We then looked at how much of the native LNG storage of these LDCs would be utilized assuming that the worst combined pattern of weather and demand experienced across the 10 years were to occur all in the same gas year. We considered the native LNG storage and sendout capabilities to determine what would be the indicative maximum utilization of native LDC LNG storage during this scenario. Our representative LDCs each had a peak LNG sendout of approximately 40% -50%[47] of their total of pipeline capacity plus LNG[48] sendout capacity, an amount that is typical of most LDCs in New England.

Like most large LDCs in New England, whose native LNG storage would enable between 8 and 15 days at their equipment's maximum daily sendout rate,[49] the full LNG storage sendout capabilities of LDC-1 and LDC-2 are just under 10 days. Notably, assuming the observed worst case (10 days of pre- and post-Deep Winter where actual sendout would hypothetically exceed pipeline capacity), we found that their actual percentage use of LNG storage would have been just under 20% of total native LNG storage. Of that 20%, 11.6% was the largest indicative total amount used over the days before December 15 and 8.3% was the largest indicative total amount used over the days after March 15.

New England LDCs Load Duration Curve

To gauge this information for all New England LDCs, we assembled data from the latest publicly available information. For pipeline capacity we used the latest FERC filed Index of Customers (IOCs) for all New England pipelines serving New England LDCs, taking care not to double count any capacity. Public data

[47] Indicative LDC-1 has native LNG deliverability representing 40% of its 2015 design day (its propane deliverability has been retired); LDC-2 has combined LNG & propane deliverability representing 50% of its Design Day.
[48] And for LDC-2 native LNG sendout plus native LDC propane sendout capability.
[49] For example, if LDC vaporization facilities enabled a maximum daily LNG sendout of 50,000 Dth/d, 10 days at this maximum rate would mean a total LDC LNG storage tank would have a capacity to hold 500,000 Dth of LNG or ~1/6th the size of the LNG storage capacity in Everett, MA..

sources were used to establish equivalent native LDC LNG vaporization capacity[50] to establish current-day infrastructure deliverability within each LDC market area.

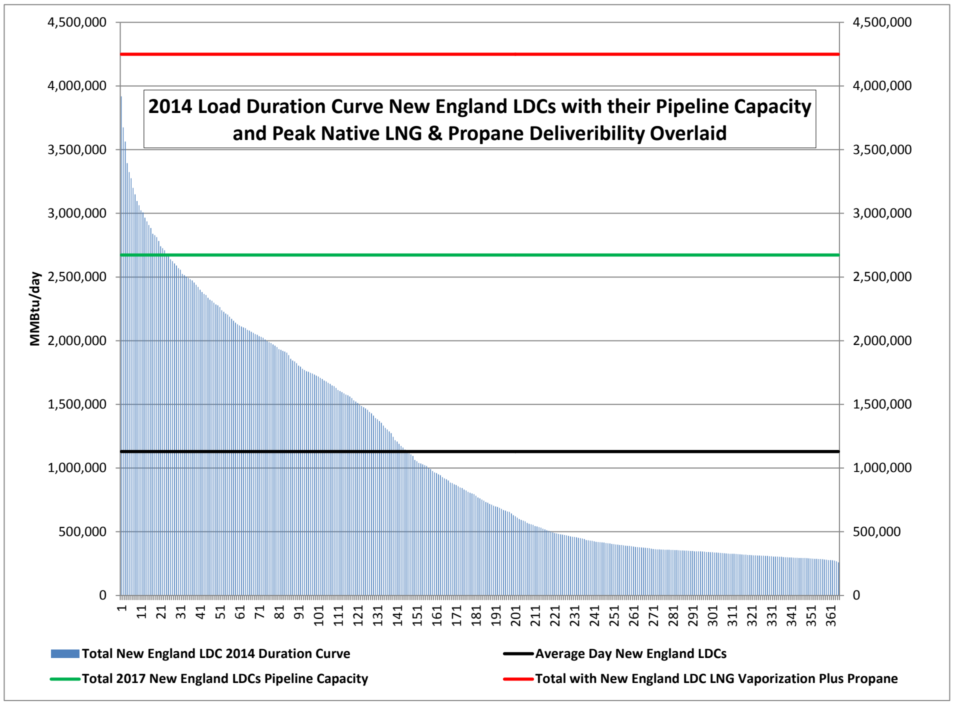

Chart 16: 2014 New England LDC Load Duration Curve with Overlay
Source: Skipping Stone

As Chart 16 illustrates, highly peaked periods (the leftmost blue vertical lines) occur over a very few days per year, with all of those days occurring in the winter peak heating season.[51] Further, existing pipeline and native LNG deliverability (red line) exceeds existing LDC sendout on the worst day by nearly 10%.

Adding pipeline capacity to the LDC's resources would raise the green (pipeline capacity) line in Chart 16 and, consequently, the red line (native LNG and propane deliverability) as well. The black line represents the average day demand for New England LDCs. This means that New England's LDCs, already using only a portion of the total capacity and a fraction of their native LNG and propane deliverability, would use an even smaller annual proportion of their contracted pipeline capacity. The distance between the black

[50] For the Massachusetts LNG and propane vaporization capacity we used recent Massachusetts DPU filings and data. For the New England LNG vaporization capacity we used New England Gas Association data which showed that New England has 1.4 Bcfd of vaporization capacity. For the Massachusetts propane deliverability we used data from the Massachusetts DPU for two major utilities which showed 0.066 Bcfd of sendout capability. For New England propane deliverability we used data from an ICF report done for ISO-NE which showed 0.137 Bcfd of total sendout capability.

[51] This is further validated by the ICF study referenced infra. Where an analysis of the load duration curves for 2020 and 2030 show that for the highest 60+ days of load duration, the residential, commercial and industrial loads (i.e., LDC loads) are at their highest. After that period, when electric generation is contributing its maximums to the load duration curves, the LDC loads are very small relatively.

average day line and the higher green line would increase, indicating a lower load factor use than would exist without the raising of the green line.[52]

Since pipeline capacity is a fixed cost imposed on an LDC's ratepayers, the effect of this lower load factor is a higher effective per unit cost of natural gas deliverability. That is, ratepayers will be paying more for peak winter gas deliverability while the bulk of their LDC's purchased pipeline capacity sits idle for more days per year than before.

[52] The overall load factor utilization is figured inversely on the distance between the black and green lines; thus raising the green line means a lower load factor utilization.

Appendix B: The Effect of a Large New Pipeline Project

Chart 17 which follows presents the ICF 2030 All Markets Load Duration Curve with the addition of an example "Big New Pipeline," an 800,000 Dth/d (0.8 Bcf/d) addition to New England's pipeline capacity.[53] In this chart, the purple line represents the total pipeline capacity into New England post the addition of a new 800,000 Dth/d pipeline. This line of course also raises the total New England gas deliverability line, at peak (i.e., including native LNG and propane) to just under 6.5 Bcf/d against a projected 2030 peak demand of just over 6.2 Bcf/d. Note that this ICF Study load duration curve is 15 years from now.

As can be seen in Chart 17, even with 10 years of load growth forecasted by ICF from 2020 to 2030, the new capacity will be 100% utilized only about 27 days a year, less than 10% of the year. And, again based upon the ICF load duration curve for 2030, the new capacity will be utilized at about 50% capacity for only an additional approximately 30-day period. For more than 300 days a year, then, a Big New Pipeline would sit idle with 0% utilization.[54]

Of note, 50% utilization over a 30 day period is the same amount of gas as 100% utilization over a 15 day period. This means that by 2030, 15 years from now, such added capacity associated with a new line might be utilized at 100% just 45+/- days a year. The 0% load factor for in excess of 300 days a year would mean that, overall, the new capacity would be utilized at just a 12%+/- annual load factor. Prior to the ICF forecasted arrival of that 2030 load – that is, between in-service date and 2030 – the load factor will be markedly less and the effective cost will be markedly higher.

In other words, a line costing approximately $547.00 per Dth-year will have an effective "per unit of use cost" in excess of $12.00 per Dth – before gas cost, in 2030. If such a line is built, that $12.00 per Dth *before gas cost* some 10 years after in-service (and after 10 years of presumed load growth) is a very expensive proposition for the ratepayers who would bear the financial burden.

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[53] This number is a likely minimum size of both TGP's NED project and Spectra's Access Northeast project.
[54] Even if such a new line were utilized to some degree over the 300 or more days, it would mean that other, currently subscribed and paid for capacity would go unutilized.

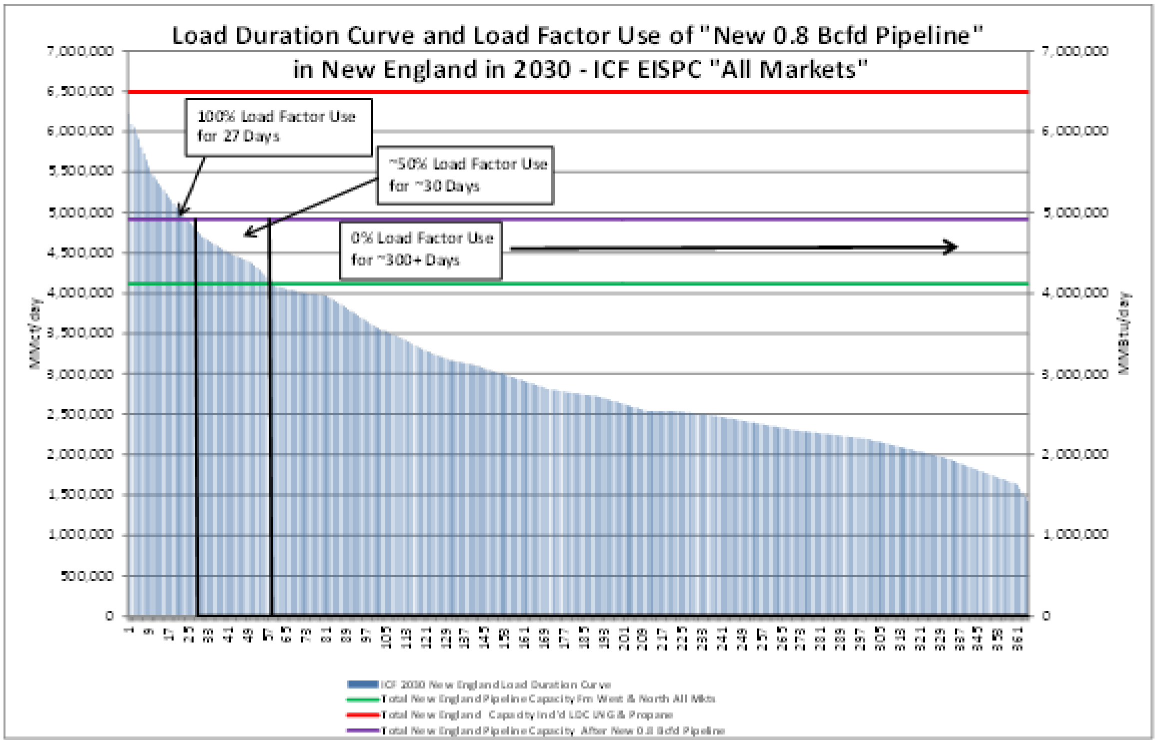

Chart 17: 2030 Load Duration Curve and Load Factor Use of New Pipeline

Sources: ICF Study, Skipping Stone

For the ratepayer absorbing those "sunk" costs in their prices paid for gas or electric service, these unused capacity costs are impacts that cannot be ignored.

Appendix C: Costs of a Winter-Only LNG "Pipeline" Strategy

By taking advantage of current (as of May 25, 2015) winter period (Dec-Mar) forward prices of Atlantic Basin LNG, about $7.95 USD to $9.20 USD,[55] LDCs can price, contract in advance, and schedule ships to arrive at Massachusetts' on-shore and/or off-shore terminals such that the same amount of daily LNG vaporization would occur as an amount of deliverable new capacity otherwise provided by a subscription to a portion of big new pipeline.

Adding in a terminal profit of $1.00 per Dth brings the price range over the next five years for New England landed LNG into the $9.00 to $10.00 per Dth range (the average is $9.59). Of course, the greater the volume of LNG contracted for, the lower the estimated transit/demurrage factor and terminal profit portion of the pricing is likely to be.

Chart 18, which follows, depicts forward NBP pricing out through 2020 with overlays of low and high average Deep Winter LNG prices plus shipping and demurrage to bring those prices to New England terminals[56].

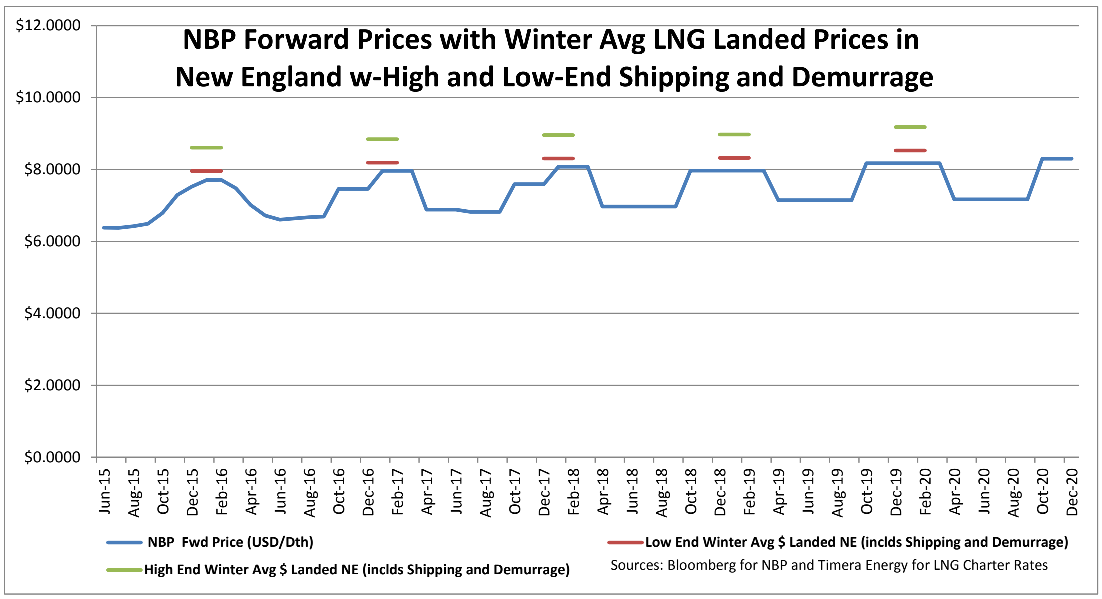

Chart 18: Forward NBP Prices through 2020 with Winter Avg LNG Landed Prices
Source: Bloomberg, Skipping Stone

[55] That is, the prices quoted at the UK National Boundary Point (NBP) which from now through 2020 landed in New England are in the $7.95 USD to $9.20 USD range before terminal profit. This estimate is calculated from the NBP price plus an estimated transit cost to Boston assuming 8 to 10 days transit from the NBP or net days sailing to New England rather than deliver the cargo to the NBP plus ten to twenty days demurrage in Boston. Notably, much of this added transit cost or time would not be required given advance planning and scheduling. In addition, while additive in this example, much if not all of the demurrage cost would most likely become embedded in the 'terminal' profit.

[56] Prices are exclusive of terminal profit and pipeline delivery charges. Pipeline delivery charges are estimated to be from 6 cents on Algonquin for the incremental cost of receipts at the offshore locations to approximately 16 cents for TGP backhauls at 100% load factor. If and to the extent parties reserved year-round FT for the LNG receipts the effective costs would be similarly greater owing to the low load factor of utilization; albeit starting from a level far less than the approximately 1.50 per Dth 100% load factor rate of a new big pipeline.

Comparison of LNG Economics to New England Projected Forward Prices

Looking at the Algonquin City Gate[57] forward prices for the 2016 through 2018 winter periods, the price is about $11.70 per Dth for 2016, dropping to about $9.15 per Dth by 2018. This apparent price convergence makes logical sense as the marginal supply of gas to both New England and the UK NBP location is ship-borne LNG.

Chart 19 has the same presentation for Algonquin City Gate pricing over the period that is currently quoted in over the counter futures markets.[58]

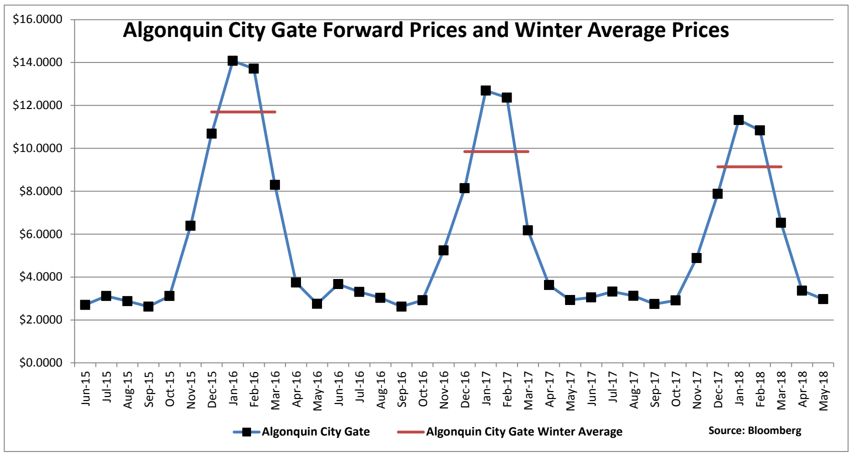

Chart 19: Algonquin Citygate Forward Prices and Winter Average Prices
Source: Bloomberg, Skipping Stone

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[57] The Algonquin Citygate price is the most representative price for spot gas purchased by buyers in New England who do not hold pipeline capacity that enables them to source gas in lower-priced production areas and is indicative of the price paid by buyers when total New England sendout exceeds a high percentage of total pipeline capacity.

[58] Skipping Stone believes that the reason Algonquin Citygate Prices are only quoted out through late Spring of 2018 is due to the uncertainty in the market as to what the 2018 winter New England capacity and deliverability infrastructure situation will be.

Appendix D: Regulatory Reform Roadmap to Better Incentivize the Winter-Only LNG “Pipeline” Solution

The Current Structure

The absence of appropriate market incentives and disincentives has led to a situation where LDCs husband their on-system LNG to protect against the possibility of both Deep Winter and late season, post-Deep Winter cold snaps. LDC concern with covering this late season cold snap issue is a historic legacy born out of the fact that the Appalachian storage fields were east of the majority of Appalachian production and the pipeline capacity to deliver that storage gas to market only ran from those storage fields to market.

Now, with the dramatic increase in Marcellus supply, with much of the supply for the Eastern US located either in the same places as the legacy storage or east of it, late season storage deliverability is no longer a concern. LDCs used to have to worry that as storage became depleted in the late winter season, they had to have their LNG satellite storage at very high levels in case of an extended late season cold snap. This was because such weather may have occurred when an LDC’s inventory of pipeline-provided storage was largely depleted due to withdrawals from such storage earlier in the winter season. This storage inventory depletion has been (and is) driven in part by the requirement under most pipeline storage agreements to “cycle” (or essentially empty) storage inventory by the end of the winter season. This cycling requirement meant that the LDC had to remove most, if not all, of their stored gas from Appalachian storage fields by the middle to end of March, making daily deliverability available to LDCs from their storage at as little as 50% or less of their deliverability when those same inventories were more full.

For the LDCs in New England, this meant that the only gas that could fill their “storage to market” pipeline capacity was gas that actually came out of those seasonally drawn-down storage fields. This is no longer the case, because with the introduction of prolific supplies from the Marcellus, most of which are located under and east of the pipelines that run from storage to New England has resulted in an almost complete abatement of the seasonal storage inventory draw-down concern.

In fact, many of the Appalachian pipeline capacity expansions driven by producer-subscribed “supply-push” projects have resulted in the producers’ year-round flowing supplies in the Marcellus basin being moved toward the market to meet up with the inlet of the pipeline capacity originally built from storage to market. This now means that such flowing supplies can and do enable LDCs to choose, throughout the winter season, between taking gas from storage or instead taking flowing, well-head, producer supplies available through the supply-push capacity meeting up with the original storage-to-market capacity. This is especially beneficial in the late winter season.

The location of the Marcellus supplies and the concomitant ability of LDCs to take flowing supplies during later winter periods means that LDCs: (1) can greater utilize their throughput associated with their satellite LNG facilities while still maintaining sufficient reserves for a late season needle peak, and (2) have no need to be prepared to have these facilities also ‘make up for’ depleted deliverability (capacity) from storage.

Introducing Market Forces

Market forces can and should be introduced into capacity and supply planning for LDCs in order to achieve the objective of right-sizing LDC capacity and supply. These incentives can be developed through modifications to the regulations associated with LDC secondary market and off-system sales.

At present, there are generally two sources of extra revenue that LDCs in New England share with ratepayers. They normally share 80%-90% of “net revenues” that they generate from use of ratepayer supported assets to make off-system sales and likewise share 80-90% of "revenues/credits" that they receive from release of pipeline capacity to others.[59]

An outcome of the 80-90% "sharing" is that the LDC gets to keep—as pure profit—the remaining 10% to 20%. Some have noted that this current system leads to perverse incentives. For example, an LDC could conceivably add unneeded capacity to their inventory, having ratepayers pay 100% of the cost, and then use that new capacity to make sales from which they get to keep 10% - 20% of the margin.[60] In essence, 100% of the cost goes to the ratepayer and then 10%-20% of the "cost-free" and "risk-free" margin goes to the LDC and its shareholders.

By focusing margin sharing on variable costs and variable revenue, the fixed reservation charge associated with the capacity used to make the off-system sale (or capacity release) may or may not be covered by the net revenues from the off-system sales or credits from capacity release.

To ensure and compliment full implementation and to maximize the benefits of the LNG solution, a system of incentives and disincentives will be needed to both achieve higher utilization and enable market forces that will serve to discipline and right-size any infrastructure additions going forward.

It is our view that introducing an expanded set of incentives and disincentives will better provide the motivations to achieve these outcomes while relying less on "top-down" regulation. The right set of incentives, properly formulated and monitored, will serve as market rules known by all and will engender short-, medium- and long-term market responses which will serve to better achieve public policy goals.

Suggested Regulatory Change Roadmap

First, Skipping Stone suggests changing the incentive structure for LDCs in order to differentiate winter period incentives from other period incentives. This would involve authorizing a higher split to LDC shareholders from LDC asset optimization activity. In addition, we suggest a differential split for capacity sales versus off-system sales into the secondary capacity market. The reason for this tilted differential is that secondary market capacity sales provide transparent price signals to the overall market by means of those prices being posted by the pipelines in near real time for all to observe.

For example, winter-period secondary market capacity sales could entitle the LDCs to retain as much as 40% of winter period capacity sales (capacity release) to the extent such sales realize less than the LDC's weighted average per Dth fixed reservation costs for all citygate delivered capacity (excluding from this weighted average computation fixed reservation costs for lateral only capacity) and as much as 60% of all revenue realized from sales to the extent the LDC realizes more than their weighted average reservation costs. This differential within the capacity sales category of incentives also serves to encourage, if not assure, right-sizing of capacity additions going forward because the incentive on the LDC is to not over-subscribe and thereby depress capacity market values – values that govern the magnitude of incentive realizations.

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[59] This does not apply to revenue from those releases that they make through their mandatory release programs to retail markets when those retail marketer releases support those marketers' sales to former firm customers of the LDC. In these transactions 100% of the revenue is credited to sales customers of the LDCs.

[60] In every instance that Skipping Stone is aware of, no attribution of fixed cost is included in the calculation of margin. Margin, for off-system sales, is defined as the sales revenue less the direct cost of gas, pipeline usage rate(s) and pipeline fuel, thus the LDC "keeps" 10% - 20% of this margin. Margin for capacity releases is 100% of the capacity release revenue; and, except when the LDC is doing a capacity release under a mandatory customer access program, where ratepayers get 100% of revenue/credit, it again gets to keep 10% - 20% of revenue/credit.

Winter-period off-system sales (i.e., secondary market sales) could entitle the LDCs to retain as much as 20% of winter period off-system sales net margin to the extent the net margin per Dth is less than the weighted average reservation cost per Dth and as much as 40% of all net revenue realized from off-system sales to the extent the LDC realizes more net margin per Dth than their weighted average reservation costs. The reasons for this differential are the same as those for the capacity sales differential – right-sizing.

Next we suggest a disincentive at the state level similar in concept to that already in effect at the federal level, where pipelines are at-risk for recovery of fixed costs associated with their expansions by means of a policy which prevents them from shifting costs not recovered under contracts with the expansion capacity customers onto the backs of existing customers. At the federal level, this at-risk policy means that pipelines must have contracts with customers—whether those customers are LDCs, producers, power plants, marketers or others—that cover the costs (including profit) of expansions or face under-recovery of those costs.

Bringing a similar policy structure to the state level will bring a similar discipline to LDC capacity planning and new capacity subscription. This can be accomplished by linking LDC cost recovery of pipeline fixed costs (through LDC rates) for new capacity to overall pipeline capacity utilization to meet native load. For example, the LDC could be at risk of cost recovery to the extent annual weather adjusted load factor of pipeline capacity utilization to meet native load fell below pre-set percentages.

By way of background, in New England, the typical LDC has around a 40% annual load factor of total native load to total pipeline capacity contract level. In this formulation, the at-risk provision could be set such that if the LDCs annual load factor citygate pipeline capacity utilization for native load is less than 40% (if this were the regulatory minimum load factor), the LDC would be at-risk for up to twice the percentage shortfall times the weighted average fixed charges for that quantity of pipeline capacity which would represent the 40% load factor utilization target.

Under this scenario, should the LDC annual sendout be less than a 38% load factor of pipeline capacity, the 2% shortfall would be multiplied by 2 to equal 4% and that percentage would be applied to the LDCs weighted average fixed pipeline charges not otherwise recovered through capacity sales (capacity release) or net margin from off-system sales. This, “up to 2 times” amount, could be established along a sliding scale. So too, could the bands of annual throughput “miss” below the nominal 40% load factor target, be set and tied to the at-risk factor. Such disincentive structure will bring a market discipline to LDC capacity planning as the FERC’s at-risk policy brings to interstate expansions.

In time, such a policy coupled with the incentives discussed above might replace current state-level capacity approval proceedings which pit reliability against cost and, regulator judgment against LDC judgment. It would instead institute a market based structure which encourages and rewards financial discipline with respect to capacity planning; the result being that both LDC and ratepayers benefit from optimal capacity utilization.[61]

Moreover, the financial incentives (LDC shareholder profit) associated with higher LDC revenue and net-revenue sharing percentages could well offset the disincentives associated with load factor utilization

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[61] State-level incentives and disincentives also could have other public-policy objectives. For instance, state-level incentives tied to LDC off-system sales could also be tilted by state regulators towards LDC sales which serve loads (including electric generation in ISO-NE) such that commensurate competition could positively impact prices ultimately paid for gas (and electricity) by New England customers. This type of incentive conditioning is available to state regulators where conditioning of LDC capacity releases cannot be so effectuated under federal non-discriminatory rules related to capacity release transactions.

targets such that “right-sized” capacity expansions (which by their nature will always reduce load factor to some extent and may well reduce load factor below the target levels depending on the size of such expansions) will still bring net benefits to LDC shareholders and ratepayers alike.

Another likely effect of such a set of policies in New England, and Massachusetts in particular, would be to incentivize greater utilization of native LDC LNG facilities and to commensurately increase revenues associated with capacity sales or net-revenues associated with off-system sales, especially in periods of high overall regional demand.[62]

As stated previously, treating the difference between the landed price of the LNG and the price of pipeline gas as a fixed cost, akin to the treatment of fixed costs for pipeline subscription, would work into both the incentive and disincentive structure such that the beneficial revenues associated with capacity sales (the capacity freed-up by higher utilization of native LNG) or the beneficial net revenues associated with off-system sales (also associated with increased native LNG utilization) would occur and offset the fixed cost treatment, while at the same time not decrease the level of overall utilization required to meet the 40% target that new pipeline capacity subscription would engender.

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[62] Especially the demand expressed by electric generators, which, once and to the extent the LNG solution becomes implemented, could be prime beneficiaries whether through call options or other contractual arrangements with either the LDCs (providing a source of margin for the LDCs) or the terminals themselves albeit in quantities far less than full cargo amounts.

Appendix E: Case Study: Winter 2014 versus Winter 2015 in New England

A review of what occurred in the New England gas market in the winter of 2015 as a contrast to that of winter 2014, both as to supply sources and price behavior, provides an instructive case study of the impact that will be possible in forward years from a rethinking of the role of LNG in New England.

First, the winter of 2014/2015 was significantly colder than the prior 2013/2014 "Polar Vortex" winter. The Effective Degree Days ("EDD")[63] for Boston in 2015 were 3,839 with a peak of 70 EDD on one day. The EDD in Boston in 2013/2014 were 3,515 (nearly 10% less) with a peak of 67 EDD on one day.

Nevertheless, the added physical gas supply to New England from ship-borne LNG during winter 2015 compared to winter 2014 had a profound impact on prices in both the natural gas market as well as the electric power market.[64] A close inspection of exactly what happened provides a helpful comparison of how the relative costs and benefits of addressing Deep Winter load growth using a large new natural gas pipeline versus a New England Winter LNG "Pipeline".

In particular, we compared LNG sendout and spot market prices for the winters of 2014 and 2015. The results of this analysis are presented in the charts that follow. From January through March 2014, LNG sendout into Algonquin, Tennessee and by National Grid averaged 56,865 Dth/d, and the average spot market price at Algonquin City Gate was $19.74. For the same months in 2015, LNG sendout into Algonquin, Tennessee and by National Grid[65] averaged 197,450 Dth/d, and the average Algonquin City Gate spot market prices were $11.22.

In other words, the additional injection of approximately 140,000 dekatherms of LNG per day on average into Algonquin and Tennessee reduced spot market gas process by approximately $8.50 on average over the course of the winter. This increase of less than 4% in total deliverability to New England had a 43% downward effect on spot prices. While it is not likely that this observed relationship between sendout and reduced prices will be linear for all quantities of gasified winter LNG sendout, the observation certainly foreshadows what is possible with a rethinking of the role of LNG in New England.

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[63] EDD are a measure of heating demand which incorporates factors in addition to temperature, like wind speed, amount of sunshine, precipitation, etc.

[64] In addition to the change in the amount of gasified LNG, oil prices, another marginal fuel used to generate electricity in winter months (and therefore influence electricity prices) saw a dramatic reduction owing to a drop in world oil prices. Notably however, in the winter of 2013/14 AGT city gate prices often prevailed at levels that were far above 2013/14 oil prices. This is in part due to the fact that many generators had neither firm gas supplies nor sufficient oil inventories at dual fuel capable locations which, in the absence of ship-borne LNG, drove city gate prices to nearly unprecedented levels.

[65] National Grid sendout over the January through March period in the two winters was statistically the same, differing between the two years by less than 3%; National Grid's gasified LNG sendout averaged 31,892 Dth/d in 2014 and 30,871 Dth/d in 2014. Gasified LNG sendout into Algonquin increased from just over 2 Bcf in total for the January to March 2014 period to over 11.3 Bcf during the same period of 2015; while gasified LNG sendout into Tennessee increased from under 0.25 Bcf in total for the January to March 2014 period to nearly 2.8 Bcf during the same period of 2015;. Notably, the peak sendout into Algonquin in 2014 was 156,126 Dth/d while the peak sendout in 2015 exceeded 463,000 Dth/d. For Tennessee in 2014 the peak sendout was just 35,161 Dth/d while in 2015 it exceeded 108,000 Dth/d. The peak sendout between Algonquin and Tennessee in 2014 was only 169,186 Dth. In 2015 that rose nearly 300% to 506,341 Dth. Moreover, this peak of over 0.5 Bcf/d in 2015 against an average of 166,580 between Algonquin and Tennessee evidences the highly flexible and responsive nature of LNG vaporization.

The following charts depict the LNG sendout by day into the New England system from Massachusetts LNG vaporization locations of Tennessee, Algonquin and the largest Massachusetts LDC, National Grid, as well as the average of these 3 major sources of LNG sendout across the 3 month period. The charts also plot the Daily AGT City Gate Price ($/Dth) and the average AGT City Gate Price across the same 90 day period.

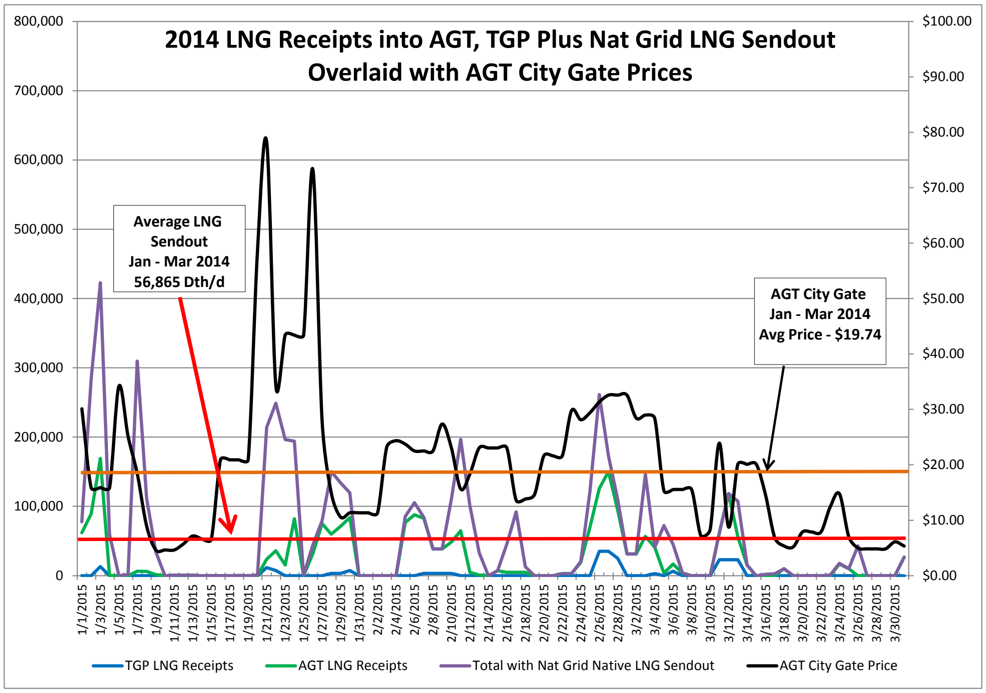

Chart 20: 2014 LNG Receipts into AGT, TGP & National Grid Overlaid with AGT Citygate Prices
Source: Skipping Stone, Pipeline Bulletin Boards, NGI

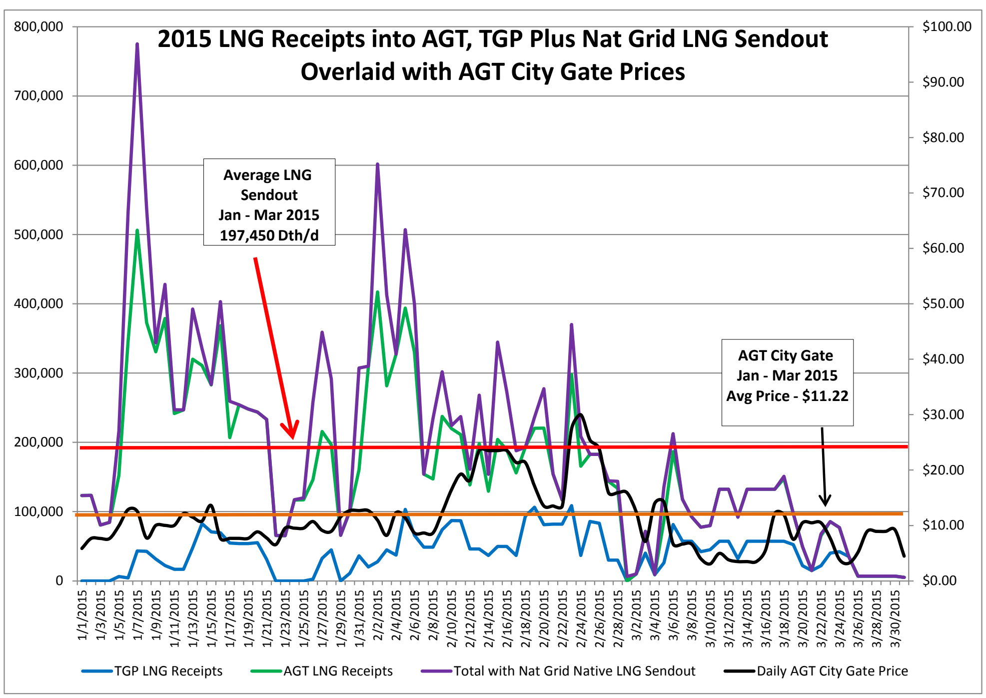

Chart 21: 2015 LNG Receipts into AGT, TGP & National Grid Overlaid with AGT Citygate Prices
Source: Skipping Stone, Pipeline Bulletin Boards, NGI

New Jersey Conservation Foundation

Expert Analysis Shows Reforms Made After Polar Vortex Already Meet Grid Reliability Concerns

MARCH 2016

The Polar Vortex events during winter 2013/2014 cannot justify the expansion of additional pipeline infrastructure. Policymakers should support ongoing reforms that enhance pipeline responsiveness to address grid reliability concerns without needing to construct expensive and unnecessary additional pipeline.

KEY POINTS

1. Developers mislead the public by saying insufficient pipeline caused outages during the Polar Vortex. In fact, pipeline flow data in the PJM region shows that some pipelines never even reached full capacity on days of peak demand.
2. Since the Polar Vortex, regulators have implemented numerous reforms that proved successful during the even harsher winter events of 2014/2015.
3. Furthermore, assessments conclude that the PJM region will do even better in 2015/2016 – *all without PennEast*.
4. Additional pipelines are not required for reliability. Success in both the PJM region and New England provide strong evidence that additional pipeline construction is unnecessary.

1. DATA SHOWS SOME PIPELINE CAPACITY WAS NOT UTILIZED DURING POLAR VORTEX

During the Polar Vortex some gas generation plants were not able to ***order*** additional gas supplies. At the same time, analysis[1] of gas flows during this period documents that some gas pipelines were never fully utilized.

PJM[2] concluded that significant **market design issues with pipeline responsiveness to customer demand** occurred during the Polar Vortex. In fact, these pipelines had available capacity even as spot market gas prices skyrocketed. Pipeline operators were unable to satisfy orders because some of the pipeline capacity was "reserved" but not used by shippers. Shippers are able to schedule a delivery that uses all of their assigned capacity and then change their mind and ask for a smaller amount prior to delivery. If the pipeline operator had better information about demand for deliveries, it would be able resell any unused capacity during periods of high demand.

Analysis of *scheduled* deliveries as compared to *end-of-day* (i.e., delivered) quantities, illuminates the differences between pipelines that underperformed as compared to those that better responded to calls for gas transportation.

[1] Analysis conducted by SkippingStone LLC., contracted by Environmental Defense Fund and Conservation Law Foundation. See: Peress, Jonathan N., (15 June 2015) Department of Public Utilities DPU 15-37. The Commonwealth of Massachusetts. Prepared Comments of Environmental Defense Fund.
2 PJM. (8 May 2014) Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events. Retrieved from http://www.pjm.com/~/media/documents/reports/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

Some pipelines offer shippers the ability to nominate deliveries hourly while other pipeline companies offer only the FERC-mandated minimum number of scheduling cycles. Spectra's Texas Eastern Pipeline ("TETCO") offers hourly nominations and scheduling to its shippers. In contrast, Kinder Morgan's Tennessee Pipeline ("Tennessee") offers only two timely and two intraday nomination opportunities. *Figures 1* and *2* compare data from two pipeline operators, and show that hourly scheduling was more effective at utilizing capacity.

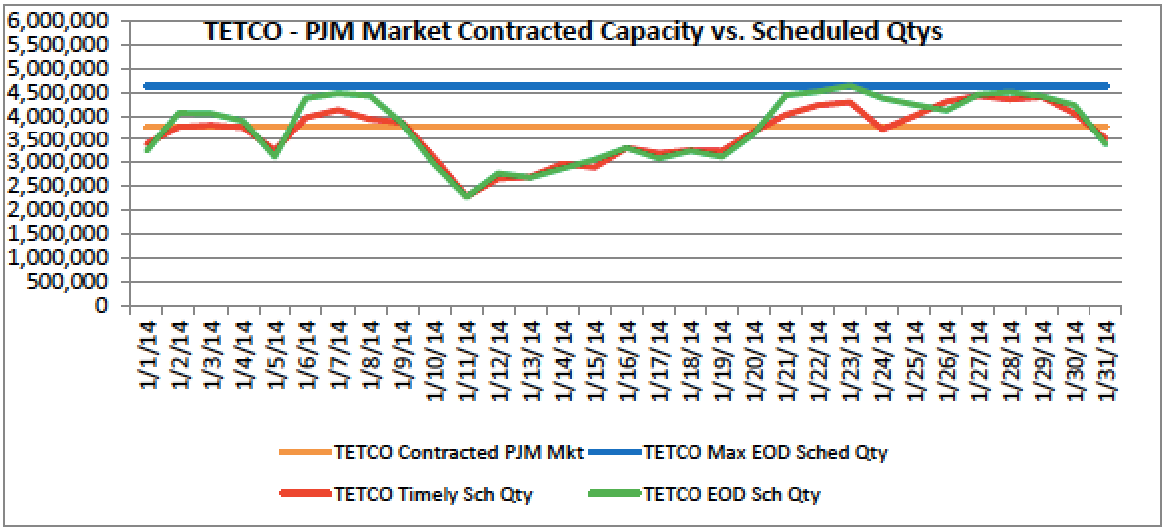

Figure 1: TETCO - PJM Market Contracted Capacity vs. Scheduled Quantities

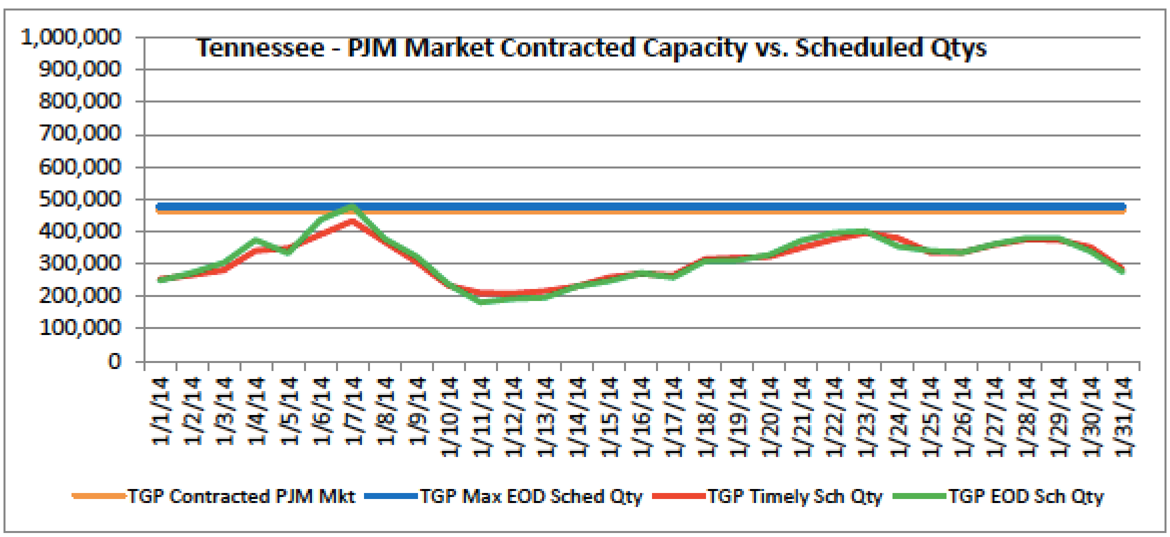

Figure 2: Tennessee - PJM Market Contracted Capacity vs. Scheduled Quantities

During the two Polar Vortex events with highest demand and system constraints, January 6-8 and 21-28, 2014, TETCO far out-performed Tennessee on two major indicators:

A. **Ability for end-of-day delivery quantities to exceed contract capacity**
TETCO's end-of-day delivery quantities significantly surpassed the sum of its contract capacity during both peak-demand periods. In contrast, Tennessee did not exceed its contracted quantities and even fell far short at some points.

B. Ability for end-of-day delivery quantities to exceed timely scheduled quantities
Liquidity refers to the extent to which shippers were able to nominate and schedule deliveries. A strong indication of liquidity is the difference between a company's end-of-day delivery quantities and it's timely scheduled quantities. By the end-of-the-day, TETCO and Transco scheduled and delivered a greater volume of gas compared to the quantity of timely scheduled quantities.

The Skipping Stone analysis suggests that a key reform would be to require pipeline operators to schedule nominations more frequently during the gas delivery day.

2. PJM AND FERC REFORMS HAVE IMPROVED PERFORMANCE

Since January 2014, regulators have introduced numerous policies that have fundamentally changed and improved the coordination of natural gas and electricity in the PJM region. Reforms relate to improvements in gas-electric coordination, providing new incentives for capacity performance, incentives for demand response as well as to gas market scheduling.

Gas-Electric Coordination

Regulators realized that reforms were needed to improve coordination, and thus, enable gas customers to obtain additional supplies during peak periods,[3] more fully utilize the existing pipeline system, and reduce forced outages. These PJM measures to ensure future reliability include: new winter reliability testing requirements, maintenance and weatherization standards, improved alignment of gas and electric markets (including gas commitment and coordination improvements), a lift on energy market offer caps, and procuring increased generation by altering the Variable Resources Requirement curve.[4]

In preparation for Winter 2015/2016, PJM engaged in additional coordination activities: [5]

- Winter operations study (Nov. 2015)
- Resource winter testing exercise (Nov. 2015 – Jan 2016)
- PJM Emergency Procedures Drill (Nov. 2015)
- Fuel Inventory Survey (Nov. 2015)
- Generation owner Cold Weather Resource Preparedness Checklist (Dec. 15, 2015)
- Numerous Reliability Coordinator winter preparedness meetings (Sept – Nov, 2015)
- Gas-Electric Coordination, including
    - MOU with PJM Pipelines – July 2015
    - Daily, Weekly, Monthly and Seasonal Coordination with pipelines in PJM footprint
    - LDC outreach – in progress

[3] Comments of PJM Interconnection, LLC , Docket AD14-19- 000, October 1, 2014.
[4] Public Interest Organizations (PIOs). (2014). Comments of Public Interest Organizations on PJM's Capacity Performance Proposal.
[5] PJM Winter 2015/2016 Preparedness, September 2015.

In addition, coordination requires ongoing discussions about operational matters throughout the year. PJM highlighted the following ongoing coordination activities:

- Monthly coordination of gas and generator planned maintenance between PJM and the pipelines
- Weekly or as needed conference calls with interstate pipelines will commence starting Nov. 1 (2015) through March 1 (2016)
- Daily review of gas nominations by PJM scheduled generators will start November 1, 2015.
- Daily review of Gas Electric Bulletin Boards (EBBs) for critical notices potentially impacting generation in the footprint.
- Ongoing PJM, MMU and Pipeline MOU discussions.

Capacity Performance

PJM instituted a major reform based on market incentives, the **Capacity Performance** Initiative. Capacity resources may receive higher payments in return for their investment in modernizing equipment, firming up fuel supplies or redesigning to fit dual-fuel use. The program will enhance reliability, as generators that do not perform will pay penalties, which may be greater than they receive in capacity payments. Early indications are that most power plants intend to improve reliability by increasing the use of dual fuel as a more cost-effective strategy than paying a substantial year-round premium for guaranteed gas supply.

NERC explains that "capacity performance will enhance the incentives for capacity resources to be available when needed most, help reduce price spikes during system emergencies, and reduce the chance of expensive forced outages."[6] It also states that, "because of the nature of the forward capacity market in PJM, the effect of capacity performance program will not be seen until the winter of 2016-2017."[7]

Demand Response

On January 27, 2016 the Supreme Court ruled that the federal regulator (FERC) has authority to regulate wholesale Demand Response. The ruling promises to have a major impact within the PJM region. "Having survived a legal challenge that could have crimped its development for years, demand response now has an opportunity to take a central role in combating climate change and reducing energy bills by taking advantage of the growing spread of advanced metering technology."[8]

Prior to the ruling, NERA noted the importance of demand response across the US, "the addition of new demand response programs continues to help address potential resource adequacy concerns for areas during their winter peak. These programs vary greatly in their availability and load reduction capability, but often provide the flexibility needed during extreme conditions."

"In past years, **no demand response** was available in PJM outside the summer peak period from June 1 through the end of September. In recent years, PJM has added a demand response type that is available all year and for unlimited uses. ***525 MW of demand response is now available*** during

[6] NERC, p.9
[7] NERC, p.12
[8] "Legal Challenge Behind it, DR Seeks to Overcome Behavioral Resistance, Varying State Rules," RTO Insider, February 2, 2016

the winter peak period, which is an increase over last winter's amount of 43 MW." [9]

Gas Market Scheduling

In agreement with Skipping Stone's assessment, FERC issued subsequent orders regarding gas-electric coordination. On April 16, 2015, FERC issued a revised final rule to improve coordination and "better ensure the reliable and efficient operation of both the interstate natural gas pipeline and electricity systems."[10] Furthermore, on October 16, 2015, FERC amended its regulations to incorporate Version 3.0 of business practice standards adopted by the Wholesale Gas Quadrant of the North American Energy Standards Board (NAESB) applicable to interstate natural gas pipelines. As part of the Commission's efforts to harmonize gas-electric scheduling coordination, these updated business practice standards contain and supplement the revisions to the NAESB scheduling standards accepted by the Commission in Order No. 809,[11] all required to be implemented on April 1, 2016.[12]

Additional Pipeline Capacity

Finally, newly approved and constructed pipeline projects have come online since the Polar Vortex. The extensive building of new pipeline capacity from the Marcellus region is documented in FERC's 2015-2016 Winter Energy Market Assessment:

> Growing Northeast natural gas production and new pipeline takeaway capacity continue to reshape the nation's flow patterns and prices. Since the start of 2014, 9 Bcfd of capacity additions have come online to further link production with markets in the Mid-Atlantic [includes New Jersey], the Southeast, and the Midwest. As a result, the Northeast corner of the nation became a net exporter of natural gas for the first time this summer.[13]

Experts point to PJM's actions since the Polar Vortex as exemplary of "ongoing growth and responsiveness in the face of 'peak event' pressures."[14]

The impact of capacity performance, a greater emphasis on demand response and improved gas market scheduling will only serve to increase reliability going forward, with major additional impacts in Winter 2016-2017 and beyond.

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[9] NERC, p.34
[10] U.S. Federal Energy Regulatory Commission. 151 FERC 61,049. 18 CFR Part 284, Docket No. RM14-2-000 (2015). Retrieved from https://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf
[11] 80 FR 23197
[12] FERC. 153 FERC 61,061. 18 CFR Parts 157, 260, and 284, Docket Nos. RM96-1-038 and RM14-2-003 (2016). Retrieved from https://www.ferc.gov/whats-new/comm-meet/2015/101515/G-1.pdf
FERC adopts NAESB Standards Version 3.0, Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (Order No. 587-W).
[13] FERC, *2015-16 Winter Energy Market Assessment*. (2015, October). Item No. A-3. Retrieved from https://www.ferc.gov/market-oversight/reports-analyses/mkt-views/2015/10-15-15-A-3.pdf
[14] Tierney, S., Svenson, E., & Parsons, B. (2015). Ensuring Electric Grid Reliability Under the Clean Power Plan: Addressing Key Themes from the FERC Technical Conferences. Retrieved from http://www.westerngrid.net/wp-content/uploads/2015/04/Full-Report-Ensuring-Electric-Grid-Reliability-Under-the-Clean-Power-P....pdf

3. ASSESSMENTS CONCLUDE THAT PJM IS WELL PREPARED

Put to the test in the harsh winter conditions of 2014/2015, the electric system experienced new record-breaking peak loads and, yet, PJM's new policies enabled the system to maintain reliable operations.[15]

The North America Electric Reliability Corporation (NERC) issued a Winter Reliability Assessment in December 2015, stating, "Regions and assessment areas have prepared well for the upcoming winter season. Lessons learned from the past two winter seasons have been implemented in planning and operating procedures at various entities."[16]

NERC describes in greater detail the success of winter weather practices adopted by PJM.

> PJM set a new wintertime peak demand record of 143,086 MW in 2015 as compared to 142,863 MW in 2014 during the polar vortex event. PJM resource performance improved during the winter of 2014-2015 in relation to performance in the winter of 2013-2014. This is attributed to the steps PJM and generation owners initiated after the winter of 2013-2014 experience. These steps included, but are not limited to, prewinter operational testing for dual-fuel and infrequently run units, a winter preparation checklist program, better communication on fuel status, and increased coordination with natural gas pipelines. Generating units that participated in the prewinter operational testing observed a lower rate of forced outages compared to those that did not test in the 2014-2015 winter. The programs in place will be continued in the winter of 2015-2016. [17]

FERC also provides a favorable assessment of conditions heading into Winter 2015/2016.

> The U.S. natural gas market is well supplied, with ample production and storage. Record breaking production continues despite lower rig counts, increased exports, and the collapse of oil prices. New natural gas pipeline expansions and projects to reverse flows on some pipelines will also provide more transportation capacity from producing to market areas this winter, though no capacity additions have been made in New England.[18]

4. ADDITIONAL PIPELINES ARE NOT REQUIRED FOR RELIABILITY

PennEast owners have tried to justify a new pipeline based largely on supposed cost savings that would occur today if price spikes experienced during the Polar Vortex were to reoccur. As we have shown, FERC, PJM and the North American Reliability Corporation conclude the opposite – that conditions have fundamentally changed since 2014.

The study by Concentric that makes these economic claims is fundamentally flawed and should not be used to justify an unnecessary pipeline.

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[15] See Tierney et al. February 2015, at p. ES-2.
[16] NERC, p.5.
[17] NERC, p.8
[18] 2015-16 Winter Energy Market Assessment, Item No. A-3, October 15, 2015, slide 2.

New England presents further evidence that pipeline capacity is not the only way to address possible pipeline supply constraints. Extensive reforms have been enacted in New England, a region with substantially fewer pipelines than New Jersey. Reforms were effective in Winter 2014/2015, as explained by Conservation Law Foundation,

> "Despite dire predictions and some of the worst winter weather on record, [with a temperature in the Boston area about 4°F below historical averages and 1.5°F colder than the year before] there wasn't a crisis. Modest market shifts made a huge difference, driving down prices, assuring the lights stayed on, and calling into question the wisdom of the region making big new bets on gas pipelines and transmission infrastructure."[19] "This winter's most important lesson was that we can significantly reduce winter volatility and prices by more wisely using and upgrading the infrastructure we already have. Wholesale prices were way down, and electric reliability wasn't at risk, despite the coldest February on record."[20]

The Acadia Center also studied the winter of 2014/2015 and concluded,

> **"This winter has undermined calls for such radical action.** Despite colder weather and greater demands on the energy system, prices for natural gas and electricity on wholesale markets were far lower than last winter. These lower wholesale prices will soon be filtering through to consumers when electric rates are reset for the next six-month billing cycle. **These price cuts occurred without any new pipeline capacity.** Instead, incremental reforms of the region's energy markets allowed us to make better use of existing resources, energy efficiency provided significant relief, and the plunge in prices for liquefied natural gas (LNG) and oil has recalibrated the economics of the region's power market." [21]

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[19] Courchesne, C. (2015, March 24). The Final Word on Winter in New England's Energy Markets, Part I: The Difference a Year Makes [Conservation Law Foundation]. Retrieved from http://www.clf.org/blog/clean-energy-climate-change/the-final-word-on-winter-in-new-englands-energy-markets-part-i-the-difference-a-year-makes/

[20] Courchesne, C. (2015, April 2). The Final Word on Winter in New England's Energy Markets, Part III: Some Lessons from a Calm, Cold Winter [Conservation Law Foundation]. Retrieved from http://www.clf.org/blog/clean-energy-climate-change/the-final-word-on-winter-in-new-englands-energy-markets-part-iii-some-lessons-from-a-calm-cold-winter/

[21] Shattuck, P., Howland, J., & Kumar, V. (2015, June 1). The Missing Energy Crisis. Part 1 of 3. CommonWealth Magazine. Retrieved from http://acadiacenter.org/document/the-missing-energy-crisis/

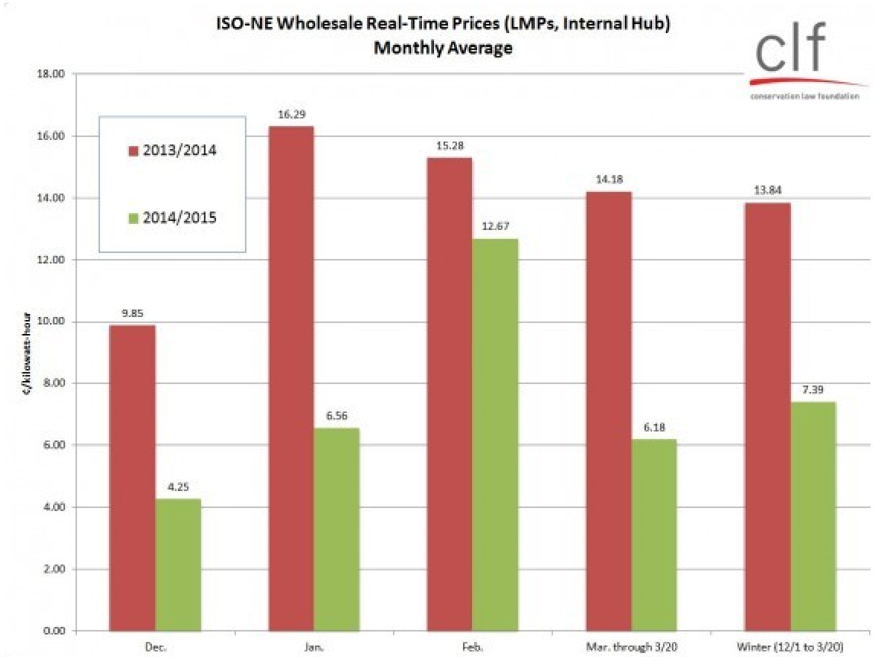

Figure 3: Despite the colder weather and record gas demand, overall wholesale electricity prices were 45 percent lower on average from December 1, 2014 – March 20, 2015 in comparison to the same time period the previous winter of 2013/2014.

Since 1909

Watson Stevens Rutter & Roy LLP

Michael K. Rutter
MRutter@watsonstevens.com

Christine A. Roy
CRoy@watsonstevens.com

Of Counsel

Mark Stevens
MStevens@watsonstevens.com

Stephen J. Resnick
rsnck@verizon.net
Member NJ and NY Bars

Richard B. Tucker, Jr.
RTucker@watsonstevens.com
Member NJ and FL Bars

Monica N. Stahl
MStahl@watsonstevens.com
Member NJ and NY Bars

Heather N. Oehlmann
HOehlmann@watsonstevens.com

Richard G. Scott
RScott@watsonstevens.com
Member NJ and PA Bars

Daniel S. Shehata
DShehata@watsonstevens.com
Member NJ and NY Bars

Camille M. Johnson
CJohnson@watsonstevens.com
Member NJ and NY Bars

Russell E. Watson (1909-1970)
A. Dudley Watson (1917-1990)
Edward L. Webster Jr. (1950-1987)
Joseph Stevens (1986-2003)

December 24, 2015

VIA CM/ECF
Office of the Clerk
United States Court of Appeals for the Third Circuit
21400 U.S. Courthouse
601 Market Street
Philadelphia, PA 19106-1790

Re: New Jersey Conservation Foundation et al v. The New Jersey Department of Environmental Protection and Transcontinental Gas Pipe Line Company, LLC
Docket No. 15-2158

Dear Sir or Madam:

This office represents Respondent, Transcontinental Gas Pipe Line Company, LLC ("Transco"), in the above matter. Transco respectfully submits this letter brief and (Fourth) Supplemental Declaration of John B. Todd ("Todd Declaration") filed herewith in response to the motion filed by Petitioners, New Jersey Conservation Foundation, Stony Brook-Millstone Watershed Association, and Friends of Princeton Open Space, requesting that this Court take judicial notice of certain correspondence between Transco and the Federal Energy Regulatory Commission ("FERC"). Please be advised that Transco does not object to this request. However, as explained in detail below, the correspondence concerning the variance is not relevant to the issues on appeal, and the characterization of the correspondence by Petitioners is not accurate.

3 Paragon Way - Suite 300, Monmouth Executive Center, Freehold, New Jersey 07728
Phone: (732) 462-1990 ■ Fax: (732) 462-1993
www.watsonstevens.com

The correspondence at issue includes (1) Transco's December 14, 2015 variance request to the FERC and (2) FERC's December 14th approval of the request. The purpose of the variance was to allow Transco to bypass the remaining 2,000 feet of the Skillman Loop by tying in the completed sections of the Skillman Loop to the existing parallel Caldwell B Lateral. The tie-ins, with paired valves at two locations, are a temporary measure in order to meet customer demands for the Project for the 2015-2016 heating season and are not a permanent solution. See Todd Declaration, ¶10. The tie-ins are located entirely within the current limits of disturbance and in areas where the pipe has already been installed via conventional trenching methods. Transco holds the property rights needed to install the tie-ins at the proposed locations. See Todd Declaration, ¶¶11 & 12. The variance request was made due to the difficulties Transco has encountered during construction of the remaining 2,000 feet by horizontal directional drill ("HDD").

It should be noted that Transco initially proposed to use the open cut method of construction through this area, however, the New Jersey Department of Environmental Protection ("NJDEP") ultimately required Transco to construct the pipeline in this area using the HDD. Despite overcoming various obstacles and delays, it does not appear that it will be possible to complete the second HDD attempt. See Todd Declaration, ¶9.

Petitioners argue that judicial notice of Transco's variance request and approval by FERC are necessary since the documents "directly contravene representations that Respondents made to both NJDEP and to this Court" as well as representations contained in the administrative record. See Petitioners' Letter Brief, pp. 3-4. Specifically, Petitioners cite to certain statements made by Transco as part of its NJDEP permit application that "Transco cannot expand the certificated corridor that has been vetted and analyzed over the past 3 years." See Petitioners' Letter Brief, p. 4. They also argue that during the course of the appeal, Transco asserted that NJDEP was "constrained from considering less damaging alternate pipeline routes," and therefore the variance demonstrates that Transco could "quite easily have obtained a variance from the certificated route…." See Petitioners' Letter Brief, p. 5.

However, Petitioners' arguments ignore the express reason for the variance request, namely, to perform work *within* the certificated corridor to allow it to bypass the remaining 2,000 feet of the Skillman Loop by tying in the completed sections of the Loop in order to meet customer demands for the Project for the 2015-2016 heating season. Petitioners also fail to acknowledge that NJDEP had been involved in the review of the Project since April 2013. NJDEP, during its informal and then formal participation in the FERC process, never sought to change Transco's proposed route paralleling the existing pipelines. NJDEP's participation in the FERC process was for the apparent purpose of minimizing any environmental impacts along the proposed, and later certificated, route. See Todd Supplemental Declaration ¶36. After fully analyzing all alternatives, NJDEP agreed that the FERC certificated route was the preferred route since the new pipeline would be collocated with it existing pipeline, thereby resulting in the least disturbance to environmental resources. See NJDEP's Merits Brief, filed September 10, 2015, at p. 38.

Petitioners also incorrectly state that the purpose of Transco's variance request is to "avoid any impacts to wetlands, transition areas, or riparian areas' to meet service commitments for the Skillman Loop of the Leidy Project." See Declaration of Aaron Kleinbaum, ¶2. The variance request has nothing to do with avoiding environmental impacts. Transco merely represented to FERC that the tie-in work would (1) be completed within the previously certificated corridor, (2) not require impacts to any wetlands, transition areas, or riparian areas, and (3) not affect any new landowners. The fact that the work would have no additional environmental impacts was not the reason for requesting the variance, but was simply one of several factors set forth in Transco's request to FERC. See Petitioners' Declaration, Exhibit 1.

For the reasons stated herein, Transco's December 14th variance request and FERC's approval thereof are not relevant to the issues on appeal before this Court and may only serve to confuse.

Respectfully submitted,

/s/ Christine A. Roy
CHRISTINE A. ROY

UNITED STATES COURT OF APPEALS
FOR THE THIRD CIRCUIT

NEW JERSEY CONSERVATION FOUNDATION; STONY BROOK-MILLSTONE WATERSHED ASSOCIATION; AND FRIENDS OF PRINCETON OPEN SPACE, PETITIONERS, V. THE NEW JERSEY DEPARTMENT OF ENVIRONMENTAL PROTECTION; AND TRANSCONTINENTAL GAS PIPE LINE CO., RESPONDENTS.	Case No. 15-2158 **(FOURTH) SUPPLEMENTAL DECLARATION OF JOHN B. TODD**

JOHN B. TODD, of full age, hereby declares, pursuant to 28 U.S.C. §1746, as follows:

1. I am employed by Transcontinental Gas Pipe Line Company, LLC ("Transco" or the "Company") as its Project Manager for the Leidy Southeast Expansion Project ("Project"), and have personal knowledge of the facts contained in this Declaration.

2. As Project Manager, I am highly involved with the implementation and planning for construction of Transco's Project. In connection with the planning of the Project, I am familiar with the need for new pipeline capacity on Transco's pipeline system in order to meet customer demand

(these customers are referred to in the industry as “shippers”) and construction requirements, including schedules for the construction of the physical facilities that are proposed. Further, I am generally familiar with the environmental permits, clearances, and approvals needed to begin and complete construction of the Project on a timely basis.

3. I make this Fourth Supplemental Declaration for the purpose of updating the Court concerning the status of construction of the pipeline across the remaining regulated area along the Skillman Loop in New Jersey and in response to the motion filed on December 17, 2015 by Petitioners, New Jersey Conservation Foundation, Stony Brook-Millstone Watershed Association, and Friends of Princeton Open Space. This declaration supplements my original declaration dated June 11, 2015, filed in support of Transco’s opposition to Petitioners’ Emergency Motion For Stay (“Original Declaration”), my Supplemental Declaration dated September 10, 2015 (“Supplemental Declaration”), my Second Supplemental Declaration dated October 2, 2015, and my Third Supplemental Declaration dated October 23, 2015.

<u>Status of Construction</u>

4. As I represented in my Second and Third Supplemental Declarations, construction across the remaining regulated area along the Skillman Loop

includes streams SS-002-005 and SS-002-006, and wetlands WW-002-008 and WW-002-009, located in Montgomery Township, New Jersey, which are being crossed by the trenchless construction method known as horizontal directional drill ("HDD") to avoid impacts. The total length of this crossing is approximately 2,000 feet and the maximum depth is approximately 80 feet below the surface.

5. Transco's HDD contractor Laney Directional Drilling Co. ("Laney") commenced drilling operations on the proposed HDD installation directly north of Cherry Valley Road on July 6, 2015.

6. It became clear early in the drilling process that geology differed drastically from the other two successfully completed drills on the Project. This is attributed to its proximity being closer to the Princeton Ridge, an area within the municipality of Princeton and northern Mercer County, New Jersey.

7. On September 15th, during the course of performing a procedure to ensure that the drill hole was clean of debris, a drilling tool was lost downhole at a location that is the approximate mid-point of the drilled hole at a depth of 66 feet.

8. Laney was ultimately unable to retrieve the drilling tool, so a second attempt to complete the HDD, along a slightly different line within Transco's easement, began on October 14th.

9. On December 12th, after overcoming various problems over several weeks and installing approximately 1000-feet of the 2,000-feet of pipe, Laney experienced increased friction so a hydraulic hammer was employed in an effort to free the pipe and complete the installation. During the course of utilizing this tool the pipe became further lodged downhole halting the installation process. It does not appear that it will be possible to complete the second HDD attempt.

Variance Request

10. On December 14, 2015, Transco submitted a variance request with the Federal Energy Regulatory Commission ("FERC"). Specifically, Transco requested permission to tie-in completed sections of the Skillman Loop to the existing Caldwell B Lateral which runs parallel to it. The tie-ins, with paired valves at two locations, are a temporary measure in order to meet customer demands for the Project for the 2015-2016 heating season and are not a permanent solution.

11. The tie-ins are located entirely within the current limits of disturbance and in areas where the pipe has already been installed via conventional trenching methods.

12. Transco holds the property rights needed to install the tie-ins at the proposed locations.

13. In its variance request, Transco represented that regulated features such as wetlands, transition areas and riparian areas would not be impacted in connection with the proposed work.

14. FERC approved Transco's variance request on December 14, 2015.

15. On December 17th, Transco, among other things, requested from FERC authorization to place into service that portion of the Skillman Loop that has been completed.

16. The tie-ins were installed on or about December 18, 2015.

17. Transco expects that the completed portion of the Skillman Loop will be ready for service on December 23, 2015.

Completion of the Skillman Loop

18. As stated in my declaration dated October 23, 2015, Transco, as a backstop measure, is seeking a major permit modification from the New Jersey Department of Environmental Protection in the event that it must complete the construction across the remaining 2,000 feet by open cut construction.

19. Assuming that a major permit modification is required to complete the construction of the pipeline across the remaining 2,000 feet by open cut construction, Transco would complete the construction after permit approval which would push completion of the Skillman Loop to sometime in early Spring of 2016.

Executed on December 23, 2015

JOHN B. TODD

CERTIFICATE OF SERVICE

I hereby certify that on December 24, 2015, I caused a copy of Transcontinental Gas Pipe Line Company, LLC's response to Petitioners' Letter Motion for Judicial Notice and the Fourth Supplemental Declaration of John B. Todd to be served upon all counsel of record via CM/ECF.

/s/ Christine A. Roy
Christine A. Roy, Esq., NJ Bar No.: 020631992
Watson, Stevens, Rutter & Roy, LLP
3 Paragon Way, Suite 300
Freehold, New Jersey 07728
Phone: 732-462-1990
Attorney for Respondent Transcontinental Gas Pipe Line Company, LLC

Dated: December 24, 2015

Report of Dr. Emile DeVito on PennEast's Impacts to Documented Populations of Threatened Long-Tailed Salamander and Endangered Red Shouldered Hawk

Education & Experience

I received a doctorate in Ecology in 1988 from University of Wisconsin-Madison, and a B.A in Zoology from Rutgers University in 1981.

Since 1989, I have served as the Manager of Science and Stewardship for New Jersey Conservation Foundation ("NJCF"). NJCF is a nonprofit corporation[1] whose mission is to preserve New Jersey's land and natural resources for the benefit of all, to protect natural areas and farmland through land acquisition and stewardship, promote strong New Jersey land use policies, and forge partnerships to help safeguard clean drinking water and other natural resources. NJCF has around nine thousand members, supporters and volunteers. NJCF owns in excess of twenty thousand acres of lands, which it stewards for the benefit of the public and the environment.

As Manager of Science and Stewardship for NJCF, I am responsible for creating management plans for NJCF's large land holdings, designed to protect and enhance their biological diversity, and to protect and enhance populations of New Jersey's rare, special concern, threatened, and endangered species of plants and animals. I am also responsible for educating government officials, advocacy groups, land trusts, teachers and students about the ecology and restoration of forest habitats and the conservation management

[1] as defined at 26 USC 501(c)(3)

needs to vertebrates, with particular emphasis on rare plants, migratory birds, amphibians, and reptiles.

Since 1998, I have served as trustee of the Pinelands Preservation Alliance, a nonprofit organization dedicated to preserving the resources of the New Jersey Pinelands.

Since 1992, I have served as an appointed public trustee of the New Jersey Natural Lands Trust. The Trust is an agency within the New Jersey Department of Environmental Protection ("NJDEP"), whose mission is to preserve land in its natural state for enjoyment by the public, and to protect natural diversity through the acquisition of open space.

In 1994, I was appointed to the NJDEP New Jersey Division of Fish and Wildlife Endangered and Non-Game Species Advisory Committee. The Committee advises NJDEP personnel on their mission to actively conserve New Jersey's biological diversity by maintaining and enhancing endangered, threatened, and nongame wildlife populations within healthy, functioning ecosystems.

In these roles, I have conducted over 100 analyses of the impacts of proposed developments and projects on New Jersey's plant and animal species.

In April of 2015, I began an analysis of the effects of the proposed PennEast Pipeline on New Jersey's plant and animal species.

Part I: Impacts to Long-Tailed Salamander

According to the NJDEP Division of Fish and Wildlife, "Long-tailed salamanders tend to inhabit clean, calcareous (limestone) spring-fed seepages, spring kettleholes, swampy floodplains, artesian wells, and ponds associated with springs" and the [A]quatic habitats occupied by long-tailed salamanders often occur within upland deciduous forests". Moreover, according to the NJDEP, "[l]ong-tailed salamanders require both wetland and upland habitats. The forests types typical of their habitat includes mature, closed canopy maple/mixed deciduous, mixed hardwood, or hemlock/mixed deciduous woodlands." (NJDEP-DFW, 2002). In Hunterdon County, long-tailed salamanders have been found to occur in shale banks, springs, spring runs, river sides, floodplains, caves, mines, and streams. (NJDEP, 2013). Long-tailed salamanders, while often found in areas with limestone (calcareous) geology, are not restricted to such areas, and are known to occur in streams with shale and argillite bedrock in Hunterdon County, NJ.

PennEast's current pipeline route will bisect this threatened species' existing documented habitat. The stream and wetland crossing method proposed by PennEast for this steeply sloped forested location will be open-cut and will also require a 75 foot swath through the forested wetlands bordering the stream, and a 125-135 foot swath of clearing through the forested riparian zone, which consists of both upland and wetland habitat elements. Since the Nishisakawick Creek is an antidegradation stream that requires a 300 foot wide riparian zone, these impacts are extremely significant because they will not only devastate the salamanders' forest habitat but result in the degradation of the creek. Moreover, the presence of long tailed salamander would result in a wetland designation of exceptional value. Studies by Cecala, et al (2014) demonstrate that any canopy gap, even as short as 10 m (32.8 feet) of channel length, negatively affects salamander movement within streams and that gaps >80 m (262.5 feet) may completely fragment stream populations. Cecala et al (2014) go on the state that their results indicate that movement by all salamander life stages were negatively affected by the presence of a canopy gap. Salamander avoidance of canopy gaps, such as that created by a pipeline corridor is considered to be the result of negative phototaxis (Cecala, 2015).

The removal of riparian and upland forest will unalterably change the structure and character of the habitat that they require. Canopy gaps created by forest removal would render the habitat open to sunlight which can result in thermal impacts to salamanders, alter site hydrology thus ruining salamander microhabitat by causing large daily swings in temperature and humidity, increase predator densities and reduce basal resources resulting from canopy removal (Wallace et al. 1997). In addition, even small canopy gaps that may have little influence on the physical structure of a stream can dramatically reduce habitat movement for aquatic animals Cecala et al (2014). Streams passing through canopy gaps may warm rapidly. Canopy gaps created by pipelines act as corridors for predators. Regions of limited canopy cover may represent poor habitat quality due to the high predator densities associated with human development (Chalfoun et al. 2002). PennEast (Resource Report 3) indicates that "new disturbances that create openings can encourage predatory species such as dogs, cats, raccoons, and snakes to enter an area that they may not have previously inhabited" and goes on to indicate that this situation can lead to increased predation on amphibians. Kiviat (2014) concludes that the species should be expected to be vulnerable to physical and chemical changes in the headwater streams and moist riparian habitats where it occurs. Barret and Price (2002) opine that "salamanders are highly sensitive to urbanization of forested land within watersheds" and recommend the protection of riparian and critical upland habitat with native vegetation to protect streams. Beans and Niles (2003) also recommend that both the aquatic and protected habitats occupied by long tailed salamanders in New Jersey should be protected from development and degradation.

Moreover, disturbance associated with the installation of the pipeline would not only impact the value of the habitat as a result of increased light and higher temperature but would modify soil structure as a result of compaction. Olson and Doherty (2011) found that soils within pipeline corridors had higher bulk density, lower depth to refusal and lower soil moisture. The decrease in soil moisture is an especially relevant impact to salamander habitat since they are prone to desiccation. PennEast indicates in Resource Report No. 3 that in-stream pipeline construction could remove vegetation and habitat, temporarily increase sedimentation and turbidity in the water column, increase the potential for streambank erosion and temporarily disturb streambed foraging areas. The impacts referenced by Penn East are all extremely detrimental to long tailed salamander even if of short duration.

The PennEast project activities proposed in the vicinity of milepost 88.4 will result in the following; the clearing of forested land, the regrading of the pipeline ROW, the compaction of soils, and the alteration of the physical structure of the native soils within the ROW. The replacement of forest with lower growing vegetation will increase the amount of stormwater runoff generated during each storm event. It is well established that following land development, especially development on steep slopes and resulting in forest clearing, peak flows and total runoff volumes will increase. As such, there will be both a greater volume of runoff and velocity as a result of pipeline construction. In addition to increasing the volume and velocity of runoff entering stream systems, these conditions will increase the mobilization and transport of pollutants (including sediments and nutrients), increase the likelihood of scour and erosion and decrease the total volume of precipitation infiltrated back into the soil leading to a decrease in the recharge of the surficial aquifer. Moreover, the increase in runoff will be exacerbated by the presence of the compacted and disturbed soils created during pipeline installation. Due to the steep slopes adjacent to the Little Nishisakawick Creek the increased runoff and compacted soils will increase the potential for erosion thereby adding yet another threat to the existing population of long-tailed salamander. The increase in runoff and sediment loading can negatively impact long-tailed salamander habitat by infilling interstitial stream habitat and smothering aquatic benthic macroinverebrates, the long-tailed salamander's primary food source.

As previously stated the proposed PennEast project will substantially modify the existing habitat of long tailed salamander on the little Nishisakawick Creek as a result of the elimination of the forested component of their habitat. Due to the conservative habitat requirements of long tailed salamander, the extant population of this listed species cannot be replaced or relocated through current mitigation measures. As such there is no way to compensate for the substantial impacts that the pipeline will have on this species and its habitat outside of avoidance.

Part II: Impacts to Red Shouldered Hawk

PennEast's Resource Report no. 3 indicates that several forest interior wildlife species may be found in the project area including raptors such as the state-threatened barred owl (Strix varia) and the state endangered red-shouldered hawk (Buteo lineatus). The report also provides some of the reasons that red-shouldered hawk is listed as being endangered and states the following: "Cutting of large continuous tracts of forests have brought declines in breeding populations in several areas. Fragmentation of Contiguous forests into smaller blocks creates more habitat for larger more aggressive species (red tailed hawk, great-horned owl and red shouldered hawk) which can out compete the red-shouldered hawk. It is directly related to the proposed construction of a new linear infrastructure corridor that establishes the basis for concern relative to habitat fragmentation especially with regard to species already considered to be threatened or endangered. Impacts to species such as the red shouldered hawk are not just ecological impacts but, as in this case, necessitate the need to satisfy New Jersey's environmental regulatory requirements.

The impact related to the removal of forested habitat in the area is especially relevant when assessing the effects of forest fragmentation. Although Resource Report No. 3 provides a generalized summary of the impacts associated with fragmentation, it provides no site-specific detail. The currently fragmented nature of the landscape in the vicinity of the pipeline should be the cause for a greater level of concern for rare area sensitive species such as the red shouldered hawk and barred owl.

The maintenance of the populations of listed species is also of direct concern to the NJDEP as the permit program emphasizes that an individual Freshwater Wetland Permit will not jeopardize the existence of a local population of a listed species. Based on the level of fragmentation in the area in the vicinity of the PennEast pipeline it is possible, if not likely, that any existing population of red shouldered hawk is a remnant population that may currently be associated with a suboptimal territory and as such the population would be very susceptible to further reduction in habitat. In a study done in southern Michigan, red-shouldered hawks managed to "hang on" for several years before being replaced by red-tailed hawks (USDA, December 2002). The Resource Report did correctly indicate that the alteration of habitat would foster the use by red tailed hawks which can ultimately outcompete red shouldered hawk for use of limited resources.

The issue of competition is especially relevant to the red shouldered hawk as increased fragmentation can result in greater competition with two another raptor species, red tailed hawk and great horned owl. Open canopy and forest fragmentation enables red tailed hawks to displace or kill red shouldered hawks (Bryant, 1986). In addition, forest clearing can cause red-shouldered hawks to be out-competed by red-tailed hawks (Dykstra, 2001, Moorman and Chapman 1996). According to Bean and Niles (2003) forest fragmentation favors habitat generalist species such great horned owl, which he describes as a voracious predator of both adult and young red shouldered hawk, and goes on to indicate that the hawks may abandon sites in which they have experienced predation. Bryant (1986) also reported that selective cutting in woodlots and failure to maintain uncut buffer zones around traditional Red-shouldered Hawk nest sites may result in local extirpation of the species.

Today it is believed that fewer than 20 pairs of red-shouldered hawks breed in New Jersey, and little is known about whether this number is increasing or decreasing, (Wurst, undated). Dykstra et al (2001) indicate that continued urban sprawl and suburban development is a threat to Red-shouldered Hawks and that they have been pushed out of traditional nest sites and nearly half of nests studied between 1963 and 1977 were abandoned. Dykstra concluded that due to the history of fragmentation and competition it was unclear whether suburban red-shouldered hawk can sustain themselves. Moorman and Chapman suggest that contiguous floodplain forests must be left relatively undisturbed to conserve this species. As such, the generalized view of fragmentation provided in the Resource Report and the absence of any attempt to address fragmentation impacts to this species or any other forest interior species simply does not fulfill their obligation to satisfy the minimum requirements of a NEPA analysis or the information necessary for an individual FWPA permit as well as a FHA individual permit.

U.S. Department
of Transportation
**Federal Aviation
Administration**

Flight Standards District Office

961 Marcon Blvd, Suite111
Allentown, PA 18109-9371
Phone (610)264-2888
FAX (610)264-3179

January 14, 2016

File: CEA0520160005

Ms. Jacqueline Evans
112 Worman Road
Stockton, NJ 08559

Dear Ms. Evans:

This letter is in response to your complaints from September 20, 2015 through December 7, 2015, concerning flights of various types of aircraft over your property in Stockton Township, New Jersey. You indicated these flights were in support of PennEast Pipeline survey operations.

Regarding flights before December 2015 for which you were able to provide registration numbers, we have determined those flights were conducted by aircraft operated by several flying schools in your vicinity. Some of the maneuvers you described are typical of student flights, although we cannot be certain they were strictly conducted by student pilots. Regardless, as long as these flights are conducted in accordance with the "Rules of the Air", Code of Federal Regulations (CFR) Part 91, they may be legally conducted over your property.

Of specific interest to you were the rules for minimum safe altitude; therefore, we discussed and sent you those rules by e-mail on November 13, 2015. The rule, Code of Federal Regulations (CFR) 91.119, pertains to both helicopter and fixed wing operations. We also contacted the flight schools operating these aircraft. We approached them from the standpoint of the FAA philosophy of "fly neighborly". This approach encourages pilots to carefully abide by the rules of the air and to conduct their flights in different airspace from time to time. This was a joint effort conducted by the Allentown and Philadelphia Flight Standards District Offices.

Concerning the flight conducted on December 7, 2015, by a Bell 407 helicopter, N407J, this was a flight on behalf of the PennEast Pipeline Project for the purpose of aerial survey along the proposed pipeline route. We reviewed the qualifications and procedures of the operator that conducted this operation, and the statements plus photographs submitted to us by witnesses that observed it. We found the operator that conducted the operation to be qualified to do it, and the operation conducted in accordance with applicable CFRs.

The statements and photographs submitted to us did not meet the evidentiary requirements supporting a finding of violation sufficient for us to proceed with any FAA action. Based on all the facts and circumstances regarding this matter, there is insufficient evidence at this time to support further investigation. Accordingly, we consider the matter closed. However, if you have any new information that would assist the FAA in pursuance of an action, please do not hesitate to contact us at this Flight Standards District Office.

Thank you for your concern and interest in aviation safety.

Sincerely,

Arthur N. Brownell

Arthur N. Brownell
Aviation Safety Inspector-Operations

Phone Conversation 1/5/16
Between Jacqueline Evans and Jeff England of Penn East
Original recording was 19:01
Recorded by Jacqueline Evans
Transcribed by Samantha Messina
A = Jacqueline Evans
B = Jeff England

Evans: Yeah well that's that's where we are all stuck because nobody is going to let you on their property so (*laughs*) (England: *Unclear*) you can't do your surveys except for from the air triangulating from a helicopter late at night with people creeping around woods. I mean I don't know I think that's the only way that you guys can get this like surveying and I don't think that that's legal so I don't know how you are gonna be able to get away with all this

England: Well those those surveys don't don't I mean we can't obtain those surveys from the air we it's it has to be on the ground because in order to evaluate wetlands it's not something you can just look at. You have to go in and and um really look at the plant life around and then you basically take a little plug of dirt that's about an inch you know and and you look at the dirt and check for subsoil you know the soil characteristics and that's the only way you can evaluate it truly though I mean it's wetlands so. Not from the air.

Evans: Well and then I have another question well because you know there uh. And and right now I'm I'm looking into this legally. Your surveyors were trespassing on my property and so all whatever survey information you have since you started this project has been obtained illegally and uh that that's that will that will come to. I will do something about that. that that I am not I I I don't want this. I am not going to cooperate with it and I am going to continue to live my life and fight it and I don't think it's going to happen and I am just going to continue to have my farm and my children here and I'm not I'm not going for this and so

(England: Well it's not ma'am) it's it's definitely nobody else has interest in flying over this area for four months but you people. Nobody. it's not, the same planes over and over nobody has interest in in this area like that it it makes no sense umm

England: I guess the only comeback I have in that I don't know that we'll agree but the only the only comeback I have for that is we have no interest in flying over incessantly. It does we gain no information from that so it's just it's not um you know we don't we obviously don't want to spend money to fly around for no reason and then particularly at night. I mean you know even if you know there are times when when when it does make sense for us to to fly a route to to evaluate things um you know but I like I said it's happened on the count on one hands the number of times it's happened in the past two years and umm but even but even then there's there there's zero information that we can gain from flying at night so you know (*stutters*). I know you probably don't believe me but I'm I'm being one hundred percent uh honest with you in saying that it's it's not PennEast. (Evans:Yeah Well) And as far as the um you know our subcontractors go um any time any one of our subcontractors or their subs or blah blah blah um the whole way down the line get to conduct a flight you have to be approved by my and and and um (*stutters*) Um I I can't I know that that um I know yourself and and probably a lot of other folks won't believe me but um uh all I can do is give you my word and you know …