

# PennEast Analysis of Alternatives

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For

The New Jersey Conservation Foundation



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# PennEast Analysis of Alternatives

## Executive Summary

As part of the Federal Energy Regulatory Commission application process, PennEast is required to complete an analysis to determine whether alternatives to its proposed pipeline, including a “no build” option, exist. The Draft Environmental Impact statement issued by FERC in July 2016 contains just one paragraph from PennEast about alternatives in which it concludes, without providing analysis, that there are no alternatives to its proposed pipeline.

In the absence of a comprehensive evaluation of alternatives by PennEast, Skipping Stone was commissioned to undertake a review of alternatives to the construction of the proposed pipeline.

As set forth in the following analysis, Skipping Stone first determined the **demand requirements** in 2011 and those projected for 2030 based on the 2014 report commissioned by the National Association of Regulatory Utility Commissioners (“NARUC”) and the Eastern Interconnect States Planning Council (“EISPC”). The NARUC/EISPC report provides a detailed picture of demand for pipeline capacity that existed in 2011 and projected demand in 2030.

Next, Skipping Stone determined a conservative estimate of **physical pipeline delivery capacity** for 2011 and 2016, based on its database of pipeline capacity contracts. Skipping Stone compared the **demand requirements** to the **pipeline delivery capacity** to determine the nature of demand that was not met by pipeline capacity in 2011 and is projected to be unmet by 2030. This analysis resulted in several important insights:

- In 2011, New Jersey demand for natural gas exceeded contracted pipeline delivery capacity in New Jersey for a period of about 20 days in the winter. By definition, this demand was met in 2011. Our analysis of pipeline capacity shows more clearly the extent of demand met through resources other than pipelines in 2011. Demand of up to 1 billion cubic feet per day was met by supplemental resources. This suggests that supplemental resources were available to meet about 20% of total peak demand in 2011.
- As described more fully below, utilities are able to meet this short-term peak demand cost-effectively by using LNG and other “peak shaving” resources available to them. According to New Jersey Natural Gas, peak shaving resources are more cost-effective than building a pipeline that operates all year.
- More than 2.3 billion cubic feet per day of pipeline capacity was constructed from 2011 to 2016 into the studied market area. As a result, the amount and duration of peak demand to be met by peak shaving resources has been substantially reduced.
- Projections suggest that demand unmet by pipeline capacity will peak at 395 million cubic feet per day of capacity by 2030, far less than the demand that existed in 2011 that was met by supplemental resources. By 2030, the period of peak demand exceeding pipeline capacity is projected as only 7 days.

Skipping Stone’s analysis of existing pipeline capacity and future market demand shows that there is no demand for natural gas, even as far out as 2030, that would be unmet by either current pipeline capacity or existing supplemental resources. PennEast would add 1 billion cubic feet per day of pipeline capacity, an

amount that is unnecessary given the small amount and duration of peak demand projected and that can already be met through peak shaving resources out to 2030, assuming such facilities are not retired.

Furthermore, having concluded that the market to be addressed by 2030 is limited to peak winter demand of short duration, Skipping Stone examines an alternative of securing liquefied natural gas (LNG) through the existing pipeline network. The Skipping Stone analysis shows conclusively that there is no demand for PennEast that can't be met through existing resources or a viable alternative. These issues are unaddressed in the DEIS, and need to be considered as no action alternatives to the proposed PennEast Pipeline.

### LNG Alternative through Existing Pipeline Network

Skipping Stone evaluated a no action alternative to address this peak period demand unmet by pipeline delivery capacity. That alternative relies only on existing pipeline delivery capacity and LNG import facilities in the Northeast that already exist in 2016. The analysis of costs shows that to meet this demand the LNG import alternative offers a cost-effective alternative to the construction of PennEast. This alternative appears to be far less costly annually than the annual cost of the PennEast Pipeline spread over the same volume that would be delivered by gasified LNG to meet peak demand.

The LNG Alternative is not only lower cost, but requires no new construction, thereby avoiding local environmental impacts. Equally important, the LNG Alternative, designed to meet peak demand, would avoid creating a year-round glut of unused capacity on legacy pipelines.

<b>All-in Cost per Dth of Gas Actually Used</b>		
	<b>PennEast Pipeline</b>	<b>LNG Alternative</b>
<b>Low End Cost</b>	<b>\$99.81</b>	<b>\$8.76</b>
<b>High End Cost</b>	<b>\$149.76</b>	<b>\$11.08</b>

Source: Skipping Stone Chart 10 infra

### Peak Shaving Resources

Pipeline capacity serving New Jersey in 2016, together with existing peak shaving supplies in New Jersey, are likely more than sufficient to meet demand projections for natural gas, even during peak demand periods, out to 2030 provided such facilities and capabilities that existed in 2011 remain available.

The 2011 data suggest that because demand exceeded then existing pipeline capacity by about 20 percent for a period of 20 days, this demand was met by utilization of on-system peak shaving facilities and supplies then available in the New Jersey market. There is no reason to believe that this same capacity would not be available to local distribution companies in 2030. Moreover, assuming continued availability of the on-system peak shaving facilities and supplies, no portion of PennEast capacity would be needed to meet this projected demand.

New Jersey Natural Gas<sup>1</sup>, an owner of PennEast, made the same point in a filing to the New Jersey Board of Public Utilities in 2015.

“NJNG utilizes its LNG facilities to provide up to approximately twenty percent of its peak design day requirements. Peak shaving facilities, such as local LNG assets, provide a very cost effective means of meeting peak customer requirements in cold weather markets. The weather-sensitive nature of NJNG’s customer requirements exhibits a pronounced peak over a limited number of days. Pipeline service, designed to provide year-round availability, is less cost-effective to meet this portion of the firm requirements of NJNG’s customers.”

### Conservative Assumptions

The extent of demand unmet by current pipeline capacity could be less, as this analysis is based on several conservative assumptions about market demand and pipeline capacity:

- Pipeline capacity is estimated based on actual contracted amounts. During peak periods, even fully contracted pipelines often deliver in excess of the contracted amounts when supplies into those pipelines are received downstream of the demand nodes to which such supplies are delivered.
- The growth rate for peak period natural gas demand in New Jersey is estimated as 25% in the NARUC/EISPC Report between 2011 and 2030, a period where the population of New Jersey is expected to grow by only 10%<sup>2</sup>.
- In addition, new standards for furnace efficiency for both new construction and replacement furnaces as well as other energy efficiency measures may reduce the growth of natural gas consumption over this period.

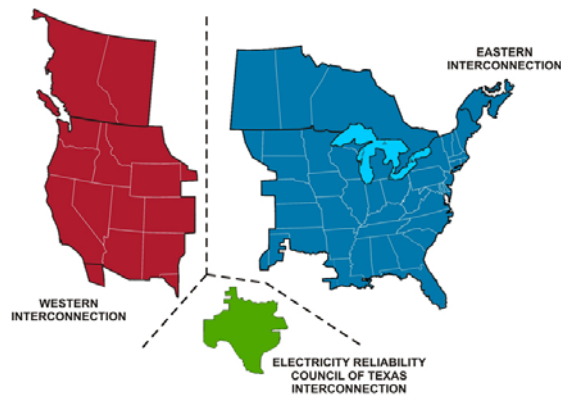
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<sup>1</sup> New Jersey Natural Gas Company for Approval of an Increase in Gas Base Rates and for Changes in its Tariff for Gas Service, approval of SAFE Program Extension, and Approval of SAFE Extension and NJ RISE Rate Recovery Mechanisms, BPU Docket No. GR15111304, at p.346. retrieved from: <https://www.njng.com/regulatory/pdf/NJNG-2015-Base-Rate-Filing-11-13-2015.pdf>

<sup>2</sup> “Projections of New Jersey’s Population and Labor Force,” NJ Labor Market Views, Issue #23, Labor Market and Demographic Research, NJ Department of Labor and Workforce Development, October 12, 2012. <http://lwd.dol.state.nj.us/labor/lpa/pub/lmv/lmv23.pdf>

## Introduction

In undertaking this analysis, Skipping Stone first drew on work done by ICF in late 2014 under a study commissioned by the National Association of Regulatory Utility Commissioners (“NARUC”) and the Eastern Interconnect States Planning Council (“EISPC”) – together NARUC/EISPC – entitled **“Study on Long-term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection”** (hereafter referred to as the “NARUC/EISPC Report”)<sup>3</sup>. The NARUC/EISPC report assembled data with respect to all regions of the Eastern Interconnect depicted in the below graphic.



Source: NARUC/EISPC Report

Within the Eastern Interconnect, the NARUC/EISPC Report looked at known and projected natural gas demand and the interaction between the gas and electric industries. The NARUC/EISPC Report looked at demand durations and demand growth in 47 sub-regions of the Eastern Interconnect. For this study, Skipping Stone looked at the NARUC/EISPC Report’s analysis of natural gas load duration curves in two of these 47 distinct modeled areas focused on by the NARUC/EISPC Report<sup>4</sup>. Those two gas demand sub-regions of the Eastern interconnect are Nos. 79<sup>5</sup> and 105<sup>6</sup> on the map that follows, and are named Philadelphia and New Jersey respectively in the NARUC/EISPC Report.

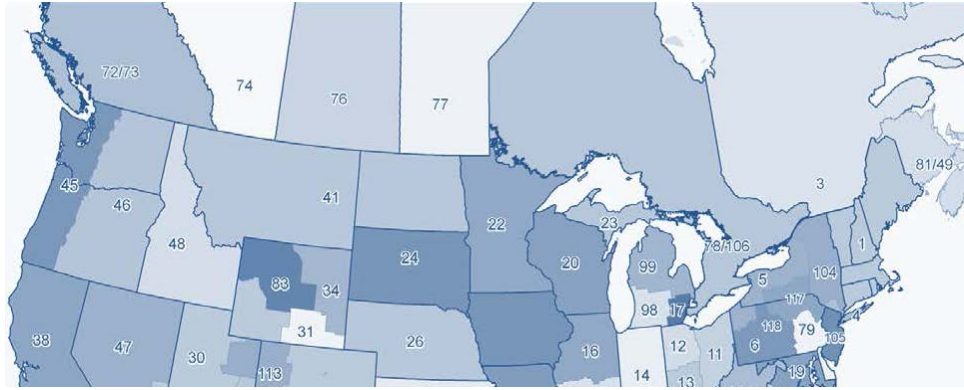
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<sup>3</sup> The 2014 NARUC/EISPC Report, produced by the ICF consulting organization, can be found at: <http://www.naruc.org/Grants/Documents/ICF-EISPC-Gas-Electric-Infrastructure-FINAL%202014-12-08.pdf>. NARUC represents the utilities commissions of all fifty states. EISPC is the Eastern Interconnect, States Planning Council is comprised of representatives from Governors’ Offices, State Regulatory Commissions, and State Energy Offices from 39 States, the District of Columbia, the city of New Orleans, and 6 Canadian Provinces located within the Eastern Interconnection (EI) electric transmission grid and convenes regularly for the purpose of studying electric transmission planning.

<sup>4</sup> NARUC/EISPC Report Page 184.

<sup>5</sup> The counties in Sub-region 79 were determined to be the following Pennsylvania counties: Philadelphia, Delaware, Chester, Lancaster, York, Dauphin, Lebanon, Berks, Montgomery, Bucks, Northampton, Lehigh, Schuylkill, Northumberland, Montour, Columbia, Luzerne, and Carbon, plus the entire state of Delaware.

<sup>6</sup> Sub-region 105 is the entire state of New Jersey.

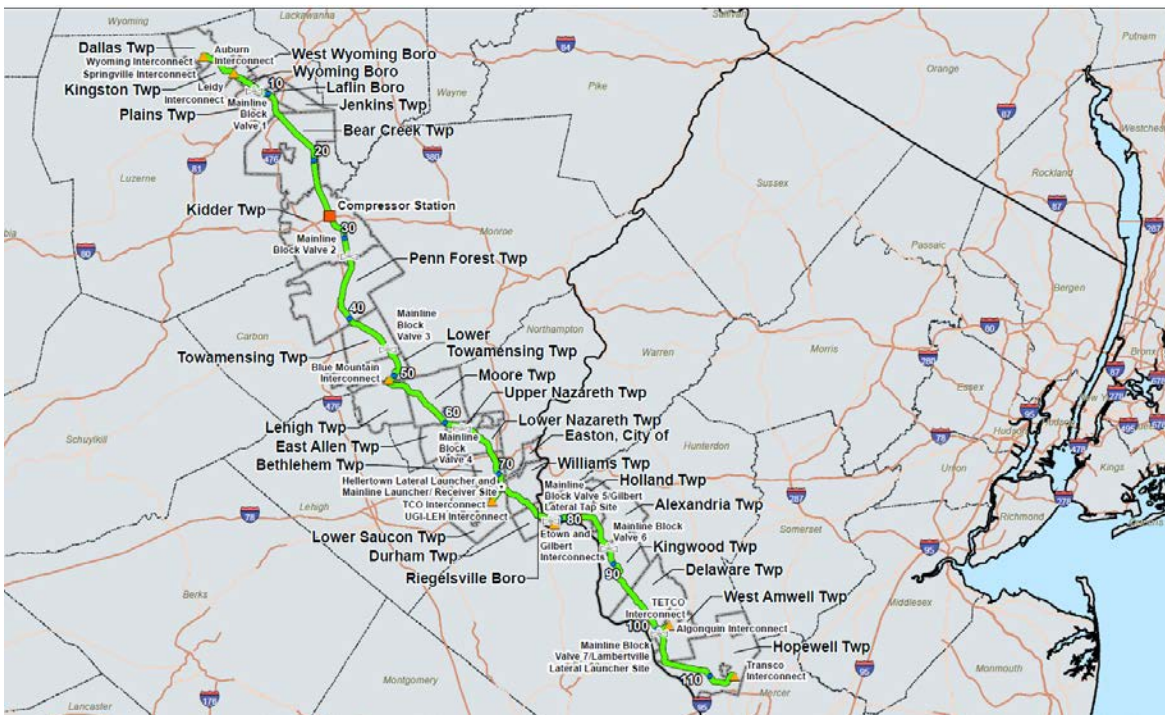


Source: NARUC/EISPC Report

## Establishing Demand Requirement

### Sub-regions Impacted by PennEast

As can be seen on the PennEast Map below, these two sub-regions are those into which the proposed PennEast will create natural gas delivery capacity.



Source: PennEast Pipeline

In Pennsylvania, PennEast traverses the counties of Luzerne, Carbon, Lehigh and Northampton and has delivery locations in Lehigh and Northampton Counties. Each county is in the NARUC/EISPC sub-region 79 (Philadelphia).

In New Jersey, PennEast traverses the counties of Hunterdon and Mercer and has delivery locations in both counties. Both of these counties are in the NARUC/EISPC sub-region 105 (New Jersey).

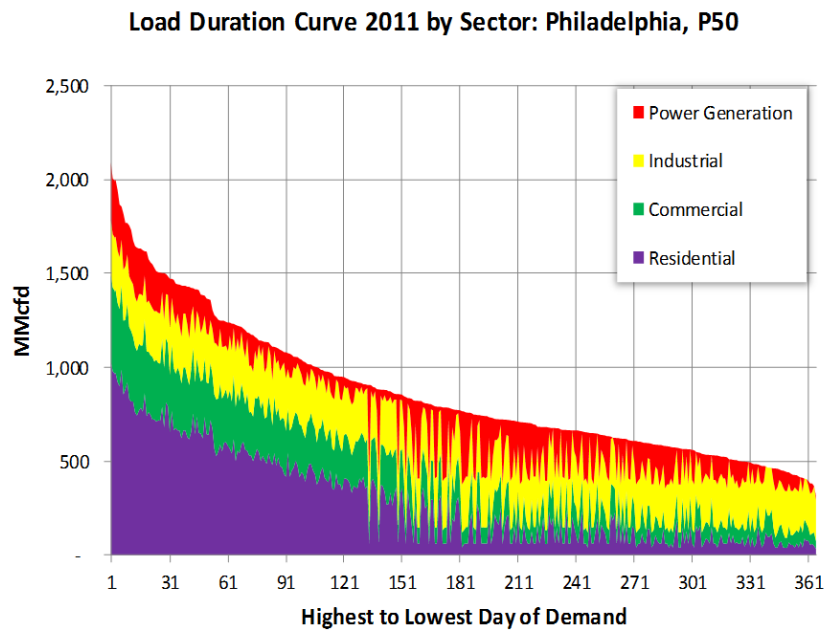


Given the proposed and possible sub-regions servable by PennEast, Skipping Stone analyzed historic demand for the Philadelphia and New Jersey sub-regions and the NARUC/EISPC Report’s projected demand growth in those sub-regions.

### Projected Load Duration Curves

The NARUC/EISPC Report provided historic (2011) and proposed load duration curves (2020 and 2030) for these two sub-regions. Skipping Stone utilized both the 2011 historic and the 2030 load duration curves for this analysis.

A load duration curve is simply a ranking of experienced load<sup>7</sup>, where the daily demands are ranked from highest on the left to lowest on the right. Below are the four load duration curves for the identified sub-regions for 2011 and 2030 respectively.



<sup>7</sup> The NARUC/EISPC Report used data for 2011 for each sub-region and then projected 2020 and 2030 load duration curves. The 2011 load duration curves are those termed here as experienced, while the 2020 and the 2030 load duration curves are those projected based upon the analysis and assumptions made in the NARUC/EISPC Report.

**Load Duration Curve 2011 by Sector: New Jersey, P50**

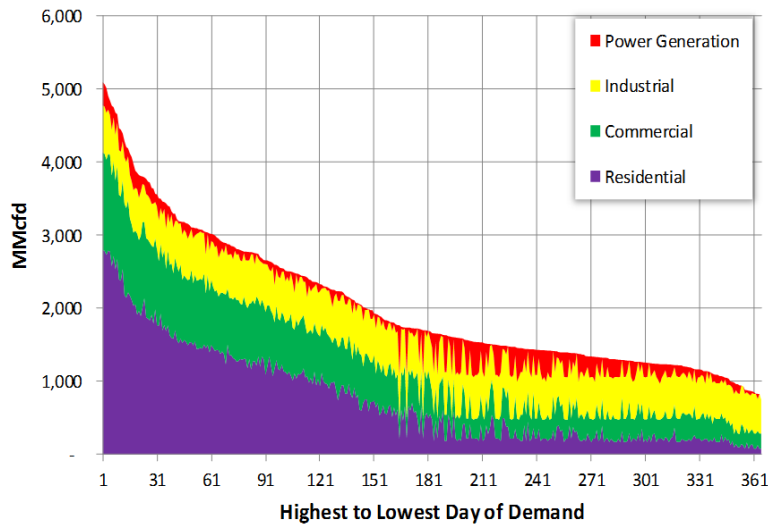


Chart 2 – Source: NARUC/EISPC Report

The loads representing winter period loads are those on the left side of each chart, as may be surmised because the purple shading represents residential gas demand, which is always greatest in the winter.

In addition, with respect to the Philadelphia sub-region, the highest 25% of demand (i.e., between 1,500 MMcfd and 2,000 MMcfd) occurs on fewer than 31 days of the year, while the other 335+ days' demand is substantially below that. Overall, Philadelphia sub-region 2011 demand represented a 42% load factor.<sup>8</sup>

Likewise, for NJ, the highest 20% of demand (i.e., between 4,000 MMcfd and 5,000 MMcfd) occurs only about 15 days of the year, while the other 350+/- days' demand is substantially below 4,000 MMcfd. Overall NJ 2011 demand represented a 40% load factor.

Following are the NARUC/EISPC Report's projected 2030 load duration curves for the same two regions.

**Load Duration Curve 2030 by Sector: Philadelphia, P50**

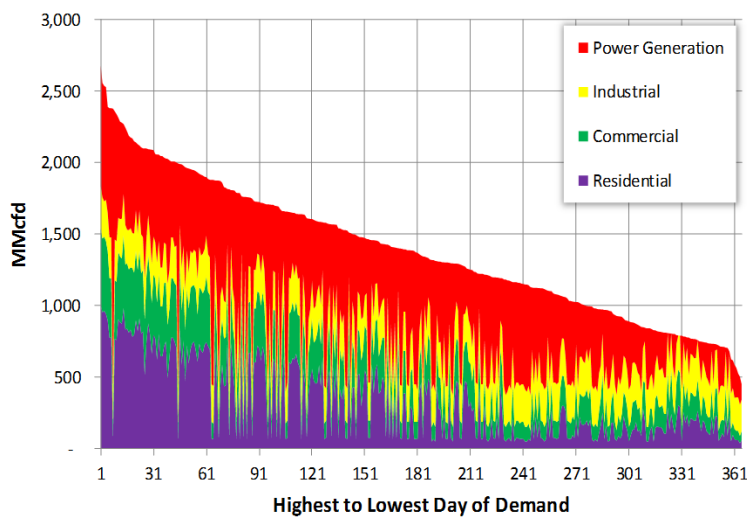


Chart 3 – Source: NARUC/EISPC Report

<sup>8</sup> This is the sum of daily demand over the year divided by the highest demand multiplied by 365.

### Load Duration Curve 2030 by Sector: New Jersey, P50

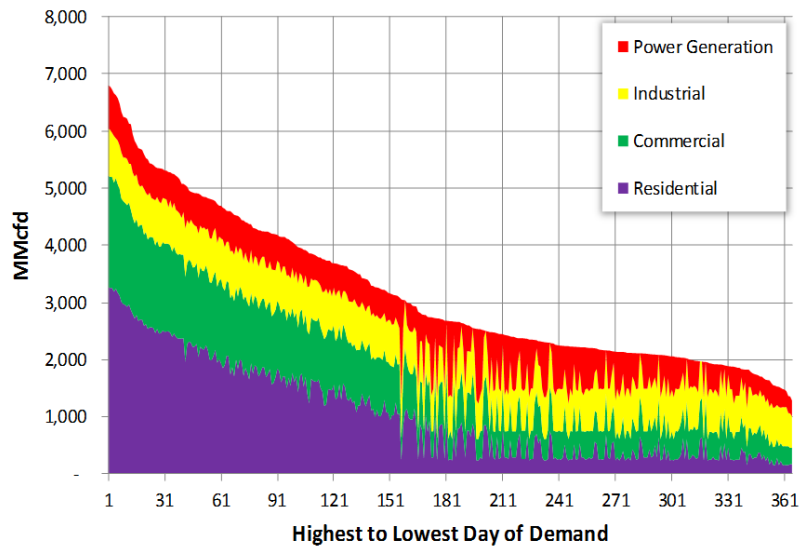


Chart 4 – Source: NARUC/EISPC Report

Much like 2011, the 2030 load duration curves are highly peaked in the winter while projected load factors are projected to increase to 52% for the Philadelphia sub-region and 47% for NJ. Also notably for the Philadelphia sub-region, the 2030 load duration curve evidences a greater amount of electric generation. This accounts for two observations gleaned from the Philadelphia 2030 load duration curve. One is the higher load factor, owing to greater use of capacity by electric generation. The other is that many of the higher demand days have high demand associated with electric generation. As this load duration curve is not the same as a seasonal load occurrence graph, one may not surmise from this curve what the calendar days associated with the higher demand days might be. This is not the case for the NJ load duration curve which in both 2011 and 2030 shows that the highest load (demand) co-occurrences are in winter. This can be deduced from the uniformly high residential and commercial demand categories occurring on the left side of the curve because those demand categories are weather (i.e., cold, winter weather) driven.

### Load Duration in the Two Sub-Regions Plotted Against Contracted Firm Pipeline Delivery Capacity

To present these load duration curves against existing pipeline capacity, Skipping Stone converted the sum of these different types of gas demands<sup>9</sup> and made one line representing the 2011 sum of demands and the 2030 sum of demands as two rightward sloping lines on a chart.

Next, Skipping Stone extracted from its data base of pipeline capacity contracts<sup>10</sup> all records for which the contracted delivery points and associated delivery point capacity was in the same counties as those

<sup>9</sup> The NARUC EISPC Report categorized the component demands depicted in the load duration curves as residential, commercial, industrial and electric generation.

<sup>10</sup> These pipeline capacity contracts are required to be posted by each interstate pipeline on a quarterly basis. This posting is called the “Index of Customers”. The Index of Customers is a listing required to be posted quarterly by the Federal Energy Regulatory Commission (“FERC”) of 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 these listings, Skipping Stone identified all capacity contracts, then deducted lateral-only capacity and customer capacity subscribed on one pipeline to another, which second pipeline

determined to be in the NARUC/EIPC Report’s Philadelphia sub-region and the state of New Jersey respectively. Skipping Stone used the January reports of 2011 and 2016, as those January dated reports have historically shown the greatest quantities of contracted pipeline capacity. Moreover, although other periods of the year often have lower contracted capacity (owing to contract shaping by pipeline customers), the capacity to deliver the gas is nonetheless still present on the pipelines.

Using this contracted capacity as a proxy for actual capability of the pipelines is appropriate because pipelines do not contract for more capacity than they can actually provide. While it is possible that under certain operating conditions pipelines can (and often actually do) provide greater delivery service than contracted<sup>11</sup>, a conservative assumption would be to show such contracted capacity as a proxy for physical capacity. In preparing the extracted data for use, Skipping Stone also reduced total capacity at contracted delivery points such that the sum of individual delivery point capacities under any contract did not exceed the contract’s total capacity.<sup>12</sup> The resulting capacities are termed “prorated quantities.”

The contracted capacity representations of physical pipeline delivery capacity for each of 2011 and 2016 by sub-region were then charted as flat lines across all days of a year and plotted against the respective load duration charts to show how experienced and projected load durations stacked up against existing capacity. The 2011 historic load duration curve is shown alongside the 2011 actual contracted pipeline capacity in 2011. The 2030 projected load duration curve is shown alongside the actual contracted pipeline capacity in 2016. Of note, the far left-most area of the following charts shows how historic and projected demand relate to historic and current pipeline delivery capacity, respectively.

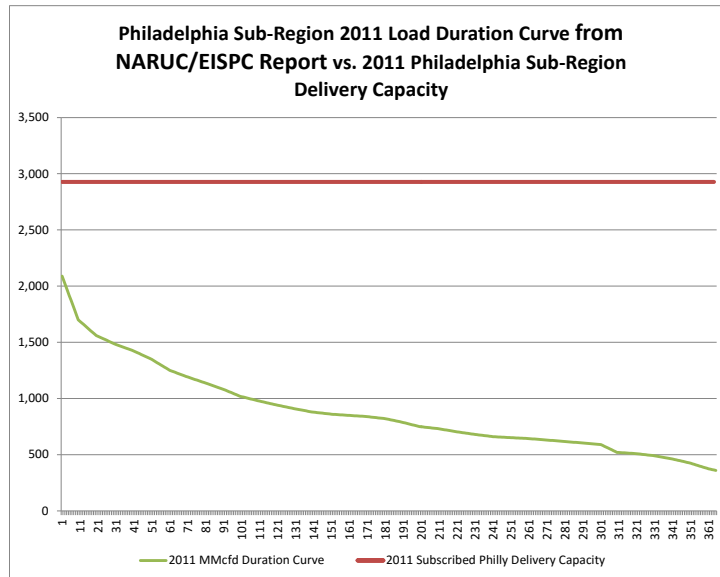


Chart 5 – Sources: NARUC/EISPC Report, Skipping Stone

delivered to the shipper’s contracted delivery point(s). This was done so as not to double count pipeline capacity actually available to the region. Note also that such postings included delivery capacity from pipeline storage to market locations.

<sup>11</sup> Often this is accomplished by means of receipt into the pipelines of gas supplies downstream of the demand locations enabling greater deliveries by means of back-haul as discussed above.

<sup>12</sup> Many pipelines permit their customers, at least under legacy contracts stemming from initial conversion from sales to transport service, to have greater delivery point capacity than transport capacity so that they can shift volumes between points owing to daily and seasonal shifts in demand among the contracted delivery points.

As can be seen in the preceding New Jersey chart, demand in 2011 exceeded then current (i.e., 2011) pipeline delivery capacity<sup>13</sup>. This 2011 demand that exceeded contracted pipeline delivery capacity was met by supplemental supplies not accounted for in the NJ contracted pipeline delivery capacity figures. This is true in most regions of the country, where there are very few days each year (occasionally as many as 30) when demand exceeds pipeline capacity. At these times, the load serving entities (Local Distribution Companies or “LDCs”) employ peak shaving supplies provided through either LNG or propane-air injections into their systems. In particular, in NJ, the 2011 load duration curve from the NARUC/EISPC Report shows that demand outstripped 2011 pipeline capacity by nearly 1 Bcfd at the peak. This indicates that the demand that exceeded pipeline capacity could very well have been met by these peak shaving facilities located within the LDC territories. Moreover, absent removal of such facilities, those facilities likely remain available today and will remain available into the future.

Likewise, LNG terminals<sup>14</sup> located at the far northern and eastern extremes of the national gas grid enable injection of gasified LNG into the integrated interstate pipelines’ national gas grid and may have been utilized in 2011 to meet this evident demand. This use of peak-shaving supplies to meet demand in excess of pipeline delivery capacity has been a foundational feature of meeting peak demand for as long as there has been a gas business.

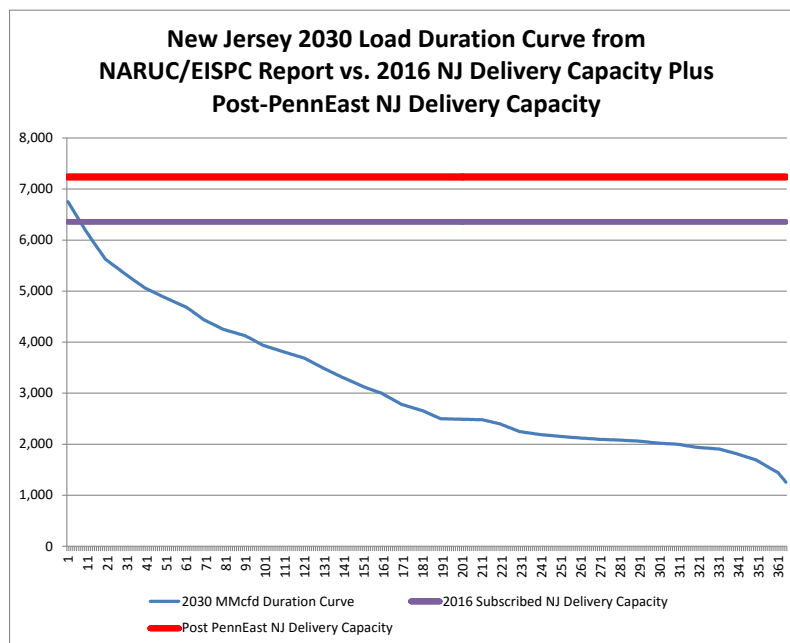


Chart 6 – Sources: NARUC/EISPC Report, Skipping Stone

The above chart shows the NARUC/EISPC Reports projected 2030 load duration curve for the New Jersey sub-region plotted against existing 2016 pipeline delivery capacity plus the proposed delivery capacity from

<sup>13</sup> Includes ~231 MMcfd of contracted capacity to pipeline interconnects or pooling points in NJ for which the contracting shipper does not have commensurate downstream contracts from the pooling point or on the interconnecting pipeline for takeaway from such locations which makes this capacity and the gas transported through it available to NJ locations.

<sup>14</sup> Distrigas (now referred to as Engie) in Everett Mass and Canaport, in Canaport New Brunswick are just two examples of such facilities. In addition to these two on-shore facilities, there are another two off-shore facilities operated by means of buoys attached to a sub-sea pipeline. The two off-shore facilities are owned and operated by Engie and Exceleerate respectively.

PennEast into the same sub-region. In contrast to the 2011 New Jersey Chart of load duration vs. pipeline delivery capacity, current 2016 contracted capacity<sup>15</sup> very nearly meets the NARUC/EIPC Report’s 2030 projected demand relying solely on currently existing pipeline capacity. Presumably, to meet the NARUC/EISPC Report’s projected 2030 demand, the current, 2016 pipeline delivery capacity, can be supplemented by the same facilities that were available in 2011 to meet that year’s demand in excess of then current pipeline delivery capacity.

Following are the same charts for the Philadelphia sub-region.

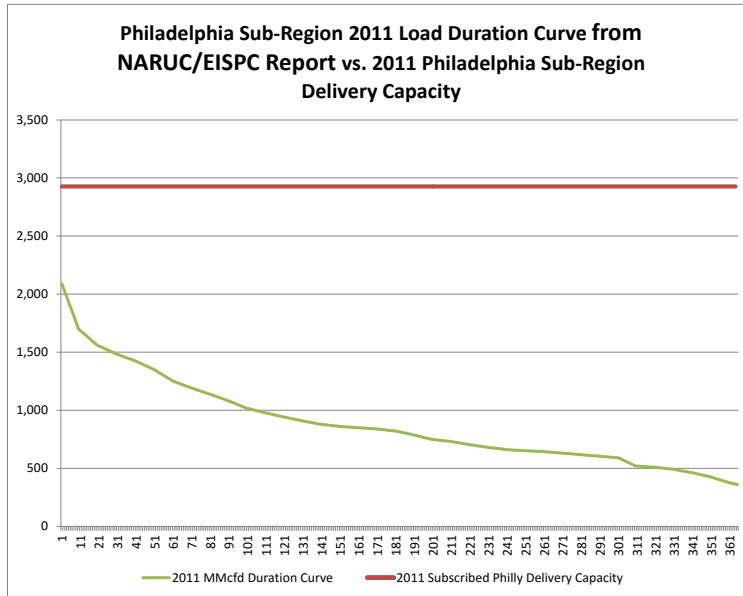


Chart 7 – Sources: NARUC/EISPC Report, Skipping Stone

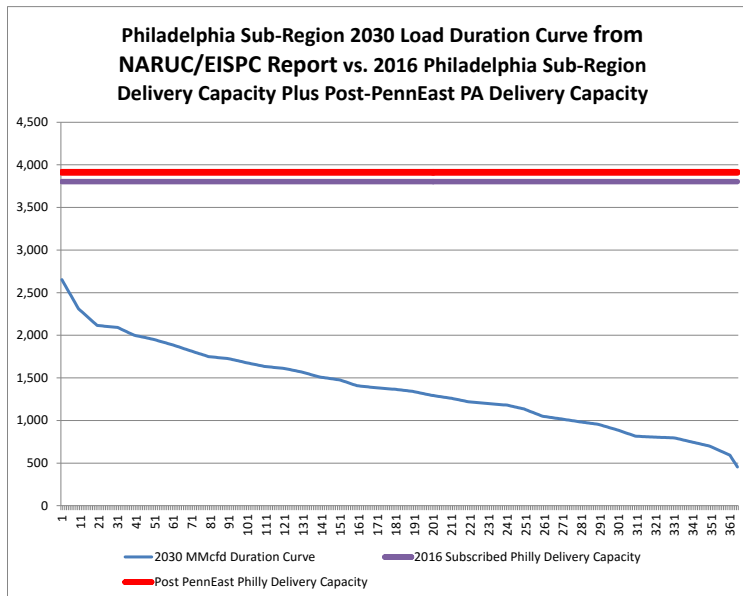


Chart 8 – Sources: NARUC/EISPC Report, Skipping Stone

<sup>15</sup> Includes 1,701 MMcfD of contracted capacity to pipeline interconnects or pooling points in NJ for which the contracting shipper does not have commensurate downstream contracts from the pooling point or on the interconnecting pipeline for takeaway from such locations which makes this capacity and the gas transported through it available to NJ locations.

Unlike the charts for New Jersey which show: a) historic New Jersey demand exceeding 2011 contracted pipeline delivery capacity and b) the NARUC/EISPC Report's 2030 New Jersey demand only slightly exceeding existing 2016 pipeline delivery capacity, the above charts for the Philadelphia sub-region's 2011 (Chart 7) and contracted pipeline delivery capacity, as well as the Philadelphia sub-region's 2016 existing pipeline delivery capacity greatly exceed the both historic and the NARUC/EISPC Report's 2030 projected (chart 8) demand, respectively.

### Assessing Demand Unmet by Pipeline Delivery Capacity in Light of Proposed PennEast Pipeline

The PennEast pipeline is proposed to be built in two sub-regions, one of which has no demand unmet by existing pipeline capacity out to 2030. The NARUC/EISPC Report's projected 2030 demand unmet by existing, 2016, pipeline delivery capacity in New Jersey is similarly limited, and is likely to occur on only 7 to 10 days per year, even as far out as 2030.

It is also apparent that the addition of PennEast will cause contracted pipeline delivery capacity for both the NJ and Philadelphia sub-regions to greatly exceed projected demand as far out as 2030. Note also that this apparent projected excess is based only on the addition of PennEast capacity and does not consider other expansions proposed or with the potential to serve the same sub-regions that may be under consideration.

Thus, given this potential short duration demand unmet by pipeline delivered gas, (i.e., a demand projected to occur on 7 to 10 days over the course of the winter), Skipping Stone in this report identifies other ways to use existing pipeline capacity to meet such demand as an alternative to the proposed PennEast Pipeline that must be considered.

### Size and Duration of Demand an Alternative Must Address

Using the NARUC/EISPC Report's estimation of 2030 natural gas demand unmet by existing 2016 contracted capacity to New Jersey<sup>16</sup>, Skipping Stone established two numbers. As discussed above, this demand could be met by existing supplemental supply facilities. That said, for the purposes of assessing a pipeline delivery alternative, Skipping Stone used the NARUC/EISPC Report's projected 2030 peak and load duration to identify the following. First, we assessed the peak daily requirement for notionally delivered pipeline supplies and second, we calculated the total requirement across all the days in which current contracted pipeline delivery capacity falls short of projected demand. The term we use for this 2030 projected peak and total demand unmet by existing pipeline delivery capacity is the "NJ Requirement."

The first of these numbers, the peak daily quantity, is 395 MMcfd. This 395 MMcfd represents the highest daily quantity projected for 2030 NJ Requirement that notionally would need to be met by pipeline delivered supply.<sup>17</sup>

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<sup>16</sup> The phrase "unmet by existing 2016 contracted capacity to New Jersey" means just that, it does not mean that the demand would go unmet. Assuming the same supplemental supplies (i.e., locally stored LNG and propane-air facilities) that were available to meet 2011 demand are not retired by 2030, those facilities would be more than adequate to meet the demand projected for 2030.

<sup>17</sup> Note of course that NJ has a substantial amount of native, peak shaving, assets (i.e., locally stored LNG which is vaporized and injected into local systems) that are normally used by Local Distribution Companies (LDCs) to meet needle peak needs. However, assuming for the purposes of the definition of the alternative to PennEast, (i.e., a pipeline), delivered supplies, Skipping Stone identified a "pipeline delivered" alternative.

The second number, the total quantity of peak period supplies required<sup>18</sup>, is 1,443 MMcf or rounded up to 1.5 Bcf. This quantity was calculated by taking the positive difference between the NARUC/EISPC Reports daily demand that exceeded 2016 contracted capacity and summing it for the apparent 7-day period of excess demand<sup>19</sup>.

## An LNG Alternative

These two sets of demand, namely 395 MMcfd and 1.5 Bcf, in total are demands that are perfectly suited to being met by LNG supplies available by contract from large LNG terminals, particularly large LNG import terminals like those located in Massachusetts and New Brunswick, Canada. Converting the MMcfd and Bcf demands to thermal equivalents<sup>20</sup> brings peak daily demand to 404,875 Dthd and total peak period quantity to 1,537,500 Dth.

For a pipeline-delivered supply alternative to PennEast to be viable, the Alternative must meet two criteria - peak deliveries and total deliveries. Moreover, because the winter cold weather that is the factor causing the requirement is not predictable as to exactly which days of each winter the cold front may pass through, the alternative has to be available over the entire pertinent period. Assuming New Jersey has weather patterns similar to those of New England, Skipping Stone's other work has determined that most extreme cold requiring the Alternative to be available occurs during the 90-day period of December 15 of each year to March 15 of the following year. This is the period Skipping Stone will term the "Deep Winter." It is this period that the Alternative would address.

From other work that Skipping Stone has done, it accessed 10 years of distribution company send-out and charted that against both that distribution company's pipeline capacity and its LNG send-out capacity. This indicative chart is displayed below.

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<sup>18</sup> This is the area of the triangle representing the total demand unmet by 2016 existing pipeline delivery capacity.

<sup>19</sup> In the NARUC/EISPC Report, the load duration curves are described as "P50" curves. P50 is used to assess probability. A P50 probability is a 50% probability; meaning 50% of the time the demand will be less and 50% of the time the demand will be more than that depicted as a P50 demand.

<sup>20</sup> All U.S. interstate pipelines transport natural gas and have rates that are based upon thermal equivalents (i.e. Dth rather than Mcf). Converting is done by multiplying the Mcf by the Btu factor. In this case Skipping Stone used a thermal content of 1,025 Btu/cf which makes the thermal factor 1.025 for ease of use.



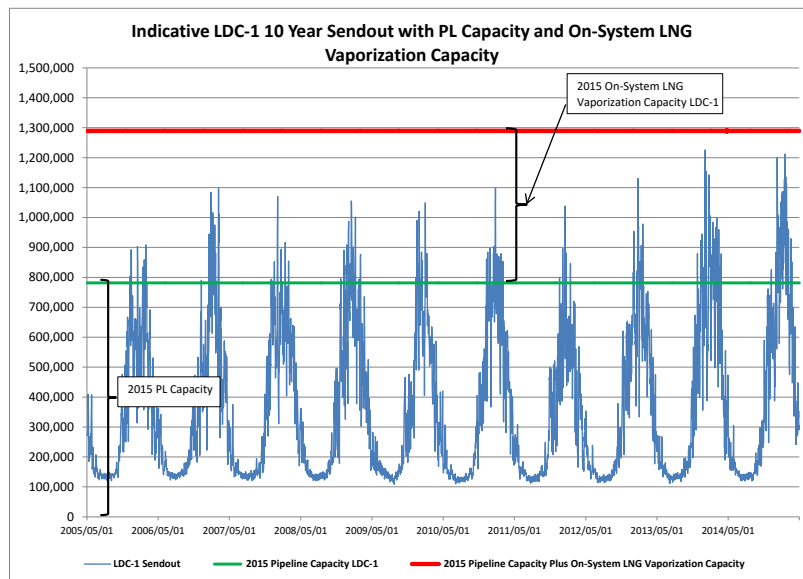


Chart 9 – Source: Skipping Stone

Where the blue send-out lines exceed the green pipeline capacity line, the distribution company’s send-out is augmented by vaporization of on-system LNG in storage. We term the period where send-out generally exceeded pipeline capacity as the “Deep Winter.”

Given that Deep Winter is (and will be) the period over which deliverability is required, together with the above analysis that establishes its magnitude and duration, Skipping Stone studied how to optimize the use of existing pipeline capacity and existing on-shore LNG terminal storage (and vaporization), as well as existing off-shore ship-borne storage<sup>21</sup> and vaporization capability<sup>22</sup>. The resulting analysis follows and shows that existing LNG infrastructure can be used to meet demands on peak days while maintaining reasonable volumes of excess supply available in the event the NARUC/EISPC Report’s projections as to load duration (impacting total quantity required) are low.

Notably, Skipping Stone’s calculated 1.5 Bcf total annual requirement is basically one-half of one LNG ship’s total supply.

### LNG Vaporization and Pipeline Transportation Logistics

The LNG business is a logistics business. For land-based (on-shore) import terminals, the most important logistics include coordinated scheduling of ships, pier-side delivery (off-loading), and vaporization (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, buoy-based, (“floating terminals”, a.k.a. Floating Storage and Regasification Units or “FSRUs”) include having the tankers with on-board vaporization lined up in advance. Fortunately, both these on-shore and off-shore logistics are well-known and predictable.

<sup>21</sup> There are two onshore LNG 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 as well as 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.

<sup>22</sup> 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.

## LNG Supply

Putting the proposed 2030 level of LNG delivery to the Northeast terminals in perspective against existing and future LNG liquefaction (supply) 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 2030 PennEast Alternative need is for 1.5 Bcf over the 50-60 day period; 1.5 Bcf is less than 20% of one day of U.S. productive liquefaction capacity in 2020 (which is less than 2/10ths % of annual U.S. productive capacity).

The U.S. market of LNG imports functions as part of the World Market for LNG, despite restrictions of the Jones Act. While U.S. sourced LNG can only be directly received at U.S. facilities from U.S. flagged ships, LNG in the World Market is a fungible commodity. For instance, assume there are two LNG carrier ships – one with LNG from any non-U.S. source destined for any non-U.S. port and the second an LNG carrier with U.S. sourced source supply that either has no destination or is destined for a non-U.S. port. In either case a U.S. buyer can contract for the quantity on the U.S. sourced carrier at a U.S. based price and the seller of that quantity can arrange with the non-U.S. sourced LNG carrier to deliver their supply to the U.S. while the U.S. sourced supply ship would deliver their cargo to where the non-U.S. sourced carrier was destined. Such transactions happen all the time in both the world LNG market as well as world oil markets.

In addition, to underscore the vibrancy of the potential for this “exchange” logistic, 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. Meeting the 2030 NJ requirement would involve scheduling the delivery and gasification of the equivalent of half a ship into one or another of the four identified terminals.

## Delivery of Gasified LNG

Notably, the vast majority of U.S. sourced natural gas bound for New England has to pass by or through New Jersey. In turn, because the gasified LNG comes into the U.S. natural gas grid at the far eastern (and/or northern) end of its extent, when such LNG is put into the system at this far eastern (or northern) extreme, capacity to move gas otherwise needed from the south and west to serve this far eastern end is instead dropped off in New Jersey. The physical needs of the far eastern end are met by the LNG “bound” for New Jersey and the gas in New Jersey bound for the far eastern end, is delivered to New Jersey. So, while the physical molecules of LNG do not reach New Jersey, the energy equivalent is delivered there. In the natural gas business this is known as either a “back-haul” or a “delivery by displacement.”

## Discussion of other Logistical and Other Benefits to PennEast Alternative

First, using LNG scheduled to and delivered from existing facilities, and transported by back-haul or displacement over existing pipelines, means that there exists an Alternative to PennEast involving no build of additional greenfield pipeline or other facilities.

Second and moreover, LNG is a very flexible resource. Once it is in the LNG storage tanks, (or in the FSRU), 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.<sup>23</sup>

### The Contract Path of the LNG Alternative (Cost Components)

While the supply to meet the NJ requirement would be delivered at one or more of the four Northeast Coast North American LNG facilities, the contract paths of the supply would differ slightly based upon its destination. Following are the descriptions of the contract paths by which the back-haul transactions would be effectuated from each of the four LNG Import facilities respectively.

#### Engie Everett

Engie is connected to Algonquin Gas Transmission (“AGT”) at Everett, MA. Engie has ~ 6,000 MMcf (6.0 Bcf) of natural gas equivalent once vaporized. Vaporized supplies would be injected into AGT. Everett can vaporize up to 500 MMcfd (0.5 Bcfd) into AGT.

The cost of such contractual transport on AGT would be on a volumetric, one-part rate, basis with a charge of \$0.2421 per Dth under the tariff rates in effect at this writing. As this transport is a back-haul, there is no fuel assessed on the transaction.

#### Either of the Two Off-Shore LNG Buoys Operated by Excelebrate or Engie along the AGT Hub-line

The off-shore Engie and Excelebrate buoys are connected to AGT along the AGT Hubline off-shore Gloucester, MA. Typical FSRU storage capacity is ~ 3,000 MMcf of natural gas equivalent once vaporized. Vaporized supplies would be injected into AGT. Typical vaporization rates for FSRUs are up to 500 MMcfd (0.5 Bcfd) deliverable into AGT.

The cost of such contractual transport on AGT would be on a volumetric, one-part rate, basis with a charge of \$0.2421 per Dth plus a Hubline surcharge of \$0.0612 for a total of \$0.3033 under the tariff rates in effect at this writing. As this transport is a back-haul, there is no fuel assessed on the transaction.

#### Canaport, New Brunswick, Canada

Repsol’s Canaport Imported LNG Storage and Vaporization terminal is connected to Maritimes and Northeast (“M&NE”) at Canaport, NB. M&NE in turn is connected to AGT at Beverly, MA. Repsol has on-site storage capacity of ~10,000 MMcf (10 Bcf) of natural gas equivalent once vaporized. Vaporized supplies would be injected into MN&E. Canaport can vaporize and deliver to AGT up to 1,000 MMcfd (1 Bcfd).

To deliver the Canaport supplies to AGT (and onward) Repsol controls 730 MMcfd of M&NE capacity to AGT. As such, Repsol embeds its cost of transportation on MN&E into its price of gas delivered into AGT. That said, the tariff rate on M&NE in the U.S. to deliver to AGT on a volumetric, one-part rate, basis is a not to exceed rate of \$0.555 per Dth under the tariff rates in effect at this writing. There is a fuel assessment on M&NE for this transaction of 1.3% of quantity received into M&NE.

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<sup>23</sup> 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.

The cost of such contractual transport on AGT received from M&NE to the same interconnects identified off of AGT above would be on a volumetric, one-part rate, basis with a charge of \$0.2421 per Dth under the tariff rates in effect at this writing. As this transport is a back-haul, there is no fuel assessed on the transaction.

### Costs to Deliver Gas from AGT into Locations to Meet NJ (or even PA) Locations Proposed to be Served as Alternatives to PennEast-provided Supplies

For those NJ (or even PA) loads seeking to be served off of Texas Eastern Transmission (“TETCO”) in NJ, AGT would contractually transport the gas by back-haul displacement from Everett to one of its interconnects with TETCO either at Lambertville, NJ, or Hanover, NJ. From there TETCO would contractually transport, also by back-haul displacement to locations in NJ or even PA.

The cost of such contractual transport on TETCO to either NJ or PA locations would be on a volumetric, one-part rate, basis with a charge of \$0.1871 per Dth under the tariff rates in effect at this writing. As this transport is a back-haul, there is no fuel assessed on the transaction.

For those NJ loads seeking to be served off of Transcontinental Gas Pipe Line (“Transco”) in NJ, AGT would contractually transport the gas by back-haul displacement from Everett to its interconnect with Transco at Centerville, NJ. From there Transco would contractually transport, also by back-haul displacement to locations in NJ.

The cost of such contractual transport on Transco to NJ locations would be on a volumetric, one-part rate, basis with a charge of \$0.13686 per Dth under the tariff rates in effect at this writing. As this transport is a back-haul, there is no fuel assessed on the transaction.

For those NJ (or even PA) loads seeking to be served off of Columbia Gas Transmission (“TCO”), AGT would contractually transport the gas by back-haul displacement from Everett to one of its interconnects with TCO either at Hanover, NJ or Ramapo, NJ. From there TCO would contractually transport, also by back-haul displacement to locations in NJ (or even PA).

The cost of such contractual transport on TCO to either NJ or PA locations would be on a volumetric, one-part rate, basis with a charge of \$0.2216 per Dth in the November through March Winter period under the tariff rates in effect at this writing. There is a fuel assessment on TCO for this transaction of 2.042% of quantity received into TCO.

### On-Shore Transport Costs through Existing Facilities – All-in Cost Range

The preceding on-shore all-in transport costs from LNG Terminals to markets in NJ (and even PA) range from a low of \$0.3790 per Dth (Everett-to-AGT-to-NJ markets served off of Transco) to a high of \$1.298 per Dth (Canaport forward haul with fuel to AGT to TCO for NJ (or even PA) markets served off of TCO with forward haul fuel in later years when gas prices are higher).

### Forward Cost of LNG Delivered to Northeast Terminals

Shipborne LNG can be delivered to Northeast LNG Terminals from a variety of originations. Assuming for the purposes of making landed North American price projections, Skipping Stone modeled LNG sourced from (or its price based upon) LNG otherwise deliverable to the United Kingdom’s National Border Point

(NBP). As of September 2, 2016 the average price per Dth in U.S. Dollars of deep winter<sup>24</sup> LNG at the NBP for the years 2016 through 2019 were \$5.682, \$5.941, \$5.945, and \$6.017. The modeled prices at NBP based upon a modeled widening differential to the Henry Hub then grew from \$6.160 in 2020 to \$7.95 in 2029. Then, using an average \$85,000 per day ship charter rate<sup>25</sup> and an average 7 days' sail plus an average 15 days' demurrage<sup>26</sup> the landed price in the Northeast ranges from an early year's<sup>27</sup> average of \$6.63 to a late year's average of \$8.28.

When on-shore transportation is added (see chart below) the all-in cost of the PennEast LNG Alternative ranges from \$10.16 per Dth to \$11.08 per Dth depending on transportation route.

As seen in the following comparison even with a nearly \$7.00 to \$8.00 per Dth premium over the supplies into PennEast (which are modeled as being discounted to the Henry Hub due to projected negative basis), the PennEast LNG Alternative is less costly on an all-in cost basis.

## Comparison of All-In Costs of Alternatives

Supplies available into the proposed PennEast Pipeline and the PennEast Alternative will be based upon the respective dynamics at work in the domestic gas market and the International LNG Market respectively.

To compare costs of the proposed PennEast Pipeline versus the PennEast LNG Alternative as two means to meet the NJ Requirement, one must look at both the cost of supply (i.e., cost of gas and the cost of LNG) and the cost of the pipeline capacity to deliver that supply to meet the NJ Requirement. Above, the cost of using existing pipeline capacity to deliver gasified LNG has been provided. Below, the cost of using a greenfield pipeline sized to meet the NJ Requirement is addressed.

### The All-in Cost of an Alternative Pipeline Sized to Meet the NJ Requirement

In looking at the cost of the capacity to deliver supply to meet the NJ Requirement unmet by currently existing pipeline capacity, it is important to identify that cost on an all-in basis. For the purposes of this analysis, "cost on an all-in basis" is based on the following.

To meet the NJ Requirement (i.e., the 2030 natural gas amount of 405 MDthd and 1.538 MMDth over the winter period) by means of a year-round pipeline entails the year-round cost of reserving that capacity. For the purposes of this Alternate Pipeline analysis, we took the PennEast cost of construction assumptions<sup>28</sup> and scaled both the compression and pipeline materials costs down to a notional 24" pipeline and 16,000 HP of compression sufficient for transporting the NJ Requirements' peak day quantity of 405 MDthd. Skipping Stone also scaled installation, engineering, inspection, line pack and other, as well as eliminating the cost of two meters in PA. Skipping Stone left all other costs of PennEast unchanged for the most part,

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<sup>24</sup> For these purposes Skipping Stone averaged the forward prices for December, January and February out through December 2019, calculated the differential between those prices and the December through February Henry Hub prices to ascertain an average differential and then grew that differential by the same amount year over year that the differential grew over the period up through December 2019 and then modeled forward NBP prices out to 2029.

<sup>25</sup> The \$85,000 per day ship charter rate is an average of \$70,000 per day (current rates) versus \$100,000 per day at the peak in the 2010 thru 2012 period. As recently as last year day rates were as low as \$32,000 per day.

<sup>26</sup> This 7 days' sail is an average of five days from NBP and 10 days from West Africa. While the 15 days' demurrage is an average of between 10 days' and 20 days' anchorage prior to unloading. Generally, this demurrage is often less when scheduled appropriately, but assumed here for the purpose of being conservative.

<sup>27</sup> Early years are assumed to be 2018, 2019 and 2020.

<sup>28</sup> These are set forth in Exhibit K of the PennEast Application to the FERC.

not related to materials costs. To calculate a rate for the Alternate Pipeline, Skipping Stone estimated an annual cost of service from which a rate would be derived. A rule of thumb cost of service for new pipelines is that it equals roughly 20% of capital costs. This cost of service for the Alternative Pipeline results in a year-round recourse rate (cost) for capacity of \$1.0788 per Dthd; whether that capacity is utilized or not. As with the proposed PennEast (discussed below), Skipping Stone then applied the 20% discount for anchor shippers to arrive at a rate of \$0.863 per Dthd. When this 100% load factor cost is annualized, then, for each Dthd reserved, the cost is \$315.00 per year.

For ease of numbers, rather than using 7 days, the following indicative example uses 10 days. Thus, if 100% of the capacity were used on 10 days of the year, then the all-in capacity cost of use would be \$31.50 (i.e., \$315.00 divided by 10). The annual cost of reserving 405 MDthd (at \$0.863 per Dthd) would total \$127,574,360.

Then, using the NJ Requirement of 1.5 Bcf and converting that to Dth, the quantity is rounded up to 1,538,000 Dth. To get the all-in capacity cost per Dth of NJ Requirement, one divides the \$127,574,360 annual cost by the 1,538,00 Dth of NJ Requirement for a result of \$82.95 per Dth in use<sup>29</sup>. Note of course that this \$82.95 is just the all-in capacity cost in use and does not include the cost of the 1.5 Bcf of gas. Again, the \$82.95 is just the effective all-in cost of the capacity to supply the NJ Requirement.

### The All-in Cost of PennEast to Meet the NJ Requirement

For PennEast, their Exhibit P shows a year-round recourse rate of \$0.5310 per Dthd. Skipping Stone reduced this rate by 20% as this is the typical discount that anchor shippers on new pipelines receive. With this typical discount, the rate for PennEast is estimated to be \$0.425 every day for year-round capacity. PennEast in its filing shows 990 MMDthd of subscribed capacity. When the 100% load factor cost (rate) is annualized, then for each Dthd reserved, the cost is \$155.13 per year.

As with the Alternative Pipeline, for ease of numbers, rather than using 7 days, the following indicative example uses 10 days. Thus, if 100% of the capacity were used on 10 days of the year, then the all-in capacity cost of use would be \$15.51 (i.e., \$155.13 divided by 10). This would make the annual cost of reserving the 990 MDthd<sup>30</sup> (at \$0.425 per Dthd) total to \$153,501,480.

Then, using the NJ Requirement of 1.5 Bcf and converting that to Dth, the quantity is rounded up to 1,538,000 Dth. To get the all-in capacity cost per Dth of NJ Requirement, one divides the \$153,501,480 annual cost by the 1,538,00 Dth of NJ Requirement for a result of \$99.81 per Dth in use<sup>31</sup>. Note of course that this \$99.81 is just the all-in capacity cost in use and does not include the cost of the 1.5 Bcf of gas. Again, the \$99.81 is just the effective all-in cost of the capacity to supply the NJ Requirement.

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<sup>29</sup> Note that even if the proposed PennEast Pipeline were utilized at a higher load factor, this only means that other pipelines serving the same NJ loads would operate at lower load factors. This means that the cost in use on these other lines would go up to the extent greater than the NJ Requirement is transported on PennEast to NJ markets.

<sup>30</sup> This is the subscribed capacity of PennEast even though the NARUC/EISPC Report projects a NJ Requirement of only 405 MDthd.

<sup>31</sup> Note that even if the proposed PennEast Pipeline were utilized at a higher load factor, this only means that other pipelines serving the same NJ loads would operate at lower load factors. This means that the cost in use on these other lines would go up to the extent greater than the NJ Requirement is transported on PennEast to NJ markets.

## Comparisons of All-in Costs

In the chart that follows, Skipping Stone presents the PennEast approach as well as the two other approaches and the comparison between their all-in costs to meet the NJ Requirement as identified by Skipping Stone. Specifically, Skipping Stone compares the proposed PennEast Pipeline, an “Alternative Pipeline” with the 405 MDthd capacity that would meet the modeled NJ Requirement, and the PennEast LNG Alternative. Note that the option titled “Alternative Pipeline” is under half the size of the proposed PennEast Pipeline. The levelized rate for the Alternative Pipeline has been modeled to be \$.863 per Dthd (at 100% load factor). This cost is at the low end for a line of the length of PennEast and sized to carry 405 MDthd. This low-end estimate is instructive because even at this low rate (cost), the Alternative Pipeline is not competitive with the PennEast LNG Alternative. This analysis shows that the economics vastly favor the PennEast LNG Alternative over both the proposed PennEast Pipeline and the Alternate Pipeline.

	A	B	C	D	E	F	G	H	
Pipeline Alternatives	Example Daily Subscribed Capacity	Days of Subscribed Capacity	Total Qty Pipeline Gas Used	Demand/ Fixed Charges (\$/Dth/d)	Demand/ Fixed Charges (\$/Yr) (A x B x D)	Pipeline Winter Gas Cost <sup>3/</sup> (\$/Dth)	Gas Cost for Gas Actually Used (C * F)	Total Cost of Gas Actually Used (E + F)	All-in Cost/Dth of Gas Actually Used
<b>PennEast</b>									
Early Years <sup>1/</sup>	990,000	365	1,025,000	\$0.425	\$153,501,480	\$3.82	\$3,917,778	\$157,419,262	\$149.76
Late Years <sup>2/</sup>	990,000	365	1,538,000	\$0.425	\$153,501,480	\$4.92	\$7,564,226	\$161,065,711	\$99.81
<b>"Alternative Pipeline"</b>									
Early Years <sup>1/</sup>	405,000	365	1,025,000	\$0.863	\$127,574,360	\$3.82	\$3,917,778	\$131,492,142	\$124.46
Late Years <sup>2/</sup>	405,000	365	1,538,000	\$0.863	\$127,574,360	\$4.92	\$7,564,226	\$135,138,591	\$82.95

	I	J	K	L	M	N	O	P		
PennEast LNG Alternative	Seasonal LNG Delivery	Average NE Landed LNG Price (\$/Dth)	Total LNG Gas Cost (I*J)	LNG Terminal Charge	Low-side Onshore Transport Cost to NJ Markets (\$/Dth)	High-side Onshore Transport Cost to NJ Markets (\$/Dth)	Total Low-Side Cost (K + L + M)	Total High-Side Cost (K + L + N)	All-in Cost/Dth of Gas Actually Used (Low-Side)	All-in Cost/Dth of Gas Actually Used (High-Side)
Early Years <sup>1/</sup>	1,025,000	\$6.63	\$6,800,859	\$1,793,750	\$388,434	\$1,277,379	\$8,983,043	\$9,871,987	\$8.76	\$9.63
Late Years <sup>2/</sup>	1,538,000	\$8.28	\$12,734,821	\$2,307,000	\$582,840	\$2,003,456	\$15,624,661	\$17,045,277	\$10.16	\$11.08

		Q	R	S	T	U
	Potential Savings From PennEast LNG Alternative	Delta Winter LNG Gas Cost w/ Low-side Onshore Transport (G - O)	Delta Winter LNG Gas Cost w/ High-side Onshore Transport (G - P)	Avoided Demand/ Fixed Charges (E)	Total Annual Savings LNG with Low-Side On-shore Transport vs Pipeline All-in (S - Q)	Total Annual Savings LNG with High-Side On-shore Transport vs Pipeline All-in (S - R)
vs. PennEast	Early Years <sup>1/</sup>	\$5,065,265	\$5,954,210	\$153,501,480	\$148,436,215	\$147,547,270
vs. PennEast	Late Years <sup>2/</sup>	\$8,060,435	\$9,481,051	\$153,501,480	\$145,441,045	\$144,020,429
vs. "Alt Pipeline"	Early Years <sup>1/</sup>	\$5,065,265	\$5,954,210	\$127,574,360	\$122,509,096	\$121,620,151
vs. "Alt Pipeline"	Late Years <sup>2/</sup>	\$8,060,435	\$9,481,051	\$127,574,360	\$119,513,925	\$118,093,309

<sup>1/</sup> Average of 2018, 2019 and 2020 Estimated

<sup>2/</sup> Average of 2027, 2028, and 2029 Estimated

<sup>3/</sup> Average of Henry Hub December, January and February of each winter adjusted downward by the average negative Appalachian supply basis (i.e., differential) to the Henry Hub as currently shown for Dominion South which has typically been the most negative of the posted forward basis quotes

Chart 10 – Source: Skipping Stone

As illustrated above, to meet the NJ Requirement, the annual savings (i.e., avoided cost) associated with the no-build, PennEast LNG Alternative, range from a low of over \$118 Million (for the high-side late years and higher LNG cost estimate) versus the Alternative Pipeline to a high of over \$148 Million (for the low-side early years estimate) versus the proposed PennEast Pipeline.

## **Conclusion**

Based upon the work performed in this report, Skipping Stone finds that at least the PennEast LNG Alternative should have been considered as a viable alternative method of meeting the NJ Requirement. There may be other even less costly no-build alternatives (i.e., continued reliance on existing, locally stored, and vaporized LNG as well as propane-air supplementals); however, based upon our review of the material filed in this proceeding, no viable alternatives were identified by either the proponents or the reviewers.