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

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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 – 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 and 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 most efficiently and cost-effectively enhances deliverability in New England would be increased 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. So 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, rather than measuring that cost as artificially spread out across the entire year – the vast majority of which it would not be used or, if used, will cause another 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 both LNG vaporization capacity from large import terminals as well as 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 initially over $340 Million a year and as much as $4.4 Billion over twenty years, as compared to a new pipeline proposal, while providing peak deliverability that will 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 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, also known as local distribution companies or "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 another 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 needed for such short time periods must be built (to have a big enough pipeline) and then 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 such 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.

To the extent, then, that New England faces a "natural gas problem" or "winter energy crisis," 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 residential or commercial 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 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 of overall system deliverability that gets the most attention (underlying the large infrastructure solution being advanced by many policymakers), pipeline capacity is only one piece of the entire puzzle. 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." For this reason, there are numerous satellite LNG facilities scattered throughout New England that compromise 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 with peaking on-system LNG resources owned by the LDCs 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 deep winter period between December 15 and March 15 ("Deep Winter"). Importantly, our analysis indicates that the combination of existing pipeline and a native LNG deliverability exceeds existing LDC sendout on the highest peak days by nearly 10% (see Chart 16 on page A9 of Appendix A). Charts 1 and 2 which follow reflect that, under current demand forecasts and in the absence of a deliverability solution, New England can generally expect deliverability shortfalls

[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.

during the Deep Winter period in the near- to mid-term future (2020 through 2030) with its current pipeline capacity.[3]

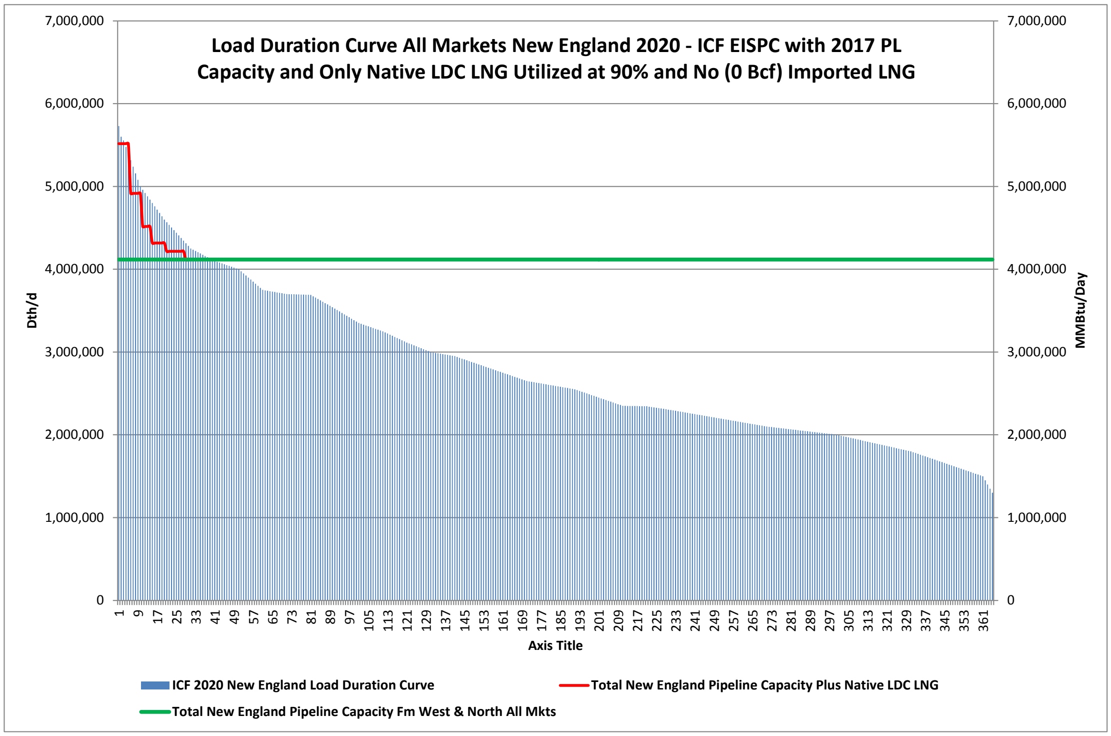

Chart 1: Deep Winter Demand and Supply Shortfall for 2020
Sources: ICF Study, Skipping Stone

[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.

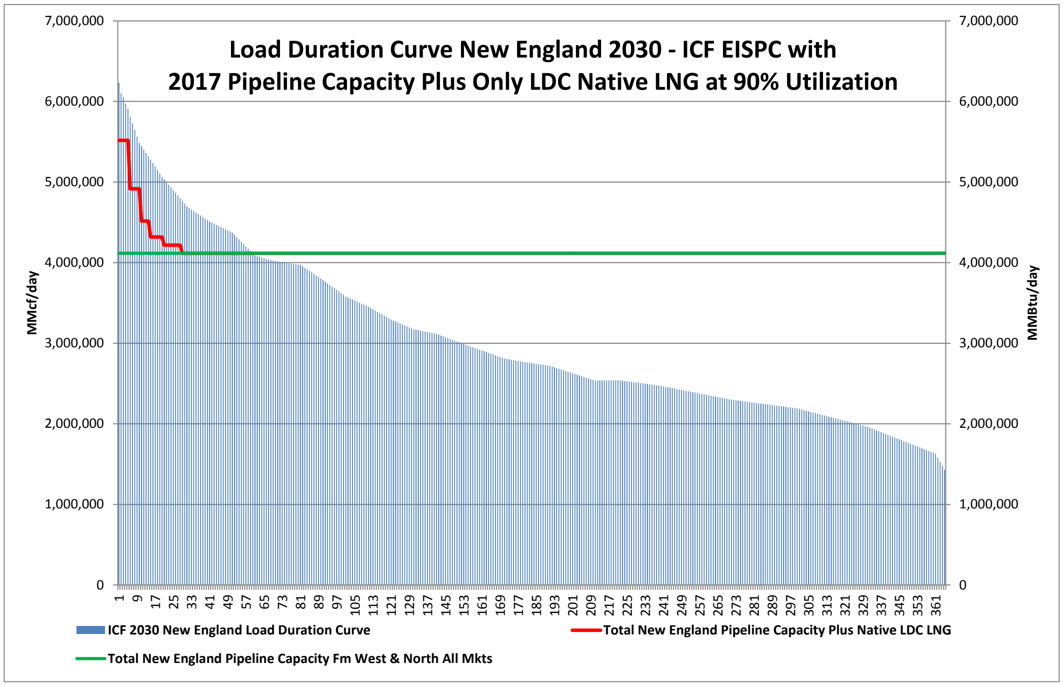

Chart 2: Deep Winter Demand and Supply Shortfall for 2030
Sources: ICF Study, Skipping Stone

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: build more pipeline capacity, or 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. As a result, building more pipelines, which would provide a year-round supply of gas—whether it is needed or not— and is simply not a cost-effective solution.

Setting aside New England's winter deliverability issue for a moment, it is normally cost prohibitive to use pipeline capacity to meet significant demand peaks. New pipeline capacity can be cost-effective when used to meet new year-round demand. In New England, the highest day of modeled demand each year for all LDCs can be as much as three times that on 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 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]

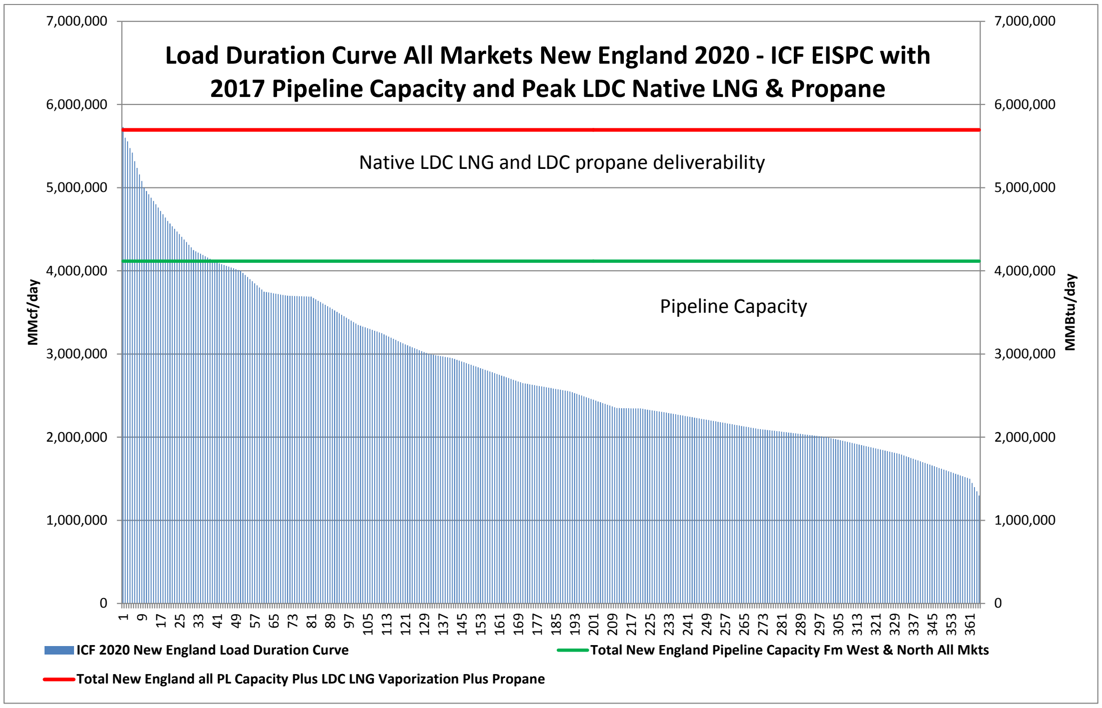

Chart 3: New England Pipeline Capacity plus LDC LNG and Propane Deliverability Overlay for 2020
Sources: ICF Study, Skipping Stone

[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.

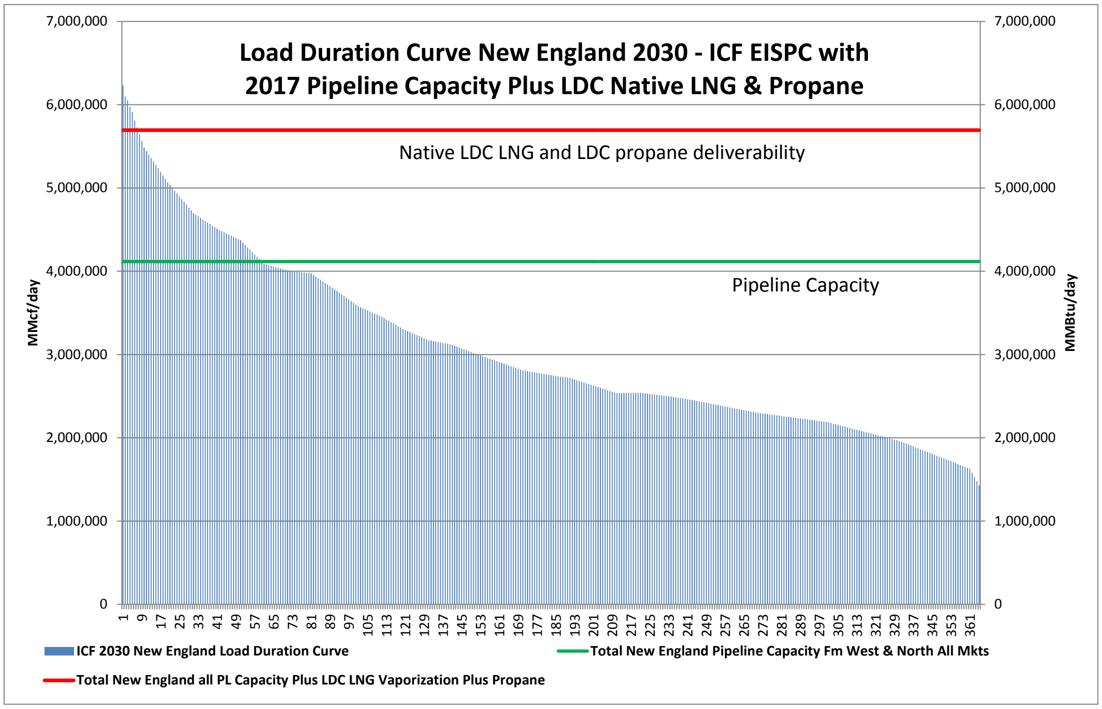

Chart 4: New England Pipeline Capacity plus LDC LNG and Propane Deliverability Overlay for 2030
Sources: ICF Study, Skipping Stone

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]

[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.

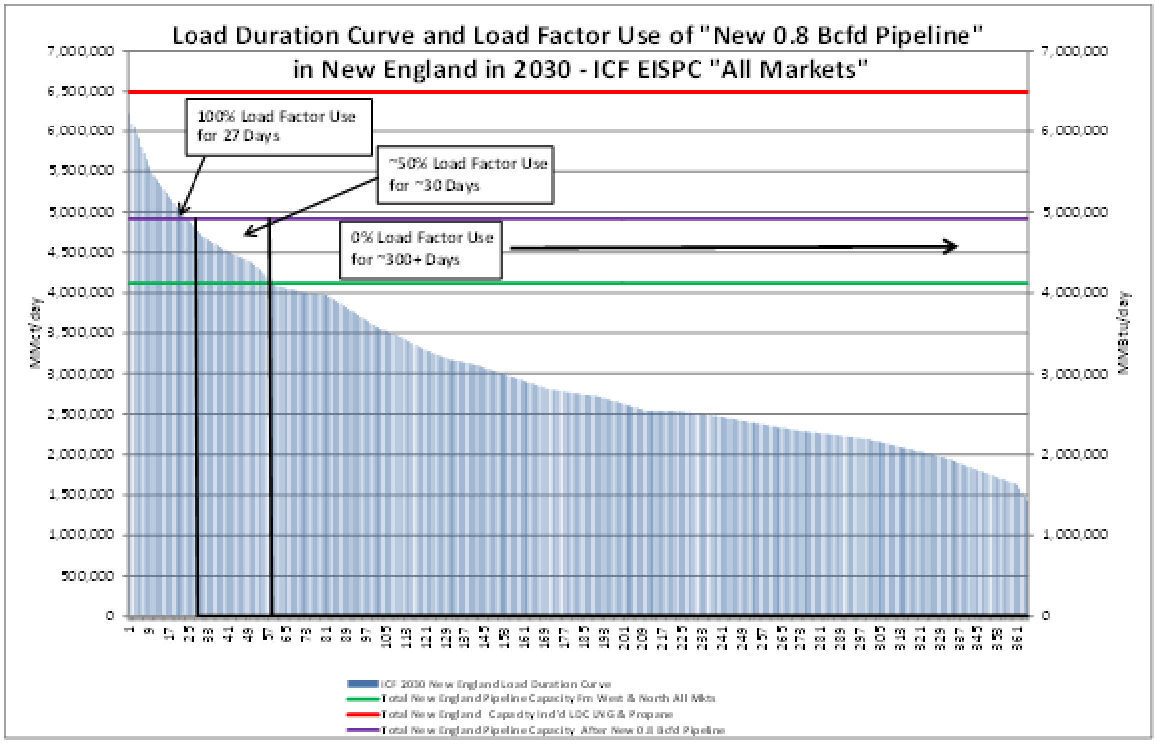

Chart 5: 2030 Load Duration Curve and Load Factor Use of New Pipeline

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 rates charged.

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) 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 one *hourly* take of 1,000 Dth it needs gets 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 does) 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]

[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] discussed 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 even 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 ***<u>100% use</u>*** of the new capacity across those 50 or 75 days, when that is not how incremental pipeline capacity is in fact 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 is used at far lower load factors than 100% across the 50 or 75 highest demand days.[13]

For the purpose of this examination, assuming 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, assuming 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 a 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 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. However, this assumes 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 un-served 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 from 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. They are aware of New England's low load factor and that the region only needs the extra capacity some 50 days a year and, 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 is the most intellectually consistent comparison from the ratepayers' perspective, as 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

Remembering that deliverability is the key metric for solving New England "gas problem," in order to have sufficient deliverability associated with LNG, one must have a sufficient supply of LNG, which is our focus in this subsection.

In short, 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)

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.

of vaporized LNG deliverability, much of which is not fully contracted or utilized at present.[19] That deliverability comes from not only 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 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] That is why 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 "kept the heat on" cost-effectively 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. That analysis, below, 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—such as gas-fired electric generators—that do not have firm year round pipeline capacity.

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]

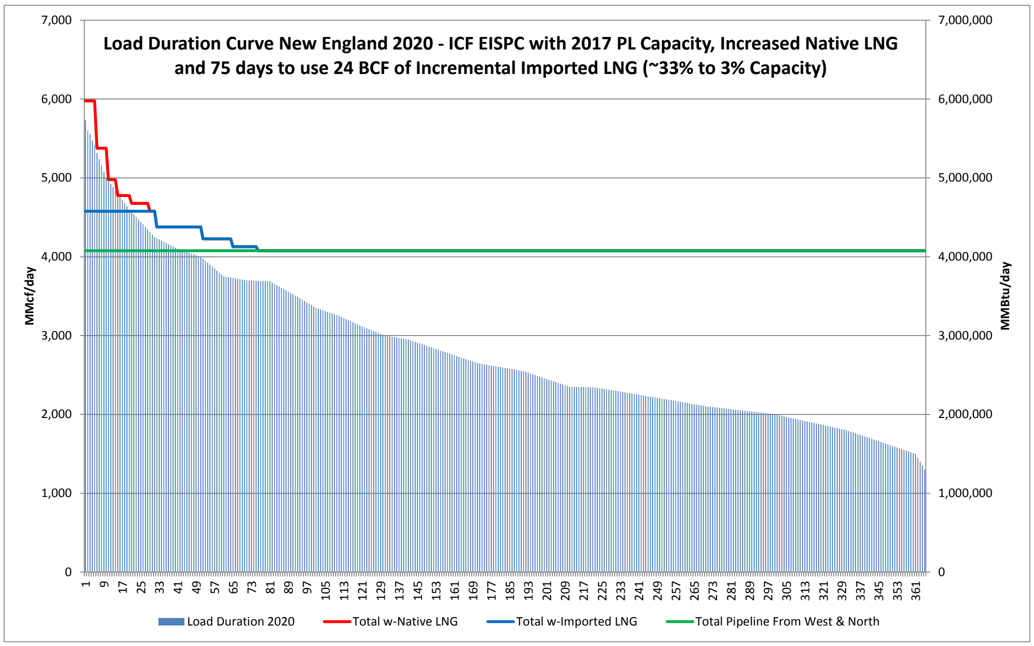

Chart 6: Load Duration Curve New England 2020 75 Peak Days Demand with LNG Overlay
Sources: ICF Study, Skipping Stone,

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 will be 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 both the peak wholesale gas and electric market prices in the New England region and potentially other regions.[23]

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[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.

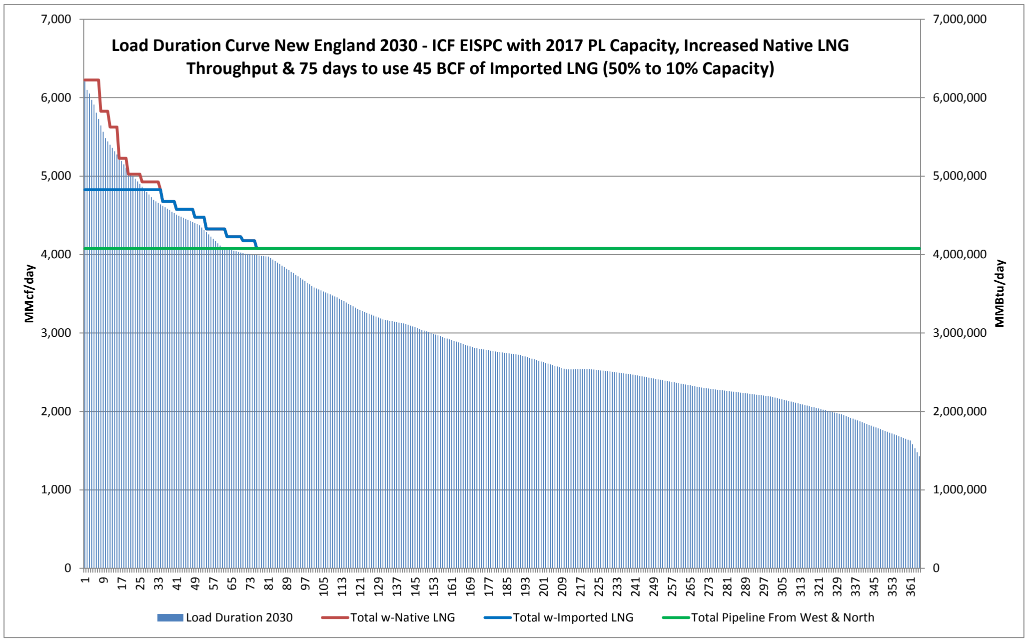

Chart 7: Load Duration Curve New England 2030 75 Peak Days Demand with LNG Overlay
Sources: ICF Study, Skipping Stone

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 in total to its many LNG storage facilities—an amount in excess of the Everett terminal's maximum truck-loading capability.[25] In total, the enhanced native LDC LNG throughput over the 90 days of Deep Winter would entail a total of 6,000 trucks across the 90 days.

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 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

[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.

driving in better weather conditions are included, it would likely entail moving 75 to 80 trucks per day in total.[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] While truck delivery is an enhancement (because 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), the enhanced LDC vaporization could instead 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).

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 how a baseload pipeline is treated—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

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[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.

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 on a new interstate pipeline that we will assume has a minimum capacity of 800,000 Dth/d. For purposes of comparison, rather than subscribing to 160,000 Dth/d of year-round pipeline capacity at rates that we will assume are consistent with the indicative rates discussed above, 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 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

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[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."

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 very 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 deliverability 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 better for their customers 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.

[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 cloudy, rainy days, snowy, winter, days, and wind-less, 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.

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About Skipping Stone

Skipping Stone is an energy 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, energy technology, renewable energy, and energy management. Skipping Stone's model of deploying 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.

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Conservation Law Foundation ("CLF") is a non-profit environmental advocacy organization dedicated to solving New England's toughest environmental problems with the law, science, and markets. CLF has offices in Massachusetts, New Hampshire, Rhode Island, Maine, and Vermont. For years, CLF has been deeply engaged in helping to devise solutions to state and regional energy problems in the policy, market and system realms guided by its over-arching goal to address the causes and impacts of climate change.

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]

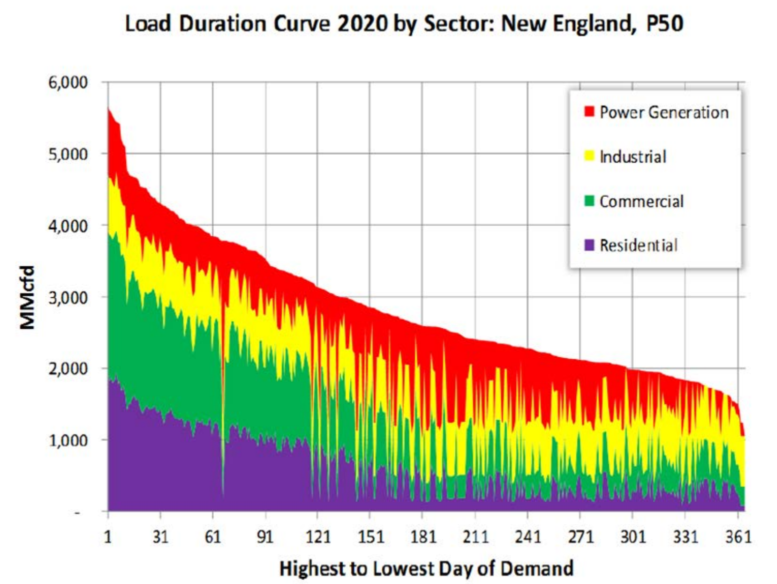

Chart 8: New England, 2020

[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

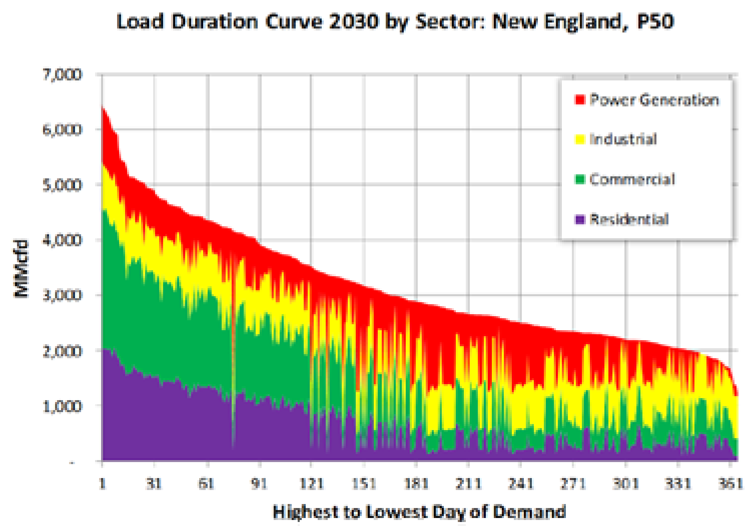

Chart 9: New England, 2030
Source: ICF Study

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.

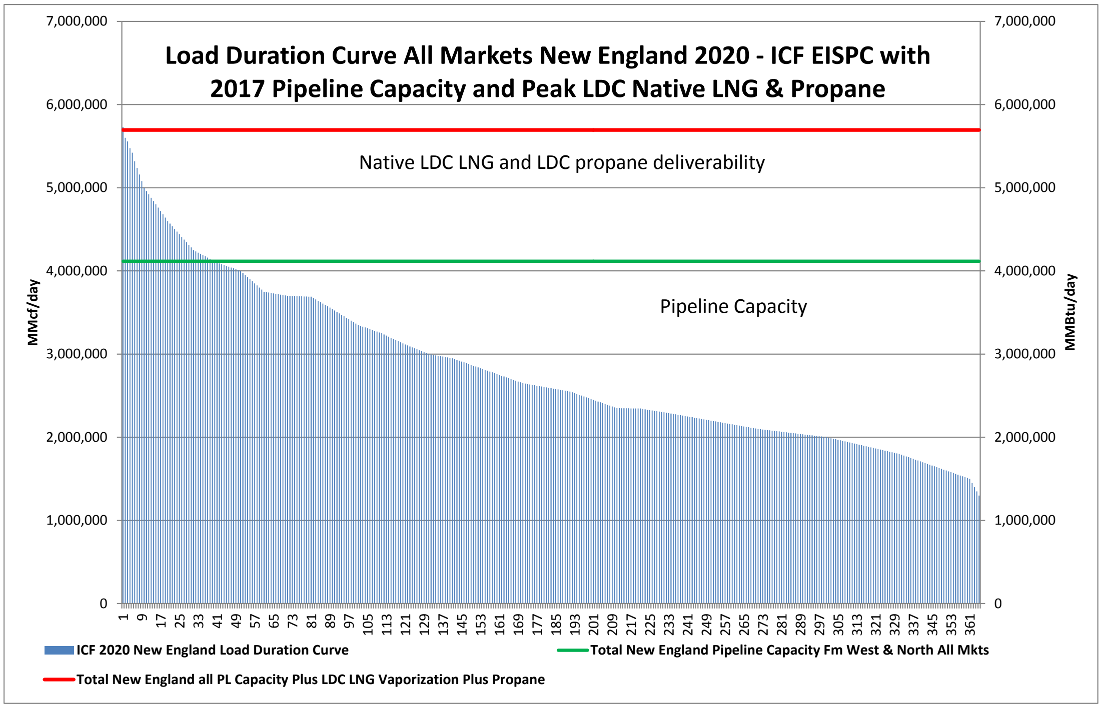

Chart 10: New England Pipeline Capacity plus LDC LNG and Propane Deliverability Overlay for 2020
Sources: ICF Study, Skipping Stone

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.

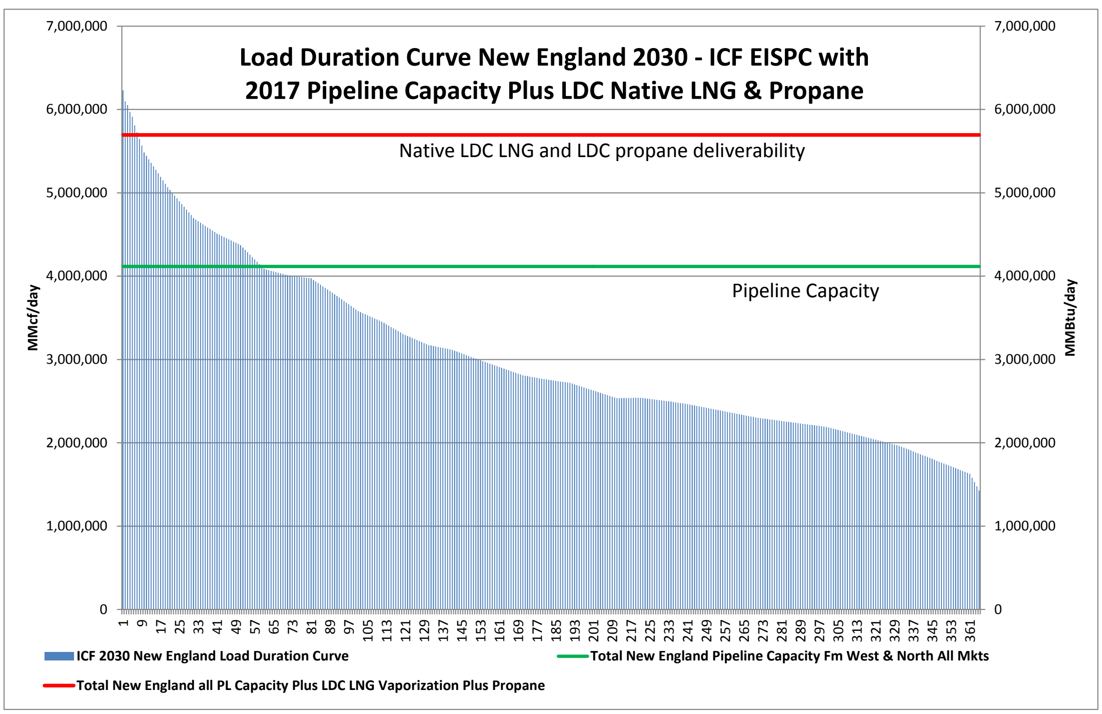

Chart 11: New England Pipeline Capacity plus LDC LNG and Propane Deliverability Overlay for 2030
Sources: ICF Study, Skipping Stone

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.

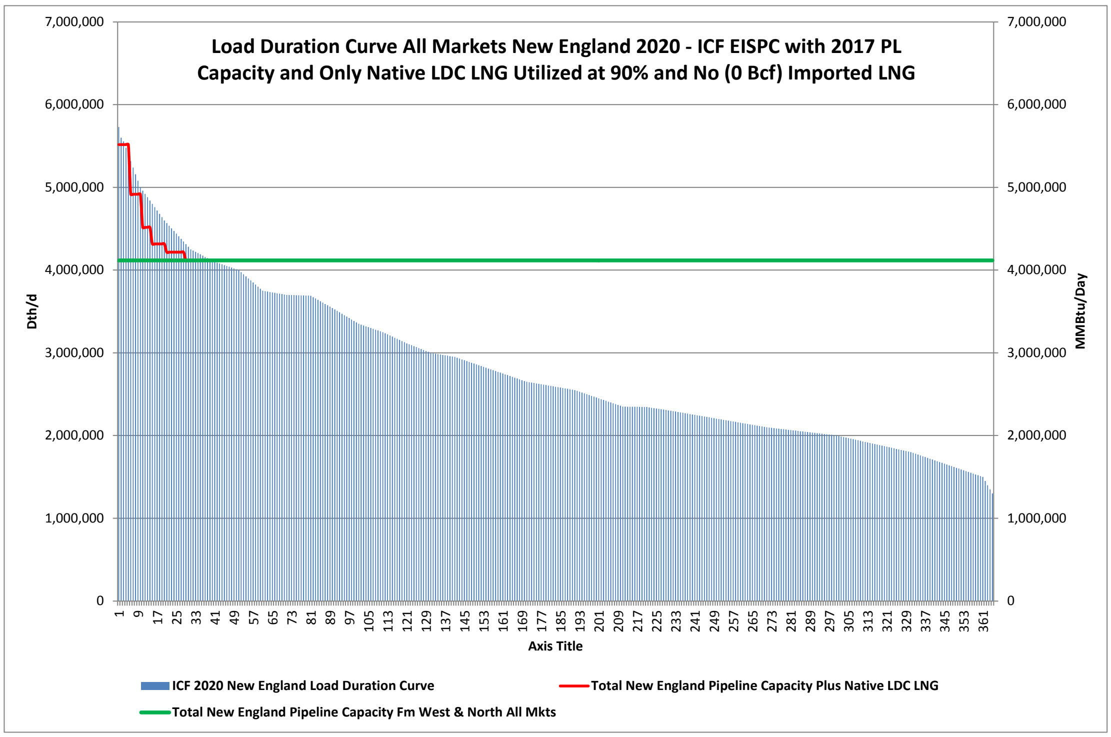

Chart 12: Deep Winter Demand and Supply Shortfall for 2020
Sources: ICF Study, Skipping Stone

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.

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[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.

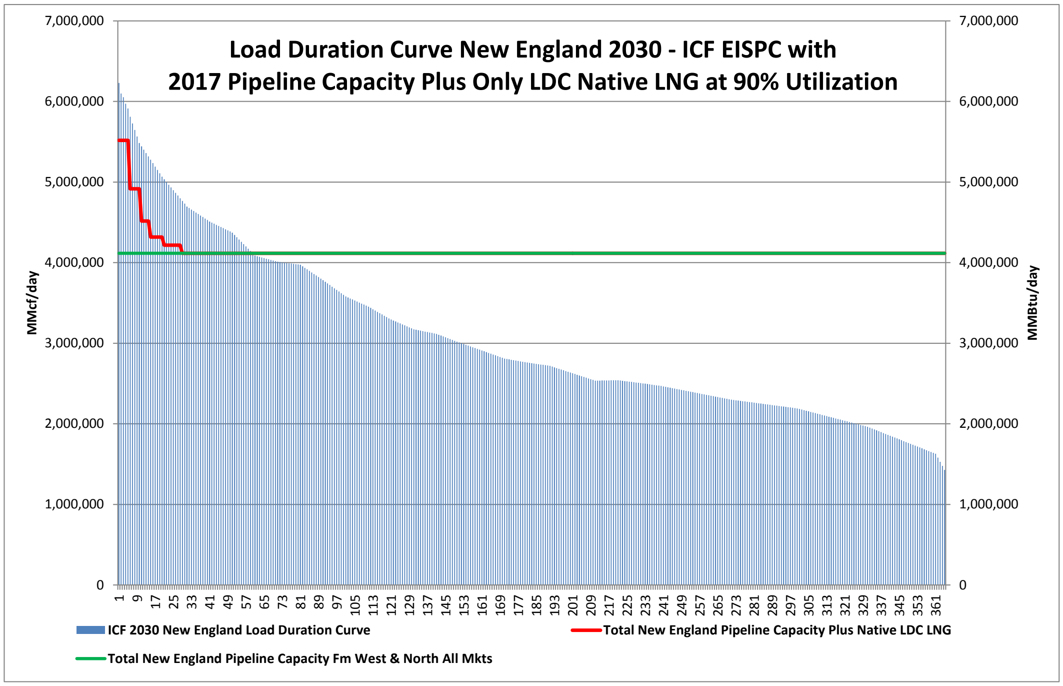

Chart 13: Deep Winter Demand and Supply Shortfall for 2030
Sources: ICF Study, Skipping Stone

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.

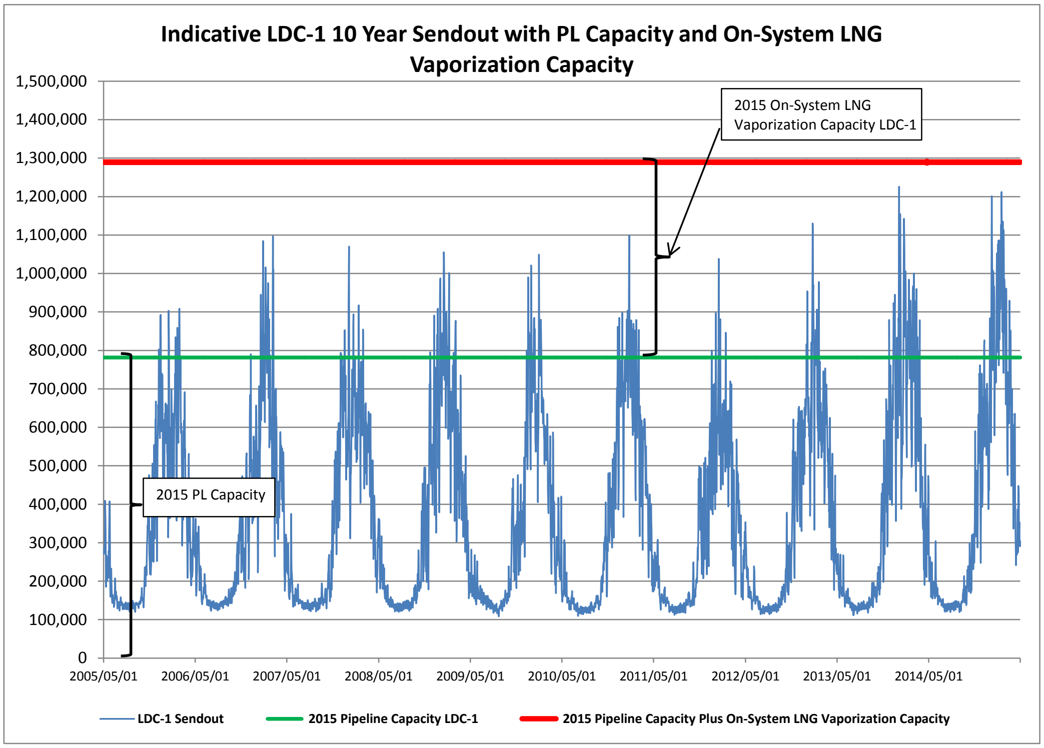

Chart 14: Indicative LDC-1 10 Year Sendout with PL and LDC LNG Capacity
Source: Skipping Stone

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).

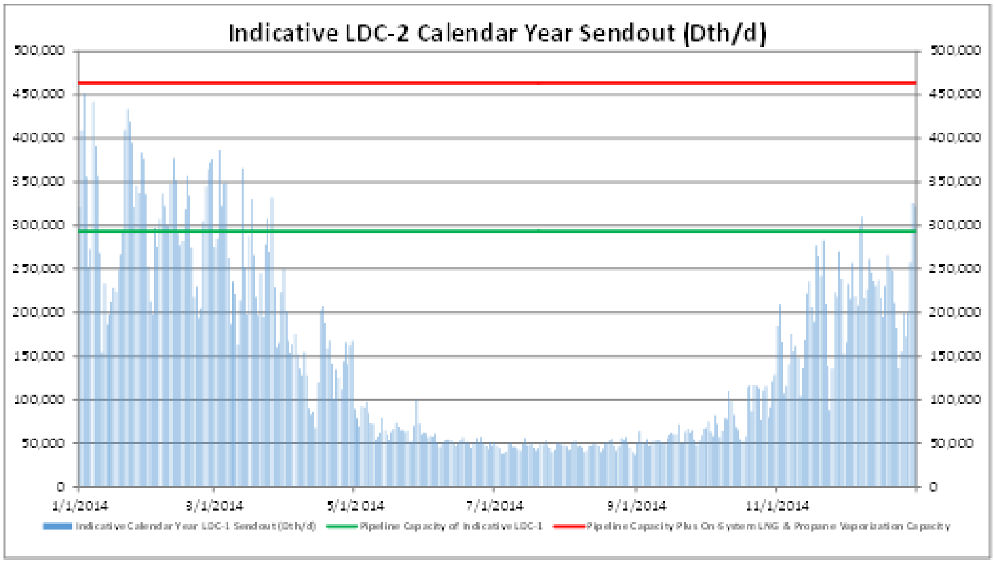

Chart 15: Indicative LDC-2 Calendar Year Sendout
Source: Skipping Stone

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.

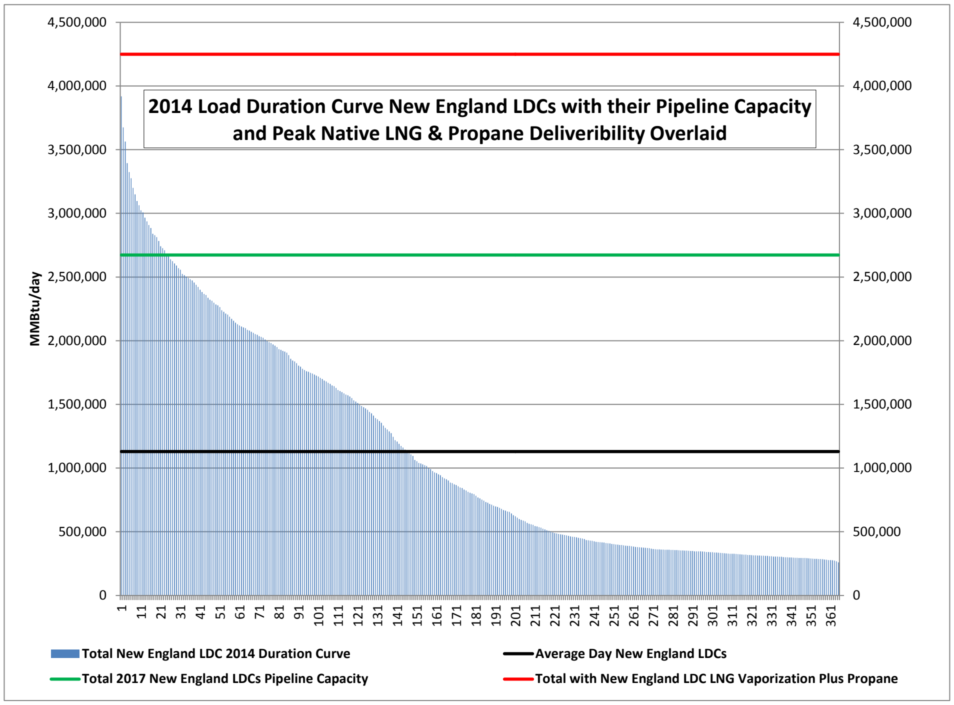

Chart 16: 2014 New England LDC Load Duration Curve with Overlay
Source: Skipping Stone

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.

[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.

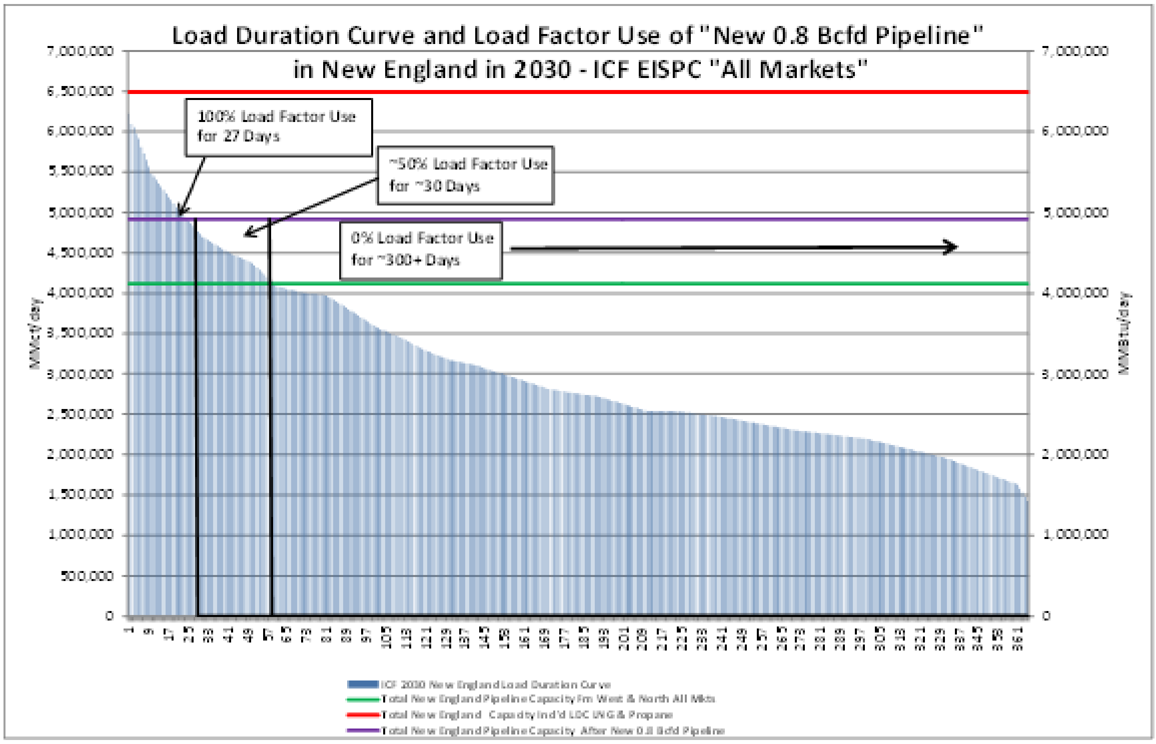

Chart 17: 2030 Load Duration Curve and Load Factor Use of New Pipeline
Sources: ICF Study, Skipping Stone

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].

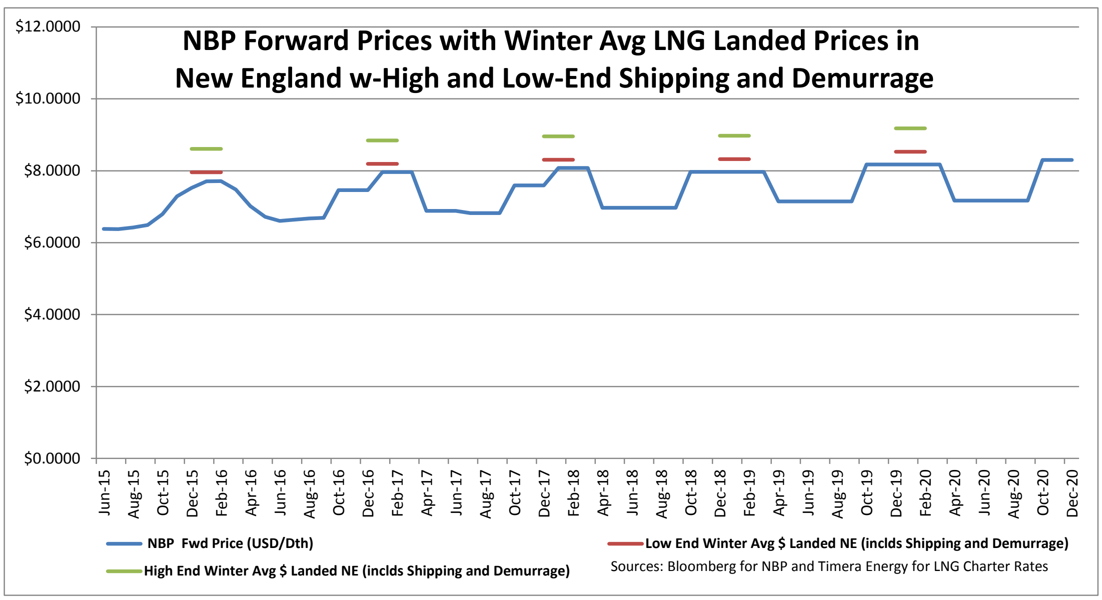

Chart 18: Forward NBP Prices through 2020 with Winter Avg LNG Landed Prices
Source: Bloomberg, Skipping Stone

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[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]

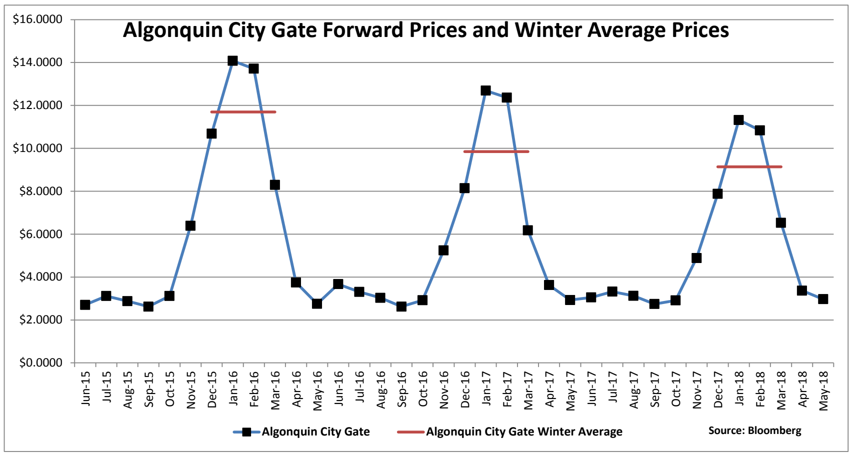

Chart 19: Algonquin Citygate Forward Prices and Winter Average Prices
Source: Bloomberg, Skipping Stone

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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

[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.

[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.

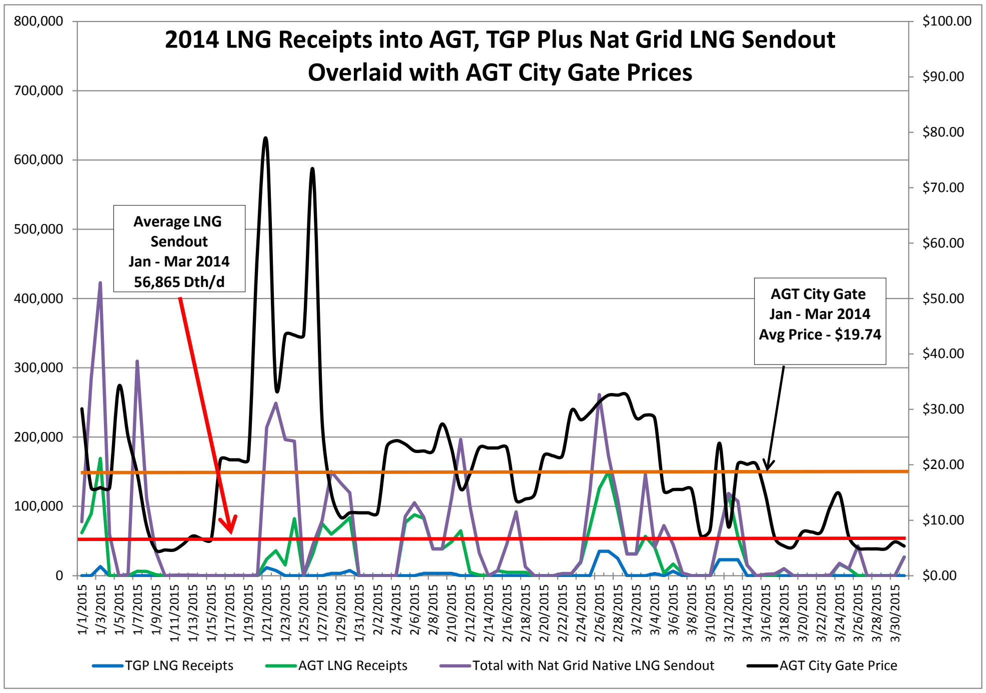

Chart 20: 2014 LNG Receipts into AGT, TGP & National Grid Overlaid with AGT Citygate Prices
Source: Skipping Stone, Pipeline Bulletin Boards, NGI

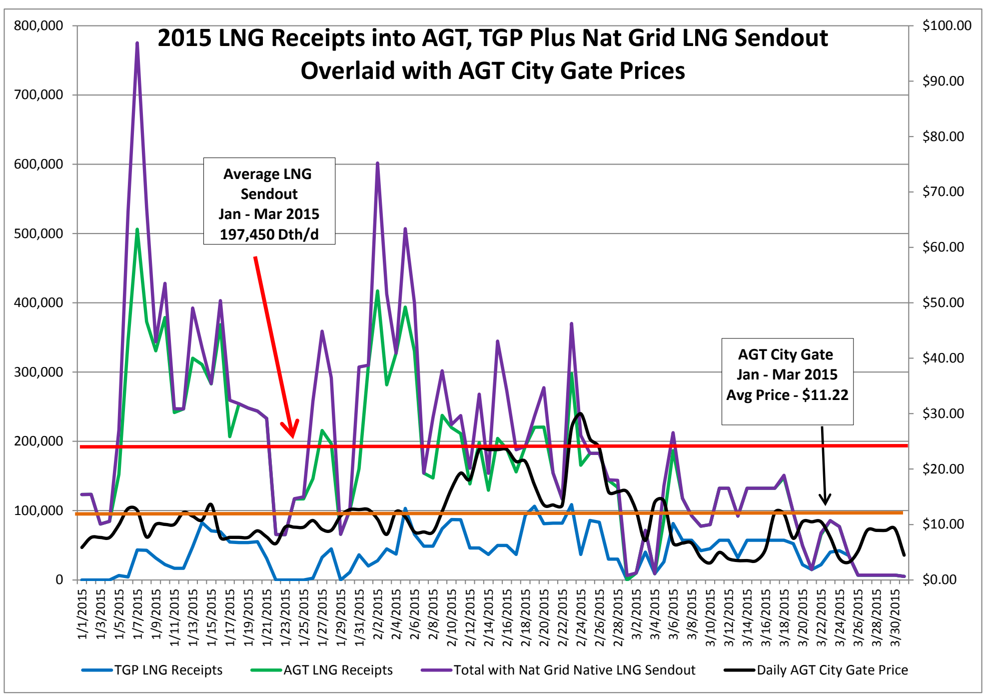

Chart 21: 2015 LNG Receipts into AGT, TGP & National Grid Overlaid with AGT Citygate Prices
Source: Skipping Stone, Pipeline Bulletin Boards, NGI