The Cost of Reliability: Reconciling Natural Gas and Electric Power Markets in New England

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During the 2013–2014 winter, New England customers paid electricity prices that were four to eight times higher than normal because of increased natural gas prices.[1] This increase was not caused by a shortage of natural gas or an unusual weather event that prevented the gas from reaching consumers.[2] Instead, New Englanders paid drastic prices for natural gas because there were simply not enough pipelines to transport the gas into the region.[3] Despite widespread acknowledgement of the problem, natural gas prices spiked again during the 2014–2015 winter.[4] Perhaps even more surprisingly, no new pipeline capacity was added to relieve the problem. Given the problematic price fluctuations, one might assume the New England power market has been decreasing its use of natural gas in favor of a less pipeline-dependent fuel. In reality, however, just the opposite is true: New England has nearly quadrupled the percentage of natural gas used for electric generation.[5]

Natural gas is increasingly becoming the choice fossil fuel for electricity generation due to its low price and low carbon footprint, relative to coal.[6] Furthermore, because natural gas generators are able to quickly start and stop generation, the fuel is especially attractive to support the growing presence of intermittent, renewable sources.[7] Electric power generators are eager to continue to take advantage of these benefits: most of the proposed generation facilities in New England are designed to use natural gas.[8] These generators, however, do not have contracts in place with producers and pipeline companies to guarantee they receive natural gas when they need it.[9] Instead, they opt to purchase unused or excess fuel on a secondary market from other entities, such as local distribution companies ("LDCs"), who *have* signed guaranteed contracts with the natural gas producers.[10] LDCs provide natural gas to residents for heating or cooking purposes.[11] They must purchase enough gas to meet customer demand on the coldest winter day when customers are using the most gas for heating, and thus, often have excess gas on most other days.[12] These secondary purchases typically result in an efficient allocation of the fuel: most days New England residents do not use all of the purchased gas from the LDCs, so the LDCs sell it to power plants to generate electricity at a reduced price.[13] As problems in New England have dem-

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1. Matthew L. Ward, *In New England, a Natural Gas Trap*, N.Y. Times (Feb. 16, 2013), http://www.nytimes.com/2013/02/16/business/electricity-costs-up-in-gas-dependent-new-england.html.
2. *Cf. Northeast Natural Gas Spot Prices Particularly Sensitive to Temperature Swings*, U.S. Energy Info. Admin. (Aug. 11, 2014), http://www.eia.gov/todayinenergy/detail.cfm?id=17491 (discussing the increased sensitivity to cold weather and pipeline shortage in the Northeast as a cause of increased winter electricity prices).
3. *Id.*
4. Wayne Barber, *Spot Power Prices Again Top $100/MWh in New York, New England*, Power Engineering (Feb. 2, 2015), http://www.power-eng.com/articles/2015/02/spot-power-prices-again-top-100-mwh-in-new-york-new-england.html.
5. Gerry Tuoti, *Debate Over LNG Pipelines Heating Up*, SouthCoast Today (Dec. 12, 2015), http://www.southcoasttoday.com/article/20151212/NEWS/151219790 (noting the use of natural gas for electricity generation grew from 15% to 59% between 2000 and 2014).
6. *See* ISO New Eng., 2016 Regional Electricity Outlook 8 (2016), https://www.iso-ne.com/static-assets/documents/2016/03/2016_reo.pdf (stating 80% of new electricity generation capacity in New England uses natural gas); *see also Environment: Carbon Dioxide Coefficients*, U.S. Energy Info. Admin., https://www.eia.gov/environment/emissions/co2_vol_mass.cfm (last updated Feb. 2, 2016) (listing carbon dioxide content of energy sources: natural gas emits only 117 pounds of carbon dioxide per million British thermal unit ("Btu"), while coal emits between 214.3 and 228.6 Btu depending on the order of alteration (e.g., lignite or anthracite)).
7. *See* U.S. Energy Info. Admin., DOE/EIA-0383(2015), Annual Energy Outlook 2015 With Projections to 2040, at 9 (2015), http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf (forecasting natural gas will increase its share of electricity generation from 42% to 55%); *see also Power Generation From Coal and Natural Gas Expected to Temporarily Converge This Spring*, U.S. Energy Info. Admin. (May 14, 2015), http://www.eia.gov/todayinenergy/detail.cfm?id=21232 (citing low natural gas prices and environmental regulations as contributing factors in coal's loss of market share).
8. *See Resource Mix*, ISO New Eng., https://www.iso-ne.com/about/key-stats/resource-mix (last updated Feb. 27, 2017).
9. Joel B. Eisen et al., Energy, Economics and the Environment 586 (Foundation Press 4th ed. 2015).
10. *Id.* at 584.
11. *Id.* at 582.
12. *Id.* at 583.
13. *See* Greg Lander, Solving New England Gas Deliverability's Problem Using LNG Storage and Market Incentives 5 (Skipping Stone 2014), http://www.skippingstone.com/New-England-Gas-Deliverability.pdf (stating that gas capacity constraints is limited to the coldest winter days when regional electricity and heating demand are both increased).

onstrated, however, the region's dependence on natural gas for power generation has led to serious price and reliability problems in the winter when residents use more natural gas for heating purposes.[14] During the coldest winter days, the LDCs need to use most—if not all—of their purchased natural gas, leaving insufficient excess capacity for electricity generation.[15]

Because the natural gas pipeline and electric generation industries developed largely independent of each other, their respective economic models are quite different.[16] Pipelines are built on long-term, guaranteed contracts, while generators of electricity make fuel purchase decisions in short-term markets.[17] Thus, without changes to the market rules or pricing mechanisms, this fundamental misalignment of markets will prevent a solution to this problem short of abandoning the numerous benefits of natural gas. To address the reliability and volatile price problems, several New England states, including Massachusetts, have investigated the ability of electric distribution companies ("EDCs"), or utilities, to contract for the necessary pipeline capacity and ultimately pass-through the costs of pipeline transportation to ratepayers.[18] This would facilitate the long-term contracts pipelines require to be built and would allow the EDCs to sell the capacity into the secondary market where gas-fired generators could purchase it without paying for the pipeline transportation costs and preserving the low cost of fuel required in competitive wholesale electricity markets.[19] State regulators, legislators, and market participants have largely abandoned this course of action due to a Massachusetts state Supreme Court decision holding regulators lacked necessary authority under the existing statutory framework.[20]

This Note will argue for an alternative—but drastic solution—that will achieve similar ends through less disruptive means. Instead of EDCs serving as the counter parties to finance pipeline construction and operation, this note will argue that ISO-NE—the wholesale electricity market operator for New England—should address the problem by amending its operating tariff to allow an independent third party to acquire firm pipeline capacity on behalf of the New England states and recover the costs through a new region-wide tariff schedule. Part I will examine how the electricity market economic model and the pipeline financing model differ and why. Part II will then review the differences between the wholesale and retail power markets, examine the legal framework of the Federal Power Act ("FPA"), and explore state restructuring of the retail electric markets. Part III of the note will introduce two proposals that pass pipeline capacity costs onto consumers through two different mechanisms: one which would facilitate the EDCs as contracting parties to capacity, and one which would facilitate ISO-NE financing an independent, third-party entity to administer the capacity for the region. This section will also show that while both mechanisms are legally consistent with the FPA, the EDC solution is problematic because it violates the general principles of state electricity market restructuring and less fairly allocates costs across the region. Instead, ISO-NE should amend its ISO operating tariff to allow for a third party to contract for gas capacity and allocate the cost recovery among the entire region. This solution would provide a wholesale market mechanism that would more accurately reflect the regional reliability benefits. Such action will achieve New England's reliability concerns, provide additional pipeline capacity, equally allocate costs among all of the regions consumers, and preserve the principles of restructuring at the state level.

I. Factual Background

The reliability and price volatility problems in New England are the result of fundamental differences in the natural gas and electric power industry market rules and business models.[21] Historically, natural gas in New England was used primarily for space heating while oil, coal, and nuclear generation provided the majority of the region's electric power.[22] However, the abundance of new natural gas from shale formations coupled with New England's move to a competitive market structure rapidly increased the region's natural-gas-fired generation to nearly 50% of all total New England electricity generation by 2010.[23] Despite this large increase in the use of natural gas, the number of pipelines serving the region remained the same.[24] This section will examine the pipeline construction and electricity generation economic models and show why the existing incentives discourage new pipeline construction for the use of electric power.

A. *Natural Gas Pipeline Economic Model: Certainty of Long-Term Contracts*

The physical characteristics of natural gas constrain how much gas can be transported and stored by pipeline.[25] Due to the physical properties of natural gas, it must be consumed on delivery, unlike coal, which can be transported by rail or truck and stored on-site.[26] The decision to build pipelines is

14. *Id.*
15. *Id.*
16. *See* Sherri A Monteith, Gas-Electric Harmonization: An AEP Perspective 4 (Am. Electric Power 2014), https://www.aep.com/about/IssuesAndPositions/Generation/docs/GEH_white_paper.pdf.
17. *See id.* at 7.
18. *See, e.g.*, Mass. Dep't of Pub. Util., Order Determining Department Authority Under G.L.C. 164, § 94A, D.P.U. 15–37, at 2 (Oct. 2, 2015), http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-37%2F1537_Order_10215.pdf.
19. *Id.* at 3.
20. ENGIE Gas & LNG LLC v. Dep't of Pub. Util., 56 N.E.3d 740 (Mass. 2016).
21. Peter Behr, *New England Worries About Mismatch of Gas and Power Markets*, E&E News: Energywire (Mar. 30, 2012), http://www.eenews.net/stories/1059962247.
22. *Id.*; *see also* Eisen, *supra* note 9, at 542–43.
23. Behr, *supra* note 21.
24. *Id.* (listing comments by the representatives of the six pipelines serving the New England region).
25. *See* Eisen, *supra* note 9, at 542–43.
26. U.S. Dep't of Energy, Natural Gas Infrastructure Implications of Increased Demand From the Electric Power Sector 1 (2015) [hereinafter U.S. Dep't of Energy, Natural Gas Infrastructure Implications], http://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf.

based on supply and demand.[27] Prospective pipeline "shippers"—the parties seeking to transport the natural gas—enter into contracts with pipeline operators to take advantage of less expensive natural gas from other regions.[28] For example, the price of natural gas may be less expensive in Texas than it is in New Jersey. To enter into a contract, a shipper in New Jersey must believe the difference in price between the two markets—known as the basis differential—justifies the cost of transporting the natural gas from one region to the other, and thus enabling the financial undertaking for a pipeline company to construct and operate a pipeline connecting the two regions.[29]

Similarly, the pipeline operator's decision to enter into a contract with the shipper is dictated by financial considerations. Pipeline construction is a capital-intensive endeavor and, unlike other modes of infrastructure, a pipeline is immovable once built.[30] Therefore, a pipeline operator must reach an agreement with the shipper that allows the operator to recover its investment and provide a return to its investors.[31] This often requires shippers to enter into long-term contracts with the pipeline operator.[32] The pipeline operator requires this long contract period to enable it to recover its capital cost and profit through FERC-regulated rate recovery.[33]

Historically, natural gas LDCs[34] have been the shippers, or purchasers, of the pipeline contracts to ensure reliable service for their customers.[35] Notably, these companies are able to recover the costs of these long-term contracts through state ratemaking mechanisms,[36] so the risk for signing a long-term contract is passed through to customers.[37]

Because gas storage is limited and most of the gas must be consumed on delivery, traditional wholesale customers purchasing the gas for resale, such as LDCs, contract for enough pipeline capacity to meet their highest demand and pay a "demand charge" to the pipeline even if they did not use the gas.[38] This guaranteed delivery service is a "firm" contract.[39] In addition to firm service, other customers (such as gas-fired generators or industrial consumers) may opt to purchase natural gas without a firm contact and only pay the commodity charge.[40] These customers can contract for "interruptible" service in which the pipeline agrees to deliver, or essentially "reroute" the firm customer's excess capacity to an alternate customer.[41] These customers pay a lower price for this service, but are subject to interrupted service when the firm customer is utilizing its peak capacity.[42] Because LDC's provide their customers with gas for the essential purpose of residential heating and they are able to pass through the cost of fuel, it makes sound business sense for them to purchase firm service from the pipeline.[43] Such service allows LDCs to provide reliable service while passing through the entire cost, including the demand charge, to the residential consumer.[44] Conversely, the other customers without the ability to pass through costs, such as industrial end users, often have the ability to use coal or oil as an input fuel if gas is not available, or if it is more expensive.[45] For these customers, purchasing interruptible service is the sound business decision because the potential loss of service is not worth the premium in price.[46] FERC facilitates the efficient allocation of contracted gas through a capacity release program that allows third parties to purchase excess gas from the primary firm service holders.[47]

Long-term firm contracts are integral for new pipeline construction because they serve as a market signal that there will be future demand and provide financial certainty to facilitate pipelines to acquire the necessary capital for construction.[48] Thus, it is the long-term contractual agreement that binds a shipper to pay the demand charge and allows for additional pipelines to be built and more capacity to be delivered.[49] However, this model of long term contracts—and specifically, the cost of the demand charge—conflict with the short term decision making inherent in the electricity market model.

B. Electricity Market Model

Wholesale electricity markets operate differently from natural gas markets. Wholesale electricity markets involve the sale of electricity for resale—typically the sale of electricity to an electric utility or market trader.[50] In restructured power markets, such as New England, grid operators—Regional Transmission Organizations and Independent System Operators—determine which generators are utilized, or

27. *Id.* at 3.
28. *See id.*
29. *See id.*
30. *Id.* at 2.
31. Am. Gas Ass'n, Ratemaking for Energy Pipelines 1 (2011) [hereinafter *AGA Ratemaking Report*], https://www.aga.org/sites/default/files/ratemaking_for_energy_pipelines_2014.pdf.
32. U.S. Dep't of Energy, Natural Gas Infrastructure Implications, *supra* note 26, at 3.
33. *Id.*
34. Local distribution companies distribute natural gas to end users for residential home heating and stovetop fuel. *See* U.S. Energy Info. Admin., Natural Gas Annual (2012), https://www.eia.gov/naturalgas/annual/pdf/nga12.pdf.
35. *Cf.* ICF Int'l, Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near Term Electric Generation Needs 8 (2012), http://www.westernenergyboard.org/ngei/documents/reference/other/2011NE-ISOngs.pdf.
36. Unlike the FERC-regulated rates mentioned in the previous paragraph, LDCs recover their costs through state ratemaking because the sale of natural gas is directly to consumers and outside of FERC's jurisdiction. *See* discussion *infra* Part II.
37. *AGA Ratemaking Report, supra* note 31, at 5.
38. The cost of the physical natural gas is often termed the "commodity charge." *See* Eisen, *supra* note 9, at 542–43.
39. Fed. Energy Regulatory Comm'n, Energy Primer: A Handbook of Energy Market Basics 25 (2015) [hereinafter FERC Primer], https://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
40. *See* Eisen, *supra* note 9, at 542–43.
41. *See id.*
42. FERC Primer, *supra* note 39.
43. *See* Eisen, *supra* note 9, at 542–43.
44. *Id.*
45. *See id.*
46. *See id.*
47. FERC Primer, *supra* note 39, at 25.
48. Gregory L. Peters, Gas & Electric Infrastructure Interdependency Analysis 76 (2012), https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Natural%20Gas-Electric%20Infrastructure%20Interdependency%20Analysis_022212_Final%20Public.pdf.
49. *See id.*
50. FERC Primer, *supra* note 39, at 35.

dispatched, through a bid-based system.[51] These bid-based systems allow the grid operators to determine the generator that can provide electricity for the least cost.[52] Generators enter their bid based on the marginal cost of generating the electricity.[53] A seller's marginal cost is typically the cost of the fuel used to generate the next unit of electricity.[54] From the business perspective of the electricity generating facilities, their dispatch potential is predicated on the purchase price of fuel.[55] This competitive short-term system allows sellers to compete to generate the lowest priced electricity and ensures the most efficient price for end-users (such as residential consumers).[56]

C. The Gas-Electric Market Mismatch

The increased use of natural gas for power generation has placed the wholesale natural gas and electric markets at odds.[57] Pipeline companies require firm contracts to facilitate investment, construct new pipelines, and build additional capacity.[58] Conversely, natural gas generators competitively bid into wholesale markets based on their short-run, marginal cost of natural gas.[59]

A firm contract includes both a commodity charge for the volume of gas and a demand charge to guarantee delivery, while interruptible service only includes the commodity charge.[60] LDCs need to be able to meet peak demand for their customers (and are allowed to pass through the cost of the gas, including the demand charge) and, thus, are willing to pay the demand charge.[61] A natural gas-fired generator (unable to pass-through costs), however, will not contract for firm service—which would require the generator to pay *both* the demand and commodity charges—because other natural gas generators that only contract for interruptible service—and only pay the commodity charge—will be able to offer a lower electricity bid.[62] Thus, natural gas generators have no incentive to purchase firm capacity because interruptible service allows them to bid most competitively.[63]

Importantly, during times of regular demand, this model is not problematic because the LDCs do not need to utilize the entirety of its contracted capacity to meet its customer demand and is able to sell its excess capacity on the spot market to power generators.[64] During peak demand (typically during the winter when customers demand more gas for home heating), however, the LDCs may utilize the full (or near-full) contracted capacity and do not release as much capacity for the generators to purchase.[65] This lack of released natural gas capacity at times of peak demand has caused reliability concerns and spikes in the price of electricity in New England, where natural gas has grown to typically account for 50% of electric generation and pipeline constraints limit additional access to natural gas.[66]

New England has experienced the most significant effects of the gas and electric market misalignment. The use of natural gas to generate electricity has grown from 15% to 46% between 2000 and 2013.[67] Because of this growth in demand for natural gas, pipeline constraints have manifested in economic and reliability costs during the winters when temperatures have caused less excess capacity for electric generation (in turn, causing increased prices for consumers).[68] For example, in the winter of 2013-2014 natural gas prices, which directly influence the price of electricity in New England,[69] spiked to $6.90 compared to $3.17 at Henry Hub—a basis differential of 85%.[70] During the winter of 2014–2015, the Massachusetts Public Utility Commission ("PUC") calculated that New England consumers paid $600 million dollars more than consumers in the PJM interconnection (the wholesale market operator of neighboring states), a region not as constrained by pipeline supply.[71]

D. The Mechanics of a Hypothetical Pipeline Contract

To illustrate a simplified version of these contracts, consider the following hypothetical example. A natural gas pipeline company (PipelineCo) believes (based on economic forecasts and internal business planning) they can transport natural gas from Houston, Texas—where gas prices are lower—to Boston, Massachusetts where prices are higher than Houston, and would allow customers to take advantage of lower costs.

51. *Id.* at 40.
52. *See* Eisen, *supra* note 9, at 695–96 (explaining that least-cost dispatch is the priority rule, but grid operators may deviate to accommodate security or operational concerns).
53. *See id*. at 696.
54. *See id*.
55. *See id*. at 698.
56. *See id*.
57. Monteith, *supra* note 16, at 4.
58. Peters, *supra* note 48, at 7.
59. Eisen, *supra* note 9, at 696.
60. *See id*. at 543.
61. *Electric Market Rules Impact Electric Reliability*, Interstate Nat. Gas Ass'n Am. (Sept. 15, 2014), http://www.ingaa.org/File.aspx?id=22585 (noting LDCs have a legal obligation to secure enough natural gas to meet customer demand).
62. *Id*. (noting existing market rules make it uneconomic for generators to sign firm contracts).
63. *Id*.
64. *See* Judah Rose, *Waiting for the Next Polar Vortex*, 152 Pub. Util. Fort. 32 (2014), http://mag.fortnightly.com/article/Waiting+for+the+Next+Polar+Vortex/1727336/212098/article.html.
65. *See id*.
66. *High Prices Show Stresses in New England Natural Gas Delivery System*, U.S. Energy Info. Admin. (Feb. 7, 2014) [hereinafter *High Prices Show Stresses*], http://www.eia.gov/naturalgas/review/deliverysystem/2013/pdf/newengland_natgas.pdf (noting significant winter price increases in New England and reliability concerns).
67. Evan Twarog, *Power in New England: Why Are Prices Increasing So Rapidly*, Atomic Insights (Nov. 19. 2014), http://atomicinsights.com/power-new-england-prices-increasing-rapidly/.
68. *High Prices Show Stresses*, *supra* note 66.
69. Dr. Jonathan Raab & Paul Peterson, New England Overview: A Guide to Large-Scale Energy Infrastructure Issues in 2015, at 51 (2015), http://www.greenribboncommission.org/archive/downloads/New-England-Energy-Infrastructure-Issues-GRC.pdf (charting the close relationship between natural gas and electricity prices in New England).
70. *Regulatory Mechanisms to Ensure Fuel Adequacy: Update on the New England Governors' Proposal to Invest in Strategic Infrastructure and Address Price Disparities*, New Eng. States Committee on Electricity (Sept. 25, 2014), http://energy.gov/sites/prod/files/2014/10/f18/08d-BDAntonio.pdf.
71. Elizabeth Mahony, *Request to Open an Investigation Into New, Incremental Natural Gas Delivery Capacity for Thermal Load and Electric Generation*, Dep't Mass. Energy Res. 2 (Apr. 2, 2015), http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-37%2finitial_filing.pdf.

PipelineCo holds a preliminary "open season"—a period in which potential customers can enter into nonbinding agreements with ProductionCo to demonstrate their interest in taking advantage of lower natural gas prices.[72] As a result of this open season period, assume three customers "sign up" for capacity on the pipeline (reserve access to the natural gas). The first customer is GasDistCo, a Boston LDC responsible for purchasing gas on the wholesale market and reselling it to Boston residents for home heating purposes. The second customer is WidgetCo, a manufacturer of widgets that is a heavy user of natural gas to make the plastics used in the widgets. The third customer is PowerCo, a Boston natural gas-fired generator that generates electricity and sells it through the competitive electricity market (discussed in detail below).

GasDistCo, as an LDC, purchases natural gas on the wholesale market and resells it to customers. GasDistCo has a defined, exclusive service territory and charges customers a regulated rate that "passes through" the price it pays for natural gas to its customers. GasDistCo would purchase firm service from PipelineCo because its customers expect reliable service and both the commodity charge and demand charge are recovered through the ratemaking process. Not only will GasDistCo purchase firm service, but it will secure firm service for the full quantity of gas required to meet customer demand for the coldest day of the year. On most days of the year, however, GasDistCo will not require the full quantity of contracted supply, and the excess capacity can be released to other customers through PipelineCo.

Conversely, WidgetCo, as a manufacturer, will subscribe to interruptible service because the lower price will allow it to be more competitive against other manufacturers. On most days of the year, WidgetCo will take advantage of the excess capacity released from GasDistCo and other firm service holders. However, should PipelineCo invoke its ability to interrupt WidgetCo's natural gas service on especially high-demand days of the year, WidgetCo would have sufficient notice because it would not be able to purchase the gas through the capacity market. WidgetCo would be able to manage the capacity constraint by either suspending operations for the short time period until service is restored or by switching to a substitute fuel in the interim.

Finally, PowerCo's choice in pipeline service illustrates the fundamental market mismatch problem. In a restructured region (such as New England), PowerCo competes against other generators by placing bids based on its marginal cost (the cost of natural gas). PowerCo will only be selected by the market operator (ISO-NE) to generate power if it can match or offer a lower bid than its competitors. PowerCo cannot choose to purchase the more expensive firm service from PipelineCo because—under normal market conditions—its competitors will opt for the less expensive interruptible service and be able to underbid PowerCo. During most days of ordinary demand, the electric power market will work efficiently and (because no generators are paying for the demand charge) the regional price of electricity will be less expensive because of the natural gas-fired generators' economic decisionmaking.

However, the net effect of PowerCo and all of its competitors purchasing interruptible service (essentially the unused capacity from GasDistCo and other firm customers) is that the generators have no recourse when GasDistCo and the other firm customers require their full contracted capacity. Unlike WidgetCo, which could manage a natural gas curtailment through differed operation behavior or fuel-substitution, PowerCo, in this hypothetical, can only operate by using natural gas to generate electricity.[73] Furthermore, the cold days in New England in which firm customers require full capacity utilization to meet consumer demand are often the same days when a region requires the most generators to be operating. Instead of PowerCo and its competing natural gas-fired generators supplying low cost electricity to the region, older oil or coal generators would produce more expensive electricity during the gas supply shortage and create price spikes (or blackouts).

The above example illustrates the maligned incentives that natural gas-fired generators face in a restructured region. The competitive bid system incentivizes generators to purchase interruptible service,[74] but high-demand curtailment produces undesirable levels of reliability and price volatility for the region's electricity markets. The next Part will examine the statutory and regulatory framework that creates these incentives.

II. Legal Background

A. *FERC's Jurisdiction*

The Federal Energy Regulatory Commission's ("FERC's") natural gas and electric power jurisdiction[75] is defined under two statutes: the FPA and the Natural Gas Act.[76] Through these statutes, FERC is granted authority to regulate electricity and natural gas sold in interstate commerce or sold for resale (known as the wholesale market).[77] Despite their distinction in subject matter, the similarities between these statutes have led courts to apply precedent nearly interchangeably.[78] FERC's authority balances broader energy

72. *See About U.S. Natural Gas Pipelines—Transporting Natural Gas*, U.S. Energy Info. Admin., https://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/develop.html (last visited Feb. 20, 2017).

73. In fact, economic realities and market rules have incentivized dual-fuel generators, which allow gas generators to switch to the dirtier and more costly oil for fuel. *See, e.g.*, *PJM to Consider Market Changes for Gas-Fired Generators*, RTO Insider (Oct. 29, 2013), https://www.rtoinsider.com/gas-fired-generators-02/.

74. *Algonquin's Innovation to Facilitate Natural Gas Acquisitions by Electric Distribution Companies Faces Uphill Battle in Face of Strong Opposition to Targeted Releases Even Following Tech Conference*, Forester Rep. (June 2016), https://www.fosterreport.com/featured-stories/algonquins-innovation-to-facilitate-natural-gas-acquisitions-by-electric-distribution-companies-faces-uphill-battle-in-face-of-strong-opposition-to-targeted-releases-even-following-tech-conference/.

75. FERC also has jurisdiction over oil pipelines, hydroelectric permitting, and liquefied natural gas permitting. Natural Gas Act, 15 U.S.C. § 717 (2012); Federal Power Act, 16 U.S.C. § 817 (2012).

76. 15 U.S.C. § 717; 16 U.S.C. §§ 791-828c (2012).

77. James H. McGrew, Basic Practice Series: FERC (Federal Energy Regulatory Commission) 117 (Am. Bar Ass'n 2d ed. 2009).

78. Transmission Access Pol'y Study Grp. v. FERC, 225 F.3d 667, 686 (D.C. Cir. 2000) ("[Courts] have repeatedly recognized the similarity of the two statutes and held that they should be interpreted consistently.").

market regulation with state PUCs that assert jurisdiction over retail sales (such as electricity or gas sold directly from a utility to a residential consumer).[79] This section will review the FPA and examine where courts have drawn the jurisdictional divide for purposes of the dormant Commerce Clause and federal preemption.

Under the FPA, FERC has exclusive jurisdiction over wholesale electricity sales and transmission and is responsible to ensure just and reasonable rates for wholesale power.[80] FERC's jurisdiction over interstate electricity transactions developed out of necessity. The Supreme Court held in *Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Co.*[81] that Rhode Island and Massachusetts could not develop state regulations that adjusted the price of wholesale electricity between utilities in the two states.[82] The Court reasoned that the dormant Commerce Clause, the implied corollary of the U.S. Constitution's Commerce Clause, which restricts the power of the states to interfere with interstate commerce, necessarily prevented states from regulating electricity that crossed state borders.[83] This decision led to the "Attleboro gap" because it prevented the states from regulating interstate electric transmission, but no federal agency had statutory authority to regulate interstate electricity at the federal level.[84] Congress passed Part II of the FPA to address the "Attleboro gap" and granted authority to the Federal Power Commission ("FPC")[85] to set just and reasonable rates for transmission service.[86] The FPA grants express authority to FERC over "electric energy in interstate commerce . . . and at wholesale in interstate commerce."[87] Importantly, however, the act explicitly states that such authority is limited "only to those matters which are not subject to regulation by the States."[88] While the line dividing state and federal jurisdiction may be clear given facts analogous to *Attleboro*, state policy implementations must avoid purposively affecting wholesale sales of electricity indirectly in violation of the dormant Commerce Clause and the Supremacy Clause.[89]

Once the FPA granted authority to the FPC to regulate interstate and wholesale electricity markets, many questions of state versus federal jurisdiction were predicated on federal preemption.[90] The Supremacy Clause of the Constitution states that federal laws "shall be the supreme law of the land."[91] In particular, courts have explicitly held that FERC's subject matter jurisdiction demands that, "states cannot have jurisdiction over the same subject."[92] Federal statutes can preempt through two mechanisms: conflict preemption and field preemption.

Conflict preemption occurs when states are preempted from regulating activity that would stand as an obstacle against federal regulation.[93] For example, in *Entergy Nuclear Vermont Yankee, LLC v. Shumlin*,[94] the Second Circuit examined a Vermont state statute requiring Entergy to secure construction permits from the state government that mirrored permits already secured from the Nuclear Regulatory Commission under the Atomic Energy Act.[95] The Court held that the Vermont statutes establishing the permit system were preempted by the Atomic Energy Act because the Vermont legislature's intent in compelling the construction permits was partially to regulate safety concerns already being regulated by the Atomic Energy Act.[96] Alternatively, state statutes can be invalidated through field preemption, which prohibits states from regulating any field that Congress intended to "occupy exclusively," even without direct statutory language.[97] Two recent cases demonstrate the FPA's ability to curb state energy regulation through field preemption.

In *PPL Energyplus, LLC v. Nazarian*,[98] the Fourth Circuit found that Maryland's attempt to encourage the construction of natural gas generation facilities was preempted by the FPA. Maryland's legislature aimed to correct a perceived shortfall in generation by offering the generation facility a twenty-year guaranteed stream of revenue through a "contracts for differences."[99] The contracts for differences would require an electric distribution company to pay the generation facility the difference between the facility's periodic revenue and its revenue requirements.[100] If the generator's revenue exceeded its set revenue requirement, however, it would be required to pay the excess revenue to the electric distribution company.[101] This mechanism provided a guarantee to the future generator[102] that a fixed revenue would be earned regardless of the generator's revenue receipts.[103] The generator was required to

79. McGrew, *supra* note 77.
80. 16 U.S.C. § 824.
81. 273 U.S. 83 (1927).
82. *Id*. at 89–90.
83. *Id*. at 89.
84. Matthew R. McGuire, *(Mis)Understanding "Undue Discrimination": FERC's Misguided Effort to Extend the Boundaries of the Federal Power Act*, 19 Geo. Mason L. Rev. 549, 553–54 (2012).
85. The Federal Power Commission is the Federal Energy Regulatory Commission's predecessor. *History of FERC*, Fed. Energy Reg. Commission, https://www.ferc.gov/students/ferc/history.asp (last visited Feb. 22, 2017).
86. *Id*.
87. 16 U.S.C. § 824(a).
88. *Id*.
89. Emily Hammond & Richard J. Pierce, Jr., *The Clean Power Plan: Testing the Limits of Administrative Law and the Electric Grid*, 7 Geo. Wash. J. Energy & Envtl. L. 1 (2016) (noting the dormant Commerce Clause and the Supremacy Clause are two important barriers to state policy), https://gwujeel.files.wordpress.com/2016/02/jeel_vol7_issue1_hammondpierce.pdf.
90. McGuire, *supra* note 84, at 580.
91. U.S. Const. art. VI, § 1, cl. 2.
92. Miss. Power & Light Co. v. Moore, 487 U.S. 354, 377 (1988) (Scalia, J., concurring).
93. Fla. Lime & Avocado Growers, Inc. v. Paul, 373 U.S. 132, 142–43 (1963).
94. 733 F.3d 393 (2d Cir. 2013).
95. *Id.* at 400–02.
96. *Id*. at 437–39.
97. English v. Gen. Elec. Co., 496 U.S. 72, 79 (1990).
98. 753 F.3d 467, 473 (4th Cir. 2014), *cert. granted sub nom*. CPV Maryland, LLC v. PPL EnergyPlus, LLC, 136 S. Ct. 356 (2015), and *cert. granted sub nom.* Hughes v. PPL EnergyPlus, LLC, 136 S. Ct. 382 (2015).
99. *Nazarian*, 753 F.3d at 473.
100. *Id*. at 473–74.
101. *Id*. at 474.
102. Maryland's Public Service Commission introduced this mechanism during the bidding in response to comments concerning Order No. 82936's request for proposals of new generation. *See* Md. Pub. Serv. Comm'n, Notice of Approval of Request for Proposals of New Generation to Be Issued by Maryland Electric Distribution Companies, at 1, 3 (Feb. 27, 2017), http://webapp.psc.state.md.us/Intranet/casenum/NewIndex3_VOpenFile.cfm?filepath=C:/Casenum/9200-9299/9214/Item_77//Case%209214%20RFP%20Issuance%20Order.pdf.
103. *Nazarian*, 753 F.3d at 473–74.

clear the market price, or match the dispatch price of electricity, when selling its energy into the wholesale market.[104]

The Fourth Circuit found that the contract for differences was field preempted because it essentially set the price received by the generator for its natural gas, which in turn allowed the generator to undercut other generating facilities during the grid operator's bidding process.[105] Because the FPA grants FERC the exclusive authority to regulate wholesale electricity prices, the court held that Maryland's incentive program violated the Supremacy Clause because it interfered with existing competitive wholesale market signals under FERC jurisdiction.[106]

In *PPL Energyplus, LLC v. Solomon*,[107] the Third Circuit found a similar incentive program in New Jersey to be preempted by the FPA. In *Solomon*, the legislature passed the Long Term Capacity Pilot Program Act ("LCAPP") to encourage new generation facilities through guaranteed 15-year contracts.[108] Like *Nazarian*, New Jersey's program compelled the electric distribution companies to sign agreements with these generators.[109] Although the contract mechanisms were different than *Nazarian*, the effect was the same: under the program, generators were guaranteed capacity at a set rate.[110] The Second Circuit found that the LCAPP program effectively set the price for capacity through its price supplement.[111] Similar to the Fourth Circuit, the Court found that FERC regulates the wholesale electricity markets through the grid operators (Regional Transmission Organizations) and the competitive bidding process.[112] New Jersey's LCAPP program encroached on FERC's regulations by allowing the generators to set an artificial price within the wholesale electric energy market.[113] By allowing the generators participating in the program to recover their revenue costs regardless of the price bid into the wholesale market, the LCAPP program disadvantaged competing generators.[114] As noted above, typically the generator can only bid its marginal cost (or the cost of the natural gas), but, like in the *Nazarian* case, the LCAPP program allowed participating generators to bid below their actual operating costs because utilities were contractually obligated to pay the generators the difference in cost.[115]

Both the *Nazarian* and *Solomon* cases reinforce FERC's exclusive jurisdiction over the wholesale markets. However, the Supreme Court has held that FERC's jurisdiction over wholesale rates does not preempt state law that is not aimed at directly undermining the interstate or wholesale rates.[116] Addressing field preemption in the context of the Natural Gas Act, the Supreme Court held in *Oneok, Inc. v. Learjet* that state antitrust laws are not preempted by FERC's statutory authority because the state laws had "broad applicability" and were not aimed to regulate natural gas companies within FERC's jurisdiction.[117] Notably, the antitrust claims against the pipeline companies alleged the companies falsely reported data that did have an effect on wholesale prices, but were still held not to be preempted because the general law was not aimed at regulating wholesale prices.[118]

B. New England's Retail Restructuring

The electricity market mechanisms described in section I.B describe the wholesale electricity market, or the sale of electricity for resale.[119] As described above, the FPA grants FERC exclusive authority over wholesale electricity transactions, but the authority to regulate retail rates are reserved for the states.[120] Any sale of electricity directly to an end user is considered a retail sale (for example: a sale from a local utility to a resident's home).[121] Federal restructuring of electricity markets in the 1970s and 1980s bifurcated the markets and transformed the wholesale market while leaving the state-regulated retail rates unchanged.[122]

However, faced with increasing electricity prices, several states investigated restructuring retail electric service to promote greater competition in the 1990s.[123] The proposals did not call for complete deregulation, but rather allowed customers to choose their electricity supplier while maintaining the regulated distribution service from utilities.[124] The primary goals of restructuring were to reduce prices and "shift the risks of assuring adequate new generation construction from ratepayers to competitive market providers."[125] Electricity prices in New England during this time were especially high and led all of the New England states to explore the possibility of restructuring.[126] Between 1996 and 2000, all of the New England states except Vermont passed restructuring statutes.[127]

104. *Id*.
105. *Id*. at 479.
106. *Id*.
107. *See* 766 F.3d 241, 246 (3d Cir. 2014), *cert. denied sub nom*. CPV Power Holdings, LP v. Talen Energy Mktg., LLC, 2016 U.S. LEXIS 2810 (Apr. 25, 2016).
108. *See id*. at 248.
109. *See id*. at 253.
110. *See id*. at 254.
111. *Id*.
112. *Solomon*, 766 F.3d at 254.
113. *Id*.
114. *Id*.
115. *Id*.
116. Oneok, Inc. v. Learjet, Inc., 135 S. Ct. 1591, 1601 (2015).
117. *Id*.
118. *Id*.; *cf*. Schneidewind v. ANR Pipeline Co., 485 U.S. 293, 305 (1988) ("Congress occupied the field of matters relating to wholesale sales and transportation of natural gas in interstate commerce.").
119. FERC Primer, *supra* note 39, at 35.
120. *See* Eisen, *supra* note 9, at 699.
121. *Id*. at 515.
122. *See* Reishus Consulting, LLC, *Electric Restructuring in New England—A Look Back*, New Eng. States Committee on Electricity 4 (Dec. 2015) [hereinafter *NESCOE Restructuring History*], http://nescoe.com/wp-content/uploads/2015/12/RestructuringHistory_December2015.pdf (listing important wholesale restructuring reform actions).
123. Electric Energy Market Competition Task Force, Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy 6 (2007) [hereinafter *Market Competition Task Force*], https://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf.
124. *Id*.
125. *Id*.
126. *See* Eisen, *supra* note 9, at 700 (stating that high electricity prices in the Northeast created a political environment conducive to restructuring); *see also* *NESCOE Restructuring History*, *supra* note 122, at 12 (citing the New England states as "the first states in the US to explore the potential benefits of retail restructuring").
127. *NESCOE Restructuring History*, *supra* note 122, at 12.

While the specific statutes vary slightly, the most important principle of restructuring was to separate ownership of generating facilities and distribution lines.[128] The statutes required the electric utility to divest of, or structurally separate, its generation facilities.[129] Before restructuring, the state utility was vertically-integrated and owned the generation facilities *and* the distribution lines to transport the electricity.[130] In its post-restructuring role, the utility would only operate the distribution lines for the transport of the newly independent generating facilities.[131]

III. Legal Analysis

A. The Massachusetts Proposal to Allow EDCs to Contract for Pipeline Capacity Is Legally Consistent With the FPA, but Violates the Principles of Electricity Restructuring at the State Level

Due to the misalignment of the natural gas pipeline and electric generation models, natural gas generators are not signing the long-term contracts pipeline operators require to construct pipelines into New England.[132] State legislatures and PUCs in the region have proposed solutions that would use state regulatory power to facilitate the necessary investment pipeline operators require. EDCs and pipeline companies in Massachusetts, for example, have proposed a plan to allow the EDCs to serve as shippers to the pipeline and pass through the pipeline transportation cost, or the demand charge, to ratepayers.[133] Unlike an LDC, which releases the excess natural gas not required to serve its customers into the wholesale market, the EDCs would release the full contracted capacity into the wholesale market for gas-fired generators to place bids.[134] A similar regulatory proposal is being examined in New Hampshire,[135] while state legislatures in Connecticut[136] and Maine[137] have already passed bills that authorize the state PUC to directly contract with pipeline companies to ensure capacity.[138] This analysis will consider the Massachusetts proposal because Massachusetts is the largest New England state and the proposal is sufficiently similar to the other state initiatives in that it seeks to use state-level ratemaking to pass through the pipeline demand charge. For the reasons below, the Massachusetts EDC proposal is consistent with the FPA for purposes of preemption, but seeking a state-level recovery of capital is inconsistent with state electricity restructuring policies.

As the *Nazarian, Solomon*, and *Learjet* cases demonstrate, states are permitted to pass legislation and regulations that affect wholesale power markets, provided the purpose of the state action is not to influence or interfere with wholesale prices.[139] The Massachusetts and New Hampshire proposals to allow EDCs to enter into pipeline capacity contracts do not interfere with FERC's wholesale natural gas or electric power jurisdiction because the effect on wholesale natural gas or electricity prices would be indirect.

Unlike the *Nazarian* and *Solomon* cases in which New Jersey and Maryland explicitly used guaranteed contract mechanisms to effectively set the price that applicable generators would bid into wholesale markets, the New Hampshire and Massachusetts proposals do not affect the marginal cost of natural gas for gas-fired generators.[140] Instead, the EDCs would release the contracted capacity into the wholesale natural gas market where gas-fired generators could sign up for capacity. Furthermore, unlike the *Nazarian* and *Solomon* cases where the states were compelling utilities to fulfill pricing contracts, under the proposed plans no EDC would be required to contract for pipeline capacity and no natural gas generator would be required to purchase the gas from the EDCs.[141]

More importantly, state PUCs allowing EDCs to pass through rates would not be subsidizing one entity at the expense of another. The *Nazarian* and *Solomon* contracts provided a potential subsidy for generators in the program that placed non-program generators at a competitive disadvantage.[142] The Massachusetts proposal would simply allow the EDCs to sell the pipeline capacity into a competitive bidding system (through ISO-NE). The rate at which the EDC sells the pipeline capacity is still determined by the wholesale market purchasers (the generators), not the respective state program or the EDC. Similarly, if a generator purchases the natural gas capacity from the EDC, there is no competitive advantage to the EDC when purchasing electricity from generators. As the utility to residential customers, the EDC is responsible for operating the transmission lines that move the electricity from the generators to the end-users (e.g., residents). In *Nazarian* and *Solomon*, specific generators were guaranteed a rate of return and were able to bid a lower price for electricity into the competitive market operated by the ISO/RTO *regardless of the cost of natural gas*.[143] Under the Massachusetts proposal, the released capacity would be available to all of the gas-fired generators connected to the pipeline and no one generator would have a competitive advantage over the other generators.

Instead, the proposed programs are more analogous to the antitrust claims alleged in *Learjet.* Like *Learjet*, where

128. *Id*. at 13.
129. *Id*. at 13.
130. *Id*.
131. *Id*.
132. *See* discussion *supra* Part II.
133. Order Determining Department Authority Under G.L.C. 164, § 94A, *supra* note 18, at 2.
134. *Id*.
135. N.H. Pub. Util. Comm'n, Report on Investigation Into Potential Approaches to Mitigate Wholesale Electricity Prices, IR 15-124, at 2 (Oct. 2, 2015), http://www.puc.state.nh.us/Regulatory/Docketbk/2015/15-124/LETTERS-MEMOS-TARIFFS/15-124%202015-09-15%20STAFF%20REPORT.PDF.
136. An Act Concerning Affordable and Reliable Energy, S. 1078, Jan. Sess. (Conn. 2015).
137. Me. Rev. Stat. Ann. tit. 35-A, § 1904 (2013).
138. The PUCs in Massachusetts and New Hampshire are examining the issue at the state regulatory level. The state legislatures in Maine and Connecticut have passed legislation.
139. PPL Energyplus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014); PPL Energyplus, LLC v. Solomon, 766 F.3d 241 (3d Cir. 2014).
140. *See Nazarian*, 753 F.3d at 479; *Solomon*, 766 F.3d at 255.
141. *See Nazarian*, 753 F.3d at 473–74.
142. *Solomon*, 766 F.3d at 252–53.
143. *Id*.

the success of a state antitrust claim for price manipulation would likely affect wholesale prices, the proposed PUC actions would likely decrease wholesale prices for the region.[144] Indeed, lower electricity prices for the region is the driving force behind the state action. However, the regulations would not be implementing any pricing mechanism that directly affects wholesale prices. Like in *Learjet*, the state action in question would not be concerned with FERC's regulatory jurisdiction over wholesale electricity prices, but rather with an increase in natural gas capacity that indirectly affects the wholesale market.

Although the Massachusetts regulatory proposal is consistent the FPA, allowing EDCs to acquire firm pipeline contracts and recover costs through state ratemaking procedures is inconsistent with the principles of retail restructuring. The two primary purposes of restructuring were to divest generation responsibilities from utilities (EDCs) to promote competition and shift the financial risk from consumers to generation facilities.[145] By allowing EDCs to purchase natural gas capacity through pipeline contracts, the state proposals are violating both principles. First, although the EDC would not be operating the generating facilities (which would constitute a direct violation of the restructuring statutes), the EDC would be moving beyond its open-access, distribution role to procure fuel. Second, states restructured retail electricity markets in an effort to shift costs away from consumers (through a utility's rate recovery mechanism) to the private sector. In the restructured market, customers would abandon generators that would underperform.[146] Before restructuring, the generators as part of the state utility simply passed through their cost of business regardless of performance.[147] The EDC capacity contracts return a comparable risk to consumers by signing long-term contracts to be passed-through to the consumers. Most problematic, the consumer risk would be concentrated and only be placed on consumers within the contracting EDC's territory, while the benefits would be state-wide. The risk would differ slightly from the traditional regulated market because if natural gas prices were to increase to an uneconomic value, the generators utilizing the gas would not be selected by consumers, but the consumers within the EDC's territory would still pay for the gas through their utility bill.

The recent Massachusetts Supreme Court decision, *ENGIE Gas & LNG LLC v. Department of Public Utilities*, has reinforced the problematic mechanics of this plan.[148] The court held invalid the Massachusetts Department of Public Utilities' authority to review and approve the final version of the plan.[149] Furthermore, the court's primary reasoning for the decision was that it "would undermine the main objectives of the [restructuring] act and re-expose ratepayers to the types of financial risks from which the Legislature sought to protect them."[150] The ruling effectively prevents any regulatory path to implement the EDC plan. The plan would now require the Massachusetts legislature to amend the restructuring statute to specifically allow for such a contract mechanism.[151]

Due to the regional cooperation that a solution would require, the Massachusetts decision is especially damaging. Eversource and National Grid—the EDCs spearheading the Access Northeast pipeline and the EDC plan—withdrew petitions for firm capacity following the decision.[152] More troubling for a long-term EDC plan, however, was the effect the ruling had on other New England states. Both New Hampshire and Connecticut withdrew pending regulatory proposals that would have implemented measures to facilitate the EDC plan.[153]

A recent FERC decision denying to EDCs a capacity release exemption also disfavors such a solution. Algonquin Gas Transmission, LLC—the pipeline operator for the proposed Access Northeast pipeline—requested a "blanket bidding exemption" to FERC's capacity release bidding requirements.[154] Capacity release requirements require that the releasing shipper (original buyer) of the gas release (resell) capacity only to the replacement shipper offering the highest rate.[155] Algonquin sought an exemption to permit the EDC's capacity manager to release to gas-generators the necessary capacity.[156] This would ensure that the contracted capacity would be delivered to the generators for which it was intended. However, FERC declined to permit a blanket exemption for all EDCs in such programs. Instead, FERC found that Algonquin did not show that such a broad exemption was necessary to ensure the EDC plan would work.[157] FERC did note, however, that it would consider "more targeted, justified proposals."[158] In addition, the capacity release rules allow for prearranged shippers. This means that an EDC proposal similar to the Massachusetts plan could move forward even without such an exemption.

However, even if the Massachusetts proposal moved forward, it would also lead to disparate benefits of consumer resources across the region. The wholesale market in New England operates within the entire jurisdiction of ISO-NE—serving all New England states—and would not be able to target the benefits of additional capacity to the state that purchased the capacity. For example, if Massachusetts allowed its EDC to sign a contract for firm service, the capac-

144. Oneok, Inc. v. Learjet, Inc., 135 S. Ct. 1591 (2015).
145. Electric Energy Market Competition Task Force, *supra* note 122, at 103.
146. *Id*. at 11 (explaining retail market competition principles).
147. *Id*.
148. 56 N.E.3d 740, 756 (Mass. 2016).
149. *Id*.

150. *Id*. at 192.
151. Peter J. Howe, 2016 The New England Energy Landscape: History, Challenges, Outlook 29 (2016), http://newenglandcouncil.com/assets/NEC-Energy-Report-October-2016-FINAL-Single-Page-Format.pdf.
152. *See* Mary Serreze, *Eversource, National Grid Withdraw Petitions for Capacity on Access Northeast Gas Pipeline*, MassLive (Aug. 23, 2016, 5:52 PM), http://www.masslive.com/politics/index.ssf/2016/08/eversource_withdraws_petition.html.
153. *See* Luther Turmelle, *Connecticut Pulls Out of Effort to Expand Natural Gas Capacity*, New Haven Reg. (Oct. 26, 2016), http://www.nhregister.com/business/20161026/connecticut-pulls-out-of-effort-to-expand-natural-gas-capacity.
154. *Algonquin Gas Transmission, LLC*, 156 FERC ¶ 61,151, at PP 3, 12, 13, 15 (2016).
155. *Id*. P 11.
156. *Id*. P 1.
157. *Id*. P 10.
158. *Id*. P 11.

ity would be released onto the wholesale market for all generators in the ISO-NE market for which all generators in New England could place a bid. By decreasing the costs across the entire region, customers in other states will benefit as well (without financing their EDC's rate recovery). Because state-level solutions—such as the Massachusetts proposal—would expose particular EDC customers to concentrated risks despite widespread benefits, a regionwide tariff would serve as a stronger solution. The hesitance of Connecticut and New Hampshire regulators to move forward without Massachusetts demonstrates the importance of regional coordination.

B. *ISO-NE Should Finance Additional Pipeline Capacity Through an Amendment to Its FERC-Approved Tariff That Would Share the Costs of Reliability Across All New England States*

The lack of pipeline capacity in New England is a serious problem that has adverse effects on electricity reliability and price volatility. However, permitting the EDCs to contract for pipeline capacity would result in a misallocation of risk and require EDCs to hold fuel contracts, which runs counter to electricity restructuring principles. As the region's Independent System Operator, ISO-NE should address the problem through a reliability amendment to its Transmission, Markets, and Services Tariff.[159] As the wholesale market operator, ISO-NE must receive approval from FERC to change its tariff.[160] The amendment would allow an independent third party to contract with a pipeline to increase capacity to the region. Specifically, ISO-NE should amend the tariff to create a new tariff schedule that would allow the third party to recover its costs from consumers in each of the New England states based on the amount of electricity used by each utility region. In 2014, the New England States Committee on Electricity ("NESCOE") proposed such a tariff amendment, known as the Incremental Gas for Reliability ("IGER") concept, but ultimately abandoned it in favor of the EDC approach endorsed by the Massachusetts proposal.[161] However, the tariff amendment approach has two advantages over the Massachusetts proposal: it properly addresses deficiencies in wholesale incentives with a wholesale solution and it more evenly distributes the costs amongst the entire region.

Natural gas-fired generators are not properly incentivized to subscribe to firm pipeline service. This problematic lack of incentive is a product of the wholesale market: the generators purchase the required natural gas on the wholesale gas market and sell the produced electricity into the ISO-NE's wholesale electricity market for customers to purchase. Both the ISO-NE tariff solution and the EDC solution would correct this market failure by passing the additional cost of firm pipeline service to ratepayers through a third party. However, unlike the state proposals permitting EDCs to contract for pipeline capacity, an ISO-NE tariff would not unnecessarily attach a retail-market participant to a wholesale contract.

Instead, a disinterested third party would provide the necessary capital for pipeline capacity and would be permitted to recover its costs from the ISO. The ISO would collect the necessary revenue for payment by charging each utility a rate based on the amount of electricity transmitted in that utility's region. The utility would pass the cost of this reliability rate onto its customers (residents or other users of its distribution lines). The ISO-NE tariff financing solution would provide a mechanism for passing through the demand charge component of firm pipeline contracts to the ratepayers who would benefit from the additional electricity reliability it would provide. However, this reliability amendment would finance the additional capacity at the wholesale level without involving retail electricity utilities (EDCs) against principles of restructuring. Because the ISO is a wholesale operator—and would only amend the tariff schedule with FERC's approval—this solution would bypass *Nazarian* and *Solomon* questions of FPA preemption.[162]

In addition, a region-wide reliability tariff would more fairly facilitate costs across the region. Increased capacity of natural gas will facilitate price stability and reliability across the entire New England grid. A reliability tariff amendment allows ISO-NE to allocate costs to each utility in each state. The tariff schedule would be assigned to each utility based on the electricity delivered in the region through the utility's distribution lines. Currently, ISO-NE can allocate costs for electricity *transmission lines* across New England if the project will provide "a benefit for all of New England."[163] Similarly, this amendment would improve reliability for the entire region and should fairly share the costs of the capacity across all New England electricity consumers. Conversely, the proposals to allow EDCs to contract for pipeline capacity would place the burden of financing the reliability and price benefits on the utilities that entered into the contract. However, the benefit would not be contained to the region of the contracting utilities. For example, if additional pipeline capacity is secured by a utility in southern Massachusetts, the gas-fired generation will lead to increased electricity in northern Massachusetts, New Hampshire, and throughout New England. Yet, it will be the southern Massachusetts utility customers that will ultimately be forced to pay for the capacity contract.

This solution is a drastic proposal because it requires transmission customers to bear a long-term capital investment. However, it should be framed as an important reliability measure to address a widely acknowledged problem.

159. *See generally Transmission, Markets, and Services Tariff*, ISO New Eng., http://www.iso-ne.com/participate/rules-procedures/tariff (last visited Feb. 23, 2017).

160. *See* 16 U.S.C. § 824d(c)–(d).

161. *See generally Summary of Stakeholder Input and Request for Further Information on Capacity Management*, New Eng. States Committee on Electricity (June 11, 2014), http://nescoe.com/uploads/RegionalInfrastructure_RequestforFurtherInfo_11June2014.pdf (summarizing IGER concept).

162. *Electric Power Markets: New England (ISO-NE)*, Fed. Energy Reg. Commission, http://www.ferc.gov/market-oversight/mkt-electric/new-england.asp (last updated Mar. 10, 2016) ("as the RTO for New England, ISO-NE is responsible for operating wholesale power markets").

163. *Transmission Cost Allocation*, ISO New Eng., http://www.iso-ne.com/system-planning/transmission-planning/transmission-cost-allocations (last visited Feb. 1, 2017) (explaining the cost allocation factors for new transmission lines).

FERC has demonstrated an appetite to consider solutions through technical conferences and broad attention. ISO-NE has also been involved in many potential solutions. In a 2015 Fuel Assurance Status Report to FERC, ISO-NE aptly commented:

> The New England states, recognizing the reliability risks and economic consequences associated with insufficient pipeline capacity, have worked diligently in an effort to facilitate the necessary investment in additional pipeline capacity. This path is not without difficulty, but may be the most direct route to a timely solution to this serious problem.[164]

Because it more fairly allocates costs and addresses the gas-electric market failure at a wholesale level, an ISO-NE tariff amendment would be an effective option to bring additional gas capacity to New England.

IV. Conclusion

New England's increased use of natural gas for electricity is increasing its need for new pipelines to be constructed. However, because of the capital-intensive financing that pipeline construction and operation require, pipelines are typically built only when there is demonstrable demand and subject to long-term contracts. Moreover, FERC approves pipeline permits only if it is deemed to be in the public interest. Typically, pipeline companies demonstrate public interest by showing market viability through shipping agreements fulfilling the entire capacity of the pipeline.

The existing regulatory system has created diverging incentives for natural gas generating facilities and New England regulators and consumers. Gas-fired generators cannot compete with other generating facilities if they purchase the right to guaranteed service because of its price premium. However, the less expensive, interruptible service leads to price volatility and reliability concerns when the region utilizes the entirety of pipeline capacity. There have been several state proposals in New England that seek to allow EDCs, or utilities, to directly contract with a pipeline company for natural gas capacity and recover the investment from ratepayers.

This note had argued that the current regulatory problem should be addressed at the wholesale markets instead of the retail markets. Although the state proposals are likely consistent with the FPA, allowing EDCs to enter into capacity contracts stands in opposition to the principles of state restructuring that prohibited EDCs from generating activities. Moreover, the fundamental principles of restructuring disfavor the state distribution companies affecting the wholesale market. Instead, as the operator of the competitive wholesale market, ISO-NE should address the problem by amending its tariff to include a new schedule to allow an independent, third party to acquire the pipeline capacity directly and recover the costs from utility customers throughout New England. Such action will achieve New England's reliability concerns, provide additional pipeline capacity, equally allocate costs among all of the regions consumers, and preserve the principles of restructuring at the state level.

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164. *ISO New. Eng. Inc.*, Fuel Assurance Status Report, Docket No. AD13-7-000, at 4 (FERC Feb. 18, 2015).