Advancing the Clean Energy Future

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June 15, 2015

Secretary Mark D. Marini and Hearing Officer David Gold
Massachusetts Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Comments on D.P.U. 15-37

Secretary Marini and Mr. Gold:

Acadia Center, Clean Water Action, Mass Energy, Berkshire Environmental Action Team, HealthCare Without Harm, Nashoba Conservation Trust, No Fracked Gas in Mass , No. Quabbin Pipeline Action, Millers River Watershed Council, Pipeline Awareness Network for the Northeast, StopNED, and Toxics Action Center appreciate the opportunity to provide comments and participate in this investigation by the Department of Public Utilities ("Department"). The Commonwealth is at a crossroads of how to best upgrade and reconfigure our energy infrastructure. The decisions made by the Department will have lasting impact. These decisions can either build on the important foundation of the Green Communities Act and the Global Warming Solutions Act to construct a fully integrated, flexible, low carbon energy future that better serves consumers and offers lower risks; or they can divert us into over-building the infrastructure of the past, condemning ratepayers to the risky and volatile prices of fossil-fuel governed markets.

In its April 27th Order on the request by the Department of Energy Resources ("DOER"), the Department asked some critical questions regarding the causes behind high regional electricity prices, the exact parameters of any constraints, and what resources or commercial mechanisms could potentially alleviate them. However, given that we do not yet have the answers to these questions, it would be premature for the Department to embark on a campaign of seeking new natural gas delivery capacity. In short, it is our overarching position that:

- There are myriad drivers of electric costs, many of which are outside the control of the Department, and the most significant of which is the supply and demand of electricity. Only by phrasing its inquiry as one of electric prices, supply, and demand, can the Department ensure that the results actually deliver the most cost-effective and lowest risk source of electricity to Massachusetts ratepayers;
- We do not know whether any additional natural gas capacity would cost-effectively reduce wholesale electric prices, once all existing market mechanisms, and the full potential for efficiency and renewable generation throughout the region are taken into account;
- If it is determined that there is insufficient gas capacity for electric generation, it should be procured by gas-fired generators, through ordinary market channels, as a cost of doing business, rather than underwritten and subsidized by electric distribution utilities.

Addressing the Department's posed questions more directly:

- The Department does not have the jurisdiction to authorize the purchase and resale of natural gas by electric distribution companies ("EDCs"), as FERC has exclusive jurisdiction over such sales, pursuant to the Natural Gas Act, 15 U.S.C. §717 *et seq.*; and "[t]he federal regulatory scheme leaves no room for either direct state regulation of the prices of interstate wholesales of natural gas, or for state regulations which would indirectly achieve the same result." *N. Natural Gas Co v. State Corp. Comm'n,* 372 U.S. 84, 91 (1963) (internal citation omitted);
- Restricting the resale of natural gas to in-region electric generators would require additional legislation that would likely be found to violate the dormant commerce clause;
- It is not within the public interest (in fact antithetical to the public interest) for electric ratepayers in the Commonwealth to bear the risk of volatile natural gas prices while ratepayers in other states and the electric generators ultimately purchasing the subsidized gas reap any benefits without any risks or costs.

DPU Additional Question 1:

What specific natural gas delivery capacity constraints are causing high regional electricity prices? Please identify and characterize constraints with respect to geographic location, time of year and/or market condition when constraint is or will be binding, and the degree to which the constraint impacts local versus regional natural gas delivery capability.

High Electricity Prices Do Not Prove Gas Constraints

The high regional electricity prices that New England has experienced over the last two winters are caused by two factors: supply and demand for electricity. Due to the prevalence of natural gas-fired facilities in ISO-NE's generation mix, prices in the electric wholesale market are frequently correlated with prices for natural gas, which in turn is driven by supply and demand for gas. However, this fact does not and should not make the issue of demand for electricity into a problem solely caused by gas supply or one that can only be addressed via gas supply.

In fact, it would be equally reasonable for the Department to conclude that the high winter prices of recent years are due to an inadequate supply of *any* resource that produces electricity or reduces electric demand. For example, bringing on more hydroelectric capacity in these key winter months would likely reduce wholesale prices – why not open an inquiry into how to procure more hydroelectricity? In phrasing this inquiry as one centered on gas delivery capacity constraints, the Department potentially misses crucial sources of energy that can deliver more cost-effective and less risky price reductions than additional gas capacity.

As the Department itself has recently stated, the high energy prices of late are the result of regional energy market dynamics, at least some of which are outside of the areas in which the Department regulates. DPU 15-40 at 1 (April 9, 2015). One of the important drivers of electricity costs that is outside of the Department's jurisdiction is one of the faster growing pieces of retail rates – transmission costs. The Energy Information Administration found that transmission expenditures have increased by five-fold over the last 15 years.[1] The reason behind this abrupt increase

[1] US EIA, *Investment in Electricity Transmission Infrastructure Shows Steady Increase*, August 26, 2014, available at: http://www.eia.gov/todayinenergy/detail.cfm?id=17711

in transmission rates is due, at least in part, to the high returns on equity guaranteed to utilities for continued investment in transmission. Even after being limited by FERC in recent decisions, these rates of return are still considered reasonable if they are as high as 11.74%. *See* FERC, Opinion No. 531-A, Docket EL11-66 (October 16, 2014). While solutions for reducing the impact of transmission rates are outside of the Department's control, imposing additional large infrastructure projects on ratepayers – in this case for pipelines – would only exacerbate this trend and further increase costs.

Before the Department Can Act, It Must Answer More Questions

Although the Department has posed many questions this inquiry, far too many questions about the cause of high electricity prices remain for the Department to take such drastic action as EDCs securing new gas delivery capacity into the region, backed up by their ratepayers. Such questions include:

- Would interference in the natural gas market spill over into other markets, such as industrial uses of fossil fuels?
- What are the many factors driving high electric prices?
- What market mechanisms are already moving forward to address the drivers of high regional electricity prices?
- Have all possibilities for market-based solutions been evaluated and given the time to work?
- Once we take these mechanisms into account, will we still have winter energy constraints?
- If so, what are the costs and benefits of potential solutions? What is the risk of future benefits not meeting projections? What solutions are best for the consumers? What solutions are in line with state policies to reduce greenhouse gas emissions, increase renewable portfolios, incentivize innovation, and reduce costs and price volatility into the future?
- Which regulators and which parties are best suited to implement any cost-effective solutions that complement existing state law and regional policies?

Only by answering these questions can the Department (or other regulatory bodies) be certain of the right forum for solutions. What's more, upon answering such questions, the Department should allow time for the public and markets to respond, new, innovative commercial approaches to be developed, and contracts for additional resources like hydro, wind, LNG, or even firm contracts for natural gas to be entered into before undertaking additional market manipulation and interference.

DOER Question 1:

Is there any legal impediment to the Department accepting and considering natural gas capacity contracts by EDCs under Section 94A, and, if approved, providing reasonable assurance of cost recovery?

The Natural Gas Act's Delegation to FERC Preempts the Department's Contemplated Action

Under the Supremacy Clause of the United States Constitution, a state law, rule, tariff or action is preempted when Congress intends federal law to occupy the field into which the state intrudes or when state regulation stands as an obstacle to the accomplishment of Congress's goals. In the Natural Gas Act ("NGA"), 15 U.S.C. §717 *et seq.*, Congress granted to the Federal Energy Regulatory Commission ("FERC") the exclusive authority to regulate both the sale of natural gas for resale and its interstate transportation. §717(b). State PUCs retain authority over the regulation of local distribution of natural gas, as well as "the sale in interstate commerce for resale, of natural gas received… within or at the boundary of a State if all the natural gas so received is ultimately consumed within such State" – i.e. wholly-intrastate transactions. §717(b) and (c).

The import of the NGA here is that because FERC has exclusive authority to regulate electric distribution companies' purchase of natural gas for resale in interstate commerce, the Department cannot regulate such actions, such as by approving long-term contracts under G.L. c. 164, §94A. *See, e.g N. Natural Gas Co v. State Corp. Comm'n*, 372 U.S. 84, 91 (1963)("[t]he federal regulatory scheme leaves no room for either direct state regulation of the prices of interstate wholesales of natural gas, or for state regulations which would indirectly achieve the same result.") (internal citation omitted).

As the EDCs are legally barred from owning generation assets other than solar under G.L. c. 164, §1A, they would have no use themselves for the natural gas they propose to procure. The only commercially viable use for such gas would be resale in interstate commerce and transportation both within and outside of Massachusetts – i.e. areas in which FERC has exclusive jurisdiction, and the Department cannot act. Even if the state legislature were to pass legislation restricting EDCs to resale only to Massachusetts gas-fired generators and bar them from resale – which would keep the resale in "intrastate" commerce, and arguably within the Department's control – such legislation would itself facially violate the dormant Commerce Clause as mandating differential treatment of in-state and out-of-state interests. *See, e.g., New England Power Co. v. New Hampshire*, 455 U.S. 331 (1982) (striking down a NH law that prohibited a utility from exporting hydropower generated in New Hampshire to another state). As such, authority in this area is explicitly preempted by Congress's assignment of FERC jurisdiction.

DOER Question 2

Is there an alternative mechanism available for EDCs or other parties to secure new gas delivery capacity to the region?

DPU Additional Question 2

What specific natural gas resources and/or commercial mechanisms could potentially alleviate each of the natural gas delivery capacity constraints identified above? What is the estimated cost and timing required to implement each potential resource/commercial mechanism?

Gas-Fired Generators Can Secure New Delivery

The perceived problems of gas supply are actually problems of gas-fired units that lack firm transportation of gas. As DOER's filing lays out, "because gas distribution customers are served by long-term contracts, the volatility of the market and corresponding higher winter prices is felt more sharply by electric distribution customers." (DOER at 3). Stated another way: the contracts obtained by LDCs and gas-fired electric generators are different, with the electric generators' interruptible contracts leaving them open to volatile prices and scarcity. Electric generators *can* enter into the same long-term, fixed contracts as LDCs – they just choose not to. Instead, electric generators procure gas capacity under interruptible contracts, which, in exchange for a lower cost, carry with them the potential for interrupted service.[2]

These interruptible contracts also do not send an adequate market signal for pipeline companies to build more infrastructure. As DOER states, "the mismatch between the availability of long-term commitments needed to stimulate necessary gas pipeline expansion and the willingness and/or ability of gas-fired generators to supply those commitments is the essential problem that is in need of a solution." (DOER at 4). DOER correctly identifies this mismatch – however, EDCs are not the only or best solution.

Clearly, the market is distorted if there are not sufficient incentives for a gas-fired generator to purchase enough fuel supply to run throughout the winter. To address this issue, we can either create incentives in the market signaling the gas generation facilities to enter into more firm contracts,[3] or we can create incentives for other resources – namely ones not dependent on volatile prices of fossil fuels – to replace them. The solution is not for another other party to enter into the contracts that the generators themselves should be seeking.

Market Mechanisms May Sufficiently Address Market Failures

Three market modifications that may address the disconnect between gas generators, gas supply, and winter capacity are already under way. However, the impacts of these modifications have not been properly modeled, nor have the potential solutions been allowed to play out. All of these mechanisms will likely have an impact on the relationship between demand for gas and electricity in winter and wholesale electric prices, and it will be difficult to predict the effects of additional natural gas supply on electricity prices until after we see the results of these changes.

First, the New England states and the regional grid operator ISO-New England have already achieved promising results from incremental market reforms to alleviate winter price spikes. ISO-NE changed market rules ranging from the frequency of energy bids[4] to compensating generators for advance purchases of LNG through the Winter Reliability Program[5], to ensure that they had enough fuel on hand to get through winter cold snaps. FERC has taken steps to improve coordination of wholesale natural gas and electricity market scheduling, including forthcoming changes to the nomination cycle.[6]

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[2] It is also worth noting that LDCs don't exclusively contract for firm pipeline capacity to meet their peak demand requirements. They use a blend of resources that meets this need in a cost-optimal manner.

[3] Presumably, gas-fired generators as market actors faced with the right market rules would take a similar approach as LDCs in procuring gas supply, by using a blend of contracting method that includes firm contracts. A similar situation occurs in the wholesale electric markets, where a blend of baseload and infrequently used peaker generating units satisfy market needs based on the balance between up front and operating costs.

[4] *See, e.g.* ISO-NE Press Release on Market Changes, December 18, 2014, available at: http://www.iso-ne.com/static-assets/documents/2014/12/emof_final_12182014.pdf

[5] FERC's approval of ISO-NE's 2014-2015 Winter Reliability Program also required ISO-NE to implement a stakeholder process to develop proposals to address reliability concerns for future winters. 148 FERC ¶ 61,179 (2014).

[6] *See, e.g.* Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, 151 FERC ¶61,049 (2015).

The drop in prices for oil and LNG on the global market provides even more leeway to pursue low-risk market reform solutions. Oil prices are about 40 percent lower than they were last summer[7], and prices for LNG have fallen with them. This has led to more LNG deliveries to New England, allowing the region to use existing infrastructure to meet peak winter demands in winter 2015.[8] As a net result, ISO-NE data show prices this winter were 40% lower than Winter 2014. LNG prices are also forecasted to remain lower than previously expected, as projected growth in demand in Asia has recently been revised downward.[9]

Second, Pay-for-Performance is a recent change to ISO-NE's market rules, creating a two-settlement market design for the Forward Capacity Market that is explicitly aimed at addressing these market failures. *See* ISO New England Inc., 147 FERC ¶ 61,172 (2014). Under the change, a resource that clears the auction will receive base capacity payments, as they previously did. A second settlement happens during delivery – when scarcity conditions exist, resources that perform above their share of capacity get a payment, while those that under-perform must pay a penalty. According to ISO-NE, "by creating incentives for generators to firm up their fuel supply, Pay-for-Performance may indirectly incentivize the development of oil or LNG fuel storage or gas pipeline infrastructure"[10] – in other words, it may address the market failures underlying this issue entirely. We will begin to see the effects of Pay-For-Performance soon, when it comes into effect in June 2018 for commitments established by FCA 9 in February 2015. We already know that the market is accommodating the Pay-For-Performance concept, as adequate capacity bid in to FCA9. What's more, by addressing the market failure itself, market corrections like Pay-for-Performance are more likely to result in generators purchasing the right amount and mix of natural gas for the New England grid – efficiently determined by the market, rather than artificial changes to the supply curve, like subsidized purchases by EDCs. When generators are purchasing the right amount of natural gas under properly incentivized contract structures, it is far less likely that we will have stranded pipeline infrastructure, paid for by ratepayers but no longer needed in our clean energy future.

The final market mechanism that might provide additional secure winter electric capacity is the Request for Proposals for Clean Energy and Transmission, expected to be issued shortly by Connecticut, Massachusetts and Rhode Island. Although the draft RFP issued by the states did not include specific targets for delivery of energy in winter months, it would be possible to structure the procurement to enable the use of clean energy to meet Massachusetts' electric needs on a year-round basis. As Acadia Center urged in its comments on the draft RFP,[11] the proposals should

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[7] *See, e.g.,*Jyoti Kainth and Neelendra Nanth, Business Today, "When it comes to oil pricing, politics trumps economics" (May 27, 2015) available at: http://businesstoday.intoday.in/story/when-it-comes-to-oil-pricing-politics-trumps-economics/1/219759.html
[8] *See, e.g.,* Jay Fitzgerald, Boston Globe, "Pipeline Opponents Say LNG is Underutilized" (March 23, 2015) available at: http://www.bostonglobe.com/business/2015/03/22/with-increase-lng-supplies-does-region-really-need-new-pipelines/mrRbwgaiKwYuAJoGXDiPMN/story.html
[9] See International Energy Agency, *Despite Decline in Oil Prices, Natural Gas Demand Outlook Revised Down,* June 4, 2015, available at: http://www.iea.org/newsroomandevents/pressreleases/2015/june/despite-decline-in-oil-prices-natural-gas-demand-outlook-revised-down.html
[10] ISO-NE, 2015 Regional Electricity Outlook at 37, http://www.iso-ne.com/static-assets/documents/2015/02/2015_reo.pdf
[11] For more information on the changes suggested by Acadia Center to enable winter-peak delivery, *see* Acadia Center's Comments to CT, MA and RI on Draft Request for Proposals for Clean Energy and Transmission, March 30, 2015, available at: http://acadiacenter.org/document/draft-new-england-clean-energy-rfp-comments/.

be amended to provide for bundled procurements of renewables and hydroelectricity that provide high capacity factors, particularly valuable during winter peaks, when generation from natural gas is least reliable and most expensive. Massachusetts could use this RFP and the accompanying procurements to ensure on-peak performance by including specific measures to ensure that the power will be provided when customers need it most. These include, but are not limited to, penalties and nullification of the contract if capacity does not qualify in the Forward Capacity Market and prioritizing on-peak performance by weight in the evaluation. Such procurements could help Massachusetts address its need for both clean energy and additional winter peak capacity.

DOER Question 3: What would be the standard of review for such contracts?

The Public Interest Standard Requires a True Alternatives Analysis

When the Department evaluates a long-term contract entered into by an LDC under §94A, it examines whether the acquisition of the resource is consistent with the public interest. *See, e.g., AIM Project,* DPU 13-157, 13-158, 13-159 (2014). Whether something is in the public interest is frequently demonstrated by it comparing favorably to the range of alternative options reasonably available at the time of the acquisition. *Id.* Within the context of LDCs, the alternatives inquiry seems limited to resources available to the LDC itself, such as other pipes, gas storage, and LNG. The only alternatives analysis appropriate here is a rigorous analysis that takes into account alternative resources, outside of those available to electric and natural gas distribution companies. A more comprehensive alternatives analysis is reasonable here, given that such a cross-subsidy has never before been attempted. Since the Department is already contemplating reaching outside of the traditional gas markets to find a solution, a true alternatives analysis that looks at all resources potentially available – in any market –is appropriate. This analysis would allow the Department to determine which of the Commonwealth's many options are the most cost-effective, reliable, and compatible with other public policy goals, such as environmental goals and protection of consumers.

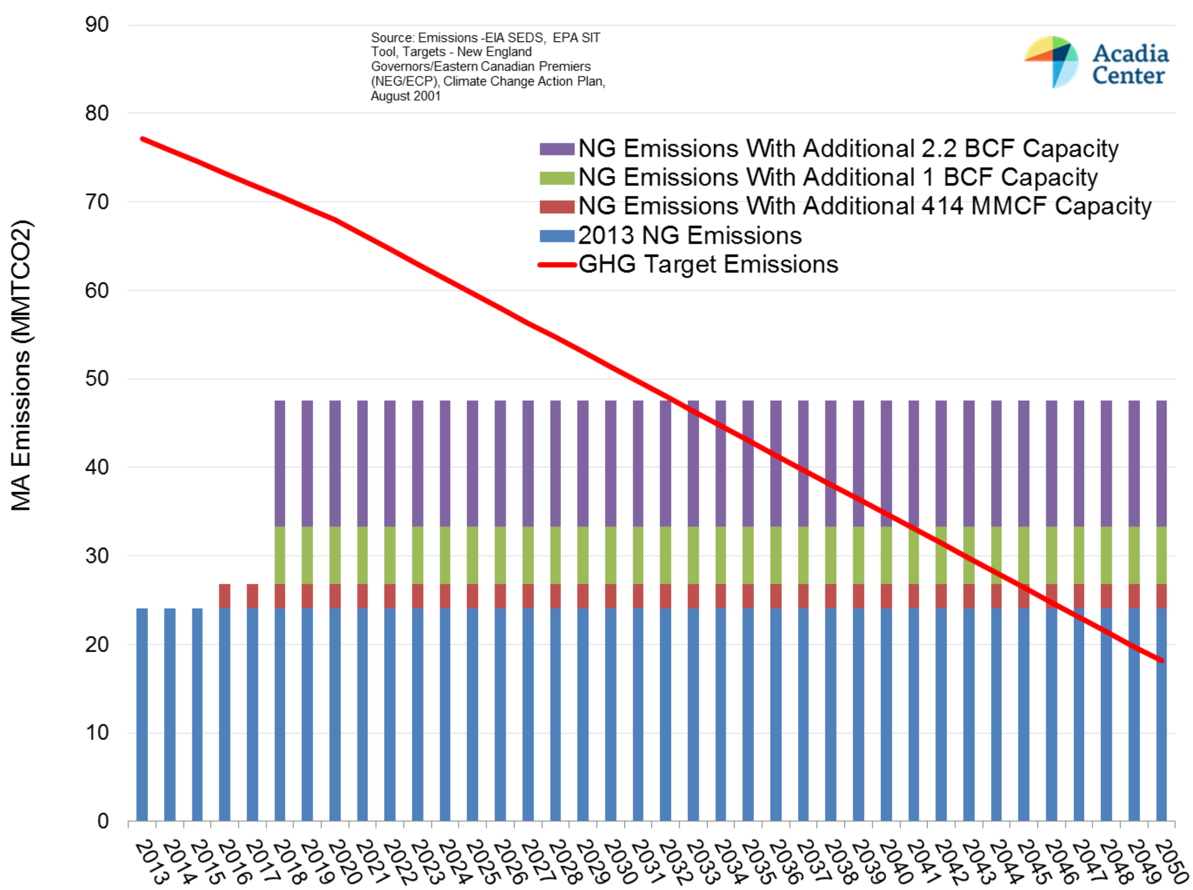
In such an alternatives analysis, the benefits, costs, and risks of the proposed purchase and sale of gas by EDCs must be compared with the benefits, costs, and risks of other viable pathways that the Commonwealth (and the region as a whole) could pursue. In this exercise, it is important to keep in mind that additional pipeline gas is only one of a large number of options that can impacts winter electricity prices. Additional investments in efficiency, energy storage, renewable energy, hydroelectric imports with high winter capacity factors, and other sources could potentially provide the needed energy at more cost-effective and stable prices than expanded natural gas capacity, and address the winter electricity price spikes even more effectively. Furthering these alternatives is also within the Department's jurisdiction—unlike many decisions around natural gas.

Costs and Benefits of EDC-Gas Contracts:

We must first determine the true costs and benefits of the proposed EDC-gas contracts. In terms of benefits, we do not yet know whether this proposal would ultimately address the problem it is intended to solve. As DOER's own filing indicates, ratepayer costs "*may* be alleviated, *in part,* with new incremental gas delivery capacity" but "it's not clear how much capacity *may* be needed to address these issues." (DOER at 2, emphasis added)

The costs of these contracts include the risks such a plan would place on electric ratepayers and the environmental costs and risks it would impose on the Commonwealth. Massachusetts has already made substantial investments in its energy future, including renewable energy, and the ongoing process to transition to smart grid technology. Actions like the one proposed for the Department here must be evaluated in the context of existing policies and seen for what they are – a change in direction that potentially abandons these substantial investments.

This proposal is wholly inconsistent with the Commonwealth's environmental statutes. Current (2013) supplies of natural gas for heating, power generation, and industry *alone* would produce emissions in excess of Massachusetts' entire greenhouse gas budget under the Global Warming Solutions Act in the year 2050. Even without any increase in pipeline capacity, Massachusetts' use of natural gas will consume all allowable emissions, leaving no room for any from transportation, heating oil or propane. Assuming similar rates of usage for new pipeline capacity, the already approved Algonquin Incremental Market and Tennessee Gas Pipeline expansions, due to come online in 2016, would cause us to exceed the economy-wide cap in 2045. Bringing in additional natural gas capacity, whether or not it is borne by EDC ratepayers, will dwarf the 2050 budget for economy-wide GHG emissions – even without any emissions from any other sector. The fact that it is impossible to reconcile additional natural gas capacity with Massachusetts climate commitments should weigh heavily against the Department championing such investments.



There are also a number of "what-ifs" in the EDC-gas proposal that would substantially impact the costs, benefits, and risks of the proposal. For instance, it is certainly outside of the public interest for the natural gas capacity procured by Massachusetts electric ratepayers to be sold outside of New England, as the ratepayers would bear all of the costs with no potential benefits. Even if the gas were somehow limited for sale within New England, it would be unfair to electric ratepayers of Massachusetts to subsidize the cost of gas available to Maine industrial customers, or even Massachusetts heating customers, if that market were to expand. Further limitation on sales to only New England generators will also not address these inequities. In fact, it would still be unfair to ratepayers to force them to take on the risk of long-term contracts while the parties who should be contracting refuse, even in the highly unlikely circumstance that the EDC earned a profit on the sale and returned all of the profit to ratepayers.[12] It would also be unfair to New England's non-gas generators, who must bear the entire cost and risk of their fuel purchases rather than collecting a ratepayer subsidy.

Finally, it is antithetical to the public interest for the electric ratepayers of Massachusetts to subsidize the delivered price of natural gas eventually purchased by Canadians or on the international market. Such an extreme event is not hypothetical. Part of the Access Northeast proposal involves reversing the Maritimes and Northeast Pipeline[13] to allow gas to flow North through New England to Eastern Canada. By latest count, there are 3 proposed LNG export terminals in Eastern Canada that intend to use natural gas from the reversed Maritimes and Northeast Pipeline:

- Converting the existing Canaport import terminal in St. John, New Brunswick into an export terminal.[14]
- Goldboro LNG in Nova Scotia, which recently received approval from the US Department of Energy receive and ship US exports.[15]
- Bear Head in Nova Scotia, which filed in November 2014, seeking to export LNG via a terminal in Point Tupper.[16]

Allowing export of natural gas through ratepayer subsidized pipelines would be even worse for the public interest than the Department taking no action, as reports indicate this could actually lead to *increased* prices. A 2014 study by

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[12] Legislation to limit the resale of natural gas to within New England or only electric generators would likely violate the interstate commerce clause. EDCs' guaranteed rates of return would also remove some, if not all, of any profit made from resale that could be returned to ratepayers. See, *infra*, for further discussion of these topics.
[13] *See* Bryan Dowling, Hartford Courant, "NU, Spectra Unveil $3B New England Pipeline Plan" (Sept. 16, 2014) available at: http://www.courant.com/business/hc-nu-spectra-natural-gas-pipeline-20140916-story.html
[14] Saint John LNG Development Company Ltd. Application for License., National Energy Board (Feb 10, 2015) available at: https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90466/94153/552726/2680218/2679691/2680348/Letter_and_Application_-_A4H4X4.pdf?nodeid=2680349&vernum=-2
[15] *See* Interfax Global Energy, "Goldboro LNG gets permission to use US gas for Export" (May 27, 2015) available at: http://interfaxenergy.com/gasdaily/article/16242/goldboro-lng-gets-permission-to-use-us-gas-for-export
[16] Bear Head LNG Application for a License, National Energy Board (Nov 6, 2014) available at: https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90466/94153/552726/2545224/2546087/2545847/Bear_Head_LNG_Export_Licence_Application_-_A4E6H4.pdf?nodeid=2545848&vernum=-2

the EIA projected that a significant and rapid increase in LNG exports (reaching 20bcf of exports over 10 years) combined with low gas production could cause natural gas prices in the Northeast to increase by 45%.[17]

The EDC-gas proposal is also rife for self-dealing, as evidenced by the number of questions the Department has posed about how best to deal with affiliate relationships. It seems evident that, regardless of how these deals are structured, the ratepayers will be the last to benefit. The Department must account for all of these costs and potential detriments to ratepayers in conducting an alternatives analysis. We believe that, on balance, weighing uncertain benefits against significant environmental costs and detriments to the public interest, the Department will find the appeal of EDC-gas contracts to be low, at best.

Costs and Benefits of Alternatives:

The next step of an alternatives analysis includes identifying the wide breadth of alternatives, and evaluating their costs, benefits, and risks. Many alternatives to additional pipeline capacity are already within the Department's regulations and precedent. For instance, long-term contracts for renewable energy could be weighted to support winter reliability, and promote demand response and energy efficiency. Before we embark on risky investments in additional fossil-fuel infrastructure, particularly on the backs of electric ratepayers, we must consider regional alternatives to this regional problem – namely, if the other New England states were to obtain equivalent levels of energy efficiency as Massachusetts, would we even need additional winter energy supply?

New England's investments in energy efficiency have already proven to be valuable in winter – without the demand reductions achieved since 2000, ratepayers would have paid an additional $1.5B in Winter 2014 alone.[18] Moreover, efficiency in Massachusetts cost around 4c/kWh – four times cheaper than that winter's average wholesale supply, and by far the most cost-effective resource we have available. It is also within the Department's authority to expand energy efficiency programs and direct resources towards addressing winter peak, geo-targeting constrained areas, and improving delivery of gas efficiency programs. Further investment in renewable energy, energy efficiency, and demand response programs will also support the Commonwealth's environmental goals, keep ratepayers' rates more consistent by lessening the proportion driven by volatile fossil-fuel prices, deliver many non-energy benefits, and utilize the most cost-effective resources the state has. In a true alternatives analysis, the full scope of economic, social and environmental benefits delivered by these alternatives should be considered – and will easily prove to be the better choice than EDC-gas contracts.

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[17] US Energy Information Administration, Effect of Increased Levels of Liquified Natural Gas Exports on U.S. Energy Markets (October 2014) available at: http://www.eia.gov/analysis/requests/fe/pdf/lng.pdf

[18] Acadia Center, Winter Impacts of Energy Efficiency In New England, April 15, 2015, available at: http://acadiacenter.org/document/winter-impact-electric-efficiency.

DOER 7: How will the contracted-for capacity be made available to the market such that the benefits accrue to Massachusetts ratepayers?

DPU Additional Question 8: Could there be restrictions placed on the release of natural gas capacity so that the released capacity only can be acquired by electric generators serving the ISO New England Market.

Limitations on Resale of Natural Gas Would Likely Violate the Interstate Commerce Clause

The only way for the EDC-gas contract proposal to address DOER's identified concerns and "make sufficient natural gas delivery capacity available to electricity generators during peak demand periods," (DPU at 2, citing DOER at 1) is if the natural gas capacity itself is sold to electric generators serving the ISO-NE market – but only those generators. To accomplish this, the market for resale of the natural gas procured by Massachusetts EDCs must be limited to electric generators in one of the six states participating in ISO-NE, and subsequent sales of such gas must be prohibited, unless they fall within this same pool of generators. Imagining a statute that attempts to restrict the sales in this way, we arrive at a law that would facially discriminate against both intrastate commerce (e.g. prohibiting sales to Massachusetts industrial customers) and interstate commerce (e.g. prohibiting sales to New York electric generators), as well as attempt to restrict commercial transactions occurring wholly outside of the state (e.g. a Connecticut generator attempting to re-sell its natural gas capacity to a Connecticut industrial customer or New York generator). A court would almost certainly strike down such a statute as violating the dormant commerce clause.

As the Supreme Court reaffirmed just last month, the Commerce Clause's grant of powers to Congress to "regulate Commerce… among the several States" also implies a further, negative command, known as the dormant Commerce Clause, which precludes the states from "discriminating between transactions on the basis of some interstate element." *Comptroller of the Treasury of Maryland v. Wynne*, 575 U.S. ___ (May 18, 2015), *quoting Boston Stock Exchange v. State Tax Comm'n*, 429 U. S. 318, 332, n. 12 (1977). Under dormant Commerce Clause precedent, courts will strike down a state law if it expressly mandates differential treatment of in-state and out-of-state economic interests in such a way that benefits the former and burdens the latter. When a state statute directly discriminates against interstate commerce, "we have generally struck down the statute without further inquiry." Brown-Forman *Distillers Corporation v. NY State Liquor Auth.*, 476 U.S. 573, 576 (1986), c*iting, as e.g., Philadelphia v. New Jersey*, 437 U.S. 617 (1978), *Shafer v. Farmers Grain Co.,* 268 U.S. 189 (1925), *Edgar v. MITE Corp.*, 457 U.S. 624, 640-43 (1982) (*plurality opinion*). Courts will also apply strict scrutiny if a law controls commerce occurring wholly outside the boundaries of the state – looking at whether the statute controls conduct in another state, which could give rise to inconsistent legislation being applied to the same activity. *Id.* Given that the contemplated legislation would also attempt to control resale of the gas by electric generators located outside of Massachusetts, in transactions that occur entirely outside of Massachusetts, it would likely fail under this line of inquiry, too.

Conclusion

Acadia Center, Clean Water Action, Mass Energy, Berkshire Environmental Action Team, HealthCare Without Harm, Nashoba Conservation Trust, No Fracked Gas in Mass , No. Quabbin Pipeline Action, Millers River Watershed Council, Pipeline Awareness Network for the Northeast, StopNED, and Toxics Action Center urge the Department to act with caution as it endeavors to address the issue of winter price spikes in the wholesale electric market. In doing so, the Department must keep in mind that additional natural gas pipeline capacity is only one of a large number of options that impact winter prices. Additional investments in efficiency, energy storage, renewable energy, hydroelectric imports with high winter capacity factors, and other sources could potentially provide the needed energy at more cost-effective and stable prices than expanded natural gas capacity, and address winter electricity price spikes even more effectively. Furthering these alternatives is also within the Department's jurisdiction—unlike the proposed EDC-gas contracting process that instigated this docket.

Sincerely,

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