STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID REQUEST FOR APPROVAL OF A GAS CAPACITY CONTRACT AND COST RECOVERY PURSUANT TO R.I. GEN. LAWS § 39-31-1 TO 9	DOCKET NO. 4627

CONSERVATION LAW FOUNDATION'S MOTION TO REOPEN THE DOCKET AND TO RECONSIDER ITS MOTION TO DISMISS THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID'S REQUEST FOR APPROVAL OF A GAS CONTRACT AND COST RECOVERY AND CLOSE THE DOCKET

Intervenor Conservation Law Foundation ("CLF") respectfully requests that the Public Utilities Commission ("PUC" or "the Commission") reopen Docket 4627 in order to reconsider CLF's August 22, 2016 Motion to Dismiss the Narragansett Electric Company d/b/a National Grid's ("National Grid") Request for Approval of a Gas Capacity Contract and Cost Recovery and to Close the Docket ("Motion to Dismiss"). Without issuing a formal order, the Public Utilities Commission denied without prejudice CLF's Motion to Dismiss at an open meeting on September 29, 2016. At the same open meeting, and also without issuing a formal order, the Commission stayed Docket 4627 and directed National Grid by January 13, 2017 to "file a report setting forth the status of the Access Northeast Pipeline project ... as it relates to proceedings in Massachusetts and other New England States (particularly the status of any regulatory proceedings)."[1] Since the September 29, 2016 open meeting, material changes constituting good

[1] *See* Docket No. 4627 – Stay of Proceedings, email from Cynthia Wilson-Frias to Docket 4627 Service List (Sept. 30, 2016) ("Wilson-Frias email").

cause to reopen this docket have occurred. Namely, both New Hampshire[2] and Connecticut[3] have rejected participation in National Grid's proposed Access Northeast Project ("ANE Project"), joining Massachusetts[4] and, effectively, Maine.[5] What was uncertain in September is certain now: the ANE Project cannot proceed. Because it has no regional path forward, the ANE Project cannot satisfy the Affordable Clean Energy Security Act ("ACES Act"), R.I. Gen. Laws §§ 39-31-1, *et seq.*, and the Commission cannot legally approve it.

I. BACKGROUND

On June 30, 2016, National Grid filed with the PUC a Request for Approval of a Gas Capacity Contract and Cost Recovery ("Petition"). Specifically, National Grid sought approval for a contract between itself and Algonquin Gas Transmission Company, LLC ("Algonquin") for natural gas transportation capacity and storage services on Algonquin's Access Northeast pipeline project ("ANE Project"). The ANE Project was regional, with a scale designed to correspond particularly to the electricity generation portfolios of the six New England states. In response, the PUC opened this Docket No. 4627. On July 7, 2016, CLF filed its unopposed Motion to Intervene. CLF became a full party to the docket eleven days later by operation of PUC Rule of Practice and Procedure 1.13(e).

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[2] *See* New Hampshire Public Utilities Commission Order No. 25,950 (Oct. 6, 2016) ("NH PUC Order"), attached as **Exhibit A**.
[3] *See* Connecticut Department of Energy and Environmental Protection, Public Act 14-107 Section 1(d) – Natural Gas Capacity, Liquefied Natural Gas (LNG), and Natural Gas Storage Procurement, Notice of Cancellation (Oct. 25, 2016) ("CT DEEP Notice"), attached as **Exhibit B**.
[4] *See Engie Gas & LNG LLC vs. Department of Public Utilities*, No. SJC-12051 (Mass. 2016), and *Conservation Law Foundation v. Department of Public Utilities*, No. SJC-12052 (Mass. 2016) (collectively, "*Engie*"), attached as **Exhibit C**.
[5] *See* Maine Public Utilities Commission, Docket No. 2014-00071, Order – Phase 2 (Sept. 14, 2016) ("Maine PUC Order"), attached as **Exhibit D**.

Parallel to this Docket, National Grid and its affiliates sought approval of ANE-Project-related natural gas capacity and storage contracts in other New England states: Massachusetts, Maine, New Hampshire, and Connecticut.

The first of these parallel proceedings was resolved on August 17, 2016, as the Massachusetts Supreme Judicial Court decided in *Engie* that the Massachusetts Department of Public Utilities ("DPU") lacked legal authority to "to review and approve ratepayer-backed, long-term contracts for gas capacity entered into by electric distribution companies." Slip Op. at 13. The Supreme Judicial Court added that such contracts were both illegal and against public policy: "the [DPU]'s approval of . . . contracts by electric distribution companies for gas capacity contradicts the fundamental policy embodied in [Massachusetts'] restructuring act, namely the Legislature's decision to remove electric distribution companies from the business of electric generation." *Id.* at 27. As a result of *Engie*, the DPU granted a request by the applicants to withdraw their petition for approval of the ANE Project in Massachusetts. *See* Order on Eversource Energy's and National Grid's Motions to Withdraw, D.P.U. 15-181 and D.P.U. 16-05 (Oct. 7, 2016).

Following the *Engie* decision, on August 22, 2016, CLF filed with the Commission its Motion to Dismiss National Grid's Petition on multiple grounds. Most fundamentally, CLF argued that *Engie* so altered the ANE Project as reflected in National Grid's request for approval that it foreclosed any possibility that the project could function on a regional scale as required by the ACES Act. Motion to Dismiss at 4-8 (citing R.I. Gen. Laws §§ 39-31-1, *et seq.*). CLF also argued that *Engie* upset the delicate balance of costs and benefits that National Grid had claimed would occur as a result of the ANE Project. CLF wrote: "In effect, National Grid is now asking Rhode Island ratepayers to subsidize a project that it alleges will benefit all of New England; yet a substantial share of New England ratepayers—including millions of ratepayers in Massachusetts—will be insulated from bearing a proportional share of the risks of this experimental and uncertain scheme." Motion to Dismiss at 7. CLF argued that as a result of the ANE Project's having been upended, National Grid could not as a matter of law demonstrate compliance with the ACES Act. *Id.*

Additional briefing on CLF's Motion to Dismiss followed, and the Commission set a date of September 21, 2016 for oral argument. One week before oral argument, on September 14, 2016, the Maine Public Utilities Commission issued an order on the ANE Project: the Maine PUC "decide[d] to move forward" but conditioned its decision "upon comparable precedent agreements with ANE and other New England states (Massachusetts, Connecticut, Rhode Island and New Hampshire) at a minimum of those states' respective load shares." Maine PUC Order at 1. Absent participation by Massachusetts, the result of the Maine PUC Order was effectively a rejection of the ANE Project.

At oral argument, counsel for National Grid argued that the ANE Project could still go forward – "if the contract is approved in Rhode Island, New Hampshire, Maine and Connecticut." Oral Argument Transcript, p. 17, ll. 19-21 (Sept. 21, 2016). In fact, National Grid argued that "[t]he facts that are still in dispute in this case ... are whether or not the contract as proposed still offers a regional solution for Rhode Island." *Id.* p. 14, ll. 14-18. National Grid continued: "whether or not electric customers in Massachusetts can contract for this capacity, ... this contract ... is being reviewed by and maybe supported by other states in New England regionally, Maine right now, New Hampshire, Connecticut." *Id.* p. 14, ll. 19-25.

Counsel for Algonquin agreed: "Algonquin believes firmly that a regional solution is best, but an ancillary effect of seeking a regional solution is that multiple states are going to have to consider and approve this." *Id.* p. 34, ll. 8-12. Algonquin continued: "This remains a regional solution. … This same contract is under consideration in Connecticut, New Hampshire, has been approved in Maine subject to entry of a written order. … [T]here's nothing that presently says this will not be a regional solution." *Id.* p. 35, l. 20 through p. 36, l. 6.

On September 29, 2016, the Commission held an open meeting and decided to "stay the proceeding immediately and order National Grid to file a progress report by January 13, 2017 on the status of the Access Northeast Project in Massachusetts and the other New England states." RI Public Utilities Commission, Minutes of Open Meeting Held September 29, 2016. The Commission also denied CLF's Motion to Dismiss without prejudice. *Id.* Counsel for the Commission confirmed this result by email on September 30, 2016. *See* Wilson-Frias email.

The following week, the ANE Project was dealt another blow. The New Hampshire Public Utilities Commission issued an order finding that the ANE Project "is inconsistent with New Hampshire law" and dismissed the petition for approval of the project. *See* NH PUC Order.

Finally, on October 25, 2016, the Connecticut Department of Energy and Environmental Protection ("CT DEEP") issued a "Notice of Cancellation." Prior to the Notice of Cancellation, CT DEEP had issued a Request for Proposals ("RFP") soliciting applications for regional energy projects; in response, Algonquin Gas Transmission, LLC had filed a proposal for the ANE Project. *See* Algonquin Gas Transmission, LLC, "Access Northeast Project Proposal" (June 29, 2016).[6] The CT DEEP Notice of Cancellation ended that solicitation on the grounds that "the issuance of administrative decisions and a court ruling in other New England jurisdictions have

[6] The Connecticut ANE proposal is available at:
http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=26&Count=30&Expand=33.4&Seq=10.

materially reduced the ability for the costs of projects to be shared among a substantial portion of the region's ratepayers." CT DEEP Notice at 2.

When CLF filed its Motion to Dismiss in August, only Massachusetts had rejected the ANE Project. Now New Hampshire and Connecticut have joined Massachusetts, and the conditions on which Maine's approval rest cannot be satisfied. Across the region, the ANE Project has collapsed.

II. THE STANDARD GOVERNING THIS MOTION

This is a motion to reopen and, as such, is governed by PUC Rule of Practice and Procedure 1.26, which provides that a docket may be reopened "for good cause shown."[7] Such motion "shall set forth clearly the facts claimed to constitute grounds requiring reopening of the proceedings, including material changes of fact or of law alleged to have occurred." *Id.*

CLF seeks to reopen the docket so the Commission can reconsider its Motion to Dismiss. The Motion to Dismiss is governed by the provisions of PUC Rule of Practice and Procedure 1.15. Dismissal of this Docket is warranted as a pure matter of law; there is no longer any material fact in dispute.

III. DISCUSSION

The decisions of New Hampshire and Connecticut not to participate in the ANE Project constitute material changes that warrant reopening Docket 4627. When it denied CLF's Motion to Dismiss without prejudice, the Commission indicated that fact questions remained regarding the participation of other New England states in the ANE Project. Any such questions have now been answered: the ANE Project cannot proceed as a coordinated, regional project.

[7] This motion is styled as a Motion to Reopen under Rule 1.26 in reliance on the Wilson-Frias email, which provides that "[a]s a result of yesterday's action by the PUC, the matter is stayed pending a Motion to Reopen."

These material changes also foreclose National Grid's attempt to show compliance with the purpose of ACES: most fundamentally, it is impossible to "ensure that the benefits and costs of [the ANE Project] are shared appropriately among the New England States" when no other states are participating in the project. R.I. Gen. Laws. § 39-31-2(2). Because National Grid's Petition cannot satisfy the ACES Act, it fails as a matter of law and must be dismissed.

Accordingly, the Commission should reopen Docket 4627, dismiss National Grid's petition, and permanently close the Docket.

A. <u>New Hampshire's and Connecticut's Rejections of the ANE Project Are Material Changes That Provide Good Cause for Reopening</u>

New Hampshire's and Connecticut's decisions not to go forward with the ANE Project effectively kill the project; that the project now has no regional path forward is a material change that warrants reopening the docket.. As is detailed above, when CLF filed its Motion to Dismiss in August, only Massachusetts had rejected the ANE Project. During the pendency of CLF's Motion to Dismiss, the Maine PUC issued an order providing that the project could move forward only if it received other states' approval as well. After the Commission ruled on CLF's Motion to Dismiss, the New Hampshire PUC rejected the ANE Project and Connecticut DEEP cancelled the RFP that formed the basis for the ANE Project's bid there. Across the region, the ANE Project has collapsed. This full regional collapse constitutes a material change in fact that warrants reopening Docket 4627. *See* PUC Rule 1.26.

That the regional collapse of the ANE Project is not only a change in fact but also a material one cannot be seriously disputed. The ANE Project was designed to be regional. National Grid's Petition explained that the ANE Project is dependent on approvals of full cost-recovery in other New England states, as CLF's Motion to Dismiss pointed out. *See* CLF Motion to Dismiss at 5 (citing Brennan & Allocca Joint Test. 34-35; Exh. NG-TJB/JEA-2 at 47, Mass. D.P.U. 16-05 (Jan. 15, 2016)). Indeed, National Grid's Petition stated not only that the ANE Project was a regional scheme but also that it "will require regulatory approvals by New England state jurisdictions in addition to Rhode Island." Brennan & Allocca Joint Test. 34 (cited by CLF Motion to Dismiss at 6). Placing this excerpt from the Petition in context underscores just how unequivocal National Grid was regarding the need for approvals in states other than Rhode Island:

> Q: Will the ANE Project require approval in New England states other than Rhode Island?
>
> A: Yes. The bulk power market in New England is a regional market, with generating facilities throughout the six New England states operating within the oversight of ISO NE. Within the region, the electric and gas delivery systems are increasingly interrelated... Consequently, this regional solution will require regulatory approvals by New England state jurisdictions in addition to Rhode Island as well as the participation by other EDCs.

Id. National Grid and its partners in the ANE Project have now failed to obtain those "required" regulatory approvals. Due to the decisions of the Massachusetts Supreme Judicial Court, the Maine PUC, the New Hampshire PUC, and Connecticut DEEP, the Project has no regional path forward. This change in circumstances cuts to the very core of the ANE Project and constitutes good cause for reopening.

B. <u>The Non-Participation of All Other New England States in the ANE Project Warrants Dismissal under the ACES Act</u>

The regional collapse of the ANE Project means that the Commission cannot find that the Project is regional in scope, nor that the benefits of the project to ratepayers exceed the project's costs, as required by the ACES Act. *See* R.I. Gen. Laws §§ 39-31-1(5); 39-31-3; 39-31-7(a). Because such findings are impossible, National Grid's Petition cannot satisfy the ACES Act and must now be dismissed.

Other states' rejections of the ANE Project resolve any questions that existed at the time of CLF's Motion to Dismiss and require dismissal on the grounds CLF set forth in that motion. CLF argued in its Motion to Dismiss that by removing Massachusetts from participation in the ANE Project, *Engie* undercut National Grid's ability to demonstrate compliance with the ACES Act.[8] Motion to Dismiss at 7-8. CLF explained this argument in more detail in its Reply in Support of its Motion to Dismiss and Close the Docket ("Reply Brief"). The ACES Act allows the PUC to approve only *regional* natural gas infrastructure projects that include a "coordinated, multi-state approach." R.I. Gen. Laws § 39-31-1(5); *see also id.* §§ 39-31-2, 39-31-7(a)); Reply Brief at 4.[9] And the ACES Act allows the PUC to approve only projects for which it finds "that the total ... benefits [of the project] to the state of Rhode Island and its ratepayers exceed the costs." *Id.* § 39-31-3. CLF argued in its Motion to Dismiss that the PUC could not approve the ANE Project absent participation by Massachusetts, because the project was no longer regional and because Rhode Island would bear a disproportionate share of the project's costs. In denying CLF's Motion to Dismiss without prejudice, the Commission determined that fact questions remained on both points.

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[8] Because CLF seeks reconsideration of its Motion to Dismiss, it is necessary to set forth briefly here the basis for that Motion to Dismiss.

[9] More specifically, as explained in CLF's Reply Brief at page 5, the PUC can only approve the Petition if it "advance[s] the purposes of [the ACES Act]." R.I. Gen. Laws § 39-31-7(a). *See also id.* § 39-31-7(c)(5) (providing that the PUC "shall certify that the proposed project(s) are in the public interest" *only if* such projects "[a]re consistent with the findings and purposes of [the ACES Act]"). The Act sets forth three purposes: 1) to "[s]ecure the future of the Rhode Island and New England economies, and their shared environment, by making coordinated, cost-effective, strategic investments in energy resources and infrastructure"; 2) to "[u]tilize coordinated competitive processes, in collaboration with other New England states . . . and ensure that the benefits and costs of such energy infrastructure investments are shared appropriately among the New England states"; and 3) to "[e]ncourage a multi-state or regional approach to energy policy." *Id.* § 39-31-2(1)-(3). Thus the Petition cannot be approved unless it reflects a regional, multi-state approach in which Rhode Island does not bear a disproportionate share of the project costs.

With the ANE Project's failure to obtain regulatory approval in the other New England states, what the PUC found was still up for debate is now settled: the ANE Project does not include regional participation, and Rhode Island cannot possibly bear a proportionate share of the Project's costs absent participation by any other New England state.

As CLF has already set forth here in detail, due to the decisions of the Massachusetts Supreme Judicial Court, the Maine PUC, the New Hampshire PUC, and Connecticut DEEP, the ANE Project has no regional path forward.[10] It is therefore impossible for the PUC to find that the Petition satisfies the ACES Act's purposes of "[u]tiliz[ing] coordinated competitive processes, in collaboration with other New England states" and "[e]ncourag[ing] a multi-state or regional approach to energy policy." *Id.* § 39-31-2(2)-(3). Accordingly, the PUC cannot as a matter of law approve the Petition. *Id.* § 39-31-7(a).

And perhaps more fundamentally, absent participation by Massachusetts, Maine, New Hampshire, and Connecticut in what was designed as a regional, five-state project, if Rhode Island were to approve the Petition then Rhode Island would bear more than its share of the ANE Project's costs while receiving only a fraction of the project's putative benefits. The economic underpinning of the ANE Project is a charge on electricity ratepayers to pay for natural-gas infrastructure buildout. *See generally* Vilbert Test.; *see also* Leary Test. 2 ("[T]he proposed Capacity Cost Recovery Provision tariff (Proposed Tariff) for the Company's electric business

[10] In theory, the Massachusetts General Court could conceivably change Massachusetts law, and the legislature or judiciary in New Hampshire could conceivably change New Hampshire law. Or National Grid could conceivably come up with a new project that, for example, places the costs of pipeline expansion on local distribution companies and their customers. But these outcomes are purely speculative and, more importantly, would bear no relationship to the petition that is before the Commission now: the resulting project would not be the one that has already undergone review by Rhode Island agencies in preparing to issue advisory opinions. *That* project is dead.

… will allow the Company to recover all incremental costs associated with the procurement of gas capacity."). The theory goes that such a charge would result in downstream benefits to electricity ratepayers throughout the entire multi-state footprint of the grid operator Independent System Operator-New England ("ISO-NE"). *See generally* Schedule GJW-3. But if such a charge is imposed only on Rhode Island ratepayers, then only Rhode Island ratepayers will be responsible for the project's costs. Meanwhile, any putative benefits of the infrastructure buildout will necessarily flow to the entire region. This conclusion is not a factual determination, but a natural and necessary consequence of the design of the ANE Project and the reality of New England's regional electricity grid. The upshot is that the regional collapse of the ANE Project means that, if Rhode Island were to approve the Project, then Rhode Island would bear a disproportionate share of the Project's costs in violation of the ACES Act – a Catch-22, to be sure. R.I. Gen. Laws §§ 39-31-2(2), 39-31-3. For this reason too, the Commission cannot as a matter of law approve the Petition. R.I. Gen. Laws § 39-31-7(a).

IV. CONCLUSION

WHEREFORE, for the foregoing reasons, CLF respectfully requests that the Commission reopen Docket 4627, dismiss National Grid's Petition, and permanently close the Docket.

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TAB A

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 16-241

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

Petition for Approval of Gas Capacity Contract with Algonquin Gas Transmission, LLC, Gas Capacity Program Details, and Distribution Rate Tariff for Cost Recovery

Order Dismissing Petition

ORDER NO. 25,950

October 6, 2016

In this Order, the Commission dismisses Eversource's petition requesting approval of a contract to purchase capacity on the proposed Access Northeast gas pipeline, and associated program details and distribution rate tariff. The Commission has determined that Eversource's proposed program is inconsistent with New Hampshire law. The legal authorities relied upon by Eversource and other supporters of the petition do not overcome the policies preventing such activity found within the Electric Utility Restructuring statute, RSA Chapter 374-F.

I. EVERSOURCE'S PROPOSAL

On February 18, 2016, Public Service Company of New Hampshire d/b/a Eversource (Eversource) filed a petition for approval of a proposed 20-year contract with Algonquin Gas Transmission, LLC (Algonquin), for natural gas capacity on Algonquin's Access Northeast Pipeline Project (Access Northeast pipeline), and for recovery of associated costs through a new distribution rate tariff, to be assessed on all of Eversource's customers. In its petition, Eversource sought approval of: (1) a 20-year interstate pipeline transportation and storage contract providing natural gas capacity for use by electric generation facilities in the New England region (the Capacity Contract); (2) an Electric Reliability Service Program to set parameters for the release of capacity and the sale of LNG supply made available to electric generators through the Capacity Contract; and (3) a Long-Term Gas Transportation and Storage Contract tariff for Eversource's rates (Tariffed Rate) to be applied through a uniform cents-per-kWh rate element on all retail electric customers served by Eversource, to provide for recovery of costs associated with the Capacity Contract.

Eversource is a public utility headquartered in Manchester, operating under the laws of the State of New Hampshire as an electric distribution company (EDC). Algonquin is an owner-operator of an interstate gas pipeline located in New England. Algonquin is owned by a parent company, Spectra Energy Corp (Spectra), a publicly-traded corporation headquartered in Houston, Texas. Algonquin has partnered with Eversource's corporate parent, Eversource Energy, headquartered in Boston, Massachusetts, and Hartford, Connecticut, and with National Grid, the parent company of EDC subsidiaries in Rhode Island and Massachusetts, to develop the Access Northeast pipeline. In general terms, Eversource Energy's EDC subsidiaries in Connecticut, Massachusetts, and New Hampshire and National Grid's EDC subsidiaries in Rhode Island and Massachusetts, are each individually seeking regulatory approval of gas capacity on the Access Northeast pipeline.[1]

The Access Northeast pipeline is intended to provide 500,000 million British thermal units (MMBtu)/day of incremental gas transportation capacity and 400,000 MMBtu/day of incremental liquefied natural gas (LNG) storage deliverability. Under its petition, Eversource would hold contractual entitlements for firm gas transportation and storage deliverability up to a

[1] The Massachusetts Supreme Judicial Court issued an order prohibiting the Massachusetts Department of Public Utilities from approving the companion petition from the Massachusetts affiliates of Eversource Energy and National Grid. The Massachusetts Court concluded such a Capacity Contract would contradict the policy embodied in the Massachusetts restructuring act, which removed electric companies from the business of electric generation. 475 Mass. 191 (2016).

Maximum Daily Transportation Quantity of 66,000 MMBtu/day, which would represent 7.4 percent of the total capacity of the Access Northeast pipeline. Eversource asserts that energy cost savings resulting from the increased supply of gas capacity to New England electric generators would exceed contract-related costs by a 3:1 ratio, excluding any additional capacity-release revenues that would be credited to Eversource's customers, thereby offering Eversource's customers significant benefits and justifying the recovery of the contract costs through rates.

II. PROCEDURAL HISTORY

With its petition in February, Eversource filed supporting testimony and related exhibits along with a motion for confidential treatment of certain information. Algonquin filed a similar motion for confidential treatment on March 10, 2016. The petition and subsequent docket filings, other than any information for which confidential treatment is requested of or granted by the Commission, are posted to the Commission's website at http://www.puc.nh.gov/Regulatory/Docketbk/2016/16-241.html.

There was significant interest in this docket from its inception. On February 22, 2016, the Office of Consumer Advocate (OCA) filed notice of its participation on behalf of residential ratepayers pursuant to RSA 363:28. Numerous other entities and groups sought intervenor status. They included Algonquin, NextEra Energy Resources LLC (NextEra), Richard Husband, TransCanada Pipelines (TransCanada), Portland Natural Gas Transmission System (PNGTS), Exelon Generation Company, LLC (Exelon), Coalition to Lower Energy Costs (CLEC), Tennessee Gas Pipeline Company (Tennessee), the New Hampshire Municipal Pipeline Coalition (NHMPC), SunRun Inc., Pipe Line Awareness Network of the Northeast (PLAN), Repsol Energy North America Corporation (Repsol), the Office of Energy and Planning, the Conservation Law Foundation (CLF), and ENGIE Gas &LNG, LLC (ENGIE). On April 22, 2016, the Commission issued Order No. 25,886, addressing intervention requests and certain procedural issues.

In its March 24, 2016, Order of Notice, the Commission indicated that before assessing the merits of Eversource's proposal, it would determine as a threshold matter whether the proposed Capacity Contract and the associated request for rate recovery, are consistent with New Hampshire law. The Commission set deadlines for initial submissions and responses on the legal issues of April 28 and May 12, respectively.

On May 10, 2016, the OCA filed a motion pursuant to RSA 363:32, for designation as Staff Advocates, Electric Division Assistant Director, George McCluskey and Staff Attorney, Alexander Speidel. The OCA alleged that, due to past involvement in the IR 15-124 investigation regarding gas supply constraints into the New England region, past pleadings at FERC, involvement in regional wholesale market meetings regarding related topics, and alleged statements made by Staff at a technical session in the instant docket, Messrs. McCluskey and Speidel should be designated Staff Advocates. This motion received the concurrence of CLF, Richard Husband, NextEra, and NHMPC.

III. POSITIONS OF THE PARTIES

A. Supporters of the Capacity Contract

Eversource, Algonquin, and CLEC[2] (collectively the Supporters) argue generally that Eversource's plans are authorized by a number of statutes, either standing alone or in combination. The Supporters' basic argument is that RSA Chapter 374-F, the electric utility restructuring statute, was intended to lower energy prices and that an EDC's purchase of gas capacity to be used by generators could further that intent. The Supporters argue as well that

[2] Although CLEC supported the legality of an EDC entering into a long-term gas capacity contract, it objected to the lack of a competitive procurement process for the Capacity Contract entered into by Eversource. CLEC Brief at 26-29.

Eversource's proposal could be considered to be part of its obligation to provide reliable service at reasonable rates under RSA 374:1 and :2; or the type of "least cost" resource planning required by RSA 378:37 and :38. They also point to the specific language in RSA 374:57, which sets forth an EDC's obligations when it "enters into an agreement with a term of more than one year for the purchase of generating capacity, transmission capacity or energy"; and to RSA Chapter 374-A, which discusses EDCs' participation in electric power facilities. The Supporters dispute the opposition arguments that Eversource's plan would violate the Federal Power Act and the Natural Gas Act. They maintain that the proposal is consistent with Federal law and thus not preempted.

B. Opponents of the Capacity Contract

ENGIE, NextEra, CLF, OCA, Exelon, NHMPC, and PLAN, (collectively the Opponents), all disagree. They argue that the most significant intention of the restructuring statute, RSA Ch. 374-F, was to do what its title promised and restructure the industry to get the EDCs out of the generation business completely. To the Opponents, lower rates were and continue to be expected as a result of that restructuring, as competition for generation services replaces the vertically integrated generation, transmission, and distribution structure that existed for decades before. The Opponents view competitive markets and retail choice for consumers as the key components of restructuring; rate effects are secondary to competition. They also claim that in the restructured market, the risks associated with investments in generation would be borne by the owners of that generation, not by the ratepayers of the regulated distribution utilities. As for the other statutes that are part of the Supporters' arguments, the Opponents' general position is that the restructuring statute controls. They argue that those other statutes do not support Eversource's proposal, either because they never meant what the Supporters argue, or because they have been superseded by the more recent enactment of RSA Chapter 374-F.

The Opponents make two additional points to support their position. First, they argue that the notion of an EDC charging customers for the costs of a gas capacity contract is fundamentally inconsistent with the requirement that assets included in rate base must be "used and useful." They also assert that the proposed Capacity Contract and the release of gas capacity to wholesale power generators is pre-empted by the Federal Power Act and the Natural Gas Act.[3] They cite to decisions by the Federal Energy Regulatory Commission ("FERC"), and recent decisions by the United States Supreme Court to argue that state laws permitting proposals like Eversource's improperly interfere with FERC's regulation of both the wholesale natural gas market and the wholesale electric market.

IV. COMMISSION ANALYSIS

A. New Hampshire Electric Utility Restructuring Statute, RSA Chapter 374-F

The threshold question regarding any potential proposal for gas capacity acquisition by a New Hampshire EDC is whether the Electric Utility Restructuring Statute, RSA Ch. 374-F, (Restructuring Statute) prohibits such activity. All parties to this proceeding make arguments based on the Restructuring Statute passed in 1996 and implemented over the course of many years, including most recently through Order 25,920 (July 1, 2016) approving the divestiture of Eversource's remaining hydro and fossil electric generation facilities. We must determine: (1) whether the functional separation of transmission/distribution activities on the one hand, and generation activities on the other, called for by RSA 374-F:3, III, would be violated by the terms of Eversource's proposal, and (2) if yes, whether this directive of the Restructuring Statute

[3] *See* Natural Gas Act 15 U.S.C. § 717c(b) (prohibiting preferential pricing for natural gas capacity releases) and Federal Power Act 16 U.S.C.§824(b)(1)(giving FERC core responsibility for regulating electric transmission and wholesale pricing).

overrides, or supersedes, all other restructuring principles and therefore prohibits the Capacity Contract and associated Tariffed Rate contemplated by Eversource.

In examining these questions, we apply traditional New Hampshire principles of statutory interpretation. The New Hampshire Supreme Court first looks to the language of the statute itself, and, if possible, construes that language according to its plain and ordinary meaning. The Court interprets statutes in the context of the overall regulatory scheme and not in isolation. The goal is to determine the Legislature's intent. Further, the Court construes statutes, where reasonably possible, so that they lead to reasonable results and do not contradict each other. When interpreting a statute, the Court gives effect to all words in the statute and presumes that the legislature did not enact superfluous or redundant words. *See Appeal of Old Dutch Mustard Co., Inc.*, 166 N.H. 501 (2014); *State v. Collyns*, 166 N.H. 514 (2014). When a conflict exists between two statutes, the later statute will control, especially when the later statute deals with the subject in a specific way and the earlier enactment treats that subject in a general fashion. *Board of Selectmen v. Planning Bd.*, 118 N.H. 150, 152 (1978); *see also Appeal of Pennichuck Water Works,* 160 N.H. 18, 34 (2010) (quoting *Appeal of Plantier*, 126 N.H. 500 (1985)).

Because the Restructuring Statute contains numerous policy directives, we begin our analysis of the statute with reference to its stated purposes.

> I. The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment. Increased customer choice and the development of competitive markets for wholesale and retail electricity services are key elements in a restructured industry that will require unbundling of prices and services and at least functional separation of centralized generation services from transmission and distribution services.

> II. A transition to competitive markets for electricity is consistent with the directives of Part II, article 83 of the New Hampshire constitution which reads in part: "Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it." Competitive markets should provide electricity suppliers with incentives to operate efficiently and cleanly, open markets for new and improved technologies, provide electricity buyers and sellers with appropriate price signals, and improve public confidence in the electric utility industry.

RSA 374-F:1, I and II.

In addition to the overall statutory purposes, RSA 374-F:3 outlines the restructuring policy principles that must govern the Commission's approach to restructuring the New Hampshire electric market. RSA 374-F:3, III states, in part:

> When customer choice is introduced, services and rates should be unbundled to provide customers clear price information on the cost components of generation, transmission, distribution, and any other ancillary charges. Generation services should be subject to market competition and minimal economic regulation and at least functionally separated from transmission and distribution services which should remain regulated for the foreseeable future. However, distribution service companies should not be absolutely precluded from owning small scale distributed generation resources as part of a strategy for minimizing transmission and distribution costs.

The disagreement in this matter is based on the multiple objectives in the sections quoted above. Supporters point to the purpose of reducing costs to customers, and argue that having EDCs purchase gas capacity for use by electric generators will further that goal. Opponents argue that competition, furthered by restructuring and unbundling, is the ultimate purpose of the statutory scheme.

In weighing the restructuring policy principles of RSA 374-F, we agree with the Opponents and find that the overriding purpose of the Restructuring Statute is to introduce competition to the generation of electricity. The competitive generation market is expected to produce a more efficient industry structure and regulatory framework, by shifting the risks of generation investments away from customers of regulated EDCs toward private investors in the competitive market. The long-term results should be lower prices and a more productive economy. To achieve that purpose, RSA 374-F:3, III directs the restructuring of the industry, separating generation activities from transmission and distribution activities, and unbundling the rates associated with each of the separate services. A more efficient structure involves placing investment risk on merchant generators who can manage that risk, and allowing customers to choose suppliers, thus enabling customers to pay market prices and avoid long-term over market costs. This purpose is underscored by the Legislature's recent strong encouragement, through the passage of HB 1602 and SB 221, to approve the 2015 Settlement Agreement that will accomplish the functional separation of Eversource's generation activities from its distribution activities. *See* 2014 N.H. Laws Ch. 310 (H.B. 1602); 2015 N.H. Laws Ch. 221 (S.B. 221); and Order No. 25,920 (July 1, 2016).

Based on that finding, we conclude that the proposal brought forward by Eversource is fundamentally inconsistent with the purposes of restructuring. Specifically, we conclude that the Capacity Contract is a component of "generation services" under RSA 374-F:3, III, which requires unbundled, clear price information for the cost components of generation, transmission, and distribution. The acquisition of the gas capacity is clearly related to an effort to serve New England gas-fired electric generators with less expensive, more reliable fuel supplies. Including such a generation-related cost in distribution rates would combine an element of generation costs with distribution rates and conflict with the functional separation principal.

Having concluded that the basic premise of Eversource's proposal – having an EDC purchase long-term gas capacity to be used by electric generators – runs afoul of the Restructuring Statute's functional separation requirement, we turn to the question of whether any of the other purported justifications would allow us to go forward in this proceeding to consider the merits of the proposal. To analyze the effect of other statutes applicable to EDCs on the Restructuring Statute, we must consider two issues. First, we must identify whether any of those statutes standing alone would support the Eversource proposal, and, if so, how those statutes are affected by the subsequent enactment of the Restructuring Statute.

B. Commission's General Oversight and Other Utility Statutes

Supporters note that RSA 374:1 and RSA 374:2 require that EDCs provide safe and reliable service at just and reasonable rates. They claim that by entering into the Capacity Contract and then selling capacity to gas-fired electric generators, Eversource would both increase reliability of electric supply and mitigate price spikes in the wholesale and retail markets in New England. That would, in turn, help Eversource meet its obligations under RSA 374:1 (safe and reliable service) and RSA 374:2 (just and reasonable rates). While we agree that those two sections of our supervisory statutes govern our regulation of Eversource's provision of distribution services, we do not agree that an EDC is responsible for either the reliability of the generation supply, or the price of such supply. That function has been shifted to the competitive marketplace for retail electric generation service in New Hampshire. For regional wholesale electric markets, the responsibility for regulating reliability and pricing remains with ISO-NE and FERC. *See* Federal Power Act, 16 U.S.C. § 824 (federal jurisdiction over electric transmission and wholesale electric sales).

Supporters also claim that the least cost planning statutes, RSA 378:37 and 378:38, create an affirmative obligation for Eversource to plan for adequate energy supply resources. The Legislature has set the goals for planning as follows:

> The general court declares that it shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost effective energy efficiency and other demand side resources; and to protect the safety and health of the citizens, the physical environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities.

RSA 378:37. In fulfilling its planning obligations a regulated utility is required to do a number of assessments, including:

> III. An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources....
>
> VI. An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state.
>
> VII. An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1.

RSA 378:38, III-VII. The Supporters reason that if the required assessments of generating capacity, price, and supply show that more gas is needed, and if the gas-fired generators are unwilling to purchase the necessary capacity, then it is the responsibility of the EDCs to do what has to be done and commit to those purchases.

Reading the planning statutes together with RSA Ch. 374-F, however, we do not find that the statutes permit the re-joining of distribution and generation functions in the manner provided by the Capacity Contract. The planning statutes must be read in concert with RSA Ch. 374-F and in light of the industries to which they apply. RSA 378:38 applies to both electric and natural gas utilities, and those industries now differ in a fundamental way. While natural gas utilities continue to arrange natural gas supplies for their residential and small commercial customers, following electric restructuring, electric utilities do not arrange electric supply for their customers. Instead, pursuant to RSA 374-F:3, V(c), electric utilities provide electric supply through default service, which is offered only to those customers who have not opted to purchase their electricity from a competitive supplier. Default service is designed to be a safety net for customers who do not choose an independent competitive supplier. Further, default service must be competitively procured. *Id.* As a result of the Restructuring Statute, electric distribution utilities are no longer required to conduct long-term planning for electric supply. Accordingly, we find that in a restructured electric industry, the planning requirements for an EDC are limited to procurements of electric supply for the EDC's default service customers. That obligation is not broad enough to justify approval of a proposal like Eversource's.

Supporters also point out that the 10-Year New Hampshire State Energy Strategy, referenced in RSA 378:38, VII, encourages exploration of ways to increase gas pipeline capacity in New England. They claim that the Strategy thus requires EDCs to explore ways to increase gas pipeline capacity. We disagree. As discussed above, RSA 378:38 applies to both electric and gas utilities. Both are required to plan to have an adequate supply to meet their customers' demand. In our view, gas supply under the State Energy Strategy is the responsibility of the gas utilities. While Eversource, an EDC, cannot enter into the Capacity Contract and have it paid for through its distribution rates, natural gas utilities might be appropriate proponents of increased gas pipeline supply under RSA 378:38, VII. *See Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities*, Order No. 25,822 (October 2, 2015) (approving firm transportation agreement for natural gas supply).

Supporters cite RSA 374:57, "Purchase of Capacity," as support for Eversource's proposal.

> Each electric utility which enters into an agreement with a term of more than one year for the purchase of generating capacity, transmission capacity or energy shall furnish a copy of the agreement to the [C]ommission no later than the time at which the agreement is filed with the Federal Energy Regulatory Commission pursuant to the Federal Power Act or, if no such filing is required, at the time such agreement is executed. The [C]ommission may disallow, in whole or part, any

> amounts paid by such utility under any such agreement if it finds that the utility's decision to enter into the transaction was unreasonable and not in the public interest.

RSA 374:57. The Opponents, however, maintain that the statute does not mean what the Supporters think it means. The Opponents argue that RSA 374:57 was enacted following PSNH's bankruptcy to tighten the commission's authority over contracting decisions for electric supply; a service EDCs no longer provide. According to the Opponents, a statute intended to give the commission authority to disallow unreasonable provisions in contracts with terms longer than one year cannot mean an electric utility can enter into a long-term contract for gas transmission.

While the Supporters' reading of the statute is plausible, we believe the Opponents have the better argument. The meaning of "capacity" in that legislation is limited to electric generating capacity and electric transmission capacity. First, the types of agreements listed are commonly associated with electric supply. Second, if gas capacity was to be included, the statute would have included references to the Natural Gas Act in addition to the Federal Power Act. Thus we find that RSA 374:57 concerns long-term contracts for electric supply and does not authorize EDCs to purchase gas capacity under long-term contracts.

Supporters claim that RSA Chapter 374-A's provisions granting EDCs authority to "enter into and perform contracts" related to "participation in electric power facilities" provide support for Eversource's petition. Supporters observe that those provisions were not repealed by subsequent enactments such as RSA 374-F. NextEra argues RSA 374-A applied to vertically integrated "electric utilities" as defined in 1975 by 374-A:1, IV and therefore that the provisions in RSA 374-A:2, I and II are inapplicable in a restructured market where electric utility has been redefined. RSA 374-A:1, IV defines electric utilities as "primarily engaged in the generation and sale or the purchase and sale of electricity or the transmission thereof." We believe NextEra is correct and that RSA 374-A no longer applies to an EDC like Eversource.

The change in the industry through the Restructuring Statute, first passed in 1996, effectively ended a restructured EDC's ability to participate in the generation side of the electric industry. Given the centrality of the separation of functions between distribution and generation in the Restructuring Statute, allowing an EDC to "participate in electric power facilities" under RSA 374-A in the manner proposed by Eversource would make little sense in light of RSA 374-F.

Opponents also argue, based upon RSA 378:28, that the Capacity Contract violates the used and useful requirement which is a basic component of utility ratemaking under New Hampshire law. Supporters counter that RSA 378:28 applies to rate base and because the Capacity Contract does not add to Eversource's rate base, and is instead an ongoing expense, the used and useful standard does not apply. The requirement that utility rate base be used and useful for a utility to include a return on that rate base in rates has a corollary principle governing expenses. That is, expenses must be prudent and necessary for providing the service offered by the utility. In this case, we have found that after enactment of the Restructuring Statute, EDCs should unbundle rates for distribution from rates for energy supply. Capacity Contract expenses are not needed to supply distribution services to Eversource distribution customers. The Capacity Contract is designed to support electric generation supply, and therefore expenses related to generation supply would be disallowed in distribution rates.

C. Federal law

As noted above, the Opponents also argued that the Capacity Contract would violate a number of federal laws, including the Natural Gas Act, the Federal Power Act, and the terms of

FERC procedures and precedent. Having determined that we cannot approve the Capacity Contract and related capacity releases under New Hampshire law, we need not reach a decision concerning federal pre-emption.

V. CONCLUSION

The proposal before us would have Eversource purchase long-term gas pipeline capacity to be used by gas-fired electric generators, and include the net costs of its purchases and sales in its electric distribution rates. That proposal, however, goes against the overriding principle of restructuring, which is to harness the power of competitive markets to reduce costs to consumers by separating unregulated generation from fully regulated distribution. It would allow Eversource to reenter the generation market for an extended period, placing the risk of that decision on its customers. We cannot approve such an arrangement under existing laws. Accordingly, we dismiss Eversource's petition.

We acknowledge that the increased dependence on natural gas-fueled generation plants within the region and the constraints on gas capacity during peak periods of demand have resulted in electric price volatility. Eversource's proposal is an interesting one, with the potential to reduce that volatility; but it is an approach that, in practice, would violate New Hampshire law following the restructuring of the electric industry. If the General Court believes EDCs should be allowed to make long-term commitments to purchase gas capacity and include the costs in distribution rates, the statutes can be amended to permit such activities.

Because that concludes this proceeding, we deny the motion to designate Staff Advocates as moot. We will address the joint motion for confidential treatment in a separate order.

Based upon the foregoing, it is hereby

ORDERED, that Eversource's instant petition is hereby DISMISSED; and it is

FURTHER ORDERED, that the information subject to Eversource's joint motion for confidential treatment should be kept confidentially, pending an order by the Commission regarding the disposition of same under RSA Chapter 91-A; and it is

FURTHER ORDERED, that the motions to designate Staff Advocates are hereby DISMISSED, having been rendered moot by the decision delineated in this Order.

By order of the Public Utilities Commission of New Hampshire this sixth day of October, 2016.

Martin P. Honigberg Chairman	Michael J. Iacopino Special Commissioner	Kathryn M. Bailey Commissioner

Attested by:

Kimberly Nolin Smith
Assistant Secretary

TAB B

October 25, 2016

PUBLIC ACT 15-107 SECTION 1(D) – NATURAL GAS CAPACITY, LIQUEFIED NATURAL GAS (LNG), AND NATURAL GAS STORAGE PROCUREMENT

NOTICE OF CANCELLATION

Pursuant to Public Act 15-107, An Act Concerning Affordable and Reliable Energy ("the Act"), the Department of Energy and Environmental Protection ("DEEP" or the "Department") released a final Request for Proposals ("RFP") for Natural Gas Capacity, Liquefied Natural Gas, and Natural Gas Storage pursuant to its authority under Section 1(d) of the Act on June 2, 2016.[1]

The 2014 Integrated Resources Plan for Connecticut ("2014 IRP"), issued by DEEP, concluded that the New England region is facing volatile electricity prices and significant risks to electric reliability due to limitations in our restructured electricity market that have driven investment in new natural gas-fired power plants, but not in the natural gas delivery infrastructure needed to ensure that those plants can run reliably all year round. The 2014 IRP concluded that investment is needed in incremental resources—including Natural Gas Resources such as natural gas pipeline capacity, natural gas storage, and liquefied natural gas, as well as clean energy resources that reduce our dependence on natural gas, such as Class I and III renewables, large-scale hydropower, energy efficiency, and energy storage.

Consistent with the 2014 IRP recommendations, the Act grants the Department, acting alone or with other states, the authority to, among other things, issue one or more RFPs to procure natural gas and clean energy resources for the purpose of securing more reliable and affordable electric service for the benefit of the Connecticut's electric ratepayers and to meet the State's energy and environmental goals and policies. The Act provides that DEEP must utilize a competitive procurement process, in consultation with the Office of Consumer Counsel, the Attorney General, and the Procurement Manager, to identify projects that provide net benefits to Connecticut's electric ratepayers. The Act makes clear that under Connecticut law the costs of these investments, backstopped by long-term contracts with the state's electric distribution utilities, may be recovered from the State's electric ratepayers, for whose benefit these resources are procured.

The RFP noted that several states within New England were considering procurements of natural gas resources. Indeed, several of the bids submitted to DEEP contemplated

[1] See Request for Proposals (RFP) for Natural Gas Capacity, Liquefied Natural Gas (LNG), and Natural Gas Storage issued June 2, 2016.

ratepayers from other New England jurisdictions funding a significant portion of the total project size. "To maximize the benefits to Connecticut's electric ratepayers," the RFP stated, "the Department will make every effort to align its procurements pursuant to the Act with related procurements undertaken in other jurisdictions. The Department reserves the right to withdraw, revise, and reissue this RFP at any time to facilitate this multi-jurisdictional coordination." RFP at 2.

DEEP received seven proposals from bidders by the required deadline of June 29, 2016. Public versions of each of these bids are available on the DEEP website. DEEP began preliminary evaluation of the bids. While such evaluation has been underway, however, the issuance of administrative decisions and a court ruling in other New England jurisdictions have materially reduced the ability for the costs of projects to be shared among a substantial portion of the region's ratepayers.

As noted in the 2014 IRP, DEEP believes that this problem of inadequate gas infrastructure is greater than one state can solve alone. Regional investment is necessary to ensure that no one state disproportionately bears the costs of addressing what is a problem endemic to our regional electric system.

Therefore pursuant to Section C.2.c[2] of the RFP, the Department hereby cancels the RFP review process without prejudice.

The Department retains its statutory authority to issue future RFPs under Section 1(d) of the Act, either on its own or again in coordination with other states in the region, to procure natural gas resources for the purpose of providing more reliable electric service for the benefit of the Connecticut's electric ratepayers and to meet the State's energy and environmental goals and policies. DEEP will monitor conditions in the ISO New England market and relevant proceedings of other New England states to determine if conditions warrant reissuance. The process for reissuance of an RFP under Section 1(d) is straightforward, and could be initiated at any time.

In 2016, DEEP issued requests for proposals for all three categories of resources eligible for procurement under Public Act 15-107. While the RFP under Section 1(d) is canceled, DEEP is concurrently advancing selection of projects in two RFPs issued this year pursuant to Sections 1(b) & 1(c) of the Act, which will contribute to the broader goals of the Act, reflecting the conclusion in the 2014 IRP that a variety of clean energy resources, such as Class I, large-scale hydropower, and conservation, "can provide an attractive alternative to natural gas generation, increasing the diversity and therefore reliability of the region's electric supply while also helping Connecticut and the region meet increasing RPS targets," as well as "reduc[ing] demand for electricity or natural gas." Going forward, we remain committed to utilizing our authority under all sections of the Act, in coordination with other states, to secure more reliable and affordable electric service for the benefit of the Connecticut's electric ratepayers and to meet the State's energy and environmental goals and policies.

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[2] *"....the Department expressly reserves the right, in its sole and absolute discretion (exercised individually)...to terminate the process described herein..."* See RFP at 11

TAB C

NOTICE: All slip opinions and orders are subject to formal revision and are superseded by the advance sheets and bound volumes of the Official Reports. If you find a typographical error or other formal error, please notify the Reporter of Decisions, Supreme Judicial Court, John Adams Courthouse, 1 Pemberton Square, Suite 2500, Boston, MA, 02108-1750; (617) 557-1030; SJCReporter@sjc.state.ma.us

SJC-12051
SJC-12052

ENGIE GAS & LNG LLC[1] vs. DEPARTMENT OF PUBLIC UTILITIES (and another case[2]).

Suffolk. May 5, 2016. - August 17, 2016.

Present: Gants, C.J., Spina, Cordy, Botsford, Duffly, Lenk, & Hines, JJ.[3]

Department of Public Utilities. Practice, Civil, Review of order of Department of Public Utilities. Electric Company. Public Utilities, Electric company, Judicial review. Gas. Administrative Law, Judicial review, Rulemaking, Agency's authority, Rate regulation. Statute, Construction.

Civil actions commenced in the Supreme Judicial Court for the county of Suffolk on October 26 and November 2, 2015.

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[1] ENGIE Gas & LNG LLC (ENGIE) filed its petition under its previous name, GDF Suez Gas NA LLC.

[2] Conservation Law Foundation vs. Department of Public Utilities.

[3] Justice Cordy participated in the deliberation on this case and authored this opinion prior to his retirement. Justices Spina and Duffly participated in the deliberation on this case prior to their retirements.

The cases were reported by Cordy, J.

Thaddeus A. Heuer (Adam P. Kahn & Jesse Harlan Alderman with him) for ENGIE Gas & LNG LLC.
David K. Ismay for Conservation Law Foundation.
Seth Schofield, Assistant Attorney General, for the Attorney General.
Thomas H. Hayman, Special Assistant Attorney General (Francis R. Powell, Special Assistant Attorney General, with him) for the Department of Public Utilities.
Cheryl M. Kimball & Matthew A. Sanders, for NSTAR Electric Company & others, amici curae, submitted a brief.

CORDY, J. These consolidated appeals are before us on a single justice's reservation and report of challenges made to an order of the Department of Public Utilities (department). Those challenges raise the question of the department's authority to review and approve ratepayer-backed, long-term contracts entered into by electric distribution companies for additional natural gas pipeline capacity in the Commonwealth pursuant to G. L. c. 164, § 94A, which requires gas and electric companies to receive departmental approval for any contract for the purchase of gas or electricity lasting longer than one year.

The plaintiffs, ENGIE Gas & LNG LLC and Conservation Law Foundation, contend that the order amounted to improper rulemaking in violation of the Administrative Procedure Act, G. L. c. 30A. They also argue that the department's determination that it has authority pursuant to G. L. c. 164, § 94A, to approve such contracts constitutes an error of law because it contravenes G. L. c. 164, § 94A, as amended through St. 1997, c. 164 (restructuring act).[4]

We disagree that the order of the department is an improperly promulgated rule or regulation. We nevertheless reach the statutory question presented by the plaintiffs, and conclude that the order is invalid in light of the statutory language and purpose of G. L. c. 164, § 94A, as amended by the restructuring act, because, among other things, it would undermine the main objectives of the act and reexpose ratepayers to the types of financial risks from which the Legislature sought to protect them.[5,6]

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[4] Statute 1997, c. 164 (restructuring act), discussed infra, restructured the electric utility industry, transforming "it from a government-regulated monopoly, to 'a framework under which competitive producers [would] supply electric power and customers [would] gain the right to choose their electric power supplier.'" Northeast Energy Partners, LLC v. Mahar Regional Sch. Dist., 462 Mass. 687, 695 (2012), quoting St. 1997, c. 164, § 1 (c) (ii). Importantly, the restructuring act separated the three utility services of generation, transmission, and distribution, and deregulated the generation component in the interests of competition. Northeast Energy Partners, LLC, supra at 696. Companies providing transmission and distribution services remain regulated by the State. Id.

[5] Because we determine that the Department of Public Utilities (department) erred in interpreting its authority under G. L. c. 164, § 94A, we need not reach the question of Federal law presented by ENGIE.

[6] We acknowledge the amicus briefs submitted by the Attorney General and by NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, and Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid.

1. Background. The department regulates the rates that both electric distribution companies[7] and local distribution natural gas companies[8] may charge their customers (ratepayers). G. L. c. 164, § 94A. See Fitchburg Gas & Elec. Light Co. v. Department of Pub. Utils., 460 Mass. 800, 801 (2011); Attorney Gen. v. Department of Pub. Utils., 453 Mass. 191, 192 (2009).

In 2015, the Department of Energy Resources (DOER) filed a petition asking the department to investigate the means by which new natural gas delivery capacity[9] might be added to the New

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[7] An electric distribution company is the "arm of a utility responsible for transmitting electricity from a generation facility or power grid to the end consumer." Franklin W. Olin College Of Eng'g v. Department of Telecomm. & Energy, 439 Mass. 857, 860 n.6 (2003). See G. L. c. 164, § 1 (defining "[d]istribution company"). Electric distribution companies provide two types of services: supply services and distribution services. See NSTAR Elec. Co. v. Department of Pub. Utils., 462 Mass. 381, 381 (2012).

[8] Local gas distribution companies "mak[e] and sell[] or distribut[e] and sell[] . . . gas within the commonwealth." See G. L. c. 164, § 1 (defining "[g]as company").

[9] Prior to the Federal restructuring of interstate pipeline service by the Federal Energy Regulatory Commission (FERC) (see FERC Order No. 639, 18 C.F.R. Part 284 [Apr. 8, 1992]), gas and the pipeline space, or "capacity," necessary to deliver it were "bundled," or sold together. Once "unbundled," the department recognized the distinction between the two elements of interstate gas services as "blurred, at best" and established that contracts for both would be similarly approved as "contract[s] for the purchase of gas" pursuant to G. L. c. 164, § 94A, under the same "public interest standard." D.P.U. 94-

England market in order to mitigate price volatility experienced by ratepayers in the Commonwealth, especially in the winter months. See D.P.U. 15-37 (Oct. 2, 2015). The DOER specifically asked whether the department, pursuant to its authority under G. L. c. 164, § 94A, could approve long-term contracts[10] by Massachusetts electric distribution companies for the purchase and resale of interstate natural gas pipeline capacity. The DOER stated that the ultimate goal of such purchases would be to lower "gas constraint-driven high prices" for electricity in New England by lowering the prices, particularly in the wintertime, of wholesale electricity across the region.

In support of its request, the DOER asserted that gas pipeline constraints have caused unreasonably high winter electric prices in New England. Unlike local natural gas distribution companies, which regularly contract for gas capacity, electric generators that use natural gas to produce electricity[11] are generally unwilling or unable to enter into long-term contracts to secure firm gas capacity. For these generators, there is added risk for such contracting because

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174-A, at 22-26 (Mar. 15, 1994). We therefore use the terms "gas" and "gas capacity" interchangeably.

[10] By the terms of G. L. c. 164, § 94A, any contract in excess of one year constitutes a long-term contract.

[11] Generation is "the act or process of transforming other forms of energy into electric energy or the amount of electric energy so produced." G. L. c. 164, § 1.

there is no means by which they can be reasonably assured of receiving enough revenue to cover the cost of securing the gas capacity over the course of each year. Pipeline companies, on the other hand, are not willing to build new pipeline capacity without having long-term contracts in place. Thus, pipeline companies do not have sufficient assurances such that they are willing to build additional pipeline capacity for natural gas-fired electric generators, despite the increasing natural gas demand for heating and as a source of supply for electric power. The DOER characterized this situation as a "mismatch" of needs and incentives that requires a "solution."

Under the DOER's proposal, (1) the department would authorize, pursuant to G. L. c. 164, § 94A, electric distribution companies to enter into contracts to purchase gas pipeline transportation capacity to be funded by the Commonwealth's ratepayers through rates set and approved by the department; (2) the pipeline owners (which in this case will include affiliates of electric distribution companies) will use those transportation contracts to help finance the construction of new gas pipeline capacity in the region; (3) after the pipelines are expanded, the electric distribution companies will release (resell) their contracted-for capacity to electric generators or "into the market";[12] and (4) the release of that capacity will increase gas supply and thus lower the wholesale price of gas and electricity.

Noting that the question was one of first impression, the DOER asked the department to determine whether "(1) there is an innovative mechanism for electric distribution companies . . . or other suitable parties to secure new, incremental gas delivery capacity into the region to the benefit of electric ratepayers; (2) review for cost-recovery of [electric distribution company] contracts for natural gas capacity by the [d]epartment under G. L. c. 164, § 94A . . . is appropriate; and (3) the standard of review the [d]epartment would apply to contracts submitted for approval under that section should be different." The DOER stated that ratepayer-funded gas capacity contracts entered into by electric distribution companies would solve the "mismatch" problem by providing sufficient financial assurance to pipeline companies to build new pipelines and infrastructure in order to provide gas to natural gas-fired electric generators.

[12] Citing to Order Accepting and Suspending Tariff Record and Establishing a Technical Conference, 154 FERC, ¶ 61,269 (Mar. 31, 2016), the Attorney General, in her brief, points out that in order to release the contracted-for capacity to the electric generation companies, the electric distribution companies would first need to obtain a waiver from FERC, because Federal law otherwise prohibits resellers from directing their contracted capacity rights to a particular party unless FERC grants a waiver. See also 18 C.F.R. § 284.8 (2015).

In response to the petition of the DOER, the department opened an investigation into the means by which new natural gas capacity might be added to the New England market, including measures that electric distribution companies might pursue. After considering input from stakeholders, including written comments submitted by the plaintiffs, the department issued D.P.U. 15-37, entitled, "Order Determining Department Authority Under G. L. c. 164, § 94A" (order). The department determined that the plain language of § 94A provides the department with the statutory authority to approve gas capacity contracts entered into by electric distribution companies, so long as the department first determines that such long-term contracts are in the public interest. D.P.U. 15-37, at 19, 43. The department further concluded that it could properly allow cost recovery for the contracts, including the cost of building the necessary pipeline infrastructure, through electric distribution rates. Id. at 12, 46. The department additionally determined that its findings were consistent with the restructuring act because the contracts entered into by the electric distribution companies would not result in the companies' reentry to producing, manufacturing, or generating electricity at wholesale, as contemplated by the restructuring act. Id. at 26-27.

The order further outlined the filing requirements and standard of review applicable to future proceedings seeking approval of ratepayer-backed contracts for gas capacity entered into by electric distribution companies. Id. at 36, 44-45. Since issuing the order, the department has docketed three petitions by electric distribution companies for the approval of such contracts; however, none has been approved at this time. The contemplated contracts are for a term of twenty years.

In October and November, 2015, the plaintiffs filed separate petitions in the Supreme Judicial Court for Suffolk County pursuant to G. L. c. 25, § 5, asking that the order be set aside on the ground that it is based on an erroneous interpretation of law. A consolidated hearing was held before the single justice, who denied the motions for judgment of default and reserved and reported the matters to the full court.[13]

2. Propriety of appeal. We first consider whether this appeal is properly before us. The plaintiffs ask the court to review the department's order pursuant to G. L. c. 25, § 5, which authorizes "an appeal as to matters of law from any final decision, order or ruling." The department argues, however,

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[13] The plaintiffs also filed motions to stay the department's order, D.P.U. 15-37 (Oct. 2, 2015) (order), which would have halted the contract review process. The motions were denied without prejudice.

that the order is not the product of an adjudicatory proceeding, nor did it adjudicate the rights of the plaintiffs; therefore, it is not appealable under § 5. See Providence & Worcester R.R. v. Energy Facilities Siting Bd., 453 Mass. 135, 140 (2009) ("A decision is 'final' for purposes of taking an immediate appeal if it completely adjudicates the rights of the parties, leaving nothing further to be decided").

We previously have held that where, as here, an agency determines that it has statutory authority to act, but has not yet exercised that authority, "such a decision is not 'final' for the purposes of judicial review under G. L. c. 25, § 5." Id. Nevertheless, we reach the merits of the question of law submitted to us by the parties because "the case has been fully briefed on the merits, . . . there is a public interest in obtaining a prompt answer to the question, and . . . the answer . . . is reasonably clear." Id., quoting Brown v. Guerrier, 390 Mass. 631, 632 (1983).[14]

3. Discussion. General Laws c. 164, § 94A, provides in relevant part that "[n]o gas or electric company shall hereafter enter into a contract for the purchase of gas or electricity covering a period in excess of one year without the approval of the department, unless such contract contains a provision

[14] In light of this conclusion, we do not reach the plaintiffs' argument that the order was issued in violation of the Administrative Procedure Act, G. L. c. 30A.

subjecting the price to be paid thereunder for gas or electricity to review and determination by the department in any proceeding brought under [§ 93 or 94]."

In its order, the department concluded that the plain language of § 94A provides it with the authority to review and approve "the purchase of gas or electricity" by "gas or electric companies." D.P.U. 15-37, at 19. It reasoned that the word "'or' . . . is used to list the entities (gas and electric companies) and the products (gas and electric purchases) and does not limit one type of company or one type of product." Id. Rather, the department ruled that the provision grants it broad "authority over both electric and gas distribution companies, without direct limiting language." Id. The department further concluded that because the meaning of the statute could be discerned from the plain language, the department need not "consider legislative history or doctrines of statutory construction." Id. Moreover, the department found that the restructuring act did not present an impediment to electric distribution companies contracting for natural gas capacity subject to department review and approval because the framework established by the department would not result in the electric distribution companies' reentry to producing, manufacturing, or generating electricity for sale at wholesale, as contemplated by the restructuring act. Id. at 27. See St. 1997, c. 164, § 193.

The plaintiffs counter that this interpretation of § 94A misapprehends the rules of statutory construction and is inconsistent with the larger statutory context of c. 164, as well as legislative policymaking embodied in the restructuring act.

a. Standard of review. We review the validity of a policy adopted by an agency charged with implementing and enforcing State statutes under the same two-part framework used to determine whether regulations promulgated by an agency are valid. Franklin Office Park Realty Corp. v. Commissioner of the Dep't of Envtl. Protection, 466 Mass. 454, 459-460 (2013). First, we employ "the conventional tools of statutory interpretation" to determine "whether the Legislature has spoken with certainty on the topic in question." Goldberg v. Board of Health of Granby, 444 Mass. 627, 632-633 (2005). Where the court determines that a statute is unambiguous, we will reject any agency interpretation that does not give effect to the Legislative intent. Franklin Office Park Realty Corp., supra at 460.

If we conclude that "the Legislature has not directly addressed the issue and the statute is capable of more than one rational interpretation, we proceed to determine whether the agency's interpretation may be reconciled with the governing legislation" (quotation and citation omitted). Biogen IDEC MA, Inc. v. Treasurer & Receiver Gen., 454 Mass. 174, 187 (2009). We defer to the agency's interpretation insofar as it is reasonable. Franklin Office Park Realty Corp., 466 Mass. at 460. Statutory interpretation, however, is ultimately the duty of the courts, and the "principle of according weight to an agency's discretion . . . is one of deference, not abdication, and this court will not hesitate to overrule agency interpretations of statutes or rules when those interpretations are arbitrary or unreasonable" (quotations and citation omitted). Moot v. Department of Envtl. Protection, 448 Mass. 340, 346 (2007), S.C., 456 Mass. 309 (2010).

Our interpretation is not limited only to determining a statute's "simple, literal or strict verbal meaning" but also considers a statute's "development, [its] progression through the legislative body, the history of the times, prior legislation, contemporary customs and conditions and the system of positive law of which they are part . . ." Kain v. Department of Envtl. Protection, 474 Mass. 278, 286 (2016), quoting Oxford v. Oxford Water Co., 391 Mass. 581, 588 (1984).

Applying these rules to the statutory language at issue, we conclude that the department erred in determining that § 94A, as amended by the restructuring act, authorizes the department to review and approve ratepayer-backed, long-term contracts for gas capacity entered into by electric distribution companies.

b. Section 94A. The parties do not dispute that § 94A has traditionally been construed by the department to apply to gas company purchases of gas and electric company purchases of electricity. Nonetheless, the department argues, nothing in the plain language of the provision prohibits the department from approving long-term contracts by electric distribution companies for gas.[15] Moreover, the department insists that because the language is unambiguous, the court need not employ the usual canons of statutory construction.

The plaintiffs ask the court to read § 94A distributively in accordance with the canon reddenda singula singulis, also known as the rule of the last antecedent, see Ross, A Rule of Last Resort: A History of the Doctrine of the Last Antecedent in the United States Supreme Court, 39 Sw. L. Rev. 325, 325

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[15] In its order, the department provided a single basis for its authority to approve long-term gas contracts by electric distribution companies: the language of G. L. c. 164, § 94A. See D.P.U. 15-37, at 14, 17-21. See id. at 15 n.16 (expressly rejecting declining to address other potential bases for authority). On appeal, however, the department provides several other potential bases of statutory authority for its conclusion, including G. L. c. 164, §§ 69I, 76, 93, and 94. We do not specifically consider these statutory bases, as they were not relied on in the department's order, and the court will not otherwise "supply a reasoned basis for the [department's] action that the agency itself has not given" (citation omitted), NSTAR Elec. Co. v. Department of Pub. Utils., 462 Mass. at 387. We nonetheless reject the department's arguments with respect to these provisions insofar as we determine that the over-all statutory scheme of G. L. c. 164 supports the plaintiffs' interpretation of § 94A as prohibiting the type of contracts contemplated by the department's order.

(2009), which states that "[w]here a sentence contains several antecedents and several consequents, courts read them distributively and apply the words to the subjects which, by context, they seem most properly to relate." 2A N.J. Singer & S. Shambie, Statutes and Statutory Construction § 47:26 (7th ed. 2014). Applying this canon to the text, the plaintiffs argue that the parallel uses of the word "or" in the first sentence of § 94A can be read only in a manner that authorizes the department to approve electric company contracts for the purchase of electricity, and gas company contracts for the purchase of gas.

The department argues, however, that we must disregard this maxim because the court uses aids of statutory construction only where the words of the statute are ambiguous. This argument misapprehends the task of statutory interpretation. The court does not determine the plain meaning of a statute in isolation, but rather concludes that a statute is unambiguous only after "consider[ing] the specific language of a statute in connection with the statute as a whole and in consideration of the surrounding text, structure, and purpose of the Massachusetts act," Custody of Victoria, 473 Mass. 64, 73 (2015), in light of the "standard rules of statutory construction and grammar" (citation omitted). Rowley v. Massachusetts Elec. Co., 438 Mass. 798, 802 (2003).

Whether the rule of the last antecedent is characterized as a rule of construction or one of grammar, it is the type of intrinsic aid we regularly use to discern the meaning of a statute. Although application of the rule here supports the plaintiffs' reading of the statute as prohibiting the department's review and approval of gas capacity contracts by electric distribution companies, it is not dispositive, because the rule "is not an absolute and can assuredly be overcome by other indicia of meaning." Barnhart v. Thomas, 540 U.S. 20, 26 (2003).

It is true, as the department points out, that the language of § 94A does not expressly forbid it from reviewing and approving contracts by electric distribution companies for gas. Nor, however, does the language clearly permit such activity. See Entergy Nuclear Generation Co. v. Department of Envtl. Protection, 459 Mass. 319, 331 (2011) ("Where . . . the scope of agency authority is at issue, we must determine whether the agency is acting within the powers and duties expressly conferred upon it by statute and such as are reasonably necessary to carry out its mission" [quotation and citation omitted]). Thus, to the extent that "the language is not conclusive as to the Legislature's intent, we may seek guidance from the legislative history." Commonwealth v. Garrett, 473 Mass. 257, 260 (2015). Moreover, taking this history together with the development of § 94A and its place with the larger statutory framework of G. L. c. 164, we conclude that the Legislature did not intend to authorize the department to approve the contracts contemplated in its order, but rather intended, with limited exceptions, to regulate the gas and electric utilities differently.

We begin by describing G. L. c. 164, § 94A, as it was originally enacted in 1926. The provision stated: "No electric company shall hereafter enter into a contract for the purchase of electricity covering a period in excess of three years without the approval of the department . . . ." St. 1926, c. 298. Section 94A was enacted to address concerns that newly consolidated "interlocking companies" would enter into contracts "for the interchange of electricity," and that the department might have to accept those non-arms' length transactions in later-filed electricity rate cases. See 1926 House Doc. No. 153, at 2.

Concerns remained, however, about how the expansion of holding companies and the consolidation of electric utilities under them would impact ratepayers. In light of these concerns, the Legislature created a special commission to investigate the control and conduct of public utilities in the Commonwealth. See Report of the Special Commission on Control and Conduct of Public Utilities (commission), 1930 House Doc. No. 1200, at 7

(1930 special report). Unlike a similar report prepared in 1925 that recommended the enactment of § 94A, but did not reference gas companies in the relevant discussion, see 1926 House Doc. No. 153, at 2, the commission was instructed to investigate both electric and gas companies. 1930 special report, supra at 7-9. The special report reflects apprehensions about the consolidation of independent operating companies, and how those consolidations might unjustly increase ratepayer cost for gas and electricity. Id. at 15-16, 34, 46-47, 52-53, 68-69, 240-241.

The report informs our understanding of the history of § 94A, as it reveals why the Legislature sought to extend St. 1926, c. 298, to gas companies: the commission predicted that the same concerns about electric companies would arise with respect to gas companies as well. Id. at 41-42. Finding that St. 1926, c. 298, provided "valuable protection against excessive charges for electricity," the report recommended extending the existing statute to cover gas company contracts for the purchase of gas. See id. at 67-68. Importantly, the special report did not appear to contemplate gas company purchases of electricity or electric company purchases of gas. To the contrary, the text of the special report supports the plaintiffs' position that the electric and gas industries were regulated separately. See, e.g., id. at 74 ("There is no necessary connection between the two kinds of business"); id. at 15 n.2, citing G. L. c. 164, §§ 22, 23 ("An electric company could not deal in gas under any circumstances"). The recommended bill was enacted in May, 1930, and appears in substantially the same form today. Compare St. 1930, c. 342, with G. L. c. 164, § 94A. Following the 1930 amendment, § 94A provided: "No gas or electric company shall hereafter enter into a contract for the purchase of gas or electricity covering a period in excess of two years without the approval of the department . . ." (emphasis supplied). St. 1930, c. 342.[16]

The department and the plaintiffs offer competing interpretations of this history. The department argues that this history does not support any finding of legislative intent to restrict the commodities to be purchased by utilities, or the types of contracts that would be subject to department review, but rather only to limit the power of the holding companies that had come to dominate the gas and electric industries. Thus, in the department's view, the concerns that prompted the amendment arose from a desire to protect ratepayers from excessive rates, with no indication that the department should be limited in its

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[16] The statute was further amended in 1941 to change the contract period from two years to one year. St. 1941, c. 400. At the time of the 1930 amendment, the Legislature had already used the "gas or electric company" or "gas or electricity" construction numerous times elsewhere in G. L. c. 164. G. L. (Ter. Ed.) c. 164 (1932), §§ 5, 11, 15-18, 30, 34, 42-43, 45-46, 55-56, 58, 60-69, 78-79, 81-84, 89, 92-96, 116-117, 124-125.

ability to review any type of commodity contract by any type of utility company.

The plaintiffs disagree, and argue that the introduction of the new language in the 1930 amendment did not alter or expand the meaning of existing and unchanged statutory language because the Legislature did not express any intent to do so. See Foster v. Group Health Inc., 444 Mass. 668, 674 (2005) ("provisions of [an] amendatory act [are] to be considered together with provisions of [the] original act"). Thus, they argue, the 1930 amendment was not made with the intent to expand electric company contracting authority to include the purchase of gas, but rather to expand the department authority to regulate gas company contracts for gas in addition to electric company contracts for electricity.

We agree, and conclude that the history and development of the statute supports the plaintiffs' distributive reading of the terms "gas or electric." In light of the history, as well as the different regulatory treatment of gas and electric utilities, it is apparent that the addition of the term "gas" to § 94A was not meant to expand the department's authority to review any type of commodity contract by any type of utility, but rather to ensure that gas companies were not free to engage in the types of transactions that might harm ratepayers when electric companies were prohibited from doing so.

Moreover, our conclusion that the Legislature intended to regulate gas and electric utilities differently is supported by other language in the statute, including the express, non-overlapping definitions of "gas company" and "electric company," even if the corporate entity engaging in one of those defined, regulated businesses is "subsequently authorized" to also perform the other function. See G. L. c. 164, §§ 1, 8A.[17]

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[17] General Laws c. 164, § 1, defines an electric company as follows:

> "a corporation organized under the laws of the commonwealth for the purpose of making by means of water power, steam power or otherwise and for selling, transmitting, distributing, transmitting and selling, or distributing and selling, electricity within the commonwealth, or authorized by special act so to do, even though subsequently authorized to make or sell gas; provided, however, that electric company shall not mean an alternative energy producer; provided further, that a distribution company shall not include an entity which owns or operates a plant or equipment used to produce electricity, steam and chilled water, or an affiliate engaged solely in the provision of such electricity, steam and chilled water, where the electricity produced by such entity or its affiliate is primarily for the benefit of hospitals and nonprofit educational institutions, and where such plant or equipment was in operation before January 1, 1986; and provided further, that electric company shall not mean a corporation only transmitting and selling, or only transmitting, electricity unless such corporation is affiliated with an electric company organized under the laws of the commonwealth for the purpose of distributing and selling, or distributing only, electricity within the commonwealth."

A gas company is defined as "a corporation organized for the purpose of making and selling or distributing and selling, gas within the commonwealth, even though subsequently authorized to make or sell electricity; provided, however, that gas company shall not mean an alternative energy producer." Id.

Indeed, the department's own order acknowledges the "different regulatory treatment of a [local distribution gas company] and [electric distribution companies]." D.P.U. 15-37, at 43.

The larger statutory context in which the term "gas or electric" is used extensively in G. L. c. 164 is also instructive. For example, G. L. c. 164, § 116, gives a duly authorized officer or employee of "a gas or electric company . . . [the right to] enter any premises supplied with gas or electricity by such company for the purpose of examining or removing the meters, pipes, wires, fittings and works for supplying or regulating the supply of gas or electricity and of ascertaining the quantity of gas or electricity consumed or supplied" (emphasis added). In an emergency, fire and police officers must allow such an authorized representative "of a gas or electric company . . . to enter any area or building in order to shut off the gas or electricity, which is or may become a source of danger to the public" (emphasis added). G. L. c. 164, § 116A. See G. L. c. 164, § 93 (granting department authority, on notice and investigation following written complaint "either as to the quality or price of the gas or electricity sold and delivered, . . . [to] order any reduction or change in the price or prices of gas or electricity or an improvement in the quality thereof" [emphasis added]); G. L. c. 164, § 76A (department has authority to supervise affiliate of both gas and electric companies with respect to extent of their activities that "affect the operations of" any gas or electric company they are affiliated with, directing that "[s]uch relations, transactions and dealings, including any payments by a gas or electric company to such an affiliated company for services or materials and supplies which enter into the manufacture, distribution or sale of gas or electricity, shall be subject to review and investigation by the department in any proceeding brought under [G. L. c. 164, §§ 93-94]" [emphasis added]).

The department, however, argues that reading the words "gas or electricity" distributively throughout G. L. c. 164 would lead to absurd results that could not have been intended by the Legislature. The department notes that it may authorize an electric company to "engage in the business of a gas company" and a gas company "to engage in the business of an electric company" if it "deems the public convenience will be promoted thereby" pursuant to G. L. c. 164, § 8A. Thus, the department argues, if the court were to adopt the distributive reading of c. 164 suggested by the plaintiffs, a gas company authorized to engage in the sale of electricity pursuant to G. L. c. 164, § 8A, for example, would not be required to report accidents caused by electricity it supplied where someone was killed (see G. L. c. 164, § 95); would be unable to enter any area or building to shut off electricity which is or may become a source of danger to the public (see G. L. c. 164, § 116A); and would be unable to stop service to a person who failed to pay his or her electricity bill (see G. L. c. 164, § 124).

These arguments are not persuasive. The "absurdities" identified by the department are easily resolved by consistently treating "gas companies" and "electric companies" separately throughout c. 164, as required by their statutory definitions. Moreover, if a gas company were to amend its corporate charter and obtain approval from the department under G. L. c. 164, § 8A, to also engage in the business of an electric company, as the department hypothesizes, it would plainly also meet the statutory definition of "electric company" pursuant to G. L. c. 164, § 1, and so would expressly be subject to the statutory provisions cited to by the department.

A final factor supports our conclusion that the Legislature did not intend to authorize the department to approve electric distribution company contracts for gas capacity and vice versa. Although we defer to an agency's reasonable interpretation of a statute it is charged with enforcing, "[t]he appropriate weight (of such interpretation), in a particular case, will depend on a variety of factors, including whether the agency participated in the drafting of the legislation . . . , whether the interpretation dates from the enactment of the legislation, and whether it has been consistently applied" (citations omitted). Board of Educ. v. Assessor of Worcester, 368 Mass. 511, 515-516 (1975).

In this case, we have not located (nor has the department identified) any instance of the department approving, pursuant to § 94A, a contract for electricity by a gas company, or a contract for gas by an electric company in the eighty-six year period since the 1930 amendment. Moreover, before issuing the order, the department had never interpreted § 94A to authorize its approval of such contracts; to the contrary, its prior orders suggest that the department also had adopted a distributive construction of the statute's language with the term gas relating to gas companies and the term electricity relating to electric companies. See, e.g., D.P.U. 95-67, at 21 (Oct. 10, 1995) ("G. L. c. 164, § 94A, requires gas and electric companies to file for [d]epartment approval all contracts for the purchase of gas or electricity of a duration greater than a year" [emphasis added]); D.T.E. 02-50, at 2 (Sept. 23, 2002) (same); D.P.U. 86-247, at 7 (Dec. 4, 1987) ("Under [§] 94A, any electric company who contracts for the purchase of electricity for a period in excess of one year must submit the contract for review"). The department's order here thus represents a significant departure from its own history of administering

§ 94A and its separate treatment of the gas and electric utilities.[18]

In light of these considerations, we conclude that the department erred in interpreting § 94A as authorizing it to review and approve ratepayer-backed, long-term contracts by electric distribution companies for gas capacity (or contracts by gas companies).

c. Restructuring act of 1997. We further conclude that the department's interpretation of § 94A is untenable in light of the 1997 restructuring act, which amended G. L. c. 164 ("An Act relative to restructuring the electric utility industry in the Commonwealth, regulating the provision of electricity and other services, and promoting enhanced consumer protections therein"). "Any judicial review of agency action embodies the principle that an agency has no inherent authority beyond its enabling act and therefore it may do nothing that contradicts such legislation." Globe Newspaper Co. v. Beacon Hill Architectural Comm'n, 421 Mass. 570, 586 (1996). For the

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[18] See also 220 Code Mass. Regs. §§ 11.00 (2016) (department's rules governing restructuring of electric industry silent as to whether restructured electric distribution company being able to purchase gas or be compensated therefor); D.P.U. 94-174-A, at 1-2 (Mar. 15, 1994) (in designing and establishing "single standard based on the public interest" to be applied to all gas commodity contracts -- for both the gas itself, and for the pipeline capacity necessary to transport it -- the department entertained comments only from, included analysis only regarding, and designed the standard only for, gas companies).

reasons discussed herein, we determine that the department's approval of ratepayer-backed, long-term contracts by electric distribution companies for gas capacity contradicts the fundamental policy embodied in the restructuring act, namely the Legislature's decision to remove electric distribution companies from the business of electric generation.

Prior to the passage of the restructuring act, electric companies were vertically integrated monopolies, controlling the generation, transmission, and distribution of electricity. See Northeast Energy Partners, LLC v. Mahar Regional Sch. Dist., 462 Mass. 687, 695 (2012). Recognizing that "the interests of consumers [could] best be served by an expedient and orderly transition from regulation to competition in the generation sector consisting of the unbundling of prices and services and the functional separation of generation services from transmission and distribution services," St. 1997, c. 164, § 1 (m), the Legislature enacted the act to separate these three utility services and open the supply of generation services to competition. Northeast Energy Partners, LLC, supra at 696-697. This functional separation of services, which limited a "'company's ability to provide itself an undue advantage in buying or selling services in competitive markets,' was regarded as a necessary first step in moving toward 'a fully competitive generation market based on customer choice.'" Id. at 697, quoting D.P.U. 95-30, at 16 (Aug. 16, 1995).

The restructuring act also removed "the business of producing, manufacturing, or generating electricity," from the department's supervisory authority. See St. 1997, c. 164, §§ 189, 193. Following the transfer by Commonwealth utilities of all generation facilities to separate ownership, no portion of the business of a generating company could "be subject to regulation as a public utility or as an electric company." St. 1997, c. 164, § 193; G. L. c. 164, § 1A (e).

Additionally, by deregulating the generation component of the electric utility industry, electric distribution companies were discharged from their duties to plan for, build, and operate or profit from the making and selling of electricity. Instead, the business of electric distribution companies is to plan for, build, and operate distribution infrastructure (e.g., poles, wires, and substations); deliver electricity; and be compensated for doing so. See, e.g, G. L. c. 164, § 1, inserted by St. 1997, c. 164, § 187 (defining "[d]istribution company," "[d]istribution service," and "[d]istribution facility").

Recognizing the circumscribed role of electric distribution companies after the restructuring act, the department exempted them from their prerestructuring act business obligations relating to fuel management and power planning. First, in 1998, the department acknowledged that the electric distribution companies would no longer be buying fuel for power plants or recovering from ratepayers the cost of fuel. Accordingly, the department exempted electric distribution companies from the previous fuel procurement and cost recovery program under G. L. c. 164, § 94G. D.T.E. 98-13, at 4 (Feb. 20, 1998).[19]

The department also exempted electric distribution companies from G. L. c. 164, § 69I, which had imposed a power planning requirement on the electric utilities, and instead directed distribution companies to focus exclusively on distribution. D.T.E. 98-84, at 1-2 (Aug. 10, 1998). Section 69I had required electric companies to assess expected customer electricity demand over a ten-year period and ensure that they would have the right fuel and infrastructure mixture to serve that expected demand.[20] In exempting electric distribution

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[19] As relevant here, G. L. c. 164, § 94G, required companies to demonstrate to the department that their plans to procure fuel for their power plants would "maintain sufficient reserves of power for purposes of reliability and efficiency." G. L. c. 164, § 94G (a). Section 94G (a) also allowed electric companies to recover their fuel costs from customers and adjust the rate based on fluctuations in fuel prices. See generally Consumers Organization for Fair Energy Equality, Inc. v. Department of Pub. Utils., 368 Mass. 599, 601-602 (1975).

[20] In relevant part, G. L. c. 164, § 69I, required that electric companies file biennial forecasts of the electric power needs and requirements of its market area for the ensuing ten-year period. D.T.E. 98-84/EFSB 98-5, at 1 (Aug. 8, 2003). Prior to the restructuring act, the department used this device to regulate electric companies' "procurement of and cost

companies from § 69I, the department recognized that the restructuring act relieved such companies from their obligation to "forecast[], plan[], solicit[] and procur[e] long-term electricity supplies for their customers." D.T.E. 98-84, at 1 (Aug. 10, 1998).

Thus, the department's exemption of electric distribution companies from both §§ 94G and 69I signaled its recognition that electric distribution companies were leaving all aspects of the generation business, including not only power plant construction, but also the planning and fuel management aspects of generation.

Moreover, in restructuring the electric industry by removing electric distribution companies from the business of electric generation, the Legislature "shifted the risks of generation development from consumers to generators" to "insulate[] [consumers] from construction, operational, and price risks . . . inherent in commodity rate regulation." D.P.U. 12-77, at 28 (Mar. 15, 2013). See D.T.E. 98-84, at 2 (Aug. 10, 1998) ("A market framework based on competition . . . will mean that the economic consequences of building too many power plants will be borne directly by investors, rather than ratepayers"). Through the restructuring act, the Legislature

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recovery associated with . . . resources to meet [their customers' electricity needs." Id.

sought to shift such risk away from ratepayers, who had been forced to pay higher rates for electricity as a result of "excessive investments" in expensive and poorly managed long-lived infrastructure projects. Black & Pierce, The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry, 93 Colum. L. Rev. 1339, 1344-1345, 1386 (1993).[21]

In this case, the department's interpretation of § 94A not only would permit electric distribution companies to purchase resources related to supply of electric generation (in this case, natural gas capacity), but also would allow the department to regulate such activity and to shift the associated costs to ratepayers. We agree with the plaintiffs that such activity would undermine the main object to be accomplished by the restructuring act, i.e., to move from a regulated electricity supply market to an open and competitive market for power. See St. 1997, c. 164, § 1 (f). Further, an interpretation of § 94A

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[21] See, e.g., Attorney Gen. v. Department of Pub. Utils., 390 Mass. 208, 219, 222, 228-229 (1983) (affirming department decision that authorized electric company to recover, through increased rates, costs it incurred in later abandoned Pilgrim II nuclear power plant). See also Norwood v. Federal Energy Regulatory Comm'n, 80 F.3d 526, 530-531 (D.C. Cir. 1996) (affirming, in part, FERC decision to allow nuclear plant operator to recover costs for prematurely closed nuclear plant based in Rowe, Massachusetts); Cost of Seabrook Plant Begins to Hit Customers, N.Y. Times, Feb. 1, 1987 (describing Massachusetts ratepayer costs associated with construction of Seabrook nuclear power plant).

that includes approval of pipeline capacity contracts by electric distribution companies would contradict the specific statutory provisions put in place under G. L. c. 164 to account for the divestiture of all generation assets by electric distribution companies. See, e.g., G. L. c. 164, § 1G. Accordingly, this interpretation would give rise to an inconsistent body of regulatory law. See D.T.E. 98-84/EFSB 98-5 (exempting electric distribution companies from G. L. c. 164, § 69I, and rescinding 220 Code Mass. Regs. §§ 10.00); D.T.E. 98-13 (exempting electric distribution companies from G. L. c. 164, § 94G).

Perhaps most importantly, however, the department's order would reexpose ratepayers to the very types of risks that the Legislature sought to protect them from when it enacted the restructuring act. Both the DOER and the department noted that gas-fired generating businesses are unwilling to assume the risks associated with long-term gas pipeline capacity contracts because there "is no means by which they can" assure recovery of those contract costs. Shifting that risk onto the electric ratepayers of the Commonwealth, however, is entirely contrary to the risk-allocation design of the restructuring act.

Equally unavailing is the department's finding that the order does not contravene the policy embodied in the restructuring act because it does not allow the use of ratepayer funds to construct a power plant. D.P.U. 15-37, at 27. As prior decisions by this court and the department make clear, power plant construction is only one aspect of the electric generation market, and in enacting the restructuring act, the Legislature sought to separate all aspects of generation from all aspects of distribution. See, e.g., D.T.E. 98-13, at 4; D.T.E. 98-84, at 1.

Moreover, the department itself has recognized that fuel procurement and planning is an integral component of the generation business, as evidenced by its exemption of electric distribution companies from § 69I. Indeed, by some estimations, fuel-related costs constitute seventy-five per cent of a natural gas-fired plant's generation costs. 3 World Scientific Handbook of Energy 72 (G.M. Crawley ed., 2013). Accordingly, prior to the enactment of the restructuring act, the department required electric companies to consider both the type and amount of fuel they would use to generate power when they calculated whether they could supply enough electricity to match expected demand. We agree with the plaintiffs that if the restructuring act does not allow electric distribution companies to finance investments in electric generation, it cannot be reasonably interpreted to permit those companies to invest in infrastructure unrelated to electric distribution service. Accordingly, we reject the department's reasoning. See Cardin v. Royal Ins. Co. of Am., 394 Mass. 450, 456-557 (1985) (agency's interpretation of statute "hardly persuasive where [it] violates the language and policy of the statute," [quotation and citation omitted]).

The department's interpretation of the statute as permitting electric distribution companies to shift the entire risk of the investment to the ratepayers is unreasonable, as it is precisely this type of shift that the Legislature sought to preclude through the restructuring act. Contrast D.P.U. 12-77, at 28 (Mar. 15, 2013) ("The legislation restructured the electric industry in the state by providing incentives to investor-owned electric distribution companies to divest their generating assets and by adopting a competitive market structure for the generation and purchase of electricity. This restructuring shifted the risks of generation development from consumers to generators, who are better positioned to manage those risks").

Our interpretation of the restructuring act is supported by the Legislature's own actions since the law's enactment. That is, where the Legislature has sought to override the risk allocation policy of the act, it has done so expressly. First, in 2008, through enactment of the Green Communities Act, St. 2008, c. 169, the Legislature directed electric distribution companies to seek proposals from renewable energy developers, and, if they received reasonable proposals, to enter into ratepayer-backed long-term contracts to buy the renewable power. See St. 2008, c. 169, § 83. The Legislature concluded that such contracts were necessary to "facilitate the financing of renewable energy generation facilities." Alliance to Protect Nantucket Sound, Inc. v. Department of Pub. Utils. (No. 1), 461 Mass. 166, 168 (2011). Importantly, in enacting the Green Communities Act, the Legislature explicitly provided the department with the authority to review and approve the ratepayer-backed renewable energy contracts. St. 2008, c. 169, § 83 ("[a]ll proposed contracts shall be subject to the review and approval of the department of public utilities").

The Green Communities Act represents a legislatively created exception to the restructuring act's general prohibition on electric distribution companies owning generation assets. To facilitate promotion of renewable energy in the Commonwealth, the Legislature allowed each distribution company to construct, own, and operate twenty-five megawatts of solar energy before January 1, 2009, and 50 megawatts after January 1, 2010. St. 2008, c. 169, § 58. Section 58 further provided that an electric distribution company had to obtain prior approval for cost recovery from the department in order to recover construction costs of a solar generation facility. Id. Although the statute has since been amended, it continues to provide an express, limited exemption from the restructuring act. See St. 2012, c. 209, § 17.

Second, in 2012, the Legislature enacted "An Act relative to competitively priced electricity," in which it authorized the department to order electric distribution companies in the Northeastern Massachusetts/Boston load zone (NEMA) to solicit proposals for electricity generation, and if they received reasonable proposals, to enter into ratepayer-backed long-term contracts to buy the generation for use in the NEMA load zone. St. 2012, c. 209, § 40. This provision explicitly permitted the department to review and approve any resulting contracts if the department determined that they were justified. Id.

These actions by the Legislature represent a clear decision to depart from the policy choice to remove electric distribution companies from the business of generation, as expressed in the restructuring act, in very specific circumstances. Here, the department's stated motive in issuing the order is to correct a perceived failure of market-based incentives to encourage wholesale generators to contract for adequate pipeline capacity. However, its means of doing so, namely by reallocating risk onto the ratepayers, is clearly prohibited by legislative policy. Thus, no matter how salutary the department may claim its policy aims to be, its order contravenes the fundamental policy embodied in the restructuring act and cannot stand. See Utility

Air Regulatory Group v. Environmental Protection Agency, 134 S. Ct. 2427, 2446 (2014) (agency authority to interpret ambiguities in enabling statute "does not include a power to rewrite clear statutory terms to suit its own sense of how the statute should operate"); Wakefield Teachers Ass'n v. School Comm. of Wakefield, 431 Mass. 792, 802 (2000) (fundamental policy decisions are province of Legislature, and not coordinate branches of government).

4. Conclusion. We conclude that the department erred in interpreting G. L. c. 164, § 94A, as amended by the 1997 restructuring act, as authorizing it to review and approve ratepayer-backed, long-term contracts by electric distribution companies for natural gas capacity. Accordingly, the department's order is vacated.

So ordered.

TAB D

PUBLIC VERSION

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2014-00071

September 14, 2016

MAINE PUBLIC UTILITIES COMMISSION
Investigation of Parameters for
Exercising Authority Pursuant to the
Maine Energy Cost Reduction Act,
35-A M.R.S. §1901

ORDER – PHASE 2

VANNOY, Chairman; MCLEAN and WILLIAMSON, Commissioners

I. SUMMARY

Through this Order, the Commission concludes that each of the Energy Cost Reduction Contract (ECRC) proposals presented in this proceeding satisfies the statutory requirements for acceptance. Specifically, neither market developments and rule changes, nor private participation in securing additional pipeline capacity will address the energy price and infrastructure concerns identified by the Legislature in the enactment of the Maine Energy Cost Reduction Act, P.L. 2013, ch. 369. Moreover, the ECRC proposals before the Commission (Spectra Energy Partner LLC's Access Northeast (ANE) and Portland Natural Gas Transmission's Continent to Coast (C2C)) are commercially reasonable, in the public interest and reasonably likely to increase pipeline capacity into the region, be cost beneficial, and enhance system reliability.

The Commission concludes that the ANE project, in the context of participation by other states in New England, would provide greater ratepayer benefits than the C2C proposal.[1] Therefore, the Commission decides to move forward with negotiation of a precedent agreement with ANE for Maine's 9% load share conditioned upon comparable precedent agreements with ANE and other New England states (Massachusetts, Connecticut, Rhode Island and New Hampshire) at a minimum of those states' respective load shares. In the event that the ANE does not proceed, or if the conditions set forth in this Order are not met, the Commission may move forward with precedent agreement negotiations for C2C, along with any necessary conditions.

II. BACKGROUND

A. The Maine Energy Cost Reduction Act

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[1] Commissioner McLean concurs in part and dissents in part to the majority decision. Commissioner's McLean's opinion is attached to this Order.

During its 2013 session, the Legislature enacted The Maine Energy Cost Reduction Act, P.L. 2013, ch.369, codified at 35-A M.R.S. § 1901 *et seq* (Act). The Act contains the following findings:

> **1. Electricity prices.** It is in the public interest to decrease prices of electricity and natural gas for consumers in this State; and
>
> **2. Natural gas expansion.** The expansion of natural gas transmission capacity into this State and other states in the ISO-NE region could result in lower natural gas prices and, by extension, lower electricity prices for consumers in this State.

35-A M.R.S. § 1903.

To facilitate the expansion of natural gas transmission pipeline capacity into the region and the State, the Act authorizes the Commission, in consultation with the Public Advocate and the Governor's Energy Office, to execute an ECRC in accordance with the provisions of the Act. 35-A M.R.S. § 1904. An ECRC is defined in the Act as "a contract executed... to procure capacity on a natural gas transmission pipeline, including, when applicable, compression capacity." 35-A M.R.S. § 1902(2). The Act limits ECRCs to a cumulative total of no more than 200,000,000 cubic feet of natural gas per day (200 MMcf/d) or 200,000 dekatherms per day (Dth/d) of natural gas capacity or for a total cost that does not exceed $75,000,000 annually. 35-A M.R.S. § 1904.

Pursuant to the Act, the Commission may also negotiate and enter contracts for the resale, evaluation, and administration of pipeline capacity acquired through an ECRC, and is responsible for assessing, analyzing, negotiating, implementing, and monitoring compliance with ECRCs. 35-A M.R.S. § 1906. The Act provides that the Commission may not execute an ECRC after December 31, 2018, but may continue to administer existing contracts and enter resale agreements for capacity purchased prior to that date. 35-A M.R.S. § 1912.

The Act specifies that, before the Commission may execute an ECRC, it must have pursued, in the appropriate regional and federal forums, market and rule changes that will reduce the basis differential[2] for natural gas delivered into New England and increase the efficiency with which gas brought into New England and Maine is transmitted, distributed and used. 35-A M.R.S. § 1904(1)(A). The Commission may not execute an ECRC if it concludes that: (1) market and rule changes will, within the same timeframe, achieve substantially the same cost reduction effects for Maine electricity and gas customers as the execution of the ECRC; or (2) private transactions will achieve, within the same timeframe, substantially the same cost reduction effects for Maine electricity and gas customers. 35-A M.R.S. §§ 1904(1)(A) and (B).

[2] "Basis differential" is defined in the Act as "the difference between the so-called Henry Hub spot price for natural gas and the corresponding cash spot price for natural gas in New England." 35-A M.R.S. § 1902(1).

The Act also requires the Commission, in consultation with the Public Advocate and the Governor's Energy Office, to retain the services of a consultant with expertise in natural gas markets to make recommendations regarding the execution of an ECRC. 35-A M.R.S. § 1904(1)(C)

To enter into an ECRC or direct a utility to do so, the Commission must determine in an adjudicatory proceeding that the proposed ECRC is commercially reasonable and in the public interest, and that the contract is reasonably likely to:

> 1. Materially enhance natural gas transmission pipeline capacity into the State or into the ISO-NE region and that additional capacity will be economically beneficial to electric consumers, natural gas consumers or both in the State and that the overall costs of the contract are outweighed by its benefits to electric consumers, natural gas consumers, or both in the State; and
>
> 2. Enhance electrical and natural gas reliability in the State.

35-A M.R.S. § 1904(2).

The Act authorizes the Commission to execute an ECRC as a principal and counterparty or to direct one or more transmission and distribution (T&D) utilities, natural gas utilities, or natural gas pipeline utilities to be a counterparty to an ECRC. In determining whether and to what extent to direct a utility to be counterparty to an ECRC, the Commission must consider, in an adjudicatory proceeding, the anticipated reduction in the price of gas or electricity accruing to the customers of the utility. Any economic loss from an ECRC sustained by a counterparty utility is deemed to be prudent and allowed recovery in rates. 35-A M.R.S. § 1904(3).

The Act also specifies that the Commission may contract jointly with other entities, including other state agencies and instrumentalities, governments in other states and nations, utilities, and generators, if it concludes that an ECRC can be achieved with the participation of these other entities. *Id.* The Governor must approve the Commission's execution or direction of the ECRC in writing before the Commission may do so. 35-A M.R.S. § 1904(4).

B. <u>Commission Proceeding - Phase 1</u>

1. <u>Background</u>

The Act requires that the Commission, in consultation with Public Advocate and the Governor's Energy Office, retain a consultant with expertise in natural gas markets to make recommendations regarding the execution of an ECRC. The Commission retained Sussex Economic Advisors, LLC (Sussex) for this purpose and, on February 26, 2014, Sussex produced its report titled "Maine Public Utilities Commission Review of Natural Gas Capacity Options." (Sussex Report)

On March 20, 2014, the Commission opened an investigation to determine what parameters should govern an exercise of its authority pursuant to the Act and to consider the Sussex Report and other analyses and testimony presented in the proceeding. Over 15 interested persons intervened in the proceeding. The Sussex Report was subject to discovery and a hearing, as was the analysis of the economic effects of constrained gas pipeline capacity on electricity prices presented by Competitive Energy Services (CES). Several parties also submitted testimony that was subject to discovery and hearing.

On November 13, 2014, after a comprehensive process consistent with the requirements of the Act, the Commission issued its Phase 1 Order in this proceeding.[3]

2. Findings and Conclusions

At the conclusion of the Phase 1 process, the Commission, through its November 13, 2014 Order, made several findings and conclusions as contemplated by the Act regarding a commitment to one or more ECRC. The Commission found that the following statutory prerequisites of the Act have been met: (1) that the Commission pursue market and rule changes to address the basis differential for gas coming into New England; (2) that the Commission explore all reasonable opportunities for private participation in securing additional gas pipeline capacity; and (3) that the Commission hire a consultant to conduct an analysis on the execution of ECRCs. Phase 1 Order at 31. In addition, the Commission found that there was evidence in the record to support a finding that the market has not, and will not, achieve the objectives of the Act. The Commission noted that, although it was too early to tell what effect market reforms would have on the supply/demand balance at peak times, the evidence suggested that the market rule changes would not cause generators or other private entities to invest in pipeline capacity. *Id.* at 33. The Commission thus concluded that incremental pipeline investment in the region would only result from contracts with natural gas local distribution companies (LDCs) or through ECRCs. *Id.* at 32.

In its Phase 1 Order, the Commission also resolved standard of review issues and determined that an ECRC pursuant to the Act is not preempted by federal law. *Id.* at 27. Moreover, the Commission tentatively decided that the counterparty to an ECRC would be a regulated utility or utilities whose customers would receive the benefits of the ECRC and that the allocation of costs among electric and gas customers in Maine would be in proportion for the benefits they realize from an ECRC.[4] *Id.* at 42.

The Commission concluded in the Phase 1 Order, however, that the statutorily-required finding of whether an ECRC would materially enhance natural gas transmission capacity and be cost beneficial to Maine consumers could only be determined by analyses of specific proposals and that such analyses would occur in

[3] Commissioner Littell dissented.

[4] Consistent with the Act, the Commission also concluded that such utility counterparties would receive timely cost recovery.

Phase 2 of this proceeding.[5] *Id.* at 37. The Commission also specified that the primary issue to be resolved in Phase 2 would be the costs and benefits of specific ECRC proposals. *Id.* at 40. The Commission emphasized, however, that during Phase 2, it would continue to monitor and assess the effects of potential market rule changes, private investment, and regional efforts, and would include developments in these areas in its evaluation of ECRC proposals. *Id.* at 37

The Commission also stated that it would consider the potential for coordination of a Maine ECRC with regional pipeline capacity efforts, project timing and flexibility, and the length of the payback period. *Id.* at 41. In the event that an ECRC is part of a larger project, the Commission stated that the calculation of the benefit side of the benefit/cost ratio will be based on the Maine proportion of the overall project rather than engage in the theoretical inquiry into whether the Maine share should be measured as relating to any particular tranche within that overall project. *Id.* The Commission noted that, if the evidence in Phase 2 supports the conclusion that one or more of the Maine ECRCs is a necessary part of the overall project, the use of Maine's share of the overall benefit in the calculation would be most appropriate. *Id.*

C. Procedural History[6]

1. Parties

The following entities were granted intervenor status during Phase 1 of this case:

- Office of the Public Advocate (OPA)
- Northern Utilities, Inc. d/b/a Unitil (Unitil)
- Maine Natural Gas Corporation (MNG)
- Central Maine Power Company (CMP)[7]

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[5] In the Phase 1 Order, the Commission found that an ECRC that would necessarily satisfy the statutory requirement that an ECRC which materially increases natural gas transmission capacity into the State or into New England would also necessarily have the corresponding effect of enhancing electrical and natural gas reliability in the State as required by the Act. Phase 1 Order at 32.

[6] A summary of the procedural history of Phase 1 of this case is included in the Phase 1 Order. Phase 1 Order at 3-8. This section of the Phase 2 Order summarizes the procedural history in this case since the issuance of the Phase 1 Order.

[7] CMP's status as a party was modified by Orders dated December 11, 2015 (Part I) and January 25, 2016 (Part II). In the January 25th Order, the Commission summarized the basis for its finding that CMP's decision to enter into negotiations with one of the competing bidders during the course of the case had affected the procedural balance in a way that required remedial action. This remedial action included CMP remaining a party to the proceeding, but prohibiting CMP from providing further

- Emera Maine (Emera)
- Portland Natural Gas Transmission System (PNGTS)
- Tennessee Gas Pipeline Company, LLC (TGP)[8]
- Maritimes & Northeast Pipeline, LLC (M&NP)
- Algonquin Gas Transmission, LLC (ALG)
- Conservation Law Foundation (CLF)
- Natural Resources Council of Maine (NRCM)
- Industrial Energy Consumers Group (IECG)
- Maine State Building & Construction Trades Council (Trades Council)
- United Association of Plumbers and Steamfitters, Local 716 (Local 716)
- Environment Northeast (ENE)
- Repsol Energy North America Corporation (RENA)
- Maine Renewable Energy Association (MREA)

During Phase 2 in this case, two additional parties were granted intervenor status:

- Northeast Energy Solutions (NEES)
- Mary Fournier

2. Two Stages in Phase 2

Phase 2 had two distinct stages. During the first stage, the Commission considered ECRC bid proposals on a standalone, Maine-specific basis. During the second stage, the Commission considered the ECRC bid proposals from a regional/multi-state perspective.

a. Evaluation of ECRC Bid Proposals from a Maine Standalone Perspective

As permitted by the Phase 1 Order, TGP, PNGTS, and Spectra[9] filed initial ECRC bid proposals on December 5, 2014. Following the submission of the bid

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evaluation of the price and material terms of any ECRC bid proposal. Part II Order at 14-16.

[8] By letter dated May 23, 2016, TGP withdrew as a party to this proceeding.

proposals, the Commission engaged London Economics International, LLC (LEI) to assist in its evaluation of the bid proposals and determine if any of the proposals satisfies the requirements of the Act. LEI filed its initial analysis in this case titled "Maine Energy Cost Reduction Act: Cost benefit analysis of ECRC proposals" on July 14, 2015 (LEI Standalone Analysis).[10] In its Standalone Analysis, LEI concluded that the benefits to Maine from each of the bid proposals do not outweigh the costs primarily because Maine would be paying 100% of the project costs, while other states in the region would be receiving approximately 90% of the benefits from the project.

Parties conducted discovery on LEI's Standalone Analysis and a technical conference was held on September 22, 2015, to allow parties to question LEI about its Standalone Analysis.

b. <u>Evaluation of ECRC Bid Proposals from a Multi-State/Regional Perspective</u>

Following the September 22nd technical conference, the parties were invited to file written comments on the process for the remainder of this case and a case conference to discuss procedural issues was held on October 22, 2015. In light of the results of LEI's Standalone Analysis and input from the parties, the Commission requested LEI to re-evaluate the benefits and costs associated with each of the ECRC bid proposals assuming that the proposals are part of a regional or multi-state effort to expand gas pipeline capacity in the region. Under such a scenario, Maine would take a smaller share of the larger project than was considered by LEI in its Standalone Analysis.

Parties were given the opportunity to file testimony regarding, or comment on, LEI's Standalone Analysis and suggest analytical revisions that LEI should incorporate in its multi-state/regional evaluation. Testimony critiquing LEI's Standalone Analysis, and/or comments and suggestions regarding LEI's forthcoming regional analysis, were filed by TGP, IECG, Spectra, OPA, CMP, and RENA on November 18, 2015. Discovery on the testimony and comments took place in late November and early December, 2015.

In recognition of the shift in focus from a Maine-only to a regional perspective, the Commission invited bidders to update or supplement their bid proposals if they chose to do so. TGP and PNGTS filed updated ECRC bid proposals on December 4, 2015. Spectra filed an updated bid proposal on December 14, 2015.

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[9] Spectra Energy Partners, LP (Spectra) is the owner of ALG and the majority owner of M&NP. In this Order, the Commission refers to M&NP and ALG collectively as "Spectra." Spectra filed a supplement and update to its initial bid proposal on February 26, 2015.

[10] The LEI Standalone Analysis was dated June 20, 2015, but was not filed in this case until July 14, 2015. On September 15, 2015, LEI filed an Errata to its Standalone Analysis.

Parties were also given an opportunity to file their own analyses and supporting testimony regarding a regional/multi-state evaluation of the competing ECRC bid proposals. On February 22, 2016, LEI filed an analysis titled "Maine Energy Cost Recovery Act: Cost benefit analysis of ECRC proposals in the context of a regional or multi-state gas pipeline expansion effort" (LEI Regional Analysis). Regional/multi-state analyses and/or supporting testimony were also filed by IECG and TGP on February 22 and February 23, 2016. Discovery was conducted on these regional analyses and testimony. Technical conferences regarding the regional/multi-state analyses and testimony were held on March 16 and March 24, 2016.

Rebuttal testimony on the regional/multi-state analyses and testimony was filed by the IECG, TGP, RENA, Spectra, and LEI on April 6 and 7, 2016. Discovery was conducted on the rebuttal testimony and hearings on the regional/multi-state analyses and associated testimony, as well as rebuttal testimony, were held on April 28 and April 29, 2016.

On May 23, 2016, TGP filed a letter withdrawing its ECRC bid proposal from consideration in this case.

3. Post-Hearing Process

Following the hearings in this case, parties were invited to file briefs and reply briefs. Briefs were filed on May 10, 2016 by the OPA, IECG, Spectra, PNGTS, CLF, RENA, and Ms. Fournier. Reply briefs were filed on May 17, 2016 by the OPA, IECG, Spectra, PNGTS, CLF, and RENA.

An Examiners' Report for Phase 2 of this case was issued on June 8, 2016. Exceptions or comments on the Examiners' Report were filed by the OPA, IECG, Spectra, PNGTS, RENA, CLF, NEES, and Ms. Fournier on June 22, 2016.

III. POSITIONS OF THE PARTIES

A. Office of the Public Advocate (OPA)

In its brief, the OPA recommends that the Commission determine that the record in this case is sufficient to find that an ECRC will provide net benefits to Maine's electricity consumers. OPA Br. at 1. The OPA further recommends that the Commission grant conditional approval of the PNGTS ECRC bid proposal for up to 45,000 Dth/day of firm transportation capacity to the Dawn Hub. *Id.* The OPA argues that the Commission's final authorization of the PNGTS bid should be contingent upon (1) an overall regional procurement of natural gas pipeline capacity of at least 500,000 Dth/day and (2) confirmation that the ECRC with PNGTS will provide net benefits to Maine's electricity or gas consumers. *Id.*

The OPA argues that its recommendation that the Commission authorize an ECRC at less than the Commission's full statutory authority represents a "relatively modest commitment" that properly reflects the continuing uncertainty about the benefits and costs pipeline investments will provide to Maine electricity and gas customers. *Id.*

at 28. The OPA argues that PNGTS' C2C Dawn proposal offers the greatest benefit for Maine ratepayers. The OPA further argues that Spectra's ANE proposal may better address regional needs but does not provide equivalent benefits to Maine and raises additional concerns. *Id.* at 28-9.

The OPA recommends that the Commission negotiate a precedent agreement with PNGTS in the next phase of this proceeding. The OPA further recommends that the Commission allow parties to provide input on the terms of any precedent agreement under consideration. *Id.* at 33-4. The OPA recommends that, prior to executing an ECRC, the Commission should conduct a final round of modeling that will allow the Commission to confirm that the ECRC will in fact provide net benefits to Maine ratepayers as required by the Act. *Id.* at 34.

In its reply brief, the OPA argues that LEI's Regional Analysis provides a reasonable basis for the Commission to find that an ECRC would provide net benefits to Maine ratepayers. OPA Reply Br. at 2-6. The OPA asserts that Spectra's claim that an ECRC must provide firm service to specific generators is unconvincing. *Id.* at 7-9. The OPA also argues that the Commission is not preempted by federal law from implementing an ECRC. *Id.* at 10-12.

B. Maritimes & Northeast and Algonquin Gas Transmission (Spectra)

Spectra asserts that the key problems to address in this proceeding are (1) inadequate natural gas pipeline capacity in New England and (2) the inability of the current pipeline system to meet the needs of natural gas-fired generators in the region. Spectra Br. at 2. Spectra argues that these problems result in the region's gas-fired generators not being able to operate during periods of system constraint. *Id.* Spectra argues that the way to solve the problem is to ensure that firm capacity is made available to as many gas-fired generators as possible, which will result in gas setting the marginal clearing price for generation in New England. *Id.*

Spectra asserts that another significant problem is electric system reliability. Spectra argues that getting firm capacity to gas-fired generators in the region will minimize the risk to electric system reliability and the associated risk of price spikes. *Id.* at 2-4.

Spectra notes that virtually all gas-fired generators in the region do not have contracts for firm pipeline capacity and must instead rely on interruptible or secondary pipeline capacity in order to run. *Id.* at 10. Spectra argues that, because of this fact, most of the region's gas-fired generators do not run during periods of constraint. *Id.* at 14. Spectra adds that the only way to ensure that generators have access to capacity is to provide the capacity on a firm basis along the entire path to the generator. *Id.* at 22. Spectra argues that electric reliability also requires firm capacity to the power plant. *Id.* at 24.

Spectra asserts that, of the ECRC proposals under consideration by the Commission, ANE best meets the needs of the region during times of constraint because it will allow gas-fired generators to run during traditionally constrained periods;

includes Electric Reliability Service (ERS) to serve fast-start units; offers a regional solution with proportional multi-state participation; would best meet the needs of electric distribution company (EDC) customers; and is likely to have the most impact on Algonquin Citygate prices. *Id.* at 30-38.

Spectra asserts that the record in this case is sufficient for the Commission to find that ANE is commercially reasonable and would be cost-beneficial to Maine. *Id.* at 38-47. Spectra identifies several shortcomings of LEI's Regional Analysis, but concludes that the record in this case provides a sufficient basis for the Commission to find that ANE meets the requirements of the Act without the need for LEI to conduct further analysis. *Id.* at 47-79. Finally, Spectra argues that, for a variety of reasons, the Commission should not approve an ECRC with PNGTS only. *Id.* at 83-85.

In its reply brief, Spectra reiterates its assertion that the record evidence in this case is sufficient to allow the Commission to approve an ECRC with ANE. Spectra Reply Br. at 6-7. Spectra argues that delaying action in this case "because of the possibility of other private market opportunities is inconsistent with the Act and the Commission's Phase 1 Order." *Id.* at 7. Spectra reasserts that a Commission finding to enter into an ECRC with PNGTS and not ANE "would not be in the public interest and could jeopardize regional action." *Id.* at 11. Spectra disagrees with the arguments of RENA and CLF regarding price volatility and reliability risks in the region and argues that such volatility and risk is best addressed through additional pipeline capacity. *Id.* at 29. Spectra argues that CLF has incorrectly identified the legal standards of the Act and contests CLF's assertion that federal law preempts the Commission from adopting an ECRC pursuant to the Act. *Id.* at 42-46.

C. <u>Portland Natural Gas Transmission System (PNGTS)</u>

PNGTS asserts that the key question before the Commission is whether any of the ECRC bid proposals satisfy the requirements of the Act and therefore justify execution. PNGTS Br. at 4. PNGTS notes that the standards of the Act are "complex" but asserts that the record in this case is extensive and provides a sufficient basis for the Commission to conclude that an ECRC for PNGTS capacity satisfies the standards of the Act. *Id.* at 4-5.

PNGTS argues that its bid proposal would provide several benefits to Maine ratepayers including reduced price volatility; enhanced reliability through access to diversified supply basins; does not constitute a "massive overbuild;" has a smaller, scalable volume; connects directly to certain gas-fired generators; delivers directly to Maine as well as New England; and mitigates risk by using existing pipeline infrastructure. *Id.* 5-9.

PNGTS argues that, in addition to satisfying all of the requirements of the Act, its proposal is superior to the ANE proposal. *Id.* at 10. PNGTS cites supply and delivery advantages and resale value, as reasons why it is the best ECRC option for Maine ratepayers. *Id.* at 10-12. PNGTS concludes that "to best achieve the goals of the Act, help the people of Maine, and set an example for the rest of New England, the Commission should pursue an ECRC for PNGTS capacity." *Id.* at 13.

In its reply brief, PNGTS refutes Spectra's arguments that are critical of PNGTS' ECRC bid proposal and asserts that Spectra's "attempts to manufacture issues with PNGTS' Proposal should be disregarded as either incorrect or irrelevant." PNGTS Reply Br. at 2-10. PNGTS argues that its proposal "is supported by sound expert testimony." *Id.* at 9. PNGTS reiterates its argument that its ECRC bid proposal is the best way to achieve the goals of the Act and help the people of Maine. *Id.* at 10.

D. Industrial Energy Consumer Group (IECG)

The IECG argues that the primary issue in this case is "the relationship between the price of natural gas in the Marcellus region of Pennsylvania, the largest and least expensive source of natural gas in the world, and the price of LNG delivered to the northeast on a firm basis from overseas LNG liquefaction facilities over the next 25 years." IECG Br. at 3. The IECG urges the Commission to join with its counterparts in the New England states to ensure that the region's marginal source of natural gas is from the Marcellus region rather than oil and imported LNG. *Id.* The IECG recommends that the Commission direct Maine's two EDCs to enter into ECRCs with ANE and PNGTS. *Id.* at 5.

The IECG asserts that the Commission should reject LEI's Regional Analysis because the analysis contains fatal methodological flaws and does not reflect the cancellation of the Northeast Energy Direct (NED) project. The IECG argues that the Commission should find that the record in this case demonstrates that the proposed ANE and PNGTS projects meet the requirements of the Act and will result in net positive impacts to Maine ratepayers. *Id.* at 10-12. The IECG asserts that Maine's participation in the ANE and PNGTS projects should "be conditioned upon collaboration with one or more other states." *Id.* at 17.

In its reply brief, the IECG argues that the Commission should reject the OPA's recommendation in this case because it is "overly conservative and will not protect Maine's ratepayers from future energy price spikes." IECG Reply Br. at 1. The IECG asserts that the Commission should disregard CLF's brief in this case "because it applies the wrong standard of review and seeks to (re-)debate issues resolved in Phase 1 of this proceeding." *Id.* at 8.

E. Conservation Law Foundation (CLF)

CLF argues that the Commission is precluded from executing an ECRC because "such action would be commercially unreasonable and incur substantial costs that do not outweigh prospective benefits, contrary to the best interest of ratepayers." CLF Br. at 2. CLF further asserts that none of the ECRC proposals satisfies the requirements of the Act. *Id.* at 6. CLF states that "[m]arket and rule changes, along with private participation in energy markets, are already driving down electricity prices, achieving substantially the same result as would execution of an ECRC." *Id* . at 2. Moreover, CLF argues that, notwithstanding the Commission's preliminary finding in Phase 1, Maine is preempted under federal law from executing an ECRC.[11] *Id.* at 2-3.

CLF asserts that the Commission should proceed very cautiously in its review of the ECRC bid proposals and, because of the substantial risks and uncertainties, the Commission should find that entering into an ECRC at this time is not in the best interest of Maine ratepayers. *Id.* at 3. CLF argues that the Commission should delay taking final action in this case until it has (1) conducted further analysis regarding changed market conditions and (2) allowed other states in the region to act. *Id.* CLF adds that "at a minimum, in light of the NED project's cancellation, the Commission should take a cautious and conservative approach, engage LEI to conduct an updated analysis, and hold this proceeding in abeyance at least until an updated report is complete." *Id.* at 7.

In its reply brief, CLF argues that Spectra's claim that ANE will alleviate market price volatility and reliability concerns ignores that fact that "for market, regulatory, legal and political reasons, ANE is unlikely to get built." CLF Reply Br. at 2-3. CLF repeats its assertion that the record in this case supports a finding that the benefits of an ECRC do not outweigh its costs. *Id.* at 5. CLF argues that Spectra, PNGTS, the IECG, and the OPA all fail to acknowledge "the steep decline in electricity prices since the peak winter of 2013/2014." *Id.* at 8. CLF criticizes the OPA for its "rush-to-contract approach." *Id.* at 9

F. Repsol Energy North America Corporation (RENA)

RENA argues that the Commission should reject the ECRC bid proposals submitted in this case by Spectra and PNGTS because both proposals would result in more capacity than is needed. RENA asserts:

> These proposals would provide a 365-day solution to a problem that is confined to the peak days within the winter seasons, a problem that can be easily remedied utilizing existing gas supply and transportation capacity to serve all of the Maine markets, without leaving New England ratepayers to pick up the cost for unutilized excess capacity for the remaining 300-plus days a year.

RENA Br. at 5.

RENA asserts that the LNG Export Scenario included in LEI's Regional Analysis is grounded on assumptions that "are so unrealistic that the conclusions generated should be discarded." *Id.* RENA further argues that the alternative studies offered in this case "are based on static inputs, truncated data, or biased assessments [and] should be rejected as unsupported and unreliable." *Id.* RENA concludes that the Commission should reject these ECRC proposals and "shift its focus to identifying and

[11] See Section IV(A) below for a detailed discussion of CLF's preemption argument and the Commission's response to that argument.

securing a more viable cost-effective solution that utilizes existing infrastructure and capacity." *Id.*

RENA argues that the region's existing capacity and near-term capacity additions are more than adequate. RENA argues that the effective use of LNG during periods of peak winter demand "provides a more effective and affordable solution than the state-funded acquisition of new incremental pipeline capacity through expensive long-term pipeline transportation contracts that will reasonably be likely to result in *no* net benefits to Maine's electricity and gas rate payers." (emphasis in original) *Id.* at 21.

RENA asserts that, after rejecting the pending ECRC proposals, the Commission should commence a Phase 3 to this proceeding, or open as new investigation, to consider other supply options. *Id.*

In its reply brief, RENA argues that there are more cost-effective options available to address the gas supply issues facing Maine and under such circumstances, the Commission "may not execute an ECRC." RENA Reply Br. at 2. RENA asserts that, with respect to gas shortfall issues, electric reliability has not been an issue. *Id.* at 4. RENA argues the suspension of the NED project does not necessarily mean that either of the ECRC proposals under consideration in this case will be cost-effective. *Id.* at 4-6. RENA asserts that proponents of the ECRC proposals have "misstated the status of LNG pricing and availability." *Id.* at 8. RENA asserts that the ANE project does not provide incremental supply. *Id.* at 11.

G. Mary Fournier

Ms. Fournier states that she is "very concerned that the costs to electric ratepayers will increase unfairly if an additional natural gas pipeline is added in Maine." Fournier Br. at 1. Ms. Fournier also asserts that she is concerned that the approval of an ECRC will result in the construction of another natural gas pipeline on her property. *Id.* Ms. Fournier notes that her property is already encumbered by a 345 kV electric transmission line and a 30-inch gas pipeline. Ms. Fournier questions the safety of locating an additional gas pipeline on her property. *Id.* at 2.

Ms. Fournier notes that the price of natural gas has gone down considerably since the Act took effect. Ms. Fournier argues that Maine's ratepayers are already paying too much for electricity and such customers should not be burdened with the costs associated with an unnecessary ECRC. Ms. Fournier asserts that "[t]he Commission should not put the ratepayers' money into this long-term rate risk to benefit the gas companies." *Id.*

Ms. Fournier notes that this expensive proceeding has been going on for over 2 years and concludes that the Commission should protect Maine's ratepayers by ending this case now without authorizing an ECRC. *Id.* at 3.

Ms. Fournier did not file a reply brief in this case.

IV. LEGAL ISSUES

A. Federal Preemption

In Phase 1 of this proceeding, CLF raised the argument that the Commission is preempted under federal law from exercising the authority granted to it under the Act. CLF argued that the actions contemplated by the Act would impermissibly affect wholesale gas and electric rates in interstate markets and impinge upon Federal Energy Regulatory Commission's (FERC) exclusive jurisdiction over wholesale rate setting established by the Federal Power Act (FPA) and the Natural Gas Act (NGA). CLF concluded that Commission action to implement an ECRC pursuant to the Act would violate both the dormant Commerce Clause and the Supremacy Clause of the United States Constitution. CMP, the OPA, and TGP argued that the Commission should reject CLF's preemption argument.[12]

In the Phase 1 Order, the Commission rejected CLF's preemption argument stating that:

> We concur with the analyses put forth by OPA, TGP and CMP. We find that the ECRA's burdens on interstate commerce, if any, are minimal and are outweighed by its benefits, which would inure to the region and not Maine alone. Entering an ECRC under the Act would not benefit in-state economic interests by burdening out-of-state competitors, nor would it comprise an attempt to set a wholesale electricity or gas rate in contradiction to the FPA or NGA.

Id. at 29.

CLF has reiterated its preemption argument in Phase 2 of this proceeding, stating that authorizing utilities to acquire gas pipeline capacity to promote the development of interstate natural gas infrastructure and thereby decrease regional wholesale natural gas and electric prices would constitute the intentional distortion of FERC-regulated markets and is barred under the Supremacy Clause. CLF Br. at 33. In support of its reassertion of the preemption argument in Phase 2, CLF cites to *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288 (2016), a United States Supreme Court decision that was issued after the completion of Phase 1. CLF states that *Hughes* struck down a state program in Maryland aimed at enhancing access to certain types of generation, and that the regulatory approach that the Act envisions violates the Supremacy Clause for many of the same reasons as the Maryland program—including that FERC, through its own actions and the delegated acts of ISO-NE, is already taking steps within its scope of the authority pursuant to the Commerce Clause to address the causes of winter price volatility. *Id.* at 34. Thus, CLF argues that any action of this Commission authorizing utilities to acquire gas pipeline capacity for the purpose of influencing wholesale energy prices is barred under the doctrine of preemption and the Supremacy Clause of the Constitution. *Id.* at 35.

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[12] The positions of the parties on the preemption issue are summarized in the Phase 1 Order. Order at 27-29.

The OPA and Spectra urge the Commission to reject CLF's preemption argument. OPA Reply Br. at 10-12; Spectra Reply Br. at 43-45. These parties note that, in Phase 1, the Commission rejected CLF's preemption argument and that the issuance of the *Hughes* decision should not change that conclusion. The OPA and Spectra state that, in *Hughes*, the Supreme Court overturned Maryland's program because it guaranteed generators a rate distinct from the clearing price for its interstate sales of capacity to PJM whose capacity auctions were the sole rate setting mechanism for sales of capacity to PJM approved by FERC. OPA Reply Br. at 11: Spectra Reply Br. at 44-45.

The OPA argues that an ECRC would not set or distort any FERC wholesale rate, nor set any FERC-jurisdictional rate for pipeline capacity under the NGA, because Maine will pay FERC-approved rates for any pipeline capacity. Moreover, the Commission would not be "setting" a wholesale electricity price established by ISO-NE. OPA Reply Br. at 11.

Spectra states that the Court intended for *Hughes* to be applied narrowly and that the Court explicitly stated that "so long as a State does not condition payment of funds on capacity clearing the auction, the State's program would not suffer from the fatal defect that renders Maryland's program unacceptable." Spectra Reply Br. at 44. Spectra further asserts that *Hughes* does not support preemption of an ECRC authorized pursuant to the Act because payments authorized by the Act are for pipeline capacity and not for the separate costs of the natural gas commodity or anything related to electric power markets. *Id.* at 44-45.

The Commission agrees with the OPA and Spectra that the *Hughes* decision does not alter the Commission's conclusion in the Phase 1 Order. Commission action pursuant to the Act does not establish or distort any wholesale rate nor does it impermissibly interfere with the ISO-NE market or the authority of FERC. It does not set a FERC-jurisdictional rate for pipeline capacity. The Supreme Court explicitly stated that the *Hughes* decision should be interpreted narrowly and that the decision does not prohibit states from employing other measures to encourage development of new generation which could have an indirect impact on wholesale electricity prices. Similarly, Maine's ECRC program acts to increase pipeline capacity into the region, but does not in any way serve to establish or distort a federally-established wholesale rate.[13]

There have been cases in which this Commission has been clearly preempted by federal law from some action, and in such cases, the Commission has the authority to declare itself preempted. However, the Commission should only do so under circumstances where preemption is obvious. The Commission is an administrative agency charged by the Maine Legislature with the responsibility and duty to carry out

[13] For a comprehensive discussion of preemption of a Commission-ordered ECRC under the NGA, see Benjamin T. McCall, Comment, The Road Less Travelled: the Maine Energy Cost Reduction Act, Economic Energy Cost Reduction Act, Economic Federalism, and a Modern Approach to Preemption Analysis under the Natural Gas Act of 1938, 67 Me. L. Rev. 312 (2015).

and implement laws enacted by the Legislature. In this case, as described above, the grounds for preemption are dubious. In such cases, the Commission should move forward, as we do here, with the implementation of the statutory direction provided to us by the Legislature.

B. LNG Storage Component of ANE Bid

The ANE bid proposal includes an LNG storage component. The proposed LNG storage facility would be located at the end of a lateral on the Algonquin system in Acushnet, Massachusetts. The facility would allow for up to 400,000 Dth/day of additional firm capacity to gas-fired generators in the region. Spectra claims that this adjacent LNG storage capability, combined with the associated ERS rate schedule, make the ANE proposal uniquely capable of meeting regional need. Spectra Br. at 31.

The OPA posits that the Commission "may lack statutory authority to enter into a precedent agreement for the LNG storage portion of the Access Northeast project." OPA Br. at 32. The OPA asserts that Spectra has acknowledged that its "quick start" service offered through its ERS cannot be provided by pipeline alone. The OPA argues that in Phase 1, the Commission concluded that "an ECRC is confined to pipeline capacity only, consistent with the statutory language defining an 'energy cost reduction contract' as a contract 'to procure capacity on a natural gas transmission pipeline.'" *Id.* The OPA further notes that the Maine Legislature's recent passage of P.L. 2015, c.445 (Chapter 445), which allows for the procurement of LNG storage in Maine under the Act, casts additional doubt on whether pipeline projects with LNG storage outside of Maine are allowed under the Act. The OPA asserts that "[t]his additional legislative authorization would not have been necessary had the existing ECRA authority authorized purchase of LNG storage." *Id.* The OPA concludes that "at a minimum, entering into an ECRC for storage amidst this legal uncertainty is an invitation for litigation and delay." *Id.*

The IECG argues that because the LNG storage component of ANE's bid "is designed as an integral part of the overall ANE pipeline system, and specifically is necessary to mitigate loss of pressure – i.e., to add compression capacity – it is expressly eligible to be included in an energy cost reduction contract." IECG Reply Br. at 7. The IECG further argues that the ANE bid is for pipeline capacity which incorporates the Acushnet LNG storage capacity that is firm from the supply to the generator. The IECG asserts that this fact "wholly distinguishes the LNG storage component of the ANE project from the type of standalone LNG storage facility authorized in the last legislative session" in Chapter 445. *Id.*

Like the IECG, Spectra argues that the OPA's concerns about the legality of the LNG storage component of the ANE proposal lack merit. Spectra notes that 35-A M.R.S. § 1902(2), which defines an ECRC, explicitly calls for the procurement of "capacity on a natural gas transmission pipeline, including, when applicable, compression capacity." Spectra asserts that the ANE project "meets this definition because it provides capacity on a pipeline, and the associated LNG storage is directly integrated with the pipeline capacity being provided." Spectra Reply Br. at 22.

Spectra argues that "[i]mportantly, LNG storage on Access Northeast is not a standalone service of the type called for under Chapter 445, but rather is a critical aspect of providing the generator specific services outlined in the Access Northeast proposal." *Id.* Spectra further argues that:

> the Act clearly references "pipeline capacity," but the Act does not say "only pipelines" may be provided nor does the Act enumerate all of the types of components associated with the provision of pipeline capacity. For example, the Act does not specifically say "regulator station," "meter station," or any number of other specific facilities which are necessary components of pipelines.... There is no such indication in the Act that the Legislature intended the term "pipeline capacity" to be strictly limited to "pipelines," particularly when the provision of pipeline capacity requires the use of other associated facilities.

Id. at 23-24.

Spectra argues that Chapter 445 is intended to allow for procurement of standalone LNG storage that is physically located in Maine and not associated with pipeline capacity. Spectra asserts that "[t]his type of project differs materially from the LNG storage associated with Access Northeast, which is located outside Maine and is directly associated with pipeline capacity." *Id.* at 24. Spectra asserts that Chapter 445 was drafted to ensure that proceedings under Chapter 445 (1) would not begin until after the current ECRC proceeding is complete and (2) would only take place if the $75 million limit in the Act had not been exhausted by the execution of ECRCs. Spectra argues that "[t]he Legislature did not want this follow-on proceeding for a special-purpose facility located in Maine to get in the way of the Legislature's larger interest in ensuring that ECRC projects currently being considered could proceed without interruption or risk." *Id.*

The Commission agrees with Spectra and the IECG that there is nothing in the Act that limits the Commission's review, and acceptance, of an ECRC bid that includes an integrated LNG storage component. Although the Act clearly references "pipeline capacity," it does not state or imply that an ECRC cannot include other components, particularly when the provision of pipeline capacity requires the use of other associated facilities. In this case, the LNG storage aspect of the ANE project is an essential component to the purpose of the pipeline project, which is to provide generator-specific services. More specifically, it is an engineering design component enabling ANE to maximize gas throughput on the pipeline while maintaining adequate minimum pressure requirements throughout the system, particularly on the G system. The Commission finds that the restrictive interpretation of the OPA is inconsistent with the overall intent and purpose of the Act and that a broader reading of section 1902(2), which permits the inclusion of an LNG storage facility that is an integral part of an overall pipeline system, is a more reasonable interpretation.

The Commission also disagrees with the OPA that the Legislature's enactment of Chapter 445 during the 2016 session supports the argument that the storage component of ANE is inconsistent with the Act's definition regarding ECRCs. Chapter 445 authorizes the Commission to consider contracts for LNG storage that is physically located in Maine and not associated with pipeline capacity. This kind of project is substantially different from the LNG storage associated with the ANE project, which is not located in Maine and is directly linked with pipeline capacity.

V. ECRC PROPOSALS AND ANALYSES

A. Description of Proposals

Pursuant to the Commission's Part 1 Order, Spectra, PNGTS and TGP filed separate ECRC bid proposals in December 2014 for consideration in this case. In December 2015, each of these three bidders provided supplemental bids that included updates to several terms of their respective offers. The key characteristics of the ECRC proposals, as summarized by LEI in its Regional Analysis, are shown in Figure 1 below.[14]

[14] On May 23, 2016, TGP filed a letter withdrawing its ECRC bid proposal from consideration in this proceeding. In its May 23rd letter, TGP informed the Commission that it had filed a notice with FERC withdrawing its Application for a Certificate of Public Convenience and Necessity for the NED Project pending in FERC Docket No. CP16-21-000.

Figure 1[15] **[Begin Confidential]**

Bidder Project name	Spectra Energy Access Northeast ("ANE")	PNGTS Continent to Coast ("C2C")	TGP/KM Northeast Energy Direct ("NED")
Project size, dekatherms per day ("Dth/d")	[redacted]	[redacted]	[redacted]
Size of ECRC offered, Dth/d	[redacted]	up to 200,000	[redacted]
Will it go forward without ECRC?	Yes, if PUC approval for electric distribution utilities	[redacted]	[redacted]
Greenfield/Brownfield?	Brown	Brown	Green+brown
Assumed in-service date	[redacted]	[redacted]	[redacted]
Financial bid ($ per Dth/d)	[redacted]	[redacted]	[redacted]
Primary receipt point(s) corresponding to financial bid noted above	Mahwah, Ramapo	Wright	Wright
Minimum term (years) coresponding to financial bid noted above	[redacted]	15	[redacted]

[End Confidential]

LEI Regional Analysis at 8.

1. <u>Access Northeast (ANE)</u>

ANE is primarily a brownfield project that will use the Algonquin mainline as well as portions of the M&NP to deliver gas to the region. The ANE project also includes changes to the mainline as well as to laterals to accommodate the use of LNG during peak periods. The project is composed of 500,000 Dth/day of pipeline and compression expansion and 6.8 Bcf of new LNG liquefaction and storage. LEI Regional Analysis at

[15] Figure 1 does not contain the LEI corrections relating to the minimum term of one of the ECRC bid proposals that was reflected in LEI's response to ODR-24-06.

17. **[Begin Confidential]** [redacted] **[End Confidential]** Pipeline gas would be purchased by the shipper, presumably during the injection season or when it is less expensive than in the winter. The LNG facility will liquefy and store gas, which will be vaporized and transported by the pipeline system to generators during periods when pipeline utilization is high and constraints on the system exist. Spectra Br. at 32.

Spectra offers Mahwah/Ramapo as the primary receipt point, as well as Brookfield as a secondary option. Brookfield intersects with the Iroquois pipeline south of Wright. Mahwah and Ramapo are interconnected with systems that deliver gas from the Marcellus region. Algonquin interconnects with Tennessee Gas Pipeline at Mahwah and interconnects with the Millennium pipeline at Ramapo. The pricing at Mahwah/Ramapo is generally considered to be equivalent to pricing at TETCO M3, which is a widely-traded and transparent hub. December 14, 2015 Spectra Supplement to ANE Proposal at 32.

Primary delivery points are four proposed power plant aggregation areas. (See Figure 2 below). ANE includes expansion of laterals on which certain generators are located, which are designed to help overcome "last-mile" deliverability issues identified by Spectra.

Figure 2 **[Begin Confidential]**

Figure ; Northeast primary delivery points

[redacted]

Source: Spectra. MPUC Docket No. 2014-00071. File No. 215. "Proposal for an Energy Cost Reduction Contract" submitted to the Maine Public Utilities Commission. December 5, 2014.

[End Confidential]

The type of service offered by ANE is Firm Transmission (FT), but it also includes firm "no-notice" service with non-ratable delivery rights. By its design, ANE is intended to provide FT to generators at all times, particularly at peak times when the generators might not otherwise have access to gas on a firm basis. Spectra Br. at 37. **[Begin Confidential]** [redacted] **[End Confidential]**

2. Continent to Coast (C2C)

The PNGTS C2C project is a brownfield expansion of PNGTS' existing natural gas system. The project can provide access to the Marcellus and Utica supply via the TransCanada Pipeline (TCPL) system and/or the Iroquois system, depending on the receipt point chosen. December 4, 2015 PNGTS Update to ECRC Proposal at 6. C2C includes three receipt point options: Dawn, Ontario; Niagara/Chippawa, Ontario; and, Wright, New York. Delivery points can be in New Hampshire or Maine, or as far south as Dracut, Massachusetts, using the Joint Facilities shared by PNGTS and M&NP. As stated in its updated proposal, the PNGTS project can provide volumes up to the 200,000 Dth/day. *Id.* at 10.

The C2C project does not involve any construction on the PNGTS system or the Iroquois system. However, as noted by PNGTS, "all three routes would necessitate some modifications around Montreal. The Dawn-to-Maine and Niagara/Chippawa-to-Maine routes would also require expansion from the Parkway to Maple points around Toronto." *Id.* at 25. These upgrades are designed to help remove bottlenecks on the TCPL system that PNGTS relies on to provide it with gas. PNGTS needs TCPL to make improvements on its system to boost pressure and flow into the PNGTS receipt point at Pittsburgh, New Hampshire. PNGTS estimates it will take between 2 to 3 years to complete the necessary expansion work required for its project. *Id.* at 10.

As noted above, the C2C proposal offers three receipt points: Dawn, Niagara/Chippawa, and Wright. Speaking to the relative merits of each receipt point, the OPA notes that not only does Dawn have access to underground gas storage facilities, it "provides access to one of the most liquid points in North America, as well as access to gas from the Marcellus, the Mid-Continent and other supply basins." OPA Br. at 20.

The Niagara/Chippawa hub is an export point from the U.S. to Canada. For either Dawn or Niagara/Chippawa to be a receipt point, gas has to flow to the Quebec/New Hampshire border on the TCPL system, as well as past the constrained Iroquois Waddington hub. For either of these receipt points, PNGTS is able to offer a negotiated fixed rate for the PNGTS downstream path. However, the TCPL path upstream of PNGTS is only available at the tariff recourse rate, which is regulated by the National Energy Board of Canada.

The Wright receipt point lies at the intersection of the Iroquois pipeline and the TGP 200 pipeline in New York. At the current time, Wright is not a widely-traded hub, so transparent pricing information for Wright is lacking.

If Wright were chosen as the receipt point, access to Marcellus at Wright may be dependent on the now-delayed Constitution pipeline project. Spectra Br. at 84. Unlike the other two options offered by PNGTS, a negotiated fixed rate is available for all three paths (TCPL, IGTS, PNGTS). *Id.* at 12.

C2C offers a variety of delivery points on the PNGTS system in New Hampshire, Maine, and Massachusetts. The FT rates offered in the proposed ECRC refer to primary delivery to Westbrook. However, because it is a postage stamp rate,[16] the rate also would apply to delivery points along the PNGTS and M&NP Joint Facilities as far south as Dracut, Massachusetts.

Finally, C2C offers FT "ratable" service, which means that service is delivered in each hour at 1/24th of the daily scheduled quantity.

B. Benefit - Cost Analyses[17]

1. LEI Regional Analysis

a. Description of Analysis

As noted above, in this phase of the proceeding, LEI evaluated the benefits and costs of the ECRC proposals as part of a regional or multi-state effort to expand natural gas pipeline capacity into and within the region. Given this analytical framework, Maine was assumed to take on a smaller share of a larger project compared to the earlier approach in which Maine was the only state paying for an ECRC, the benefits of which accrued to all states in the region. LEI analyzed each of the proposals as supplemented by the bidders in their December 2015 submissions.

In its Regional Analysis, LEI created two baseline scenarios: one included a generic LNG export facility in Eastern Canada (LNG Export Scenario) and the other did not (No LNG Export Scenario). As noted by LEI, several LNG export projects have been proposed, and although LNG exports from Eastern Canada are not certain, they have the potential to materially affect gas prices in the region. In addition, in the LNG Export Scenario, LEI assumed that the LNG facility does not contract for FT on an incremental pipeline project. The modeling of this scenario has little to do with one's expectation of whether or not an LNG export facility is likely to be built in Atlantic

[16] A postage stamp rate is uniform across delivery points.

[17] In addition to the LEI, CES, and Brattle analyses discussed below, other analyses and reports authored by firms such as ICF, Analysis Group, Black & Veatch regarding the benefits of incremental pipeline capacity in the region have been offered for consideration by the Commission in this case. IECG Br. at 6; OPA Br. at 8; RENA Br. at 12, 16; Spectra Br. at 9, 70, 76. Because the authors of these analyses and reports were not presented as witnesses in this proceeding, neither the Commission nor any of the parties have had the opportunity to conduct discovery on these analyses and reports nor test the underlying methodologies and assumptions. Accordingly, the Commission places limited weight on these studies and reports.

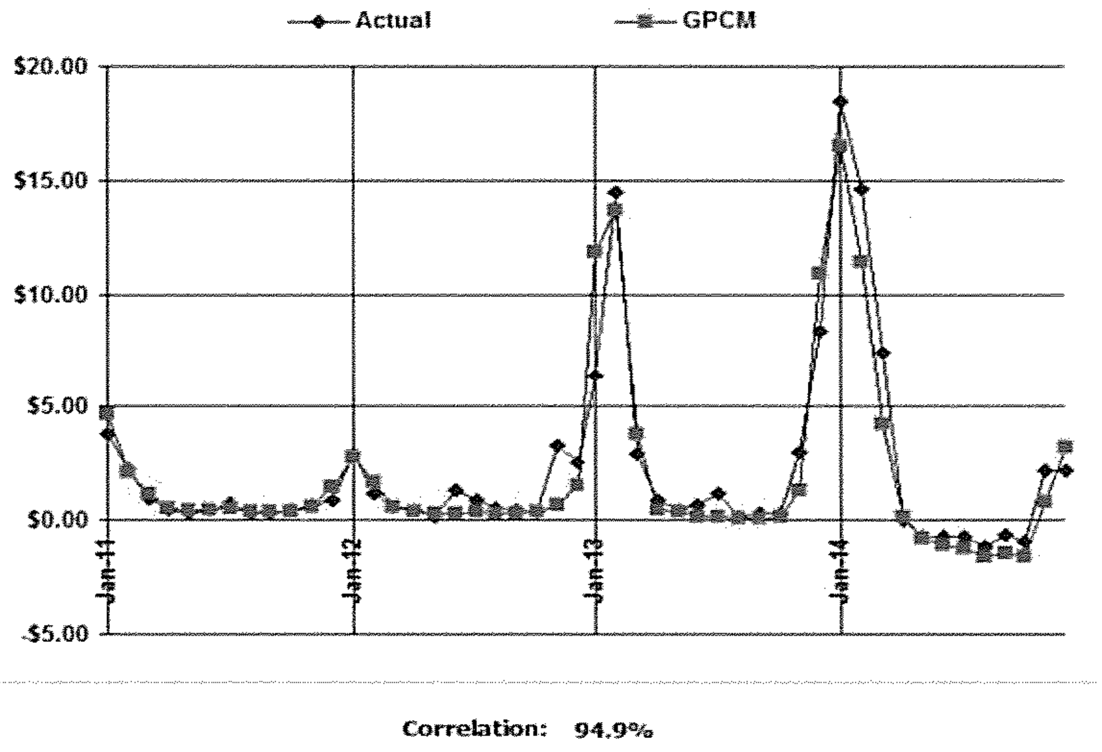
Canada and additionally whether such a facility would be built without a firm pipeline transportation contract. Rather, the scenario models what effects a significant but variable price sensitive source of gas demand, without a corresponding firm transportation contract, might have on regional gas pricing. LEI characterized the two scenarios as "bookends" to enable the Commission to examine the potential net benefits of the ECRC proposals under a broad range of potential future market conditions. March 24, 2016 Tr. at 121.

After the LEI Regional Analysis was conducted, the NED project announced its cancellation. The cancellation of the NED project has two effects. First, it eliminates that project from consideration for an ECRC. Second, it raises issues about LEI's Regional Analysis and results, given that both of LEI's baseline scenarios included 552 MMcf/day of supply associated with then-existing contractual commitments with the NED project.

To model gas prices, LEI used GPCM, which is a widely-used integrated network model of the North American natural gas market. As described in LEI's Regional Analysis, GPCM is based on pre-programmed supply curves, demand curves, and pipeline and storage tariffs and capacity. LEI Regional Analysis at 56. Using these inputs, GPCM projects gas prices for supply-area and market-area hubs. GPCM's solution algorithm searches for the lowest-cost path to meet gas demand, given supply costs and variable pipeline costs.

In most cases, the market price of gas is capped by GPCM at a given multiple of the FERC-approved pipeline maximum rates. However, for about 16 pricing points in the Northeast, including the Algonquin Citygate, prices are not capped. The uncapped pricing points have exhibited very high price spikes in recent years, and GPCM has a calibration process that allows the model to reflect this observed historical trend and apply it to future conditions. GPCM's backcast of Algonquin Citygate prices shows that the price spiking model captures historical trends fairly accurately (see Figure 3).

Figure 3. GPCM backcast of Algonquin Citygate prices



LEI Regional Analysis at 59.

Using the natural gas prices from GPCM, LEI then used its proprietary simulation model, POOLMod, to forecast New England wholesale electricity prices through 2030. POOLMod simulates the dispatch of generating resources in the market using least cost dispatch principles to meet projected hourly load, given technical assumptions regarding generation operating capacity and availability of transmission.

To replicate economically rational entry and retirement decisions, LEI simulated the energy and capacity markets on an integrated basis. LEI tracks the profits that existing and new entry capacity are projected to earn over time. These profits are then evaluated in conjunction with projected capacity prices in order to assess the need for economic retirement. Similarly, potential energy market and capacity market profits, as modeled, are compared to the breakeven prices required of new entrants, in order to simulate economic new entry. New entry and retirement decisions are then accounted for in both the capacity and the energy market simulations.

Based on its analysis, LEI concluded that, in the LNG Export Scenario, all of the ECRC project proposals would have positive net benefits to Maine, i.e. that project benefits were greater than the project costs. See Figure 4 below. In the No LNG Export Scenario, LEI found that none of the ECRC proposals would have benefits to Maine that were greater than their costs. LEI noted that the larger projects had larger net benefits as well as the potential for larger net losses. LEI Regional Analysis at 51.

LEI based its analysis on the primary evaluation criteria established by the Commission in its Phase 1 Order, which are net benefits to Maine gas and electricity ratepayers. Benefits included gas price benefits to Maine gas customers; electric energy price benefits to Maine electricity customers; and any additional cost-mitigating impacts, for example, the market value associated with the resale of the contracted pipeline capacity driven by incentives for arbitrage.

Consistent with the Phase 1 Order, the project benefits were measured only over 10 years, while the costs were to be measured over the proposed term of each ECRC.

The results of LEIs analysis are summarized in Figure 4 below.

Figure 4 **[Begin Confidential]**

Summary of ECRC Proposals
Benefits and Costs are NPV, 2016$ Millions
(LEI Corrected Calculation for ANE)

	ANE	C2C Niagra	C2C Wright	C2C Dawr
ECRC Parameters				
Size of regional project (Dth/day)	[redacted]	[redacted]	[redacted]	[redacted]
Maine' share @ 9% (Dth/day)	[redacted]	[redacted]	[redacted]	[redacted]
Reservation rate ($/Dth)	[redacted]	[redacted]	[redacted]	[redacted]
Term (yrs)	[redacted]	[redacted]	[redacted]	[redacted]
Contract cost (annual)	[redacted]	[redacted]	[redacted]	[redacted]
Contract cost (NPV)	[redacted]	[redacted]	[redacted]	[redacted]
No LNG Export Scenario				
Benefits	[redacted]	[redacted]	[redacted]	[redacted]
Benefit-cost ratio	[redacted]	[redacted]	[redacted]	[redacted]
Net benefits	[redacted]	[redacted]	[redacted]	[redacted]
Net benefit-cost ratio	[redacted]	[redacted]	[redacted]	[redacted]
LNG Export Scenario				
Benefits	[redacted]	[redacted]	[redacted]	[redacted]
Benefit-cost ratio	[redacted]	[redacted]	[redacted]	[redacted]
Net benefits	[redacted]	[redacted]	[redacted]	[redacted]
Net benefit-cost ratio	[redacted]	[redacted]	[redacted]	[redacted]

[End Confidential]

LEI corrected calculation for ANE from ODR-024-006.

Benefits and costs are measured asymmetrically, as per the Phase 1 Order in this proceeding. Benefits are counted for the first 10 years of a project, and discounted to the present. Project costs are counted for the life of the project ("Term") and discounted to the present.

b. Critique

Several parties offer critiques of the LEI Regional Analysis that range from it being fatally flawed to it providing a useful basis for evaluating the ECRC bid proposals.

Spectra argues that the LEI Regional Analysis underestimates several key aspects required for a useful analysis. Specifically, Spectra asserts that LEI's calculation of benefits fails to account for added reliability that additional pipeline capacity and the ability to support "fast-start" natural gas generation capability can provide to reliable grid operations. Spectra Br. at 44. Spectra also raises concerns related to several elements within LEI's Regional Analysis which, Spectra contends, understates wholesale electric prices. These include: (1) the use of average monthly gas prices rather than hourly prices; (2) availability of LNG during constrained hours; and (3) an under-representation of oil. *Id.*at 50. Spectra believes the results of the LEI Regional Analysis are not reflective of the value additional pipeline capacity would provide to the region.

The IEGC also raises several concerns with the LEI Regional Analysis. First, the IECG notes that the LEI Regional Analysis includes the NED project in the base case, and asserts that, now that the NED project is not moving forward, the results of the LEI analysis are no longer reliable. IECG Brief at 3. Second, IECG agrees with Spectra that LEI's reliance on monthly, rather than daily prices, diminishes the price effects of peak periods and also biases the results in a manner which understates the impact on prices by -2 to +5%. *Id.* at 13. Finally, IECG argues the LNG supply curves used by LEI are not substantiated and should not be used. *Id.* at 10.

The OPA also argues that because of the cancellation of the NED project, neither of the LEI scenarios in its Regional Analysis are representative of a possible future. OPA Br. at 9. However, the OPA concludes that the loss of supply from the NED project in the base case is generally offset by the demand from an unlikely LNG exporter such that the LNG Export Scenario can be used as a useful framework for evaluating the impact of changes in the supply/demand balance in New England. *Id.* at 11.

RENA agrees that the cancellation of the NED project does not invalidate the LEI analysis. RENA Br. at 13. However, this is due to RENA's belief that the LDCs that contracted with the NED project will be required to identify alternative supply sources. As a result, the LEI base case (No LNG Export Scenario) is still a valid reference point for the Commission to consider. *Id.* However, RENA maintains the LNG Export Scenario as modeled by LEI is unrealistic because a large export facility with limited access to supply would not go forward without firm capacity. *Id.* at 14. For these reasons, RENA claims that LEI's No LNG Export Scenario is the only viable analysis in the case. *Id.* at 17.

2. CES

a. Description of Analysis

In early 2013, the IECG retained CES to undertake a study of natural gas supply and prices in New England. CES completed its initial study in March 2013 and issued an internal report to the IECG on April 5, 2013. That study was attached as an exhibit to the Direct Testimony of Richard Silkman and Mark Isaacson of CES in Phase 1 of this proceeding (CES 2013 Report). Silkman/Isaacson Direct Testimony at 9. CES issued an updated report to the IECG on February 7, 2014 titled "Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices" (CES 2014 Report) that was also attached as an exhibit to the CES testimony. *Id.* at 12. The most recent version of the CES model was attached as Exhibit 1 to the February 22, 2016 Direct Testimony of Dr. Silkman on behalf of the IECG.

In its most recent analysis, CES modelled generic pipeline expansions in increments of 0.2 Bcf/day. IECG Exhibit 1 at 19. CES determined the value of the incremental pipeline capacity by deriving hourly demands for natural gas by generators using the output of a dispatch model for the ISO-NE region. CES relied on actual hourly generation by unit (fuel) type during a single historic year (calendar year 2013), as reported by ISO-NE, and CES' assumptions about the heat rate of the units. The outputs of the CES model are the capacity of each type of unit operating, the amount of natural gas required to power the units that are operating, and the characteristics of the unit that is operating at the margin and therefore setting the clearing price in New England. CES Exhibit 2 at 11. When the fuel requirements for natural gas generators exceed the amount of available pipeline capacity, CES assumed that the next units dispatched would be fueled by LNG, propane, or oil at prices estimated by CES. Thus, the LNG, propane, and oil prices were inputs to the model. *Id.* at 13. According to the IECG, the CES analysis indicates that the ANE project would provide net savings to the region of $1.37 billion per year. IECG Br. at 2.

b. <u>Critique</u>

In Phase 2 of this proceeding, certain parties have commented that the Commission should not rely on the CES studies as a basis for moving forward. For example, RENA argues that:

> The conclusions reached by CES are driven by hard-wired assumptions for fuel prices which are unrealistic and not representative of the ways in which these prices are formed in the actual markets, vastly overstating the benefits of expanded pipeline capacity ....The CES study looks at the market as both price inelastic and fixed, which fails to account for the dynamic nature of the gas and electric markets in New England....It should not be relied upon as the Commission formulates their opinion with respect to the issues currently before it.

RENA Br. at 16.

The OPA noted that "[w]hile the CES approach has provided a useful and informative framework for conceptualizing the region's need for additional gas pipeline capacity... the assumptions used in the analysis likely overstate the electricity price reductions associated with additional capacity." OPA Br. at 8-9. The OPA further notes that "[t]he LNG and oil prices used in CES' modeling do not reflect current or expected near-term market conditions" and "the effect of these inflated LNG prices is to overstate the impact and projected benefits of additional pipeline capacity." *Id.* at 21.

LEI expressed similar concerns regarding the CES analysis. LEI notes that the CES methodology is static and that gas supply, demand, and price are all treated as input assumptions, and are all fixed at given levels. LEI Rebuttal Testimony at 6. LEI asserts that the CES analysis is very sensitive to LNG price assumptions which, in its view, is unrealistic and does not reflect the way in which LNG is used in New England. *Id.* at 8. In addition, LEI states that CES does not account for the impact of changes to market rules. *Id.* at 14. LEI concludes that the CES analysis likely overstates electric power prices and that this overstatement is likely to result in similarly overstated benefits from incremental pipeline capacity. *Id.* at 15.

3. Brattle Curve

a. Description of Analysis

The OPA provided a curve (Brattle Curve) developed by its consultant, the Brattle Group, that "attempted to derive an overall relationship between Algonquin City Gate prices and changes in net supply, based on the scenarios modeled by LEI throughout this proceeding." OPA Br. at 11. The Brattle Curve was first presented by the OPA at the March 16, 2016 technical conference and used primarily in the questioning of the LEI witnesses during the April 28, 2016 hearing. Using the assumed levels of pipeline capacity and resulting natural gas prices for the winter of 2021/22 from various LEI scenarios, the Brattle Curve purports to establish a relationship between incremental pipeline capacity additions and gas prices. The shape of the Curve indicates that price reductions from capacity additions are the largest when supply is constrained, and that there are diminishing returns with each successive increment of new capacity.

b. Critique

In response to OPA's questions about the Brattle Curve, LEI witnesses identified several concerns regarding reliance on the Brattle Curve to evaluate the benefits of new pipeline capacity. First, LEI witnesses observed that the Curve is developed from point estimates from just a single winter period and drawn from different studies with different assumptions. April 28, 2016 Tr. at 174. Second, LEI witnesses explained that the scenario results used to develop the Curve are from model runs that have different demand drivers and supply drivers. *Id.* at 175. For these reasons, LEI witnesses indicated that the Brattle Curve was useful directionally, but did not provide a basis to determine actual price levels. *Id.* at 176.

4. Discussion

a. LEI Regional Analysis Provides a Reasonable Basis for Consideration of ECRC Proposals

The Commission notes that no modelling tool or technique is without flaws, and that the set of assumptions used by the analyst is likely to introduce further inaccuracies. This is particularly true for energy prices, which are inherently volatile and difficult to forecast accurately, and which are a function of physical and market conditions that are both complex and continuously changing. Thus, the specific dollar amounts that result from the LEI modeling should not be considered a precise outcome. However, the results of the modeling do provide an indication of the relative magnitude of the benefits that are likely to result from each ECRC proposal, and whether the benefits are reasonably likely to outweigh the costs. With this understanding of the usefulness and limitation of the modelling efforts, the Commission concludes that the LEI Regional Analysis is methodologically sound and provides a reasonable and conservative basis to evaluate the benefits of the ECRC proposals.

First, LEI's Regional Analysis is the only analysis that is consistent with the conservative methodology established in the Phase 1 Order, which requires that benefits be measured over the first 10 years and costs be measured over the full term of the ECRC. Moreover, the LEI Regional Analysis is also preferable to the alternative analyses because GPCM inputs are regularly re-calibrated to actual historical prices, which provides greater confidence that its projections will be reasonably accurate. With respect to this calibration feature, the Commission agrees with the OPA's observations that further confidence in the accuracy of GPCM is provided by the fact that the period against which the most recent calibration was done spans a large range of conditions, from mild conditions to very tight conditions in record-cold weather. OPA Reply Br. at 3. Finally, although the Commission generally agrees that LEI's use of monthly versus hourly averages understates expected benefits of an ECRC by removing some level of electricity price spikes that would likely occur during infrequent weather events, this result is consistent with our conservative approach to analyzing the ECRC proposals.

b. <u>CES and Brattle Curve Analyses</u>

The CES and Brattle Group analyses also provide useful information, but the limitations of these analyses should be recognized. In contrast to the LEI's Regional Analysis, which is a multi-year forward-looking analysis designed to simulate market conditions over time, the CES analysis is a 1-year backward-looking snapshot that fixes parameters, such as gas demand, gas supply and gas prices.

The Brattle Curve is a meta-analysis of selected result points from several scenario runs where the various gas capacity offerings were associated with price consequences calculated by the model for the region. These points as a scatterplot were overlaid with a simple cubic regression function in one variable only, that of gas capacity. The Brattle analysis did not control for any of the other numerous factors resulting in that price and quantity. However, the Brattle Curve is helpful in showing that there are plausible and reasonable patterns emerging from the LEI model, that being the diminishing marginal benefit to reducing regional gas price by adding firm capacity.

VI. MARKET EVENTS AND CONDITIONS

The following discussion summarizes market developments and market conditions in the region since the issuance of the Phase 1 Order.

A. Pipeline Expansion

During the pendency of this proceeding, there have been several pipeline expansion projects to increase capacity into and within the region that have been announced, including the three projects that were submitted as ECRC bid proposals in this case. The ANE and C2C bid proposals are discussed in Section V above. As noted above, the third ECRC bid proposal, the NED project, has been cancelled. In addition to these three projects, the Commission has been monitoring developments regarding the following projects in the region.

1. TGP Connecticut Expansion Project

On March 11, 2016, FERC issued a Certificate of Public Convenience and Necessity to TGP for the Connecticut Expansion project. The TGP Connecticut Expansion project, which will provide 72,000 MMcf/day of additional pipeline capacity for the region, is expected to be completed in the fall of 2016.
http://www.kindermorgan.com/business/gas_pipelines/east/connecticut/

2. Algonquin Incremental Market (AIM) Project

The AIM project, which will provide an additional 342,000 MMcf/day of pipeline capacity for the region, is expected to be in service in November 2016.
http://www.spectraenergy.com/Operations/US-Natural-Gas-Operations/New-Projects-US/Algonquin-Incremental-Market-AIM-Project/

3. Atlantic Bridge Project

The Atlantic Bridge project, which will provide an additional 132,700 MMcf/day of pipeline capacity into the region, is expected to be in service in November 2017.
http://www.spectraenergy.com/content/documents/SE/Operations/US_NatGas_Ops/Projects-US/AtlanticBridge/AtlanticBridgeFactSheet.pdf This project will also allow the flow to be reversed on the M&NP, allowing gas to flow from south to north. There are currently subscriptions for 106,276 MMcf/day in the south-to-north direction on M&NP with capacity for an additional 294,000 MMcf/day that is currently unsubscribed. May 28, 2016 Tr. at 47.

4. Mainline Open Season

This is a proposed expansion by TCPL of its facilities with receipt points at Empress, St. Clair, Dawn, Kirkwall, Niagara Falls, Chippawa, Parkway, and Iroquois. No delivery points other than those along the existing system are proposed. An open season was conducted between November 29, 2013 and January 15, 2014. There is no further information on this project in the record.

B. Market and Rule Changes

Subsequent to the Phase 1 Order, the Commission has also been monitoring changes to regional market rules and related processes,[18] as well as other regional initiatives. These are summarized below.

1. Pay for Performance (PFP)[19]

PFP is a change to the ISO-NE forward capacity market (FCM) rules that took effect after issuance of the Phase 1 Order in this proceeding. The PFP program, by design, is a reliability program, not a program that is intended to address cost. PFP provides incentives and penalties for performance or non-performance by generators during system shortages, or "scarcity events." These incentives and penalties are intended to provide incentives for generators to be available and to operate during these periods. The results of the two forward capacity auctions (FCA) conducted since the PFP rule changes took effect, FCA 9 and FCA 10, suggest that the changes may be having an effect that better assures reliability, but such changes have not consisted of natural gas generators acquiring pipeline capacity on a firm, long-term basis. For example, FCA 9 resulted in a new 725 MW natural gas combined cycle unit with duel-fuel capability and FCA 10 resulted in three new duel-fuel generators with a total capacity of 1,302 MW. http://www.iso-ne.com/static-assets/documents/2015/02/fca9_finalresults_final_02272015.pdf http://www.iso-ne.com/static-assets/documents/2016/02/20160211_fca10_initialresults_final.pdf. Dual-fuel capability enables a gas generator to operate using an alternative fuel, most notably, oil, when natural gas is either unavailable or expensive. Thus, although PFP appears to be addressing its intended target concerns about reliability, it will not also resolve the problems of high price levels and volatility in the ISO-NE market that result from infrastructure constraints.

2. Energy Market Offer Flexibility

Energy market offer flexibility changes to the ISO-NE market system, which became effective in December 2014, are designed, in part, to facilitate participation by gas generators in the energy market by allowing them to update their bids after their gas prices are known. Prior to these changes, because of timing differences between the markets, generators had to submit final bids to the ISO before knowing the actual price they would pay for gas. http://www.iso-ne.com/static-assets/documents/2014/12/emof_final_12182014.pdf

These changes enable generators to adjust their bids to reflect any changes in gas prices that may have occurred between the time they bid and the time that they purchase their gas supply. The desired effect of these changes is to improve reliability and reduce risk premiums that might otherwise have been included in the bids.

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[18] The Commission regularly monitors and participates in ISO Reliability, Market, and Planning Advisory Committee meetings.

[19] PFP is intended to replace the existing ISO-NE Winter Reliability Program.

However, these changes are not expected to have a material effect on overall price levels or price volatility.

3. Gas Market Scheduling Changes

In the Phase 1 Order, the Commission discussed FERC's institution of a North American Energy Standards Board (NAESB) consensus forum that would harmonize gas and electric industry scheduling processes. Phase 1 Order at 26-7. In April 2015, FERC released a final rule adopting NAESB recommendations that revises FERC's regulations to better coordinate scheduling between wholesale natural gas and electricity markets. http://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf Changes include moving the nomination deadlines for scheduling gas transportation to later in the day and incorporating an additional intraday scheduling opportunity. These changes are intended to allow for more efficient use of existing facilities, which may mitigate the need for capacity expansions to some degree but cannot be expected to address the overall issue of pipeline constraints in the region. Phase 1 Order at 27.

4. Clean Energy RFP

On November 12, 2015, the Connecticut Department of Energy and Environmental Protection, the Massachusetts Department of Energy Resources, Eversource Energy, National Grid, and Unitil issued a Request for Proposals for electricity projects to further the clean energy objectives of the states of Massachusetts, Connecticut and Rhode Island. (Clean Energy RFP). Several proposals have been received and are undergoing evaluation. https://cleanenergyrfp.com/.

The Clean Energy RFP has the potential to result in significant new renewable energy being added to the ISO-NE market. However, at this point, there is substantial uncertainty regarding the potential outcome of the Clean Energy RFP and whether the result will be significant additional generation resources that do not rely on natural gas. Nonetheless, LEI's baseline modeling assumed the addition of 1000 MW of resources through a DC intertie.

VII. ACT REQUIREMENTS AND DECISION CRITERIA

As discussed in Section II(A) above, the Act specifies that, prior to the execution of an ECRC, the Commission shall: (1) pursue market and rule changes that would increase the efficiency with which gas is transmitted into the region and have substantially the same cost reduction effects as an ECRC; (2) explore all reasonable opportunities for private participation in securing additional pipeline capacity that would have substantially the same cost reduction effects as an ECRC; and (3) hire a consultant to make recommendations regarding an execution of an ECRC. In the Phase 1 Order, the Commission found that these prerequisites were satisfied. Phase 1 Order at 31. However, with respect to market rules and private participation, the Commission stated that, during Phase 2, it would continue to monitor and assess the effects of potential market rule changes, private investment and regional efforts, and would include developments in these areas in its evaluation of ECRC proposals. *Id.* at 37.

The Act further requires that an ECRC must be commercially reasonable, in the public interest and reasonably likely to: (1) enhance pipeline capacity into Maine or the region that will be economically beneficial to ratepayers such that costs are outweighed by benefits and (2) enhance reliability in the State. In the Phase 1 Order, the Commission found that any enhanced pipeline capacity into the region would have the corresponding result of increasing physical system reliability and, thus, the requirement would necessarily be satisfied by an ECRC. *Id.* at 32. Therefore, the primary issues before the Commission at this point in the proceeding are: (1) whether the statutory prerequisites continue to be satisfied and (2) whether it is reasonably likely that the benefits of a proposed ECRC from lower and less volatile natural gas and electricity prices will outweigh the costs.[20]

The Commission explicitly recognized in the Phase 1 Order that, as is the case whenever considering long-term investments and forecasts of energy prices, there is a significant degree of uncertainty which requires the Commission to act conservatively and consider whether an ECRC is cost-beneficial over a broad range of possible futures. Accordingly, the Commission specifically noted that its primary evaluation criteria will be the net benefits to Maine ratepayers through an examination of proposed ECRCs under a range of potential future market conditions to ensure that the benefits of an ECRC are "robust", given the uncertainty inherent in any forecast of future market conditions.[21] *Id.* at 40.

Moreover, in recognition of the inherent uncertainty in projecting energy prices 20-25 years into the future, and the risk that inaccurate projections would result in substantial costs to ratepayers, the Commission adopted a conservative evaluation criteria that would require any ECRC to provide net benefits calculated by comparing the net present value of benefits over the first 10 years of the ECRC with the net present value of the cost of the ECRC over its full term. The Commission noted that this approach is equivalent to applying a higher discount rate to the benefits and represents an appropriately conservative evaluation approach. *Id.* at 41.

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[20] The Commission noted in the Phase 1 Order that the Act did not intend that the Commission conduct an examination of the relative cost-effectiveness of alternative solutions. Phase 1 Order at 34. The Commission, recognized, however, that the possibility and likelihood of other actions or events, such as non-ECRC financing of new pipeline, conservation, efficiency, or increased use of LNG and oil, all must be considered in determining whether an ECRC is warranted.

[21] This approach of examining various future scenarios using relatively conservative assumptions is the same as Commission evaluations of other long-term ratepayer investments, such as long-term contracts for electricity and energy efficiency programs. Part 1 Order at 30.

VIII. DISCUSSION AND DECISION

The Commission concludes, as it did in the Phase 1 Order, that the statutory prerequisites for the execution of ECRC have been satisfied. Moreover, for the reasons discussed below, the Commission concludes that the ECRC proposals presented in this proceeding satisfy the requirements of the Act in that they are commercially reasonable, in the public interest, and reasonably likely to have economic benefits to ratepayers that outweigh their costs.

A. Statutory Prerequisites

As stated in the Phase 1 Order, the Commission has continued to monitor and assess the effects of potential market rule changes, private investment, and regional efforts on future pipeline development. With respect to such market and rule changes, there appears to be little dispute in the record that recent changes will not result in private participants,[22] particularly natural gas generators, making long-term commitments for pipeline capacity.[23] Accordingly, the Commission concludes that the statutory prerequisites continue to be satisfied.

B. Commercial Reasonableness

The Commission concludes that the terms of the ECRCs, as currently proposed, are consistent with industry practice and are commercially reasonable. It is important to note that any precedent agreement that results from this proceeding will be in compliance with FERC regulations which ensure reasonableness and non-discrimination.

C. Public Interest

An ECRC that satisfies the goals and the requirements of the Act and is reasonably likely to be cost beneficial to ratepayers is in the public interest. This is especially the case in light of the market dynamics and consequential market failure discussed in Section VIII(E) below that result in the lack of an incentive for economic investment in pipeline capacity by generators or other private participants that would benefit electric and natural gas ratepayers. This market dynamic further supports the conclusion that State action to remedy the detrimental effect on consumers caused by the market failure is in the public interest.

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[22] As discussed in the Phase 1 Order, the Commission does not view LDC long-term commitments for pipeline capacity to serve their customers' demand to be "private participation" within the meaning of the Act. Such precedent agreements are executed based on Commission approval with the understanding that the costs are prudent and recoverable from ratepayers.

[23] The market conditions and dynamics that make it unlikely that natural gas generators will invest in new pipeline capacity are discussed in Section VIII(E) below.

D. Net Benefits Discussion

As noted above, in the Phase 1 Order, the Commission specified that, due to the significant degree of uncertainty inherent in any long-term forecast of future market conditions, it would act with conservatism by evaluating the costs and benefits of proposed ECRCs over a broad range of market conditions. Phase 1 Order at 40. The Commission indicated that it would approve an ECRC only if the benefit/cost analysis concluded that ratepayer benefits were "robust" under a variety of future assumptions. *Id.* Based on the net benefit analyses presented in this case, the benefits of both the ANE and C2C ECRC proposals are robust and are reasonably likely to outweigh the costs under a variety of future scenarios.

1. Benefit/ Cost Analysis

The benefit/cost analysis required under the Act is a difficult undertaking. The commitment for pipeline infrastructure is long-term which requires modeling of likely benefits in distant years. The analysis is further complicated by the fact that there is a greater degree of certainty about the cost of an ECRC than there is about the benefits. The cost is determined by the reservation rates detailed in each of the ECRC proposals. Although, there is some degree of uncertainty regarding these rates,[24] it is bounded to a greater degree than the uncertainty associated with the benefits. The benefits of each of the ECRC proposals are more difficult to accurately quantify because of the number of variables involved and the associated uncertainty, such as those related to supply and demand interactions in the applicable domestic markets, as well as in the world markets for oil and LNG.

The Commission also notes that, in deciding whether to move forward with an ECRC proposal, the potential cost of inaction should also be considered. Shortage of pipeline capacity has already cost Maine electricity customers hundreds of millions of dollars over the last few winters.[25] Accordingly, it is important to emphasize that, although the cost of the proposed ECRCs – a dollar outlay – is known and real, the potential costs of not acting are just as real, even if the calculation of such costs cannot be done with certainty.

2. LEI Modelling Results

As described above, LEI provided two modelling scenarios referred to as: (1) the LNG Export Scenario and (2) the No LNG Export Scenario. LEI has referred to these two scenarios in the 2016 analysis as bookends with one bookend showing benefits that exceed costs and the other bookend showing costs that exceed benefits. For the

[24] **[Begin Confidential]** [redacted] **[End Confidential]** The rate associated with the TransCanada portion of the C2C proposal may be changed by the Canadian National Energy Board. The PNGTS rate is subject to some change based on the actual cost of the project.

[25] See OPA August 22, 2014 Phase 1 Br. at 10-17.

reasons discussed below, the Commission concludes that the LNG Export Scenario provides a reasonable and conservative proxy for likely future scenarios and that the results of the No LNG Export Scenario run should be substantially discounted.

a) No LNG Export Scenario

The results of the No LNG Export Scenario show that the costs of the ECRC proposals will be greater than the ratepayer benefits. However, as discussed further below, the assumptions underlying the LEI scenario analysis are, in general, conservative and the No LNG Export Scenario, in particular, has a significant flaw that limits its relevance in the overall cost/benefit analysis. In particular, this scenario includes 552 MMcf/day of capacity associated with the NED project. This capacity represented contractual commitments between NED and various entities, most notably natural gas LDCs, at the time the analysis was conducted. However, subsequent to the analysis, the NED project was cancelled. Thus, under LEI's methodology, this capacity would not be included in the base case because it is no longer a committed project.

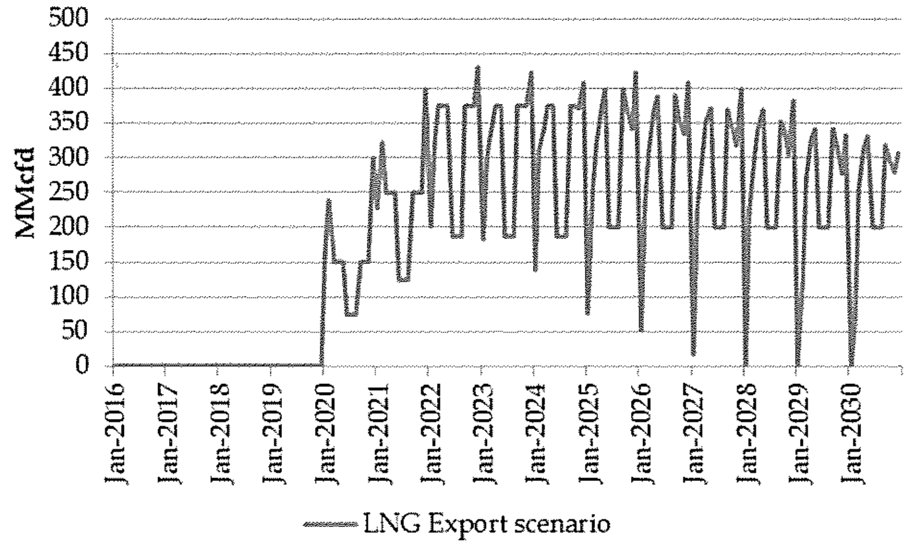
Although there is some possibility that LDCs and other entities that had contracted for capacity on NED will contract for pipeline capacity on other newly developed projects, such an assumption must be considered speculative at this point. Further, this scenario does not account for the fact that gas-fired generation in the region is a demand that is not balanced by firm transportation on pipelines as is the case with most LDC loads. Therefore, given the overall conservatism generally built into the LEI analysis as discussed below, the speculative nature of any assumption regarding a NED replacement, and the lack of accounting for how gas-fired generation operates without firm transportation, the Commission concludes that the results of the No LNG Scenario must be substantially discounted.

b) LNG Export Scenario

The LEI LNG Export Scenario provides a reasonable basis to analyze the economics of the ECRC proposals. Although presented by LEI as a case reflecting the demand of an LNG Export facility not accompanied by any corresponding new pipeline capacity, the scenario may also be viewed more generally as depicting conditions in the regional market in which there is a significant amount of new, price-sensitive demand for natural gas that is not accompanied by new pipeline capacity. In particular, this scenario realistically reflects market conditions created by the expected entry of new natural gas generators which are unlikely to acquire firm pipeline capacity for the reasons discussed in Section VI above, and which would exhibit a similar demand pattern to that of LEI's modeling. Because gas generators for the most part do not have firm transportation, they bid into the energy markets based on the gas and transportation route they can secure the next day. When gas prices are high, a generator may switch fuels or bid at such a high rate that they will not be dispatched. This pattern of large, but variable and very price sensitive demand, is similar to that of the LNG facility modeled by LEI.

Figure 5

Figure Eastern Canada LNG export flows, LNG Export scenario



Price-Sensitive Demand Modeled by LEI

LEI Regional Analysis at 28.

Thus, the Commission will refer to this scenario as the "Price-sensitive Demand Scenario". In terms of quantity, the demand associated with the LNG facility as modelled by LEI ranged from about 225 MMcf/d in 2020 to about 425 MMcf/d in 2023, and then declined gradually through 2030. For the reasons discussed below, these demand quantities are coincidentally representative of the demand from potential new gas generation not modelled by LEI. Further, this scenario was modeled with the NED supply of 552 MMcf/day. As previously stated, this project was canceled.

First, the results of recent ISO-NE forward capacity auctions and expected generator retirements indicate that there will be significant additional demand from natural gas generators, much of which was not included in the LEI analysis. In particular, LEI included only 330 MW of new thermal capacity, presumably natural gas combined-cycle facilities, in 2019 (LEI's expectation for FCA 10) and assumed that there would be no new thermal capacity added in each of the next 5 years. LEI Regional Analysis at 63. However, shortly after the LEI analysis was completed, ISO-NE released the results of FCA 10 which included 1,300 MW of new natural gas generation receiving capacity supply obligations, in addition to the 1,700 MW that resulted from FCAs 7 – 9. February 29, 2016 ISO-NE Press Release: http://www.iso-ne.com/static-assets/documents/2016/02/20160229_fca10_finalresults.pdf. Thus, in light of the results of FCA 10, beginning in 2019 there will be about 1,000 more MW of new gas generation in the region than was assumed by LEI. Moreover, subsequent FCAs may have similar results to FCA 10, quite in contrast to the LEI assumption of no new gas capacity for the next 5 years.

Second, LEI expects there to be 2,245 MW of coal, oil, and nuclear capacity retired over the analysis period. LEI Regional Analysis at 63. In contrast, according to the February 2016 Regional Electricity Outlook of the ISO-NE, more than 4,200 MW of the region's coal, oil, and nuclear capacity has retired or plans to retire soon. In addition, the ISO-NE report describes as "at risk", an additional 6,000 MW of coal and oil-fired generators in the region. Furthermore, according to the ISO-NE, the retiring resources are likely to be replaced by natural gas generators. This difference between the level of retirements assumed by LEI and the retiring and "at risk" generation described by ISO-NE, and the differences in FCA results described above, indicate the potential for significant additional demand for gas from the power sector in the region compared to the LEI analysis. At the lowest end of the spectrum, if the only difference is from the known results of FCA10 relative to the LEI modelling (1,000 MW), this is equivalent to a demand of 180 MMcf/day. However, if additional gas generation results from FCA 11-16, an assumption that appears likely given the results of FCA 7-10, future plant retirements, and the expectation of the ISO-NE that much of the retired capacity would be replaced by natural gas generation, indicates that demand for natural gas from the power sector would approach, or exceed, the demand modelled by LEI in the LNG Export facility.

Finally, additional gas generation may result given the uncertainty of whether LEI's assumption that the Clean Energy RFP will result in the addition of 1,000 MW of renewable resources to the market will actually occur.

For all these reasons, the use of this Price-sensitive Demand Scenario provides a reasonable representation of future natural gas demand, and as such, it provides a reasonable basis to analyze the benefits of the ECRC proposals.

c) Benefit/Cost Modelling

As required by the Phase 1 Order, the LEI analysis compared 10 years of benefits against costs over the 15 or 20-year term of the ECRC. The Phase 1 Order recognized that this represents a conservative approach. As a result, the approach adopted by the Phase 1 Order, which is not typical in economic analyses, provides substantial comfort that the benefits are not likely to be overstated.

E. Market Dynamics Relating to ECRCs

1. Generators

Due to the dynamics of the electricity and natural gas markets, natural gas generators do not have an apparent economic incentive to secure or invest in pipeline capacity. This is in contrast to regulated LDCs that do make long-term investments in pipeline capacity based on planning requirements set or approved by regulators and expected cost recovery from their ratepayers.

Natural gas generators' profit margins are not a function of the cost of natural gas, but are based on the generator's heat rate (the amount of gas burned to generate a MWh of electricity) relative to the heat rate of the marginal generating unit which sets the uniform clearing price that is received by all generators in the region. This means that high gas prices are simply a pass through to the consumer, and generators are indifferent to the actual real-time cost to obtain natural gas supply. This situation is further complicated by the fact that many companies that own gas generation in New England also own other types of generation, such as nuclear and wind and, because such other plants are also compensated at the uniform clearing price set by the marginal unit, a reduction in the price of natural gas actually diminishes the profitability of the owners' non-gas resources.

2. Ratepayer Interests

As a consequence of these market dynamics, investment in pipeline capacity that would be economic and that would benefit electric and natural gas ratepayers may not occur without state action. In considering ECRC proposals, therefore, we must understand the ratepayers' unique position with respect to various future gas supply scenarios. The ratepayers' interest differs from typical investors in that, in contrast to typical investors that seek increased value of the investment, the desired outcome of an ECRC investment is a reduced value of the investment. This unique position of ratepayers should be considered under three basic future scenarios.

In the first scenario, if an investment in pipeline capacity has little or no value in the secondary transportation market for natural gas, this means that natural gas-fired generators are not paying a premium for transportation in addition to the commodity cost of gas to produce electricity. This is important because the New England electricity market clears each increment of generation on a uniform clearing price. If the clearing prices are high because of gas pipeline constraints, then every generator regardless of their fuel type collects the clearing price for that increment of time. The result is that, when gas transportation constraints exist, the resulting premium is multiplied across all the electric generation for that period of operation. This effect means that small and predictable decreases in gas forward pricing can have significant effects on reducing electric cost and volatility.

In the second scenario, the quantity of the pipeline capacity investment has a limited effect in the reduction in gas transportation costs. However, in this event, there would be a residual value for the investment which can be monetized in the secondary transportation market. In such a case, some benefit would accrue from the resale of the firm capacity in the secondary market and some benefit would accrue from the reduction in natural gas generators' transportation costs which again is multiplied across the electricity generation market.

A third scenario could theoretically exist in which the region is in an oversupplied state for natural gas. In that case, a purchase of pipeline capacity through an ECRC would have a known cost, but little or no value on the secondary gas transportation market. With respect to electricity, this would be a future in which natural gas generators are readily able to take advantage of excess capacity in the secondary spot market and, therefore, there would be little or no reduction in the uniform clearing price of the real-time auction and thus no real benefit. This scenario could result from significant excess pipeline capacity or low-priced alternative fuels, such as LNG or oil.

F. Regional Coordination

The Legislature recognized the potential importance of regional coordination in addressing the New England pipeline infrastructure issues by explicitly authorizing the Commission to contract jointly with other state entities. 35-A M.R.S. § 1904 (3)(B). As described above, the other New England states (with the exception of Vermont) are exploring electric utility participation in pipeline projects as a means to increase pipeline capacity into the region. The progress in the other states can either be bolstered by Maine's action or hindered by Maine's inaction. Thus, by moving ahead with an ECRC conditioned on other states' participation, Maine will take an important step to increase the likelihood of a regional solution that will result in ratepayer benefits and that equitably allocates both the benefits and costs of pipeline expansions across the region.

G. ECRC with Access Northeast[26]

As discussed above, the two ECRC proposals before us are reasonably likely to have benefits that outweigh their costs. However, for the following reasons, the Commission, at this time, decides to pursue a precedent agreement with the Access Northeast Project and not with the C2C project. This decision is based, to a significant degree, on our conclusion that ANE is more likely to succeed as a regional solution. By its design, the ANE project results in increased capacity for each New England State with the exception of Vermont. In addition, EDC commitments regarding the ANE project are currently the subject of proceedings in a number of states. Moreover, Connecticut and New Hampshire appear likely to move forward in considering EDC commitments with the ANE project in the near future. In addition to the regional interest in ANE, the net benefits associated with ANE, on a net present value basis, are about 1.7 times greater than the net benefits of the C2C proposals.[27]

Regarding the C2C project, the Commission has additional concerns that, although the cost of transportation would be established on the PNGTS system, there would be uncertainty regarding the reservation costs associated with transportation on TransCanada that may be changed by Canada's National Energy Board.

The Commission does recognize, however, that the ANE project may not come to fruition, or the conditions imposed by this Order may not be met. If either of these events occurs, the Commission may reconsider the C2C proposal and any related conditions regarding participation by other states.

At this point, however, the Commission concludes that the best path forward for Maine and the region is to proceed with negotiations to finalize a precedent agreement with Access Northeast for 81,000 MMcf/day, or 9% of the project, whichever is less, consistent with Maine's load share in the ISO-NE market, conditioned on the other New

[26] Commissioner McLean dissents from this recommendation.

[27] Additionally, if the benefits of the project are expanded to an equivalent period of the costs, the net benefits associated with ANE, on a net present value basis, would be about three times greater than the net benefits of the C2C proposal.

England states, with the exception of Vermont, participating in the ANE project for a minimum quantity equal to their respective load shares. Based on a purchase quantity of 81,000 MMcf/day, and the reservation charge in the ANE proposal, the annual cost to Maine of the ANE ECRC will be approximately **[Begin Confidential]** [redacted] **[End Confidential]**, well within the statutorily-authorized $75 million.

H. <u>Next Steps</u>

The Commission may initiate a process to develop a precedent agreement regarding the Access Northeast project to be entered into by one or more of the State's T&D utilities depending on the status of regional actions. The initial discussions and negotiations of a precedent agreement will include Spectra, Commission Staff, and the contracting utility or utilities. After these discussions and negotiations are concluded, the precedent agreement will be subject to review and comment from the OPA and the applicable utilities.

Finally, the statute requires the Governor's written approval prior to executing any precedent agreement. Our process going forward will comply with this statutory requirement. The Commission may also opt to inform the Governor of the majority and dissenting opinion and the status of negotiations.

IX. CONCLUSION

For the reasons discussed in this Order, the full Commission concludes that the ECRC proposals presented in this proceeding satisfy the requirements of the Act. The majority of the Commission concludes that the ANE project, in the context of participation by other states in New England, would provide greater ratepayer benefits than the C2C proposal. Therefore, the Commission decides to move forward with negotiation of a precedent agreement with ANE for Maine's 9% load share conditioned upon comparable precedent agreements with ANE and other New England states.

Dated at Hallowell, Maine, this 14th day of September, 2016.

/s/ Harry Lanphear

Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR:	Vannoy Williamson	
	McLean	Concurring in part and dissenting in part. See attached Dissenting Opinion

OPINION OF COMMISSIONER MCLEAN CONCURRING IN PART AND DISSENTING IN PART

I concur with the majority on several threshold issues in this case. I agree that each of the ECRC proposals presented in this proceeding satisfies the statutory requirements for acceptance. I concur that neither market developments and rule changes nor private participation in securing additional pipeline capacity will address the energy price and infrastructure concerns that are specifically identified in the Act. I agree that both the C2C project and the ANE project are commercially reasonable, in the public interest, and reasonably likely to increase pipeline capacity into the region. I also agree that the record in this case supports a finding that both the C2C project and the ANE project are cost beneficial and will enhance system reliability. I also concur as to the issue of preemption and the usefulness of the LEI modeling in analyzing and assessing the cost and benefits of the proposals.

However, for the reasons described more fully below, I dissent from the majority's finding that the ANE project better and more completely meets the statutory criteria than the C2C proposal. My reading of the record[28] compels the conclusion that the C2C project is preferable to the ANE project because it poses fewer legal and mechanical obstacles, has a significantly more favorable net cost/benefit ratio and better satisfies the public interest requirement of the Act. I therefore adopt, in part, the exceptions filed by the OPA and conclude that the Commission should move forward with the negotiation of a precedent agreement for a portion of the C2C Dawn project that represents Maine's share of a regional project.

In light of the results of the LEI modeling, and based on information in the record, I conclude that the Commission is obligated to act under its legislative directive. Although not the pivotal deciding factor in reaching my conclusion, a failure to do so may close the door on a regional solution to address pipeline constraints that lead to volatile and harmful price impacts. By recommending execution of a contract, Maine leaves open the issue for other New England states, the ISO-NE market, and the Governor to assess and also act.

As noted above, I agree with the majority that both projects generally satisfy the Act's requirements. The fundamental question, therefore, is which of the two projects better and more completely meets the statutory provisions. I have concluded that C2C Dawn is the preferable option.

Title 35-A, section 1904 (2) provides that, to enter into an ECRC or direct a utility to do so, the Commission must determine in an adjudicatory proceeding that the proposed ECRC is commercially reasonable and in the public interest, and that the contract is reasonably likely to:

[28] I find the arguments of the OPA and PNGTS in their briefs and reply briefs convincing. See OPA Br. at 28-33; OPA Reply Br. at 7-9; PNGTS Br. at 5-12; PNGTS Reply Br. at 2-10.

1. Materially enhance natural gas transmission pipeline capacity into the State or into the ISO-NE region and that additional capacity will be economically beneficial to electric consumers, natural gas consumers or both in the State and that the overall costs of the contract are outweighed by its benefits to electric consumers, natural gas consumers, or both in the State; and

2. Enhance electrical and natural gas reliability in the State.

The C2C Dawn project is likely to most completely address all of these various requirements for Maine. It is the least-cost project, ensuring the public interest requirement of the Act is satisfied. The C2C project is preferable to the ANE project because of the relative size and costs of the two projects. The LEI Regional Analysis indicates that the benefit/cost ratio of the C2C project is two orders of magnitude higher than that of the ANE project and is, therefore, more likely to achieve ratepayer benefits.[29] The benefits of the C2C Dawn project also include supply and delivery advantages, direct delivery to Maine, high resale value, liquid receipt point, and scalability.[30] Moreover, the C2C project is less risky because the total costs to ratepayers will be significantly less than the costs of the ANE project. Another advantage to the C2C Dawn project is that it does not buy so much capacity that a private sector or market-based solution could not still emerge to assure that Maine ratepayers not bear more of the burden of the investment in pipeline capacity than is absolutely necessary.

In addition to the specific application of the statutory provisions, I have also concluded that the C2C Dawn project may be more likely to occur than the ANE project, namely, it's a more pragmatic choice. There is information in the record indicating that the ANE project may not proceed to the construction phase that gives me serious pause. The ANE project faces several legal challenges in other New England states and at the FERC.[31] These include a wide array of challenges at both the state and federal level including whether the actions contemplated would be subject to federal preemption among other state law claims. While I do join the majority rationale and conclusion on the issue of preemption, I acknowledge that the specific quick start

[29] LEI Regional Analysis at 50; See Figure 4 at page 25 of this Order which is based on LEI's corrected calculation for the ANE project from ODR-024-006.

[30] PNGTS Br. at 5.

[31] *See e.g.,* two cases before the Massachusetts Supreme Judicial Court, *Engie Gas & LNG LLC v. Department of Public Utilities*, Case No. SJC-12051 and *Conservation Law Foundation v. Department of Public Utilities*, Case No. SJC-12052; and two cases before the FERC, *Algonquin Gas Transmission,* Docket No. RP16-618-000 and *NextEra Energy Resources, LLC and PSEG Companies v. ISO-New England Inc. LLC*, Docket No. EL16-93-000. In preparing for deliberations dated July 19, 2016, I reviewed pleadings in these cases. Subsequently, the Massachusetts Supreme Judicial Court and the FERC rendered decisions in some of these cases. In consideration of the instant Opinion, I have not relied on any decisions rendered after July 19, 2016.

technology that is part of the ANE project raises more preemption concerns than any aspect of the C2C project. I am also aware of legal challenges asserting that the LNG storage component of the ANE project may be at odds with certain provisions of the Act. On balance, I believe that there is a greater likelihood that the C2C Dawn project will get built due to fewer opportunities for legal infirmity and litigation delay.

So the C2C Dawn project is the pragmatic choice, due to its greater likelihood to proceed and in a more timely way, and the less risky choice, due to its better cost-benefit ratio and direct benefits to Maine. To assure that the Maine share of a project has been advanced, I support a contract for a portion of the C2C Dawn project that represents Maine's share of a regional project. Maine should only proceed with commitment for its load share on a regional basis, but that load share need not be contained in one project joined by each individual state, and in fact multiple projects may lead to tailored outcomes that benefit the overall regional needs as well as individual state needs.

The record does not contain a lot of information regarding the appropriate amount of pipeline capacity needed by the region to address the problem. Reference is made to a need of between 1 bcf/day and 2 bcf/day.[32] Given the complexity of the question, I believe this is an area that could be further explored in a follow-on phase.

Should Maine proceed with an ECRC for the PNGTS C2C-Dawn project, more process would be required. Before execution of a contract, a timely Commission process should be established to address issues including, but not limited to, appropriate partners for the C2C project, Maine's load share on the C2C Dawn project, and risk mitigation associated with pricing along the TransCanada portion of the C2C Dawn route.

[32] See February 22, 2016 Testimony of Dr. Silkman/CES at 11; February 22, 2016 Testimony of Skipworth and Scully at 3; IECG Brief at 7.

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 11(D) of the Commission's Rules of Practice and Procedure (65-407 C.M.R. 110) within **20** days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought. Any petition not granted within **20** days from the date of filing is denied.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21** days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.