STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2014-00071

October 1, 2014

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

EXAMINERS' REPORT

Note: This Examiners' Report is written in the form of a Commission Order but is the Staff's recommendation. Parties may file comments on or exceptions to this Report by close of business on Wednesday, October 15, 2014 for consideration by the Commission.

I. SUMMARY

Based on the evidence in this proceeding, we find that it is unlikely that the benefits to Maine consumers will exceed the costs of pipeline capacity if the State of Maine (or designated counterparties) enters into an Energy Cost Reduction Contract pursuant to The Maine Energy Cost Reduction Act, unless the cost of pipeline capacity is very low. Nevertheless, we will proceed to a Phase 2 proceeding where we will invite proposals for our consideration. We will perform an independent cost-benefit analysis of each proposal that is submitted to inform our determination as to whether sufficient benefits will result to Maine consumers of natural gas and electricity of entering an Energy Cost Reduction Contract.

II. THE MAINE ENERGY COST REDUCTION ACT

During its 2013 session, the Maine Legislature enacted The Maine Energy Cost Reduction Act, P.L. 2013, c.369, codified at 35-A M.R.S. § 1901 *et seq* (Act). The Act contains the finding that the expansion of natural gas transmission pipeline capacity into Maine and other states in the New England could result in lower natural gas prices and, by extension, lower electricity prices for consumers in Maine

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 Energy Cost Reduction Contract (ECRC) in accordance with the provisions of the Act. 35-A M.R.S.§1904. The Act limits the amount of ECRCs to a cumulative total of no more than 200,000,000 cubic feet 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.[1] 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 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.

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] cost for natural gas delivered into New England and increase the efficiency with which gas brought into New England and Maine is 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; and 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).

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.

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 accomplish the following objectives:

1. to materially enhance natural gas transmission pipeline capacity into the State or into the Independent System Operator of New England (ISO-NE) region;

2. that the additional capacity it provides will be economically beneficial to Maine's electric consumers, natural gas consumers, or both;

3. that the overall costs of the contract are outweighed by its benefits to Maine's electric consumers, natural gas consumers, or both; and

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[1] For the purpose of this Report, we assume that 1,000 Dth is equivalent to 1MMcf, although we acknowledge that a Dth is a unit of energy and an MMcf is a unit of volume.

[2] The “basis differential” is difference in gas prices between the point of supply and the point of delivery, which in New England is currently represented by the Algonquin city gate, a point of substantial constraint in moving gas west to east.

4. to enhance electrical and natural gas reliability in the State.

35-A M.R.S. §1904(2).

The Act authorizes the Commission to direct one or more transmission and distribution (T&D) utilities, natural gas utilities, or natural gas pipeline utilities to be counterparty to an ECRC. In determining whether and to what extent to direct a utility to be a counterparty to a 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 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 Commission may execute an ECRC as a principal and counterparty. *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).

An ECRC may be funded by just and reasonable assessments on the bills of ratepayers of T&D or natural gas utilities, as approved by the Commission. In determining these assessments, the Commission must consider the anticipated benefits to different categories of ratepayers as a result of the ECRC. 35-A M.R.S.§1905 (1). When the Commission enters the ECRC, assessments on utilities to recover all net costs to the Commission may be made in proportion to the anticipated reduction in price of electricity or gas, as applicable, as a result of the ECRC, as determined in an adjudicatory proceeding, and may be recovered in utility rates. 35-A M.R.S.§1905(2).

Finally, the Commission may establish and direct the payment to the Energy Cost Reduction Trust Fund (pursuant to 35-A M.R.S. §1907) of a volumetric fee on the use of gas by a consumer of natural gas obtained from a source other than a gas utility or natural gas pipeline utility of this State in proportion to the anticipated reduction in the price of gas accruing to that consumer as a result of the ECRC, as determined by the Commission in an adjudicatory proceeding. 35-A M.R.S. § 1905(3).

III. PROCEDURAL HISTORY

A. Notice, Intervention, Schedule and Scope

On March 20, 2014, the Commission opened an investigation to determine what parameters should govern an exercise of its authority pursuant to the Act. The Notice of Investigation (NOI) indicated that we would consider the regional analysis provided by the Sussex Economic Advisors titled "Review of Natural Gas Capacity Options" dated February 26, 2014.[3]

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[3] The Act requires the Commission, in consultation with the Public Advocate and the Governor's Energy Office, retain the services of a consultant with expertise in

The NOI was provided to stakeholders and persons interested in regional gas and electric issues within Maine as evidenced by participation in recent proceedings and Maine Legislative proceedings on this subject. The NOI invited the participation of interested parties in this matter, including those who wish to submit proposals for an ECRC.

The NOI set out numerous issues for comment and invited comment on any additional issues that the Commission should consider. The NOI scheduled a conference of counsel to discuss an appropriate schedule and to explore "the possibility of moving expeditiously in this case with possible resolution of some or all of the issues by mid-May." NOI at 7. The Commission invited comments of the parties regarding setting a schedule that would allow it to move expeditiously, stating:

> While we recognize that the issues in this proceeding are complex, we are mindful of the pace with which events are unfolding in the region and market price consequences that could result from delay.

Id.

The NOI also invited the submission of proposals for natural gas pipeline capacity additions through the execution of an ECRC that would reduce energy costs in Maine, stating:

> If any proposals are found to be within acceptable parameters as found in this investigation, the Commission may determine whether to execute one or more ECRC in response to such proposals.

Id. at 6.

By Order Granting Intervention issued April 8, 2014, the Commission granted petitions to intervene for the following entities:

Office of the Public Advocate (OPA)
Northern Utilities, Inc. d/b/a Unitil (Unitil)
Maine Natural Gas Corporation (MNG)
Central Maine Power Company (CMP)
Emera Maine (Emera)
Portland Natural Gas Transmission System (PNGTS)
Tennessee Gas Pipeline Company, LLC (TGP)
Maritimes & Northeast Pipeline, LLC (MNE)
Algonquin Gas Transmission, LLC (ALG)
Conservation Law Foundation (CLF)
Natural Resources Council of Maine (NRCM)
Industrial Energy Consumers Group (IECG)

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natural gas markets to make recommendations regarding the execution of an ECRC. 35-A M.R.S. §1904(1)(C).

Maine State Building & Construction Trades Council (Trades Council)
United Association of Plumbers and Steamfitters, Local 716 (Local 716)
Environment Northeast (ENE)

Two additional late-filed petitions to intervene were granted by the Hearing Examiners on May 21, 2014 and June 6, 2014, respectively for the following entities:

Repsol Energy North America Corporation (RENA)
Maine Renewable Energy Association (MREA)

A conference of counsel was held on April 8, 2014 at the Commission to discuss the scope of issues, procedure and schedule for this case. On April 16, 2014, parties filed initial comments addressing these matters.

On April 30, 2014, the Commission issued its Order Part 1 – Schedule and Invitation to Comment on Motions[4] which:

- Established an initial schedule for Phase 1 of the proceeding that would conclude in early September;
- Established that the case would include a Phase 2, in which proposals could be submitted and evaluation of those proposals could occur, which could run parallel in time to Phase 1; and
- Invited responses to TGP's motions for protective order and to allow the Hearing Examiners to rule on procedural matters. MNE, ALG, PNGTS, CMP and MNG filed comments or opposition to TGP's protective order terms.

Order Part 2 – Schedule and Scope, with Commissioner Littell's dissenting opinion was issued on May 5, 2014. This Order included the reasoning for the majority decision outlined in Order Part 1. The majority concluded that:

> …in order to be most responsive to the Legislative intent of the Act, we should move as quickly as possible consistent with our obligations to obtain and evaluate relevant evidence to determine whether the Commission should enter an ECRC to support additional gas pipeline capacity into the region to provide benefits to Maine.

Order Part 2 at 4.

In its Part 1 and 2 Orders, the Commission stated it will not limit the scope of the

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[4] Order Part 1 at footnote 2 indicated that Commissioner Littell dissented from the schedule decision of the majority and that the Dissenting Opinion would be issued with the Part 2 Order.

issues to be considered in each phase of the proceeding, although it was possible that, "based on our conclusions in Phase 1, some issues relating to particular proposals will be moot, or clearly resolved." Order Part 2 at 11.

A revised schedule was established on May 28, 2014 in which technical conference and hearing dates were set. A technical conference on the Sussex Report and Sussex's responses to data requests was held on June 27, 2014. Direct prefiled testimony was filed by TGP, MNE, ALG, MNG, CMP, PNGTS, OPA, NU, NRCM, and CLF. Technical conferences on direct testimony were held on July 17 and 18, 2014, in lieu of written discovery.

B. Protective Orders

On April 16, 2014, Tennessee Gas Pipeline Company, L.L.C. moved for the issuance of a protective order, pursuant to 35-A M.R.S.A. § 1311-A, Maine Rule of Civil Procedure 26(c), and Chapter 110, § 10(F) of the Commission’s Rules, to govern competitively sensitive information describing terms of any ECRC proposal, including information about business plans, market analysis and projections, competition, financial projections, and pricing details. PNGTS, MNE, ALG, CMP and MNG filed objections to the terms of TGP's proposed protective order.

In its May 13, 2014 Order, the Commission directed the following:

- that the process be as open and transparent as possible;
- the restrictions on access to competitively sensitive information in proposals be narrowly drawn;
- that access be granted subject to an appropriate protective order to any representative of any non-competitor party;
- that competitor access to ECRC proposals' confidential information be drawn narrowly and for which clear harm can be shown; and
- that the designation of confidential items would extend equally to all competitive entities in this proceeding.

On June 5, 2014, TGP filed an amended motion for protective orders numbers 2 and 3. On June 10, 2014, the Hearing Examiners invited parties comment on TGP's motions. MNE and ALG again objected to TGP's proposed treatment of confidential ECRC information with respect to its representation of both bidding and non-bidding parties.

The Hearing Examiners issued the following protective orders in this proceeding:

- Protective Order No. 1 (May 16, 2014) governing commercially sensitive and proprietary information gathered by Sussex in the development of its Report.

- Protective Order No. 2, 3, and 4 (July 3, 2014) governing TGP's commercially sensitive and proprietary information related to ECRC projects.

Temporary Protective Order No. 5 governing commercially sensitive information subject to Freedom of Access Act was also issued and later revoked.

On July 23, 2014, MNE and ALG filed a Motion for Reconsideration of the Hearing Examiners' July 3rd Procedural Order ruling and modification of Protective Orders Nos. 2, 4, and Temporary Protective Order No. 5. IECG and the Trade Union parties filed their opposition to MNE and ALG's Motion.

C. Hearings, Briefing, and Evidentiary Rulings

The Hearing Examiners conducted a case management conference on August 4, 2014 at which it heard argument regarding evidentiary disputes which were ruled upon by procedural orders issued on August 4, 2014 and August 21, 2014. An August 4, 2014 motion by MNE and ALG to admit the Supplemental Testimony and Late-Filed Exhibit of Susan F. Tierney was denied on August 5, 2014.

Hearings on all testimony and the Sussex Report were held on July 31 and August 5, 6, and 7, 2014. Briefs and Reply Briefs were filed on August 22 and 29, 2014, respectively.

TGP, IECG, Local 716 and the Trades Council (collectively, Joint Parties) filed a motion to incorporate further evidence (Boston Globe article) into the record on August 26, 2014, to which MNE and ALG objected. On August 26, 2014, IECG, Local 716 and the Trades Council appealed the Hearing Examiner's exclusion from the record of “A Bold Collaboration,” authored by David Trueblood, published in Conservation Matters (June 22, 2001) by CLF, as an admission. Responsive filings of CLF and IECG were filed on September 3 and 10, 2014 respectively.

On September 17, 2014, TGP filed public versions of its proposed ECRC, and indicated it would release confidential versions to parties after obtaining executed Non-Disclosure Agreements from parties pursuant to Protective Order No. 2. TGP requested consideration of its ECRC proposal in Phase 1 of this proceeding.

On September 19, 2014, PNGTS filed an objection to and motion to exclude TGP's commercial documents and requested that the Commission issue a request for proposals (RFP) to solicit bids. TGP filed its response on September 22, 2014.

On September 23, 2014, the Commission deliberated *sua sponte* whether to reopen the Phase 1 record to invite evidence regarding a new regional pipeline project which was the subject of an article in the Boston Globe on September 16, 2014.

The Commission decided to continue on the existing schedule but allow parties to comment on this matter in their exceptions to the Examiners' Report.

On September 29, 2014, MNE and ALG filed an ECRC proposal for consideration.

IV. POSITIONS OF THE PARTIES

A. Office of the Public Advocate

The OPA's position is that New England has insufficient pipeline capacity to meet peak demand for natural gas during the winter months and that this shortage of pipeline capacity has already cost Maine electricity customers hundreds of millions of dollars over the last two winters. Specifically, the OPA states that winter pipeline constraints increased Maine electricity costs by more than $180 million in the winter of 2012-13, and even more in 2013-14 and that pipeline capacity constraints are already having significant but less easily quantified impacts on Maine's economy and environment. The OPA further states that the measures ISO-New England has implemented to maintain grid reliability during the winter impose additional costs on Maine electricity consumers.

The OPA argues that the basis differential from the Marcellus shale region to New England is artificially high and that the underlying natural gas supply and demand fundamentals indicate that high basis differentials will persist and may increase absent intervention. The OPA notes that as oil and coal-fired generation retires, it will be replaced by natural gas fired generation, increasing regional demand for natural gas; that production from the offshore resources in the Maritimes will decrease; and, absent long term contracts for delivery, LNG deliveries to the region are likely to continue to be minimal.

The OPA concludes that additional pipeline investment in the region will be undertaken to meet gas LDC load growth, but that there is a market failure that is preventing private entities from addressing pipeline capacity constraints. In the OPA's view, market reforms may improve electric reliability, but will not result in additional pipeline capacity and lower electricity costs.

For these reasons, the OPA urges the Commission to pursue an ECRC by seeking proposals in the next phase of this proceeding. In considering such proposals, the OPA recommends the proposal evaluation be based on the Total Resource Cost Test and that the Commission consider the full range of consumer benefits including, reduction in electricity costs to Maine consumers, incremental reliability benefits, revenue from re-sale of pipeline capacity, hedging value, cost of the hedge, and the potential cost of an unhedged basis differential.

B. Tennessee Gas Pipeline, IECG, Trades Council, Local 716

Tennessee Gas Pipeline, IECG, Trades Council, Local 716 (Joint Parties) state that executing an ECRC will provide substantial benefits to Maine and that the Commission should act with urgency. In support of their position, the Joint Parties argue that the requirements of the Act have been satisfied. Specifically, the Joint Parties state that the Commission has pursued regional processes and that such activities are unlikely to achieve the same benefits within the same time frame as an ECRC. Moreover, the Commission has explored opportunities for private market participation and that the private market is unlikely to achieve the objectives of the Act. The Joint Parties argue that the lack of private participation is the result of market failure, that market and rule changes will not solve the existing market failure in a timely manner, and that intervening in the market will not distort the market. The Joint Parties note that the Commission, through the Sussex Report, has complied with the Act's study requirement.

The Joint Parties argue that an ECRC is reasonably likely to enhance gas transmission capacity into ISO-New England and that New England is the relevant geographical area. Further, the Joint Parties assert that an ECRC is reasonably likely to be economically beneficial and the overall costs of an ECRC would be outweighed by its benefits to Maine ratepayers. For support, the Joint Parties cite to the Sussex Report, the CES analysis and the Brattle Group recommendations. The Joint Parties also state that an ECRC is reasonably likely to enhance electric and natural gas reliability in Maine. Finally, the Joint Parties emphasize the cost and risks of the Commission not acting pursuant to its authority under the Act.

C. Maritimes & Northeast Pipeline and Algonquin Gas Transmission

MNE and ALG urge the Commission to carefully consider the risks and potential costs to ratepayers when reviewing any ECRC proposal. Specifically, MNE and ALG state that the Commission should: 1) determine whether it is in the public interest at this time to enter into an ECRC based on the risk of Maine investing in gas capacity; 2) if it is determined that an ECRC is appropriate, mitigate the risks by making only an incremental investment in an ECRC; and 3) if procuring an ECRC in Phase II, establish explicit selection criteria that specifically set forth parameters to maximize benefits and minimize costs to Maine.

MNE and ALG acknowledge that Maine and New England experienced two very difficult winters of high electric costs because natural gas-fired generators within the ISO-New England control region generally do not secure firm pipeline transportation to their facilities. However, according to MNE and ALG, the question is whether or to what degree Maine consumers should uniquely shoulder, through an ECRC, the costs of bringing more natural gas to the region in an effort to solve a regional problem that is deeply complex. MNE and ALG note that an ECRC would bring Maine only 8% of the regional benefit, but 100% of the costs and that new regional electric market rules may lower the basis differential by requiring generators to have firm fuel supplies. MNE and ALG also caution that government actions to lower natural gas supply volatility could chill future investments in generation and private investment in pipeline capacity and the goal of an ECRC should not be to “crush” the basis differential.

Finally, MNE and ALG state that, if the Commission pursues an ECRC, it should consider only a modest incremental investment in pipeline capacity and focus on projects that will go in-service quickly. This approach will allow Maine to mitigate the risk of costly long-term commitments and determine whether and to what degree these costs are offset by real benefits for Maine. Additionally, MNE and ALG state that this approach will allow visibility into whether there are unintended market consequences from the ECRC and additional time to let assumptions play out in actuality rather than through projections and speculation. MNE and ALG note that, if the Commission later determines that further investment in capacity is warranted, the Act allows the Commission to evaluate such an opportunity for further action until 2018.

D. Portland Natural Gas Transmission System

PNGTS states that the ECRC mechanism has given the Commission the potential to create great change in Maine’s energy landscape, but that a wrong step could result in undesirable consequences. In particular, PNGTS states that the Commission must be wary of over-purchasing capacity which would benefit upstream New England states instead of Maine, wasting taxpayer dollars on uncertain benefits that may never materialize, delays, political controversy, permitting issues arising from construction, and a perceived failure of transparency behind Commission action.

PNGTS argues that, while the Commission must proceed carefully, if it concludes that it has satisfied its statutory prerequisites for an ECRC, the evidence strongly supports moving forward with an ECRC for capacity on PNGTS’ Continent to Coast Project (C2C). PNGTS states that its project offers a lower, fixed negotiated transportation rate than the current recourse rate and enhances diversification of supply with mature liquid trading points, customized scaling, in-state deliverability for Maine, and volume and pressure support to a very constrained part of the New England grid. Specifically, PNGTS states that its project will materially enhance natural gas transmission capacity into Maine, and since PNGTS runs through Maine, such an ECRC would materially enhance capacity specifically within Maine, rather than within another upstream New England state. Finally, PNGTS argues that its project would also avoid the potential problems that may be created by over-purchasing capacity because it has a smaller, scalable volume.

E. Northern Utilities

Northern states that, given the complexities of the natural gas markets and transmission system, as well as the state of integration between the natural gas and electric power markets, the Commission should use caution in evaluating whether to move forward with an investment in interstate natural gas pipeline capacity. Before the Commission makes such an investment, Northern states that the Act requires it to determine whether private transactions and changes in market rules will lead to the same cost savings as an ECRC. Northern states that, unlike natural gas generators, LDCs like Northern contract for gas supply and firm interstate pipeline capacity that is sufficient to meet the requirements of their customer base. This is because LDCs have an obligation to serve its customers, and acquiring sufficient capacity to meet peak demand and load growth requirements is part and parcel of that obligation.

Northern argues that, while the Commission cannot necessarily rely on generators to purchase firm pipeline capacity, the private sector is addressing the capacity issue in New England as shown by various regional pipeline capacity expansion projects. Northern further states that, if the interstate pipelines construct sufficient new capacity based predominantly upon contracts with LDCs and other market participants, it may be unnecessary for Maine to enter into an ECRC.

Finally, Northern states that the Commission should rule that LDCs that maintain resource planning processes which result in contracting for firm capacity resources necessary to meet the needs of their customers should be exempt from contracting or funding requirements associated with an ECRC. Northern states that where an LDC has taken measures to plan for the capacity demands of its customers, subjecting the LDC and its customers to support additional capacity pursuant to the Act will adversely affect resource planning efforts and thereby undermine traditional private investment from such LDCs.

F. Maine Natural Gas

MNG states its willingness to procure firm capacity to meet the design day requirements of its sales customers through an ECRC authorized under the Act. MNG argues that if the Commission determines an ECRC is appropriate then MNG’s customers should bear the proportionate costs of that ECRC in relation to the capacity benefits received by them. MNG notes that it has not traditionally held upstream pipeline capacity primarily because it has a limited design day requirement. However, due to current market conditions, MNG is currently evaluating its options with respect to holding firm upstream capacity for its sales customers.

MNG states that, in the event that it has already entered into a binding precedent agreement to meet some or all of the design day requirements of its customers at the time an ECRC contract is executed, MNG and its customers should be exempt from any ECRC costs, other than those costs that are associated with obtaining capacity to satisfy its requirements not otherwise met by contracting directly with a pipeline for existing pipeline capacity.

G. Bangor Gas Company

BGC states that evidence in the proceeding generally supports a preliminary finding that it would be in the “public interest” for the Commission to further explore an ECRC under just and reasonable terms and conditions. BGC believes that it is more beneficial for Maine to engage in the development of additional pipeline capacity on a cooperative basis with other States, and that “going it alone” presents risks and costs that should be significantly outweighed by the reasonably likely resulting benefits. BGC further states that evidence supports a threshold finding that entry into an ECRC could be done on commercially reasonable terms, although final terms would have to be solidified through a follow up process at which time the Commission and parties could examine specific proposals. Moreover, BGE states that the record supports a general finding that an ECRC is "reasonably likely" to materially enhance natural gas transmission capacity into Maine or the ISO-New England region and enhance natural gas and electric reliability.

BGC states that the costs and specific benefits of an ECRC, and a fair assessment of their reasonable probability, require further fact finding and exploration. BGC further argues that identification of specific direct and indirect beneficiaries and a relative quantification of those benefits are necessary to make an informed judgment over which utilities and which ratepayers should help defray the costs of an ultimate ECRC. Accordingly, BGC states that the Commission should hold a follow up proceeding to fully evaluate the beneficiaries of the particular project(s) and determine a process that will implement rate making and recovery mechanisms that fairly allocate the costs to the group of beneficiaries.

H. Central Maine Power Company

CMP states that the Commission has satisfied the three precursor requirements for the execution of an ECRC. Specifically, CMP argues that the Commission has pursued in appropriate regional and federal forums market and rule changes that would reduce the basis differential, and that, given past history with attempts at capacity market reforms, it would appear to be extremely unlikely that market or rule changes will, within the same time frame, achieve substantially the same cost reduction as the execution of an ECRC. CMP also argues that the Commission has explored all reasonable opportunities for private participation in securing additional gas pipeline capacity that would achieve the objectives of the Act and that it does not appear that private, free market participation will produce the needed gas pipeline capacity as electric generators appear unwilling to commit to multi-year contracts with pipeline entities due to the uncertainty of long-term revenue streams in the New England electricity market. Thus, CMP argues that market intervention by the Commission in the form of an ECRC should be strongly considered, especially as part of a regional effort.

CMP also argues that an enhanced standard of review in this case is not warranted; that an ECRC will likely need to be executed by a regulated utility as opposed to the Commission Itself; that the costs of an ECRCs should be allocated to utilities and their customers in proportion to how the benefits from the ECRC are realized; and that as parties to an ECRC, utilities should be given full cost recovery. Finally, CMP states that the Commission should pursue a regional approach, noting that if Maine were to try to support adding additional pipeline capacity by itself, it would be incurring 100% of the costs of such expansion and receiving less than 10% of the regional benefits that an investment would yield through reduced wholesale electric prices.

I. Conservation Law Foundation

CLF states that this proceeding is highly unusual and undertaken with the singular goal of identifying and implementing a means of reducing the cost of electricity and natural gas for Maine consumers utilizing recently obtained statutory authority that permits the Commission to do what no other state has done before—to directly contract for, or order others to contract for, the purchase of natural gas pipeline capacity and to finance that purchase using charges on electric ratepayers. CLF supports efforts to reduce energy costs for consumers, but is opposed to the kind of market intervention and ratepayer subsidy and risk that characterizes the Commission's proposed action under the Act.

CLF argues that the record in this proceeding demonstrates the solution to concerns about natural gas supply, electric reliability and price during periods of peak demand is being developed in the energy markets themselves and should be enhanced and refined by regulatory adjustments to those markets, not through state intrusions that could muddle price signals and stifle private investment while putting Maine ratepayers at risk. Moreover, CLF states that the landscape and markets in which these policy decisions are being played out are volatile and subject to rapid change as illustrated by changes that have been seen over the past year.

CLF further argues that even if Maine were, in the absence of a regional effort, to invest in gas capacity to the maximum extent allowed by the law, the effect of this investment on the reliability and basis concerns would be minimal and thus fail to meet the requirements of the statute. Instead, it would amount to at best a hedge, a gamble that post procurement in-service market conditions might allow Maine to resell its capacity position for a profit. The risks in this approach are obvious in that such future "hedge-type" sales prices are not only speculative but the mere purchase by Maine would send potentially harmful price and public investment signals that could both stifle private investment for years and expose ratepayers to high investment risks.

Finally, CLF argues that the Commission's attempt to develop natural gas pipeline capacity on the backs of Maine electric ratepayers is legally suspect in that a Maine-only investment fails to meet the "benefits" requirements of the statute as it would not meaningfully impact the stated basis or reliability concerns. Of equal concern, according to CLF, any form of public subsidization of gas pipeline would be unprecedented and risk violating the exclusive jurisdiction of the Federal Energy Regulatory Commission (FERC) over wholesale electric and gas rates, as well as the dormant commerce clause of the U.S. Constitution, and may also amount to an unconstitutional delegation of the Maine Legislature's taxing power. For these reasons, CLF strongly urges the Commission to conclude in this Phase 1 proceeding with a finding that a contract for natural gas capacity is not in the best interests of Maine ratepayers.

J. Environment Northeast

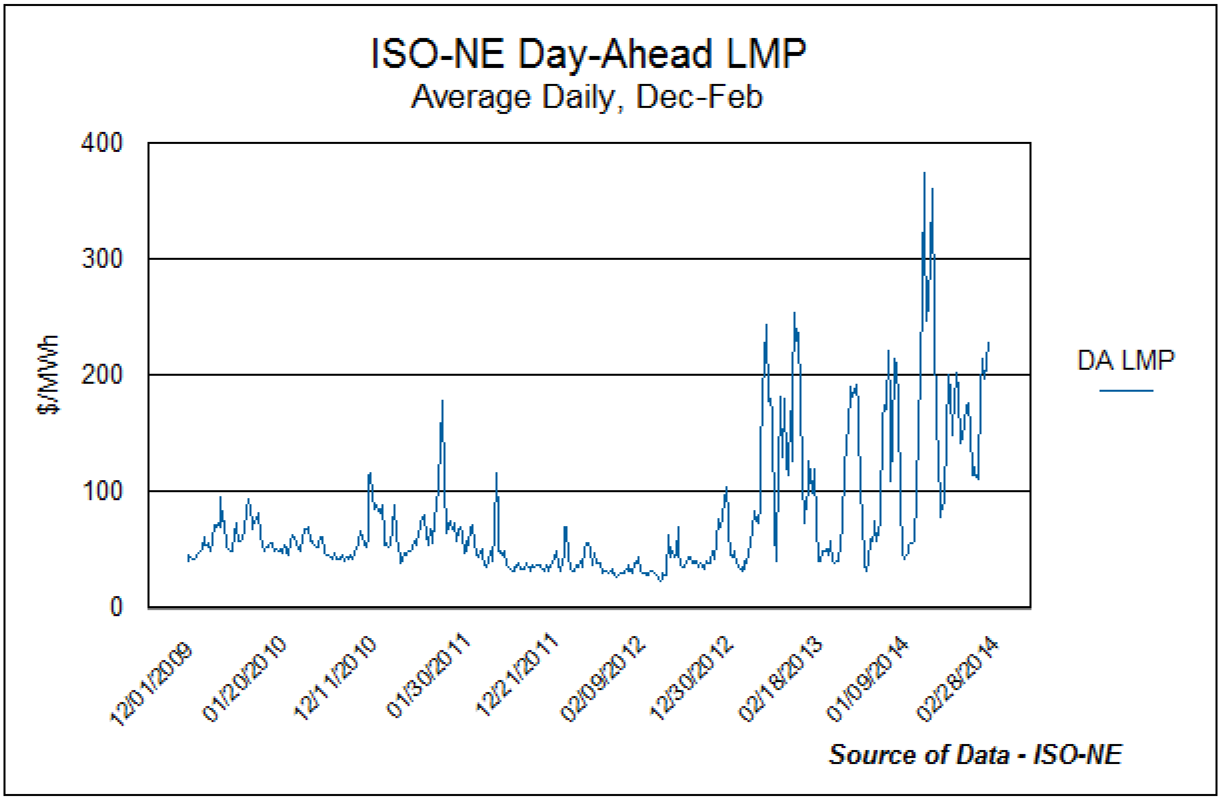
ENE argues that it would be premature to pursue an ECRC. ENE states that the conditions precedent to an ECRC set forth in the Act have not been met, particularly the condition that market mechanisms to address the natural gas basis differential problem must be explored first. ENE states that the Sussex Economic Advisors report done at the request of the Commission is inadequate by failing to analyze all options available to reduce the basis differential or recommend which option, or combination of options, would be the lowest cost and pose the lowest risk for ratepayers.

ENE further states that the evidence shows that even in locations where natural gas pipeline capacity has been increased, electricity prices do not always fall, calling into question the very premise of the assumption underlying this case. ENE argues that the totality of the evidence does not support taking the unprecedented step of having electric ratepayers backstop investment in a new natural gas pipeline.

V. OVERVIEW OF THE MARKETS

The Act resulted from concerns about natural gas and electricity price increases over the past several years driven by constraints on natural gas supply into and within the New England region. Natural gas prices drive wholesale electricity prices in New England because gas-fired generation plants are on the margin in most hours of the year, and, thus, set the market clearing price of energy in ISO-NE. Because of New England’s reliance on gas to generate electricity, gas supply constraints also create concerns about the reliability of the regional grid. This supply constraint condition was particularly evident in the level and spikey nature of wholesale power prices during the last several winters, driven by the same characteristics in the underlying cost of natural gas.

Figure 1:



It is estimated that Maine ratepayers paid nearly $185 million more in electricity costs than they did in winter 2011/12, even though the 2012/13 winter was comparatively mild. More than two thirds of that total increase was attributable to just two months: January and February 2013.[5] ISO-NE estimates that New England consumers paid $3 billion more for electricity during December, January and February of 2013-14 than they would have had adequate pipeline capacity from the south existed.[6]

The situation in Maine and New England is in sharp contrast to most other parts of the United States where natural gas prices are relatively much lower. Domestic natural gas production has increased significantly over the past several years, driven by shale gas production most notably from the Marcellus shale. See Figure 212 below.

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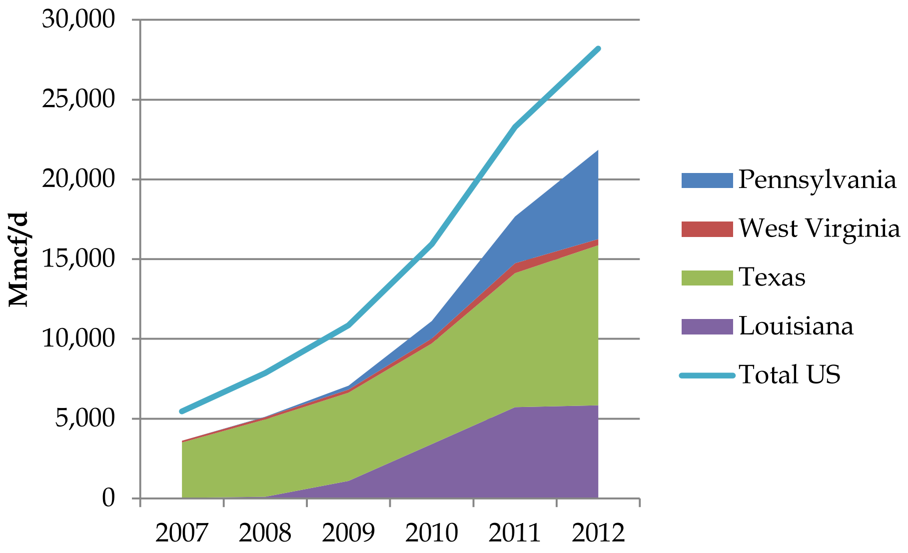
[5] Sussex Report at 50.

[6] IECG Brief at 65.

Figure 21. Shale gas production (gross withdrawals from shale gas wells), selected states and total United States



Source: Energy Information Administration ("EIA")

The Marcellus shale lies in much of Pennsylvania, as well as parts of New York and Ohio, and most of West Virginia. From negligible production in 2007, by the final months of 2013, production had reached over 14 billion cubic feet per day ("Bcf/d"), about 18 percent of US gas production.[7] The problem for New England is that expansion of gas delivery infrastructure (interstate pipelines) has lagged behind growth in gas demand. This lag has created large price differences between gas prices in New England and gas prices in the Marcellus producing region and at Henry Hub. The difference in prices between a supply point and a delivery point is referred to as a "basis differential."

New England consumes about 2,500 million cubic feet per day (MMcf/d) on a yearly average basis. See **Error! Reference source not found.**3 below. On a yearly average basis, gas consumed in New England grew through 2011, but by 2013 consumption was somewhat lower on average than in 2011 or 2012. However, gas is mostly consumed in the winter, and average wintertime demand has increased in the past few years. See **Error! Reference source not found.**3.

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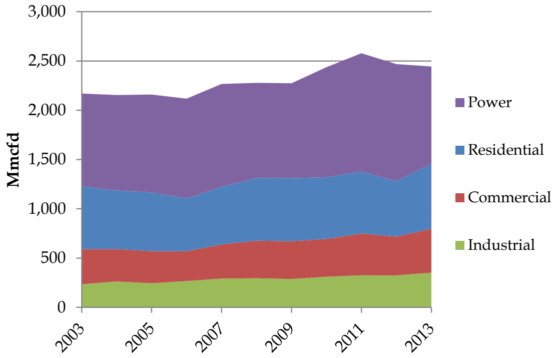
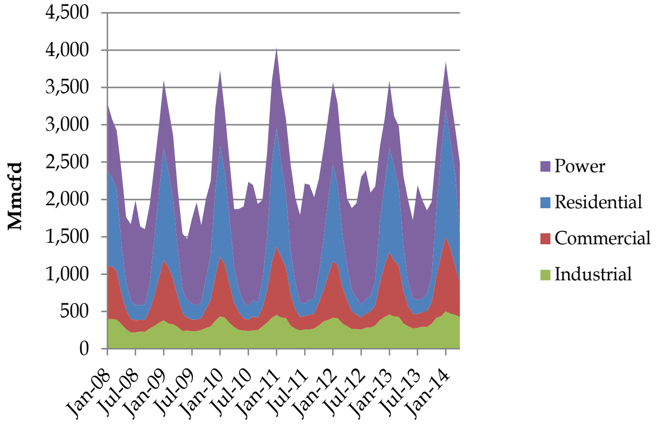
[7] Energy Information Administration. "Marcellus region to provide 18% of total US natural gas production this month." *Today in Energy*. December 9, 2013.

Figure 3. Natural gas consumption in New England

Annual Average, 2003-2013



Monthly Average, 2009-2014



Source: Energy Information Administration ("EIA")

Each gas-consuming sector has a characteristic seasonal profile of demand:

- **Industrial**: Gas consumed by industrial customers tends to be fairly steady across the seasons with a moderate increase in the winter months compared with the summer. This is because much of the gas is used in industrial processes that run all year round.
- **Residential and commercial:** Gas consumed by residential and commercial customers in New England is much more "spikey" within the year than industrial consumption—it peaks sharply in the winter because gas is used to heat homes and businesses. The local distribution companies ("LDCs") that deliver gas to residential and customers plan for this spikiness in a number of ways. LDCs contract for firm gas transmission capacity to match their expected peak day, also known as "design day," load. LDCs also own and

operate LNG peaking facilities, to have back up supplies for extreme weather conditions.

- **Power sector demand for gas:** Gas demand from the power sector peaks in the summer—this is shown in **Error! Reference source not found.**3 by the wide area shaded in purple that fills in the "valleys" left by residential, commercial, and industrial demand during the summer. Because its peak demand season is opposite to the other sectors, the power sector has plenty of access to natural gas pipeline capacity in the summer. However, although the power sector uses less gas in the winter, it uses gas at the same time the other sectors need it for heating-- and that is when gas supply capacity can fall short of demand.

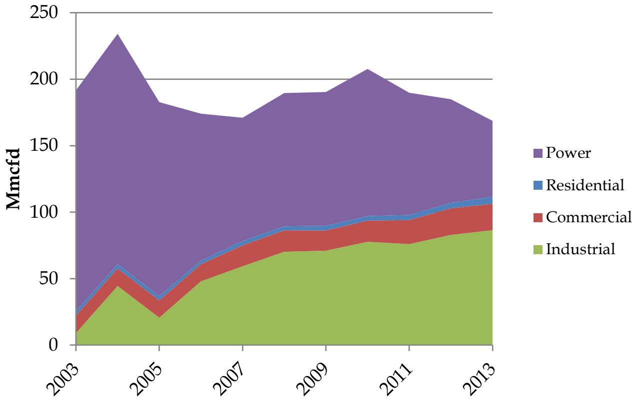
The composition of gas demand (residential, commercial, industrial, power) has important implications for the amount of gas transmission capacity that is needed. As shown in **Error! Reference source not found.**3, because residential and commercial demand are both strongly seasonal, during a winter month gas demand will regularly exceed the annual average level of 2,500 MMcf/d. On a daily basis, demand is even more volatile, driven by variations in the weather. On any given winter day, temperatures can be much lower than average for the month, and on those extra-cold days gas demand surges. Peak day demand—the demand expected on the coldest days of the year--determines the capacity for which gas infrastructure must be designed.

Gas demand also shows intra-day peaks, sometimes known as "needle" peaks in the wintertime, that tend to occur in the mornings as residential and commercial customers turn up their thermostats at the same time that power demand ramps up; and in the late afternoon and early evening as, again, more gas is needed for heating load.

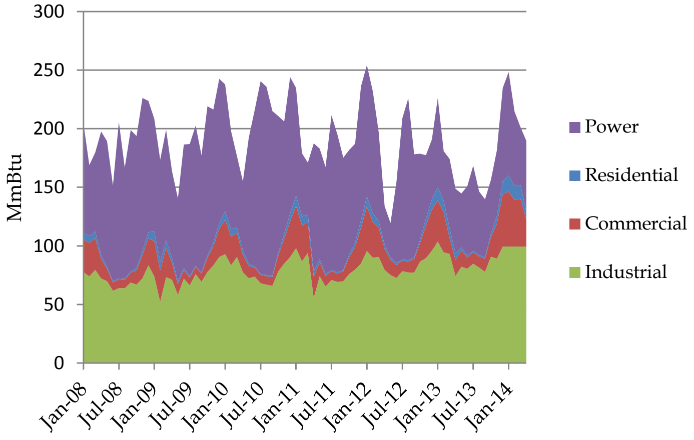
At about 170 MMcf/d, Maine's gas consumption was about 7% of total New England gas consumption in 2013. Gas consumption in Maine has a different profile compared with New England. Unlike New England, gas demand in Maine is primarily from the industrial sector. See Figure 4. Residential and commercial demand is a much smaller share compared with New England broadly. Gas used in the power sector in Maine has been declining since its 2004 peak.

Figure 42. Natural gas consumption in Maine

Annual Average, 2003-2013



Monthly Average, 2009-2014



Source: EIA

New England has no indigenous natural gas supply resources or production, and no underground storage facilities. Underground storage of natural gas is crucial for balancing gas supply and demand across the months, as well as for meeting shorter-term changes in demand. Depleted oil or gas wells, depleted aquifers, and salt caverns all serve as gas storage. However, no underground gas storage exists in New England, as New England's geology is not suitable—the lack of this is one of the major reasons New England basis is so volatile.

New England's gas supply infrastructure consists of:

- **Five gas transmission lines.** Five major transmission lines bring gas into New England. Maine is the last stop on the line for gas from the United States coming in on the Tennessee, Algonquin, and Iroquois systems. However, gas from the Portland Natural Gas Transmission System ("PNGTS") and the Maritimes and Northeast Pipeline ("MN&P") reaches Maine before southern New England.
- **Four liquefied natural gas import terminals.** New England has three LNG import facilities and access to the Canaport facility in New Brunswick. These terminals are not used to full capacity very often. LNG is a global market, and there is competition from buyers in Europe who are currently willing to pay much more than New England gas prices.
- **LNG peak-shaving facilities.** LNG peaking facilities store gas in above-ground vessels, for use by LDCs on days when gas demand is extremely high.

These supply sources are summarized in Figure 5 below.

Figure 5: New England Gas Supply Sources[8]

Supply Sources	Physical Pipeline Capacity at New England State Borders	Firm Contracted Capacity Serving New England Demand
Pipeline	(Bcf/d)	(Bcf/d)
Tennessee Gas Pipeline	2.0	1.3
Algonquin Gas Transmission	1.4	1.3
Iroquois Gas Transmission	1.1	.2
Maritimes & Northeast Pipeline	.9	.9
Portland Natural Gas Transmission	.2	.2
LNG Imports (Firm Supplies)		
Everett LNG	.7	.7
LNG Imports (Non-Firm Supplies)		
Neptune LNG	.4	0.0
Northeast Gateway	.8	0.0
LNG Peak Shaving	1.4	1.4
Total	8.9	6.1

A map showing the current New England interstate natural gas pipeline infrastructure is provided below as Figure 6[9]:

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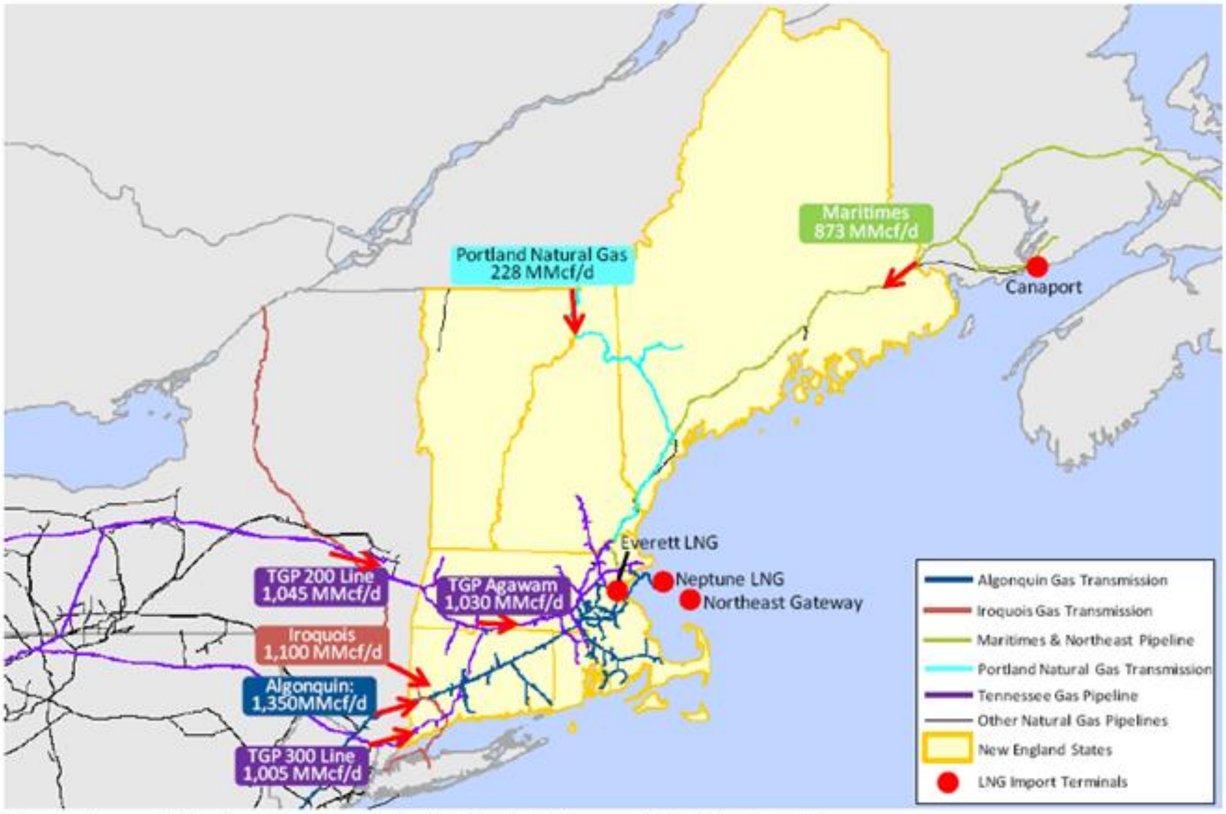
[8] Black & Veatch, "Natural Gas Infrastructure and Electric Generation: A Review of Issues Facing New England", 14 December 2012, Table 1.

[9] Black & Veatch, Phase 1 Report: http://www.nescoe.com/uploads/Phase_I_Report_12-17-2012_Final.pdf

Figure 6: New England Natural Gas Infrastructure



Source: Energy Velocity, LCI Energy Insight, Pipeline Electronic Bulletin Board Data

A number of new pipeline projects intended to bring more Marcellus area gas into New England have been announced and are in various stages of development. These are described in Section VI.A. below.

Within the wholesale natural gas market, purchasing entities include LDCs, gas marketers, industrial end-users and electric generators. Although LDCs typically acquire long-term firm pipeline capacity to supply some portion of their customer load provided the LDC base load is large enough to make it economic to do so,[10] the other entities and smaller LDCs typically have not, relying instead on short term or interruptible capacity for their gas. There may be many reasons the non-LDC entities have not made such investments. With respect to generators, the evidence in this proceeding suggests the reasons may be: (1) the market rules do not incentivize generators to make the investment; and/or (2) a mismatch exists between the nature of the required commitment to acquire pipeline capacity, which is long-term, and the nature of a generator's revenue stream, which is relatively much shorter term, and

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[10] LDCs enter long term contracts for capacity and supply necessary to serve sales customers delivered commodity and maintain upstream capacity rights for load of commercial and industrial customers taking capacity assigned delivery (only) service in accordance with regulatory policies in the jurisdiction.

thereby precludes a generator from being a credit-worthy counterparty. The evidence in this proceeding also indicates that, although additional pipeline investment in the region is being undertaken, it appears substantially to be by LDCs, which can recover the costs through regulated rates. In contrast, the other entities, including generators which in New England are non-utility merchants, may not be in a position to secure long-term contracts for natural gas pipeline capacity.

Natural gas service penetration in Maine is relatively low as compared to other parts of the continental U.S. and, as a result, LDC load size is relatively small. Only one of Maine's four LDCs has grown large enough for it to be economic for it to enter long term contracts for upstream pipeline capacity. Maine's other three LDCs contract with marketers or purchase gas on the spot market to cover their demand. In addition, unless they have capacity assignment programs, LDCs do not contract for supply or reserve upstream pipeline capacity for commercial and industrial load that elects to contract with competitive marketers for delivered supply as "transportation-only" or "delivery" customers of the LDC. Consequently, a significant part of Maine's LDC load is not served with pipeline capacity for which the LDC holds long term contract it has entered. Load for which supply and upstream capacity is purchased year-to-year in the competitive market is subject to the effects of basis fluctuation to a greater extent than capacity that is secured under a long term contract.

VI. MARKET EVENTS AND REGIONAL INITIATIVES

A. Pipeline Capacity Expansions

There are several pipeline projects (or potential projects) discussed in this proceeding that, if developed, would substantially increase capacity into New England.[11] The expansion projects that appear to be certain to be constructed are as follows:

TGP Connecticut Expansion: This project is an expansion of existing TGP infrastructure within New York, Massachusetts, and Connecticut. With an expected in-service date of November 2016, the expansion will deliver 72,100 Dth/day from TGP Iroquois transmission interconnection at Wright, NY to Zone 6 delivery points in Connecticut. This project is part of the Connecticut Comprehensive Energy Strategy which, in part, envisions increasing Connecticut's residential and commercial natural gas penetration rate to 50% by 2020, or the equivalent of approximately 300,000 new natural gas customers over the next seven to ten years.

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[11] There is an additional possible project referred to as Access Northeast which is a plan by Spectra Energy Corp., of Houston, and Northeast Utilities, the parent of Nstar and Western Massachusetts Electric Co., to invest $3 billion to bring an additional 1 billion cubic feet of gas a day into New England. The project was recently announced in the Boston Globe (September 15, 2014), but is not part of the record in this proceeding.

Algonquin Incremental Market (AIM) Project: AIM is an expansion of the existing Algonquin pipeline that will provide an additional 342,000 dekatherms per day ("Dth/d") of natural gas pipeline capacity to the New England region. The project will create additional capacity between Algonquin's existing receipt point at Ramapo in Rockland County, New York, and various Algonquin city gate delivery points in Connecticut, Rhode Island, and Massachusetts. The receipt point at Ramapo provides AIM shippers access to increasing supplies of domestic production via upstream interstate natural gas pipelines that interconnect with Algonquin. Spectra Energy is in the permitting process for AIM. Open seasons for the project have closed and Algonquin Pipeline has executed precedent agreements for all of the project capacity with ten shippers. All shippers are LDC utilities; eight are investor owned utilities and two are municipal utilities. Certificate applications for the project were filed with the FERC on February 28, 2014. The applications provided a target in-service date of November 1, 2016 and requested a certificate order from FERC no later than January 31, 2015.

The following additional projects are proposed and under development, but their subscription level, costs and final authorizations are not yet confirmed:

Atlantic Bridge Project: Spectra Energy is in the process of developing the Atlantic Bridge Project. Much like AIM, Atlantic Bridge is designed to further expand capacity along the existing Algonquin pipeline. The Atlantic Bridge project is also designed to permit the ability to physically delver natural gas from south to north into the Maritimes & Northeast Pipeline. Algonquin and Maritimes held an open season for the Atlantic Bridge project between February 5, 2014 and March 31, 2014. The response to the open season was expressions of interest that included LDCs, power generators, industrial and other customers from southern New England, Northern New England and Atlantic Canada. Unitil Corporation participated in the open season as an anchor shipper. Algonquin and Maritimes are now in the process of negotiating with these potential customers to determine the final scope of the project, based on specific receipt and delivery point requirements, maximum daily quantities, and other contractual terms. Based on commercial commitments, Spectra will determine whether it is economic to move the project forward. The minimum contractual commitment required to move this project forward is estimated at 100,000 Dth/d. Maximum capacity of the project could be more than 600,000 Dth/d. The estimated in-service date for the project at the smaller capacity level would be November 1, 2017; a larger facility could extend the in-service date to 2018.

Northeast Energy Direct: Kinder Morgan/Tennessee Gas Pipeline are in the process of developing a new pipeline facility. The proposed project would have a receipt point with Iroquois and Constitution Pipelines at Wright New York and would extend 179 miles through northern Massachusetts terminating at Dracut. Other delivery points and laterals will be determined through negotiations with shippers. The project capacity is currently estimated to range from a minimum of 600,000 Dth/d up to 2,200,000 Dth/d. A non-binding open season was conducted between February 13, 2014 and March 28, 2014. The estimated filing date for major permitting applications is third quarter 2014, with an estimated beginning date for construction in the second quarter of 2017. During the pendency of this proceeding, Kinder Morgan issued a press release announcing it has to date received interest in 500,000 Dth/d in the project.

Mainline Open Season: TransCanada Pipelines Limited has proposed an expansion of its facilities with receipt points at Empress, St. Clair, Dawn, Kirkwall, Niagra Falls, New York, Chippawa, Parkway and Iroquois. No delivery points other than those along the existing system are proposed. Volumes and prices have not been specified. The open season was conducted between November 29, 2013 and January 15, 2014. There is an anticipated in-service date of November 2016.[12]

Continent to Coast Expansion Project (C2C): Portland Natural Gas Transmission System, a partnership owned by TransCanada Pipelines (61.71%) and GazMetro (38.29%), is proposing the C2C project as a non-construction expansion to its existing facility. By increasing compression on the pipeline from its current contractual operating pressure of 1,250 psi to its Maximum Allowable Operating Pressure of 1,440 psi, PNGTS will be able to expand its current capacity of 168,000 Dth/d to 335,000 Dth/d – a 167,000 Dth/d increase from its receipt point in Pittsburg, New Hampshire to its delivery point at the joint facilities with Maritimes & Northeast Pipeline in Westbrook, Maine. From Westbrook, Maine to Dracut, Massachusetts, PNGTS owns 210,000 Dth/day of firm capacity entitlement on the Joint Facilities. PNGTS is offering a $0.60/Dth/day fixed negotiated rate for the C2C Project. PNGTS offers its C2C Project as an option for an ECRC contract. The C2C binding open season was conducted between December 3, 2013 and January 24, 2014. This project has an expected in-service date of November 2016.[13]

As shown in Figure 7 below, currently proposed pipeline capacity expansions of between 1,281,100 and 3,381,200 Dth/d represent between a 23 and 60 percent expansion of the region's existing 5,600,000 Dth/d pipeline capacity highlighted in Figure 5 above.

Figure 7: Proposed Pipeline Expansions

Project	Minimum Capacity (Dth/day)	Maximum Capacity (Dth/day)	In Service Date
Tennessee Gas Pipeline Connecticut Expansion	72,100	72,100	November 2016
Algonquin Incremental Market	342,100	342,100	November 2016
Atlantic Bridge	100,000	600,000	November 2017
Northeast Energy Direct	600,000	2,200,000	November 2018

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[12] Sussex Report at 39.

[13] Prefiled Testimony of Cynthia Armstrong at 4-6.

Mainline Open Season (TCPL)	NA	NA	November 2016
Continent to Coast	167,000	167,000	November 2016
Proposed Expansions	1,281,100	3,381,200	

B. Regional Initiatives

1. ISO-NE Market Rule Changes

The New England Independent System Operator (ISO-NE) recently adopted market rule changes known as Pay for Performance (PFP) in an effort to address reliability issues of the region's electricity grid. Through the forward capacity market, PFP is intended to incentivize generators that receive capacity payment to "firm up" their fuel commitments, and thus eliminate the need for the Winter Reliability Program and other similar measures.[14] The PFP is intended to increase system reliability and is not designed to incent generators to invest in pipeline capacity on a long-term basis for the reasons discussed above. ISO-NE's own analysis of the impact of Pay for Performance indicates that for most natural gas-fired generators the most cost-effective—and for many, the only economically feasible—way to mitigate this risk will be to invest in dual fuel capability so that they can run on oil during those periods when pipeline natural gas is scarce. Generators may also contract for LNG, although there is substantial uncertainty about the price and availability of such arrangements. In concept, further market rule changes could be adopted to eliminate the mismatch. However, such rules would be likely to be controversial and take many years to be adopted and implemented.

2. North American Energy Standards Board

The FERC instituted the North American Energy Standards Board (NAESB) consensus forum that would involve both the electric and gas markets.[15] The NAESB consensus process provides an opportunity to introduce market reforms to both the gas and electric industries, including hourly pricing in the electric markets that reflects hourly constraints in the gas market. The reforms require pipelines to accept and schedule hourly variations in flow, thus facilitating hourly price signals that should better match the electric markets. The goal of these improvements is "to better

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[14] ISO-NE's Winter Reliability program included a number of measures designed to increase reliability through the use of winter demand response programs, incentives to ensure that oil-fired generators incrementally increase their fuel oil inventory, payments to dual fuel units for testing their switching capacity, and market monitoring changes aimed at increasing generators flexibility.

[15] See FERC RM-14-2-000, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, Notice of Rulemaking Proceeding (Mar. 20, 2014).

coordinate the scheduling of natural gas and electricity markets in light of increased reliance on natural gas for electric generation, as well as to provide flexibility to all shippers on interstate natural gas pipelines." FERC RM-14-2-000, NOPR Summary (March 20, 2014). It is hoped that the refined market design may make more efficient use of existing facilities to help mitigate the need for an expensive multi-decade commitment of dollars to bring forth potentially market disruptive capacity expansion. On July 8, 2014, the Commission registered to participate in meetings in this matter.

3. Governors Infrastructure Initiative

On December 5, 2013, the New England Governors issued a letter in which they committed to work together, in coordination with ISO-NE and through the New England States Committee on Electricity (NESCOE), to advance regional energy infrastructure expansion. The NESCOE initiative identified two primary goals: 1) expand pipeline capacity to increase natural gas supply into New England, reducing supply constraints and associated energy price volatility, and 2) expand electric transmission to facilitate utility-scale development and delivery of no-to-low carbon energy resources.

NESCOE responded by reaching out to the ISO-NE and other key stakeholders to develop potential solutions to the regional infrastructure issues. On June 20, 2014, NESCOE presented to NEPOOL a proposal on the tariff approaches for incremental transmission and natural gas pipeline capacity with the intent of a vote on the proposal in September, 2014. However, on July 31, 2014, the Massachusetts Legislature adjourned without acting on a bill to enable that State to procure levels of no-and/or low- carbon power and as a result NESCOE sought an extension of time on the NEPOOL vote so as to provide Massachusetts State officials time to evaluate options associated with moving forward.

VII. LEGAL ISSUES AND STATUTORY PREREQUISITES

Two legal questions were raised in this proceeding relating to our exercise of authority under the Act. First, is the Commission pre-empted under federal law from exercising the authority under the Act? Second, what is the applicable standard of proof when determining whether to enter an ECRC contract? We address these questions in subsections VII. A. and B.

In addition, in subsection VII.C., we will address whether the statutory prerequisites to entering an ECRC have been met.

A. Federal Preemption

CLF observes that Congress enacted the Federal Power Act (FPA) and the Natural Gas Act (NGA) and vested in FERC the exclusive authority to regulate wholesale energy rates. CLF contends that the primary purpose of the ECRA is to reduce the marginal price of electricity as set in ISO-NE's Forward Capacity Market by natural gas generators. CLF Brief at 23. CLF states that the dormant Commerce Clause prohibits states from regulating wholesale electric and gas sales between utilities in different states, because state regulation would place a direct burden on interstate commerce.[16] Because the Act sets out a scheme that seeks to directly impact wholesale electric and gas rates in interstate markets, CLF argues it impinges on FERC's exclusive jurisdiction over wholesale rate setting as established by the FPA and the NGA and violates the Commerce Clause. Accordingly, CLF reasons, the Act and any ECRCs entered into based upon it, violate the Supremacy Clause and the dormant Commerce Clause of the U.S. Constitution and are preempted by the FPA and NGA. *Id.* CLF argues that the Act puts in motion a series of actions that if undertaken by a private commercial entity "would amount to normal market behavior and interaction." CLF argues that these same actions, when undertaken by a state entity with express intent to influence energy markets, become federally preempted regulatory action affecting interstate wholesale rates. *Id.* at 24.

Several parties urge the Commission to reject CLF's interpretation of federal preemption. CMP states that CLF's arguments positing violation of the dormant Commerce Clause fail for several reasons. First, CMP asserts, the ECRA permits the State to participate in the natural gas capacity market as a market participant but does not regulate wholesale and gas sales. Therefore, CMP contends, the market participant exception to the Commerce Clause applies, citing *Tri-M Group, LLC v. Sharp,* 638 F.3d 406, 415 (3d Cir. 2011) ("courts treat the question of whether the state is acting as a market participant as a threshold question for dormant Commerce Clause analysis.") CMP Reply Brief at 9.

Further, CMP notes, more recent precedent than that cited by CLF replaced the "indirect-direct" Commerce Clause test with a determination of whether the state regulation discriminates against out-of-state interests, either on its face or in practical effect. If state regulation does discriminate, then it is usually unconstitutional. If not, then the *Pike*[17] balancing test applies to determine whether the putative benefits from the regulation exceed its burdens on commerce. *Id.* at 9-10. CMP concludes that the ECRA does not discriminate against out-of-state interests either in intent or practical effect as it facilitates price reduction benefits that would be enjoyed in the entire ISO-NE region. Moreover, CMP points out, the purpose of the Act is to increase natural gas capacity in New England for purposes of increasing access to natural gas by gas fired electric generators in an effort to reduce costs and increase reliability. CMP concludes that given the local interest in these effects, "it is likely that a reviewing court would allow a substantial burden." *Id. at 10, citing Pike, 397 U.S. 137 (1970)* at 142 ("the

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[16] The dormant Commerce Clause restricts states from either "unjustifiably … discriminating against or burdening the interstate flow of commerce" or imposing "regulatory measures designed to benefit in-state economic interests by burdening out-of state competitors." *See Baldwin v. G.A.F. Seelig, Inc.,* 294 U.S. 511, 522 (1935) and *New Energy Co. of Indiana v. Limbaugh,* 486 U.S. 269, 273-74 (1988).

[17] *Pike v. Bruce Church, Inc.*, 397 U.S. 137 (1970).

extent of the burden that will be tolerated will of course depend on the nature of the local interest involved.")

OPA urges us to reject CLF's "overly broad reading of the preemptive effect of FPA and NGA, which if adopted would make broad swaths of state actions on energy policy unconstitutional…" OPA Reply Brief at 10. OPA observes that even the case law cited by CLF warns against concluding that every statute that has some indirect effect on wholesale rates is preempted. Finally, OPA notes that the Commission recently addressed this issue in brief submitted to the Third Circuit Court earlier this year in *PPL Energy Plus, LLC v. Solomon, No. 13-4330 (3rd Cir., Jan. 24, 2014)* (stating "a decision affirming the District Court's unduly expansive view of federal jurisdiction under the Federal Power Act ("FPA") could spark a firestorm of litigation challenging long-standing procurement practices that enable States to ensure that their citizens are safely provided with reliable, clean, and affordable supplies of electric power.")

TGP also rejects CLF's assertion of federal preemption, observing that neither the Act nor the execution of an ECRC constitutes a regulatory measure designed to benefit in-state economic interests by burdening out-of-state competitors. TGP Brief at 38. TGP argues that nothing in the record suggests the existence of any discrimination or any burden on commerce. TGP posits that entering a well-structured ECRC would also fall within the "market participant" doctrine which allows the state to favor its own citizens over others. Id. at 39. Similarly, TGP argues that CLF's attempts to invoke preemption under the Supremacy Clause of the U. S. Constitution also fail because nothing in the Act or in the record of this proceeding evidences an intent to regulate matters within the scope of the FPA or NGA. Id. Neither the Act nor an ECRC would attempt to set a specific rate for wholesale electricity or natural gas transportation or sales. Id. at 40.

> 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.

B. Standard of Proof

Prior to approving any ECRC, the Act requires the Commission to determine whether the contract is “reasonably likely” to achieve the goals of the Act. 35-A M.R.S. § 1904(2). A question has been raised regarding what should be the required standard of proof for whether the objectives in the Act are reasonably likely to be met; specifically, whether an elevated standard of review should be adopted, such as a “high level of confidence.”

CLF argues that a heightened review is appropriate due to the unprecedented nature of the Act, the large potential cost of an ECRC to the State’s ratepayers, and the risks of market intervention in the highly volatile natural gas markets. For these reasons, CLF recommends that the Commission adopt the "high level of confidence" standard of proof in this proceeding as it did when establishing the system benefit charge for the Efficiency Maine Trust's (EMT) Triennial Plan. *Order Approving Efficiency Maine Trust's Second Triennial Plan,* Docket No. 2012-00449 at 14, 32 (Mar. 6, 2013).

CMP argues that an enhanced standard of review is not warranted in this case, stating that the standard of proof generally used by the Commission is the preponderance of evidence standard. CMP notes that the Commission has not used an enhanced standard in examining long-term contract proposals under either Section 3210-C or the Ocean Energy Act (P.L. 2009, ch. 615), and that the Commission awarded long-term contracts for off-shore wind projects with estimated over-market costs of approximately $190 million and $187 million respectively, *Orders Approving Term Sheets,* Docket No. 2010-235 (February 26, 2103 and February 19, 2014).

The Joint Parties argue that "reasonably likely" is a lower standard than a preponderance of the evidence, set purposefully by the Legislature to reflect the urgency with which the Commission should act to alleviate the harmful effects of the present energy market conditions to Maine and its confidence in the Commission. Joint Parties' Brief at 8. The Joint Parties reference Law Court case precedent and conclude that it is a very low threshold to meet.

BGC argues that the cases cited by the Joint Parties are not parallel with the task before the Commission here and that the standard should be higher than preponderance of the evidence. BGC Reply Brief at 1-2. BGC contends that the use of "reasonably likely" in the context of approval of an ECRC is more like the Commission's approval of long-term contracts for renewable energy contracts. *Id.* BGC asserts that the statutory standard must require that the Commission find that an ECRC is "likely" to yield benefits to ratepayers, similar to the directives in 35-A M.R.S.§ 3210-C. *Id.* at 3.

We acknowledge that this proceeding is unprecedented in many ways and that the consideration of an ECRC raises substantial issues of risks and costs to ratepayers and market interference. As a general manner, the Commission carefully scrutinizes the evidence and arguments in any proceedings that involve potential risks and costs to ratepayers. Due to the potential consequences of any decision regarding an ECRC, we will proceed cautiously and carefully to examine the risks, costs and benefits to ratepayers of any ECRC. In doing so, we will examine all proposals under various future scenarios using relatively conservative assumptions so that we can have a high degree of confidence that an ECRC will benefit ratepayers.

In this sense, there is no practical disagreement as to how the Commission should proceed to analyze ECRC proposals. As to the particular standard of proof, the Commission's general practice is to apply a preponderance standard. *See, e.g., Bangor Hydro-Electric Company, Proposed Schedule to Provide for Residential Heat Pump Service Rate,* Docket No. 92-255 (Mar. 19, 1993). We see little purpose to creating a precedent of deciding on a case-by-case basis whether preponderance or some heighted standard should be employed based on a determination of the "importance" of the particular proceeding. This is especially the case in that the Commission, unlike a court, has an affirmative duty to act in the public interest and, accordingly, it is extremely rare for the Commission to decide a proceeding based on the burden of proof or standard of review. We will, therefore, generally apply the "preponderance of the evidence" standard in this and other Commission proceedings relating to determinations made under the Act.

C. Statutory Prerequisites and Requirements

As a prerequisite to pursuing and ultimately executing an ECRC, the Act requires that the Commission: (1) pursue market and rule changes to address the basis differential for gas coming into New England; 2) explore all reasonable opportunities for private participation in securing additional gas pipeline capacity; and 3) in consultation with the Public Advocate and the Governor's Energy Office, hire a consultant with expertise in natural gas markets to make recommendations regarding the execution of an energy cost reduction contract.

These prerequisites have generally been satisfied. The Commission has participated in regional and federal forums. These activities have included participation in FERC Dockets AD12-12-000, RM14-2-000, EL13-66-000,[18] establishment of the New England Gas-Electric Focus Group, and participation in processes to develop market rule changes directed at improving the efficiency gas/electric industry coordination. The Commission has also, as a primary focus of this proceeding, explored all reasonable opportunities for private participation in securing additional gas pipeline capacity that would achieve the objectives of the Act. Finally, to satisfy the requirements of Subsection 1(C) of Section 1904, the Commission retained Sussex Economic Advisors, LLC ("Sussex") which has produced a report entitled "Maine Public Utilities Commission Review of Natural Gas Capacity Options", dated February 26, 2014 (the "Sussex Report).

Before entering into an ECRC, the Act requires the Commission to determine, in an adjudicatory proceeding, that the agreement is commercially reasonable and in the public interest and that the contract is reasonably likely to: (1) materially enhance natural gas transmission 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.

Any 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. The question of whether an ECRC would be reasonably likely to enhance natural gas transmission capacity into

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[18] FERC Docket EL13-66, *New England Power Generators Assoc., Inc. v. ISO New England Inc.*

the State or into the ISO-NE region in a manner that would benefit be beneficial to consumers can only be determined by analyses of specific proposals.

In addition, the Act precludes execution of an ECRC if the Commission concludes that market or rule changes and/or private participation in securing additional pipeline capacity would achieve substantially the same cost reduction benefits for Maine consumers as an ECRC. Because time has not allowed these events to play out, the effects of recently announced pipeline expansion projects and market rule changes such as PFP is not yet known. However, this does not preclude the Commission from moving to Phase 2 of this proceeding, in which specific ECRC proposals and the effects of market rule changes and private investments can be considered on a parallel track.

VIII. THRESHOLD DETERMINATIONS BEFORE EXECUTING AN ENERGY COST REDUCTION CONTRACT

A. Existence of Market Failure

The purpose of the Act is not to interfere with an otherwise functioning market simply to collapse the basis differential, but rather to address any market failure to protect Maine consumers from the present economic phenomenon whereby they are subject to a much higher basis differential than the rest of the country. Thus, an initial question the Commission must address in this proceeding is whether there is some type of structural flaw or “market failure” that prevents the market from acting efficiently and making the necessary investments to sufficiently expand pipeline capacity into the region. If a market failure does exist, we must determine whether an ECRC is an appropriate means to address an existing market failure and, if so, will the benefits be reasonably likely to outweigh the costs.

There is evidence in the record to support a finding of market failure. Based on the analyses of forward price basis differentials, Brattle Group witnesses Newell and O’Laughlin concluded that, “basis differentials appear to exceed the cost of new capacity while fundamentals are arguably tightening, and yet no market participants (other than gas LDCs to meet their own customers’ load) are signing up for firm transportation service to support capacity expansion.” This lack of commitment from competitive market participants may be an indicator that the market is failing to operate efficiently. However, the recently announced expansion projects described in Section VI.A. suggest that market participants may be responding to the fundamentals, and it remains unclear at this point to what extent the market will by itself invest in sufficient levels of new capacity.[19]

B. Private Sector Investment

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[19] We are as yet unable to determine whether these preliminary responses are entirely from regulated entities such as LDCs, or include competitive market participants responding to recent structural changes in electric markets.

Pursuant to the Act, before an ECRC can be authorized, the Commission must explore the potential for the private sector investment in increased pipeline capacity. Only after determining that private sector actions will not resolve the basis differential issue would the Commission undertake action authorized by the Act to cause an ECRC to be entered. The question the Commission must answer is whether the level of proposed private sector investment in regional pipeline expansion will sufficiently reduce the burdensome costs to Maine energy consumers of the high localized basis differential, and further, if not, whether an ECRC will do so.

As noted above, there is a substantial amount of pipeline expansion proposed to be placed in service in the region over the next 2 – 4 years. The record also indicates numerous countervailing events, such as non-gas filed generating plant closures, that may spur greater demand for natural gas fired generation in New England. Consequently, at this point, it remains unclear whether these incremental long-term capacity expansions described above will achieve the electric price reduction objectives of the Act.

In addition, it is too early to tell what effect the ISO-NE, FERC and NAESB market reforms will have on the supply/demand balance for gas at peak times and, correspondingly, the basis differentials during those peak times. However, most of the evidence in the case suggests that the PFP market rules would not cause generators to invest in pipeline capacity.

IX. POTENTIAL FOR BENEFITS FROM AN ENERGY COST REDUCTION CONTRACT

The primary question to be addressed in this proceeding is whether an ECRC is an appropriate means to address any existing market failure and, if so, will the benefits be reasonably likely to outweigh the costs. Based on the evidence before us, we conclude that it is not likely to be in the best interest of Maine consumers for the State to act alone in this regard, as the costs of a Maine-only ECRC would likely exceed the benefits.[20],[21] This is the case because (1) the costs would be fully born by Maine consumers, yet the benefits would be spread region-wide; and (2) due to the likelihood that new capacity will be funded by firm contracts from the private sector (see Section VI.A. above), the incremental benefits of an ECRC diminish significantly.

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[20] Given the status of the Governors' Initiative and any effort to invest in pipeline capacity on a regional basis, we have limited our review to the potential benefits of a Maine-only ECRC.

[21] The evidence and analyses discussed in this section appear to include only benefits to electricity consumers, and appear not to include potential benefits to natural gas consumers, nor potential benefits from an ECRC as a "hedge". As noted in Section X below, these potential benefits will be considered in our consideration of specific ECRC proposals.

There could be circumstances that would change these conclusions. For example, if Maine could acquire firm capacity very inexpensively, or if no other expansion projects move forward, it is possible that a Maine-only ECRC could be beneficial. However, it is more likely that the costs of a Maine-only ECRC would exceed the benefits. These conclusions are drawn from our review of the evidence and analysis presented by Sussex and CES as discussed below.

A. Sussex Report

The Commission retained Sussex Economic Advisors, LLC (Sussex) which has produced a report entitled "Maine Public Utilities Commission Review of Natural Gas Capacity Options", dated February 26, 2014 (Sussex Report). The Sussex Report was commissioned pursuant to the Act's requirement that, prior to entering into any ECRC, the Commission in consultation with the Public Advocate and the Governor's Energy Office, hire a consultant with expertise in natural gas markets to make recommendations regarding the execution of an energy cost reduction contract. Sussex developed a range of reductions in New England Locational Marginal Prices (LMPs) of electricity as a function of reductions in the basis differential. The Sussex report examined the basis differential between New England and its traditional gas supply region, the Gulf of Mexico. Sussex also developed a range of costs for additional pipeline capacity for a range of capacity from 350,000 to 700,000 Dth/day. Costs for the incremental capacity were assumed to range from $1.00 to $2.00 per Dth/day.

The Sussex Report indicates that it is unlikely that a Maine-only ECRC would be cost effective. Sussex estimated the potential electric LMP savings from a range of reductions in the basis differential from 25% to 75% against annualized costs for pipeline capacity ranging from $1.00 to $2.00 per Dth/day. To illustrate the potential effect on the basis differential from incremental pipeline capacity, Sussex observed that the expected addition of the Spectra AIM (342,000 Dth/day) and the TGP Connecticut Expansion (72,000 Dth/day) projects to the New England region in November 2016 corresponded with a forward natural gas price reduction of approximately 35%. Sussex also observed that the addition of over 1,000,000 Dth/day of pipeline capacity into New York City corresponded to a 65% to 70% reduction in forward natural gas prices there.

By way of illustration, using the mid-point of its pipeline capacity cost estimates and assuming Maine contracted for 50,000 Dth/day, Sussex determines that annual costs to the State of Maine would be $27 million. To achieve this same level of savings in electricity prices, Sussex notes that the ECRC must result in a basis reduction in the range of 15% to 20%. Based on the observed relationships of the other expansions on the forward prices, Sussex concludes this 1% incremental capacity addition to the region is not likely to have a substantial effect on the basis premiums for the region.[22] At the maximum amount of capacity permitted by the Act

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[22] "50,000 Dth/day represents an incremental capacity addition of approximately 1% of peak day demand for New England. A capacity addition of that magnitude is not

(200,000/Dth/day), assuming it could be acquired at the lowest price in the range explored by Sussex, the annual costs to Maine would be $73 million. To achieve this level of savings in electric LMPs, the corresponding basis reduction would have to exceed 45%. We believe this level of savings is unlikely from a 200,000 Dth/day expansion given that the 410,000 Dth/day combined AIM and TGP CT expansions correlated to only a 32% reduction in forward natural gas prices.[23]

B. CES Analysis

A second estimate of the economic effects of constrained gas pipeline capacity on LMPs was provided by Competitive Energy Services (CES). The CES testimony updated two earlier estimates CES had conducted for the IECG on the reduction to electric LMPs attendant with increased gas pipeline capacity in New England. The CES model estimates the impact of gas pipeline capacity constraints on LMPs by using available data on the existing gas pipeline capacity into the region. It also relied on prior studies of regional natural gas demand – including LDC weather sensitive and weather non- sensitive demand. Based on hourly reported generation unit dispatch by the ISO, electric generation demand was also estimated. By developing its model in this way, CES was able to estimate the impact various amounts of pipeline expansion would have on the marginal electric prices.

CES estimated the economic benefits of potential new pipeline capacity to New England, based on estimated supply (deliverability) and demand for natural gas, and the impact on gas prices. It then calculated the impact of gas prices on LMPs. Although before making a final determination on any ECRC the Commission would develop its own estimate of benefits, the CES analysis provides a useful basis for examining the potential for an ECRC to be beneficial.

Although the CES analysis addressed only the potential benefits of new pipeline capacity and not the costs, we can examine “breakeven” points for costs to provide insight into the potential net benefit of an ECRC.

CES provided the economic benefits of adding pipeline capacity in the following increments.[24] (As we understand the CES analysis, these increments are relative to currently existing capacity levels, and reflect no assumptions or forward-looking projections of expansion projects, such as those discussed in Section VI.A.)

- The first 200 MMcf/d of capacity saves New England consumers $690 million per year in energy costs from the power sector;
- The second 200 MMcf/d saves consumers another $591 million;

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likely to have a substantial effect on the basis premium for the New England region.” Sussex Report at 62, bullet 1, sub-bullet two.

[23] Sussex Report at 48.

[24] CES Prefiled Testimony at 26.

- The third 200 MMcf/d saves consumers another $467 million;
- The fourth 200 MMcf/d saves consumers another $418 million;
- The fifth 200 MMcf/d saves consumers another $284 million, and so on;

The results reported by CES are for all of New England. Maine consumes about 10 percent of the power in New England,[25] so benefits to Maine would presumably be about 10 percent of the benefits to New England, assuming no substantial transmission congestion.

As shown in the table below, the "breakeven" costs of an ECRC range widely depending on how much other pipeline capacity is added. At the high end, which assumes that the Maine ECRC provides the only new capacity for the region, the "breakeven" cost point is $0.95 per Dth/day, which is below the low end of the cost range assumed in the Sussex Report. Moreover, as discussed in Section IX.A. above, because of the Spectra AIM and TGP CT Expansion projects, which will add more than 400,000 Dth/day of capacity for the region, a Maine ECRC would be in the third or higher tranche, requiring the cost per decatherm to be substantially less to reach the breakeven point, as shown in Figure 8 below.

Figure 8: Illustration of Potential ECRC Benefits/Costs

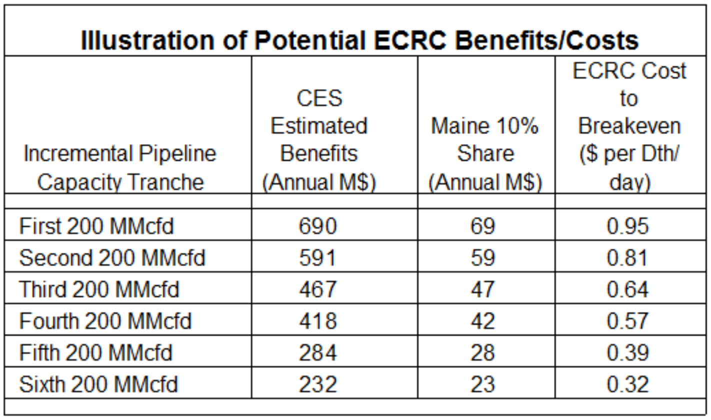

Illustration of Potential ECRC Benefits/Costs

Incremental Pipeline Capacity Tranche	CES Estimated Benefits (Annual M$)	Maine 10% Share (Annual M$)	ECRC Cost to Breakeven ($ per Dth/ day)
First 200 MMcfd	690	69	0.95
Second 200 MMcfd	591	59	0.81
Third 200 MMcfd	467	47	0.64
Fourth 200 MMcfd	418	42	0.57
Fifth 200 MMcfd	284	28	0.39
Sixth 200 MMcfd	232	23	0.32

Although CES's analysis implied it would not be favorable under most circumstances for Maine to go forward on its own, in testimony, Dr. Silkman argued somewhat differently. He stated that Maine should consider going forward alone, and then asking the New England states to hold it harmless if regional actions that expand gas capacity (such as the Governor's Initiative under way in the NESCOE process) were to impact the value of Maine's investment. The problem with this position is that even if the states held Maine harmless from the effects of state-sponsored projects, this would not protect the value of Maine's investment from the impacts of private pipeline development. It does not matter who builds the other capacity or when it is built—any new capacity at any time would reduce the impact and value of an ECRC. A "hold harmless" agreement, because it would apply only to state-sponsored capacity, would

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[25] ISO-New England Capacity, Energy, Loads, and Transmission (CELT) reports.

not protect Maine from the effects of capacity built by the private sector, which as noted above, includes over more than 400 MMcf/d of private sector capacity already under development.

In summary, we conclude:

- Because the analyses in the record (Sussex, CES) do not provide forward projections of gas supply or demand, we cannot determine the extent to which the private sector investments already underway will by themselves reduce basis substantially once they go into service;

- There is already more than 500 MMcf/d of new pipeline capacity in development by the private sector;

- The new capacity will very likely reduce basis, which would provide benefits to Maine consumers through lower power prices, without any cost to Maine consumers;

- New capacity would reduce benefits of an ECRC through reduction in basis and narrower opportunities for arbitrage;

- Based upon CES's estimate of benefits and a range of firm pipeline capacity costs, under certain scenarios a Maine-only ECRC could provide some net benefits, but such potential benefits are strongly dependent on the contract cost as well as the amount of pipeline capacity caused to be built by others (including the private sector and other states);

- A "hold harmless" agreement could be difficult to implement and, even if implemented, would not hold Maine harmless from the effects of private sector investment.

X. PHASE 2 – CONSIDERATION OF ECRC PROPOSALS

As discussed in Section IX above, it appears that a Maine-only ECRC is not likely to provide net benefits to Maine consumers. However, given the importance of this matter, the uncertainty with respect to the effects of market rule changes and private investment, and the possibility that, under some conditions, an ECRC could be beneficial, we decide to move forward to Phase 2 in which specific ECRC proposals will be considered and evaluated. Because this section of the Order contains the requirements for and evaluation criteria of ECRC proposals, there is no need for the issuance of a formal Request for Proposals.[26]

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[26] This Report does not address whether or when the Commission should consider the ECRC proposals that have been filed in this case to date. However,

Rather, we discuss below how the solicitation will be structured, when proposals will be due, and how the proposals will be evaluated. We emphasize that, during Phase 2, we will continue to monitor and assess the effects of market rule changes and private investment, and will include these factors in our evaluation of ECRC proposals.

Finally, we observe that the ECRA authorizes the commission to enter into an ECRC until 2018. We do not here determine what further process we might adopt or whether or when we would be invite offers at other junctions in the future. We may consider these issues in Phase 2, including whether to establish an annual filing date or to consider additional proposals only when there are significant changes in the region that indicate action may be warranted.

A. Contract Counterparty

CMP has taken the position that the commercial counterparty to any ECRC should be a regulated utility, as opposed to the Commission itself.[27] We agree with CMP in this regard. A private gas industry enterprise may not have experience in contracting directly with a regulatory agency, such as the Commission, and may view such a contract as inherently risky. Moreover, project developers seeking an ECRC may have credit support demands that can be met only by certain creditworthy counterparties, such as regulated utilities

We also agree with CMP and the Joint Parties that the determination of which utilities would be counterparties to an ECRC will be based on to which group(s) of consumers the benefits would flow. The allocation of costs among electric and gas customers[28] in Maine will be in proportion to the benefits that they realize from an ECRC.[29] In determining the extent to which an LDC would have ECRC counter-party or cost obligations, the Commission will consider the LDC's existing firm capacity commitments and will not assign cost responsibility of an ECRC to LDCs that have acquired sufficient pipeline capacity on their own. Finally, consistent with 35-A M.R.S. § 1904(3)(A), utilities that enter into an ECRC will receive timely cost recovery.

B. Proposal Requirements

Parties are free to comment on this in exceptions, as they are on whether to reopen the record to obtain further evidence regarding the Access Northeast project.

[27] CMP Brief at 11.

[28] CLF argues that it is somehow inappropriate for the Commission to direct ECRC cost recovery from electric customers because the contract is for natural gas pipeline capacity. We reject this argument. Upon a finding that an ECRC will reduce electricity costs, it would appear evident that it is appropriate for electric ratepayers to bear a fair share of the costs of the contract.

[29] We do not decide now whether customers of consumer-owned utilities will be allocated costs of an ECRC.

To move forward with Phase II, the Commission requests that all ECRC proposals be submitted by a date to be determined by the Commission. At that point, the Commission will, in an adjudicatory proceeding, evaluate the proposals and decide whether to pursue discussions regarding one or more of the proposals.

Phase 2 proposals shall, at a minimum, include:

- **Project and facility description,** including route; points of receipt and delivery and liquidity of those points; maximum daily quantity; delivery pressure; greenfield project versus take-up and relay; addition of compression; project status.
- **Type of product provided,** including: volume of capacity, or options for volumes of capacity; term of ECRC (number of years); scalability of project and ECRC; receipt and deliver point flexibility and options.
- **Financial bid**: Price per dekatherm for the ECRC as well as unit price (per dekatherm or million cubic feet) for the entire route from the supply region if more than one pipeline is needed to complete the route from supply region to Maine not just the incremental ECRC cost for the segment proposed.
- **Project and construction schedule,** including major milestones such as expected receipt of all regulatory approvals; current status of permits; completion of engineering design; procurement of construction materials; major construction activities; availability for testing; the date of commercial operation; status of open season process.
- **Bidder’s credit information,** including but not limited to a description of corporate structure; three years of financial statements for the bidder; a description of any financial security associated with the proposal.
- **Experience and references:** A general description of the bidder’s background and experience in pipeline projects similar to this project, including any affiliated companies, holding companies, subsidiaries or predecessor companies. Safety performance records should also be included.
- **Risk mitigation:** For example, consequences of delays in operation date.
- **Frequency of nominations allowed**.
- **Benefits associated with the applicable trading hub(s)**

C. Evaluation Criteria

In considering ECRC proposals, as directed by statute, the Commission’s primary evaluation criteria will be the net benefits to Maine ratepayers. Consistent with our approach when evaluating other long-term ratepayer commitments, such as long-term contracts authorized pursuant to 35-A M.R.S. § 3210-C, we will examine the costs and benefits of the 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. Although we will not adopt a strict Total Resource Cost metric, as suggested by the OPA, we will be cognizant of simple wealth transfers in our evaluation.

We generally agree with the OPA that the Commission should include in its evaluation a wide range of customer benefits. These include: reductions in electricity costs to Maine consumers; increased reliability benefits (including a reduction in reliability costs; revenue from re-sale of pipeline capacity; hedge value; structural benefits to Maine’s pipeline infrastructure; and carbon and other emission reductions.

As noted in Section VII.C. above, we would also consider the potential benefits to natural gas consumers. Although LDC’s may acquire firm pipeline capacity for some of their customers, a large percentage of natural gas usage in Maine is served by short-term or interruptible capacity and, thus, would likely benefit from an ECRC.[30] Other important evaluation criteria will include the potential for coordination of a Maine ECRC with regional pipeline capacity efforts, project timing and flexibility, and the length of the payback period. We decline to establish a specific scoring system at this time, as urged by some of the parties.

Finally, during Phase 2 we will continue to monitor and assess the effects of market rule changes and private investment, and will include these factors in our evaluation of ECRC proposals.

October 1, 2014

Respectfully Submitted,

/s/ Carol A. MacLennan
Carol A. MacLennan

/s/ Mitchell Tannenbaum
Mitchell Tannenbaum

With Advisory Staff

Faith Huntington
Denis Bergeron
Michael Simmons

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[30] The Act recognizes this and provides an explicit mechanism (“Volumetric fee”) to allow the Commission to allocate costs to such customers in proportion to the benefits they would realize. 35-A M.R.S. § 1905(3).