REDACTED

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2012-00504

December 18, 2013

MAINE PUBLIC UTILITIES COMMISSON
Long-Term Contracting

ORDER DIRECTING UTILITY TO ENTER INTO LONG-TERM CONTRACT

WELCH, Chairman; LITTELL and VANNOY, Commissioners

I. SUMMARY

Through this Order, we direct one or more of Maine's investor-owned transmission and distribution utilities to enter into long-term contract(s) for capacity and energy with Apex Clean Energy Holdings, LLC (Apex), for the output of the Downeast Wind Project (Downeast Wind). The Project is a 90 MW wind facility to be constructed in Washington County, Maine. The Commission will determine the utility contractual counterparties during the process of approving the final contract(s).[1]

II. PROCEDURAL BACKGROUND

During its 2006 session, the Legislature enacted an Act to Enhance Maine's Energy Independence and Security (Act). P.L. 2005, ch. 677. Part C of the Act (codified at 35-A M.R.S. § 3210-C) authorized the Commission to direct investor-owned transmission and distribution (T&D) utilities to enter long-term contracts for capacity resources and associated energy. As required by the Act, the Commission adopted rules to implement the Act (Chapter 316).

Chapter 316, § 5.B. provides that the Commission solicit bids for long-term contracts with capacity resources through the issuance of a request for proposals that contain all standards, procedures and requirements for the solicitation process, as well as a standard form contract. In 2008, the Commission issued its first long-term contract request for proposals, which resulted in the Commission ordering Central Maine Power Company (80% of the output) and Bangor-Hydro-Electric Company (20% of the output) to enter into a long-term contract with Evergreen Wind Power III LLC on October 8, 2009. A second request for proposals, issued in 2010, resulted in the Commission directing CMP to enter into a five year contract with the Verso Renewable Capacity

[1] Commissioner Littell writes a separate concurrence. See attached Opinion of Commissioner Littell. Commissioner Vannoy dissents. See attached Dissenting Opinion of Commissioner Vannoy.

Project on January 12, 2011. On October 24, 2012, the Commission issued a third request for proposals pursuant to 35-A M.R.S.§ 3210-C and Chapter 316 of the Commission rules entitled Request for Proposals for Capacity and Associated Energy and/or Renewable Energy Credits (2012-1013 Release) (RFP).

Pursuant to the RFP, initial proposals were due on or before March 1, 2013. The Commission received multiple timely submissions.

After Staff discussions of initial proposals with the fourteen RFP respondents, the following six proposals were put out for comment to OPA, CMP, and BHE and submitted to the Commission for formal consideration:

1. Project 1- A portfolio of existing renewable resources located in the State of Maine
2. Apex Wind Energy Holdings LLC-Downeast Wind Project- A new 90 MW wind facility located in Washington County, Maine
3. Project 3- A new renewable energy facility located in Maine
4. Project 4-[2] A new renewable energy facility located in Maine
5. Project 5- An existing energy facility not located in Maine
6. Project 6- A new energy facility located in Maine.

CMP, BHE, MPS and the Public Advocate filed comments on the proposed contracts. On September 24, 2013, five of the six projects were then submitted to the Commission for deliberation.[3]

III. CONTRACTING AUTHORITY

A. Overview

As stated above, section 3210-C of Title 35-A, provides the Commission with the authority to direct investor-own utilities to enter into long-term contracts for capacity and energy under certain circumstances. The underlying purpose of this authority, in the Commission's view, is to take advantage of opportunities to use long-term contracts for capacity and energy with utilities as a means to lower capacity and energy costs or otherwise benefit Maine ratepayers. A long-term contract with a

[2] Project 4 submitted two different project scenarios for Commission consideration the first involved a twenty-five year contract term and the second a forty-five year term.

[3] Project 6 requested additional time to restructure its proposal and will be brought before the Commission at a later date.

creditworthy counterparty such as a utility can be very valuable to developers or owners of generation resources and may be necessary to obtain financing for new projects. Accordingly, project developers and owners may be willing to offer utilities contractual terms that would be beneficial to electricity ratepayers. For example, project developers or owners may be willing to sell capacity and energy at a discount from expected future prices. Such contracts may also provide a low-cost hedge against possible rising electricity prices. Moreover, by allowing for financing of projects and subsequent development that might not otherwise occur, long-term contracts could facilitate the construction of generation facilities in Maine. Such new generation could serve to lower capacity costs in Maine, enhance reliability, reduce volatility and greenhouse gases and promote the State's renewable energy development policies. *See* 35-A M.R.S. §3210-C (2) & (3).

B. Statute

Section 3210-C specifies that the Commission may direct investor-owned T&D utilities to enter into long-term-contracts for "capacity resources" and any available energy associated with the capacity resource to the extent that the purchase of the energy fulfills the State's renewable energy expansion policies, or will lower the cost of electricity for ratepayers. 35-A M.R.S. § 3210-C(3). The statute specifies that the Commission select proposals that are competitive and the lowest cost relative to similar bids. Among such proposals, the statute provides a priority order that establishes new resources as well as renewable resources as a high priority in the selection of proposals. 35-A M.R.S. § 3210-C(4).

Section 3210-C also specifies that the long-term contracts should be no more than 10 years, unless the Commission finds that a longer term to be prudent. Finally, the section requires the Commission to ensure that long-term contracts be consistent with the State's goals for greenhouse gas reduction and the regional greenhouse gas initiative.

C. Implementing Rules

The Commission's long-term contracting implementing rules (Chapter 316) state that contracts for capacity resources may not exceed the amount necessary to ensure the reliability of Maine's grid or to lower customer costs. Specifically, the rules state that the Commission may authorize a contract for capacity resources if: 1) the contract is a least cost means to address a local grid reliability need; 2) the contract is necessary for the resource to be developed, the resource will significantly lower regional capacity costs, and the contract prices are not expected to be higher than market prices; or 3) the contract prices are significantly below expected market value. The rules further state that the Commission may authorize contracts for associated energy if: 1) the contract is necessary to fulfill the State's new renewable resource policy, is necessary for the resource to be developed, and the contract prices are not expected to be higher than market prices; or 2) the contract prices are significantly below expected market value. Ch. 316, §5.

IV. COMMENTS

A. Office of the Public Advocate

OPA submitted comments on the six proposals on August 15, 2013. As a threshold matter, OPA questioned the statutory authority of the Commission to direct utilities to enter into long-term contracts that do not contain a separate provision for a capacity product and the benefits of capacity provided under the contract must be analyzed separately from any associated energy. In the view of OPA, if the contract does not provide a capacity product, the Commission may not authorize a contract for energy because it would not be associated with capacity resources under paragraph A of 35-A M.R.S. § 3210-C.

OPA also raised concerns over the assumptions used in the Staff cost/benefit analysis of the proposals. Specifically, OPA found that it was inappropriate to include any scenario that incorporated a carbon regime, that the ISO-NE CELT 2012 Report load growth forecasts were too aggressive, and that capacity prices after 2019 were most likely too low considering proposed revisions to the forward capacity market.

OPA also indicated that only the Project 5 proposal would qualify as a capacity resource and thus, in OPA's view, meet the statutory requirement for a capacity resource contract. In addition, OPA's interpretation of Staff's analysis found that Project 5 proposal would also provide the strongest likelihood of benefit to the ratepayers through lower electricity prices. Although OPA did list the other proposals by order of preference, it recommended a contract only with Project 5 and against the other proposed contracts.

B. Utilities Comments

In its comments, CMP stated that both the "bundled" energy and capacity structure of certain proposals and the "pass-through" approach proposed by others create significant risk to both the T&D counterparties and ratepayers and provide no concrete benefit. CMP's preference is that a capacity product not be included with the long-term contracts. In addition to the structural issue with the capacity inclusion, CMP stated that the long-term contracting statute envisioned the creation of a bi-lateral market in ISO-NE not the forward capacity auction that was developed. As it currently exists the only opportunity for a transaction in capacity is through a contract for differences which creates accounting difficulties for CMP.

CMP noted that the contracts proposed presented significant risk over their terms and should not be entered into unless significant financial benefits are reasonably certain to be obtained for ratepayers. CMP's belief is that this is a high barrier to meet, "where significant and certain benefits would need to be demonstrated before a long-term contract could be found necessary". CMP continued by noting that the bar was set even higher for existing projects as the statute has clearly demonstrated preference for new capacity resources. Based on its interpretation of the statute and analysis, CMP concluded that none of the proposed contracts would provide the required level of financial benefit to offset the risks proposed by such contracts.

BHE/MPS overall had more optimistic view of the proposals' potential benefit to ratepayers and based on their analysis recommended entering to contracts with all of the six proposals provided that:

- the Commission is satisfied the proposed contracts provide sufficient protections to ratepayers in the event Maine LMP's are lower than forecasted;
- that the resulting portfolio represents a reasonable percentage of the total state energy portfolio, diversity of generation types, and contract terms; and
- that allocation is fair across all T &D utilities' service territories.

V. DISCUSSION

A. Legal Analysis of Capacity Requirements in Long-term Contracts

As noted above, OPA raises the issue of the interpretation of the term "capacity resource" in the enabling statute. On its face, in certain provisions of the statute, the language does appear to suggest that all long-term contracts under 35-A M.R.S. § 3210-C should contain a transaction for a capacity product; however, other provisions in section 3210-C use the term "capacity resource" more broadly. In their totality, the statutory provisions indicate that a "capacity resource" is a physical generating plant as opposed to a commodity that is being transacted in the regional market.

Section 3210-C(1)(A).defines "capacity resource" as "any renewable capacity resource, nonrenewable capacity resource or interruptible, demand response or energy efficiency capacity resource." A "nonrenewable capacity resource" is defined as an "electric generation resource other than a "non-renewable capacity resource." 35-A M.R.S § 3210-C(1)A).

Section 3210-C(1)(D) defines "renewable capacity resource" as having the same meaning as in section 3210(2)(B-3) , which states "Renewable capacity resource" means a *source of electrical generation* (emphasis added).

When read together, the statutory definitions indicate that the term "capacity resource" means a physical generating plant as opposed to capacity as a commodity. Accordingly, we disagree with OPA that a capacity commodity component must be analyzed separately and found to be beneficial to ratepayers before an energy transaction can be authorized.

B. Award of Long-term Contract to the Downeast Wind Project

Downeast Wind is a new 90 MW wind generating facility proposed to be developed in Washington County in BHE service territory within the towns of Cherryfield and Columbia, Maine, The project anticipates that commercial operation will begin before the end of 2016.

The Apex proposal is structured as a long-term contract for the entire energy output and capacity value of Downeast Wind. The contract is for a twenty-year term beginning with the commercial operation of the facility. The energy produced under the contract is priced at 88% of the real time locational marginal price at the future ISO-NE designated node for the Project in the day-ahead market (DALMP). The contract will have a price floor of $45/MWh at the interconnection node in year 1, escalating at 1.5%, with a ceiling of $110 MWh. Apex will retain all renewable energy attributes from the project.

Downeast Wind will be required to use commercially reasonable efforts to qualify the facility into the ISO-NE Forward Capacity Market (FCM). If Downeast Wind participates in the FCM, 50% of all of the capacity revenue shall be credited to the T&D utilities. Beginning in June 2020, in each month that Downeast Wind does not qualify, clear and deliver to the FCM at least 30 MW of capacity, for each kW of shortfall below 30 MW, the contract payments would be adjusted downward by an amount equal to the kW shortfall times $4.00 per month up to an annual maximum adjustment of $200,000.

We begin our analysis by determining whether the Apex proposal satisfies the requirements of Section 3210-C, principally whether it presents a sufficient likelihood of ratepayer benefit through lowering electricity costs and providing a volatility hedge over the term of the contract. *See* 35-A M.R.S. §3210-C (2) & (3). We note our general agreement with the utilities that there is risk to long-term contracts in that their economics depend on future projections of energy and capacity prices and, in the case of the proposed contracts, the energy pricing is sensitive to the assumed differential between the node LMPs and the hub LMPs. It is for this reason that we take into account both quantitative economic analyses (including sensitivity analyses), as well as more qualitative considerations.

The analysis of the likelihood of ratepayer benefits involves the comparison of proposed long-term contract prices with the future capacity and energy costs and, thus, involves forecasts of future energy prices. Using "high" estimates of future natural gas prices and potential carbon policies, a proposal becomes attractive. On the other hand, under "low" estimates of future prices, a proposal becomes much less attractive. In addition, we have analyzed proposals with respect to the policies of section 3210-C, hedge value, volatility reduction, impact on the competitive electricity environment, and price suppression potential.

Considering the above criteria, we approve only the Downeast Wind proposal. Downeast Wind satisfies all of the policy goals outlined in section 3210-C(2) and is the most advantageous under the prioritization criteria outlines in section 3210-C(4). This project presents a sufficient likelihood of providing ratepayer benefits over the term of the agreement to outweigh the risk inherent in long-term contracting. We find that this project provides benefits to ratepayers across the widest range of future scenarios, and due to its modest size, presents relatively low risk exposure to ratepayers. Additionally, the project presents new renewable capacity resource located in Maine and would create no net emission of greenhouse gases. *See* 35-A M.R.S. § 3210-C(4).

The structure of the Downeast Wind project's contract is an energy price discount off the day-ahead locational marginal price with an escalation floor and ceiling. This approach reduces the potential for significant discrepancy between the day-ahead market and the contract price. Because of the price cap, the contract structure will also provide a measure of protection to ratepayers against volatility in the wholesale market over its 20-year term. Accordingly, we find that the 20-year term for the Downeast Wind contract to be prudent and in the ratepayers' interest as required by statute and rule.

We further conclude that the Downeast Wind project will have a "price suppression" effect. A price suppression effect occurs when a zero marginal cost resource (i.e. a resource that bids into the market at zero) displaces generation resources with greater marginal costs of production, thereby lowering the wholesale prices of energy. Because the Downeast Wind project will have a zero marginal cost, it will provide a measurable price suppression effect. Based on Staff's analysis, Downeast Wind presents an estimated price suppression benefit to ratepayers with a net present value of $6 to $8 million with most of the benefit occurring in the early years of the contract.

As a new Maine-based project, Downeast Wind provides non-pricing benefits including significant land lease payments to blueberry growers as well as employment benefits in a particularly economically challenged part of the State. Based on the NREL JEDI economic impact analysis model, the projected direct employment impact of the project includes 17 jobs in the development phase, 110 jobs in the construction phase and 7 operation phase jobs.

Finally, the Downeast Wind project will reduce carbon emissions and thus the external costs of electricity generation. While carbon markets internalize some of these costs, carbon prices in the prevailing regulatory market (RGGI) are below most estimates of carbon emission costs. New renewable energy resources, such as the Downeast Wind project, tend to offset generation from a natural gas facility and other units, with its associated estimated CO_2 emissions (0.53 kg CO_2/kWh) as well as associated upstream and indirect emissions. *See* Environmental Protection Agency EGrid 2000, accessed through http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html. Staff's analysis indicates that avoided carbon from Downeast Wind project will create savings with net present value of between $17 and $37 million dollars depending on the model forecast utilized. The more modest savings arise under existing RGGI program while more aggressive savings occur under scenario projections modeled with a federal carbon regime in place.

C. Analysis of the Remaining Proposals

Of the remaining contract proposals, the Commission finds that the proposals presented too much risk of cost to ratepayers in the lower market price scenarios to offset the potential benefits in a higher price environment. [4] The Commission determines that this risk exists in the proposals due to a variety of factors from contract length, to project size, technology and proposal price. Certain projects that were more favorable in certain forecast scenarios, although still presenting more risk than Downeast Wind, had other deficiencies based on the ranking criteria in section 3210-C(4), which places the highest priority on new renewable capacity resources located in Maine.

Accordingly, we

ORDER

1. That one or more of Maine's investor-owned transmission and distribution utilities enter into long-term contract(s) for capacity and energy with Apex Clean Energy Holdings, LLC (Apex), for the output of Downeast Wind;

2. Delegate to staff the administration of the drafting of the long-term contract consistent with this Order; and,

3. That the transmission and distribution utility/utilities actively participate in good faith in the long-term contracting process with Apex and Staff.

Dated at Hallowell, Maine, this 18th day of December , 2013.

BY ORDER OF THE COMMISSION

/s/Harry Lanphear

Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Littell

COMMISSIONER CONCURRING: Littell

COMMISSIONER DISSENTING: Vannoy

[4] Commissioner Littell would have approved Project 3 as well. See attached concurring opinion.

Concurring Opinion of Commissioner Littell

I. OVERVIEW

Long-term contracts are a Legislatively-mandated mechanism to provide ratepayer value by reducing prices, future price uncertainty and price volatility. The "cost" of reducing prices, future uncertainty, and volatility is the cost of a reasonable hedge evaluated under a variety of future scenarios to assess its likelihood of achieving these purposes. There is a statutory preference in the evaluation toward (1) lower customer costs, (2) stable pricing ("reduce volatility), and (3) cleaner forms of generator capacity ("reduce greenhouse gas emissions").

Pursuant to the statute, the Commission issued a request for proposals ("RFP") on October 12, 2013 and received a spectrum of long-term contract proposals ranging from renewable to natural gas to nuclear units. In this round of RFP responses as others, staff negotiated with project developers on price and other terms to arrive at the best offers from developers. This process further narrowed the proposals to those that provided the most robust potential benefits to ratepayers. At the end of this staff-developer negotiation, the Commission was presented with the most competitive among the proposals which include a number of new and existing Maine projects. Fortunately, two of new Maine projects also provide the lowest pricing and the best ratepayer value over time as well as lower greenhouse gas emissions and thus fulfill the statutory goals.

In evaluating the economics of these proposals, I observe that electricity prices are at or near a trough -- a low point -- in energy prices. Virtually all experts and market players anticipate that both natural gas and electricity prices will rise over the next several years and the long-term. The benchmark NYMEX Henry Hub future natural gas prices currently shows escalation in excess of 5% to 6% per year in later years.[5] Natural gas prices influence electricity prices. For this reason, now is precisely the time to take advantage of the low cost long-term contract offers.

In addition to cost reductions, the long-term contracting statute instructs the Commission to consider reductions in price volatility. Since the 1973 Oil Embargo price volatility in electricity markets has steadily increased. The recent two decades saw low natural gas and electricity prices in the 1990s followed by a tremendous rise in both natural gas and electricity pricing beginning in 2004-2005 and peaking in 2008-2009 and then a sudden decrease with the advent of natural gas fracturing techniques beginning in roughly 2008 and continuing through the present. Within these broad

[5] Based upon the September 19, 2013 preliminary settlement results, the CME Group / NYMEX Henry Hub natural gas price curve exceeds 6% per year escalation from year 2019 to 2020 and 2020 to 2021. Escalation exceeds 5% per year from year over year 2018 to 2019 and annually onward through the end of 2025.

trends, the price of natural gas and electricity has produced a price trend chart that looks like a roller coaster.

In the 1990's when electricity markets were restructured, Maine and the region bet on low priced natural gas. The Maritimes & Northeast Pipeline was built through Maine and five new merchant natural gas plants were built in Maine. That bet turned as Maine experienced high natural gas and oil prices from 2005 through 2009. History suggests that this uncertainty and price volatility will continue to be hallmarks of modern energy markets and offer insight as to why the Legislature places a value on projects that reduce the volatility of electricity prices.

The possibility that the federal Production Tax Credit (PTC) and Investment Tax Credit (ITC) may expire permanently strengthens the rationale for acting now while this federal support is there to reduce the price consumers of new clean energy and capacity. To decline to take advantage of federal tax support is to miss a rare opportunity to address the inequality of Maine's power prices in comparison to states with historical federal support for dams, nuclear and coal plants such as the Tennessee Valley, the Bonneville Power Authority in the Northwest or the Hoover Dam.

The purpose of a long-term contract as authorized in Maine statute is to provide a hedge to provide limited price protection for ratepayers from unpredictable price increases. An appropriate long-term contract will provide stability and price certainty by providing a known price over time. Determining what has been the appropriate price to set to provide benefit for ratepayers is a complex endeavor. The Commission looks to modern portfolio analysis, commonly used to assess a risk-adjusted price for investments, for insight into how to reduce electricity price volatility.

For these reasons, I concur in selecting Downeast Wind for which there is a Commission majority. I would also select Project 3. Both projects are new renewable energy projects located in Maine with extraordinarily good pricing terms, price suppression and hedge value that will reduce Maine ratepayers electricity bills, reduce price volatility, and reduce greenhouse gas emissions.

II. DISCUSSION

1. Statutory Mandate

The Commission can authorize a long-term contract for a "capacity resource" defined as "any renewable capacity resource . . . " for "any energy" to the "extent necessary to fulfill the policy of the State. 35-A M.R.S. §3210-C(1)(A), (3)(A) & (3)(B) Specifically, the policy of this State is:

A. That the share of new renewable capacity resources as a percentage of the total capacity resources in this State on December 31, 2007 increase by 10% by 2017 and that, to the extent possible, the increase occur in uniform annual increments;

B. To reduce electric prices and price volatility for the State's electricity consumers and to reduce greenhouse gas emissions from the electricity generation sector; and

C. To develop new capacity resources to reduce demand or increase capacity so as to mitigate the effects of any regional or federal capacity resource mandates.

35-A M.R.S. §3210-C(2).

The statutory contracting goals are clear: to increase Maine's renewable energy resources, reduce electricity prices, reduce volatility, and reduce greenhouse gases. In discussing how to apply the goals of the statute to the proposals the Commission received, several statutory observations are relevant in review of these projects. First, while the new renewable capacity increase mandated in § 3210-C(2)(A) is different than the Renewable Portfolio Requirement set forth in § 3210, but the emphasis is on new and renewable capacity is nonetheless the same. Second, the policy is to reduce electric prices, price volatility and greenhouse gases from electricity generation under § 3210-C(2)(B) – reductions of all three are the statutory goal and policy. Section 3210-C places all three of these goals on equal footing. Although taking the language of §3210-C in its totality emphasis on reducing ratepayers costs is appropriate, the Commission would err to exclude these other statutory purposes. Third, there is a statutory emphasis on developing *new* capacity resources in Maine and mitigating regional or federal capacity mandates.

Among capacity resources meeting the competition and pricing, volatility and clean generation standards, the priority for ranking among resources is made explicit in § 3210-C(4)(B). Section 4 *Priority of capacity resources* reads as follows:

> In selecting capacity resources for contracting pursuant to subsection 3, the commission shall apply the following standards.
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> A. The commission shall select capacity resources that are competitive and the lowest price when compared to other available offers for capacity resources of the same or similar contract duration or terms.
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> B. Among capacity resources meeting the standard in paragraph A, the commission shall choose among capacity resources in the following order of priority:
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>> (1) New interruptible, demand response or energy efficiency capacity resources located in this State; (2) New renewable capacity resources located in this State; (3) New capacity resources with no net emission of greenhouse gases; (4) New nonrenewable capacity resources located in this State. The commission shall give preference to new nonrenewable capacity resources with no net emission of greenhouse gases; (5) Capacity resources that enhance the reliability of the electric grid of this State. The commission shall give preference to capacity

> resources with no net emission of greenhouse gases; and (6) Other capacity resources.

35-A § 3210-C(4).

> New resources are the priorities 1 through 4. We received no proposals in priority category 1. The Commission received four final proposals that fit within category 2 "new renewable capacity resources located in this State." The Commission received three proposals in categories 4, 5, or 6 for two natural gas plants and one nuclear station. Of the final proposals meeting the pricing, volatility and clean generation standards are first priority with two were classified as priority two: Downeast Wind and Project 3.[6] Because the renewable proposals are competitive and the lowest price – particularly the wind proposals which are below or at forecasted market prices – the Commission has sufficient proposals that fit within the "new renewable capacity resources located in this State" category to proceed with selecting the best among them.

For this set of proposals, the limitations section focusses the Commission on the aspect of these proposals that would lower customer costs:

> Capacity resources contracted under this subsection may not exceed the amount necessary to ensure the reliability of the electric grid of this State, to meet the energy efficiency program budget allocations articulated in the triennial plan as approved by the commission pursuant to section 10104, subsection 4 or any annual update plan approved by the commission pursuant to section 10104, subsection 6 or to lower customer costs as determined by the commission pursuant to rules adopted under subsection 10.
> 35-A M.R.S. §3210-C(3).

In sum, contracts which are reasonably likely to lower ratepayer costs while reducing price volatility and reducing greenhouse gas emissions are deemed beneficial. The Commission evaluates proposals based on costs and benefits under a variety of projected future scenarios. The review is robust and does not depend on one particular set of assumptions as to what the future holds. In particular, the Commission looks at both low and high price electricity price regimes. Finally, when necessary to determine which projects are competitive the Commission also considers other statutory goals such as Maine's Wind Power Act[7] and the recently enacted Omnibus Energy Act which asks the Commission to examine increased access to natural gas supplies.[8]

2. Application of Statutory Criteria to the Proposal

[6] Of the remaining Finalists, both Projects 4a and Project 4b did not meet the pricing, volatility and greenhouse gas requirements of § 3210-C 4.A.. Project 1 is classified as priority 5 and Project 5 as priority 6, the two lowest ranking priorities.

[7] *See* 35-A M.R.S. §3402.

[8] *See* PL 2013, ch. 369, Sec. B-1, Omnibus Energy Bill (new 35-A M.R.S. §1912).

Under the long-term contracting statute, the Commission is charged with evaluating pricing, hedge value, volatility reduction benefits, price suppression benefits, integration costs, and greenhouse gas reductions. In some cases, the Commission would also assess reliability and compliance with the Triennial Plan. To carry out this statutory mandate, the Commission analyzes each element as follows:

A. Ratepayer Value.[9]

The Commission's price analysis starts at the final bid price for capacity and energy and then adjusts for cost reduction and additional system costs. Because Commission staff provide ranges of benefits and costs, this analysis takes the mid-points from the staff developed scenarios for all benefits and costs including suppression price benefits, hedge value, and the costs of integration. This analysis concludes that Downeast Wind and Project 3 are beneficial for Maine ratepayers with current market pricing. These are the two most cost-effective of the proposals and show ratepayer benefits from the staff-prepared low gas price scenario to high priced scenarios that include a high price for carbon. The two projects stand out because they demonstrate ratepayer benefits over a variety of future scenarios. These Maine renewable resources out compete a nuclear plant and an existing natural gas plant proposal.

The scenarios prepared by Commission staff with the Commission's consultant, London Economics (LEI), show ratepayer benefits evaluated under this range of market scenarios. There is substantial positive ratepayer benefit across multiple futures for Downeast Wind and Project 3. For Downeast Wind, ratepayer price reductions occur across all staff scenarios Downeast Wind shows price reductions across all scenarios regardless and without hedge value, price suppression, and system integration costs. For Project 3, staff's analysis shows positive benefits in all scenarios when the market price suppression effects, the hedge value, and system integration costs are included in the analysis.[10]

<u>1. Price Suppression Effect</u>

The price suppression effect describes how a lower bidding resource tends to drive energy prices down by displacing other higher cost resources. Renewable resources such as hydro, wind and solar have no fuel costs and low operational costs compared to coal, oil and natural gas plants. Wind facilities operate when the wind is blowing and then the fuel is free. Solar generates well when the sun is shining. Run-of-the river hydro-electric dams generate strongly when there are good river flows. Nuclear plants also must run at minimal levels so when demand is low, nuclear units may bid into the markets at a low price. Coal, oil and natural gas plants have higher variable operations and maintenance costs and fuel costs resulting in higher energy price bids

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[9] *See* 35-A M.R.S. §3210-C(4).
[10] REDACTED

than hydro, wind, solar and nuclear units.

Wind, hydro and solar generators often bid into the market at near zero due to the resource being available at negligible marginal cost. Prices can even go negative because a nuclear unit has a high cost to shut down completely and some wind qualifies for the production tax credit. New England's regional system operator, ISO-NE, is updating its energy bid system to allow for negative energy bids.[11] Those near-zero (and negative) bids displace other more costly units which are often natural gas plants and less often coal or oil burning units – these renewable generators are "price takers" meaning they will get the clearing price of electricity without adding to the clearing price because they pull the clearing price down when they come onto the system. The real-time clearing price for electricity is reduced by these zero-bidding resources.

The Commission has previously observed that on-shore wind can have a substantial price suppression effect

> ISO-NE has estimated in its studies that in the single study year of 2016, the energy price can decrease by $0.60/MWh per 1 GW of new on-shore wind generation in the region. . . . Moreover, the development of renewables in New England serves as a hedge against price volatility that can result with changes in natural gas prices.[12]

In theory, this suppression effect goes down over time as the units become part of the capacity mix of the region. Staff assumed a 25-year reduction of the suppression effect to zero which is probably overly conservative and reduces the value of the suppression effect for Project 3 by approximately half. This is a very conservative approach with the suppression value used to value customer benefits likely underestimated. Nonetheless, the price suppression effects of both Projects are measurable and substantial.

2. Price and Portfolio Hedge Value

Uncertainty amid unstable prices and uncertainty regarding fuel availability are hallmarks of 21st century energy markets. World oil prices are high and rising. U.S. natural gas prices are low but rising as well. Historic price movement shows prices climb far above and fall below the expert predictions. Unpredictable price swings are worse now than in the past: "resource price volatility is also at an all-time high,"

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[11] The Midwestern System Operation (MISO) has already implemented negative pricing (negative location marginal prices (LMPs)) and has experienced instances in its system where pricing does go negative when wind resources are producing well. MISO operates a system which is more extensive than ISO-NE in terms of generators, load served and geography.

[12] MPUC RPS Report 2011, *Review of RPS Requirements and Compliance in Maine*, at 56, citing ISO-NE Planning Advisory Committee, *2011 Economic Study Update*, September 21, 2011.

according to Fraser Thompson, a senior fellow with the McKinsey Global Institute.[13]

In the context of global market swings, the statute asks the Commission to reduce volatility. This is important for Maine consumers and businesses because the risk of price instability (volatility) affects both affordability and the ability to make long-term business decisions. A hedge is a financial term for purchase in the future to protect against price movement up or down. Price hedges cost money because they pay another entity to take on the price risk. Just as insurance prices compensate insurers for assuming the financial risks of loss, a hedge prices is the price of financial insurance against price moving in one direction. In some years, a hedge contract pays off and other years, the Commission sees hedging loss for a regulated utility such as a natural gas company.

3. Resource Diversity

Price volatility can be reduced and price security increased through portfolio diversity. A portfolio hedge is the value of having diverse generation resources rather than putting "all of your eggs in one basket." More precisely, it is the marginal benefit in volatility reduction that having one less electricity generator without fuel risk in the portfolio. The risks of natural gas system and oil and gas price uncertainty are reduced by adding non-fossil fuel based generators onto the system.

Volatility is fundamentally a characteristic of a market, not of individual units. It is a mistake to consider volatility on a facility-by-facility or contract-by-contract basis because new resources can have an effect of reducing overall market volatility. Some resources can reduce market volatility and others add to it.[14]

A volatility reduction benefit is obtainable under current New England market conditions for all renewable projects because the current and historic price-risk profile of wind, hydro and biomass reduces portfolio risk at the equal or lower pricing. Portfolio risk diversification reduces price risk from current market conditions by moving toward generation resources with lower operational and fuel costs, i.e. away from a resource reliance on natural gas and oil. Mean-variance analysis by staff has shown this price volatility reduction benefit can be obtained with equal or lower electricity prices by adding wind, hydro and biomass to the New England electricity system.

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[13] Saqib Rahim, *Does Abundance Create a Mirage of Cheap, Stable Energy Supplies?*, E&E Energy Wire, September 27, 2013.

[14] In an electrical system that is planned and managed with integrated resource planning, the analysis would be for the system as a whole for system planning purposes. In an electrical system, like New England's that is restructured with competitive energy and capacity markets, the analysis is on the margin because each generator retirement or addition moves the entire system marginally toward to lower or higher price conditions and also marginally toward lower or higher risk (price volatility) conditions.

Reducing volatility requires analysis of the risk based on actual history of generator and fuel cost. Application of risk management techniques, such as a Monte Carlo analysis, provide understanding of the risk profiles and how to reduce that profile at a reasonable or optimal price to minimize ratepayer risk and cost.[15] The fundamental point here is that a singular focus on one type of resource increases, as opposed to decreases, ratepayer exposure to volatility over time.

Modern portfolio theory (also know as “Markowitz” or “Mean-variance” portfolio theory) is another approach applied to analysis of the price versus risk of electrical generation mixes. Mean-variance portfolio theory has most widely been applied in the investing realm to determine asset allocation between stocks, bonds, and other assets to maximize investment return at a chosen risk level. A central tenent of mean-variance portfolio theory is that there is often a benefit at no cost (i.e., no reduction in return) that is obtainable by investing amongst asset classes with uncorrelated returns. The same investment return can be achieved with lower risk. So for example, modern porfolio theory posits that it is not generally wise to invest entirely in type of stocks or entirely in bonds or entirely in real estate just as it is not wise to rely entirely on one type of electricity generation. For a certain price level, one can arrive at an investment mix to minimize investor risk. The analogy to the electricity generation mix is that the same or lower electricity price can be achieved at lower risk.

Utilizing actual cost data from the Energy Information Agency (EIA), staff conducted a mean-variance portfolio analysis of five electrical generation assets categories for the Maine and New England electricity market (natural gas, nuclear, wind, hydro, and biomass). This analysis is based on cost data for energy prices from each generator category for the last eight years for which data is available, 2004 to 2012. The price risk of 100% of a generation technology is represented by the green dots in the figure below. For example, a natural gas generator provides the cheapest electricity (higher on y axis is cheaper), but also higher risk based on its historic high price volatility.

This qualitative analysis suggest that the New England electricity mix (labeled “NE” in Figure 1 below) does not allocate price and risk efficiently. This means that one could achieve the same price of electricity, but with lower risk, by moving left towards the efficient frontier (labeled “NE ↓ risk”). One would move in this direction by adding hydro, wind, and/or biomass, and reducing nuclear.

The risk-adjusted price is particularly useful because both the price of electricity and reductions in volatility are presented in an analytically robust calculation. The mean-variance model suggests the optimal electrical generation portfolio that results in the lowest risk-adjusted price is one that contains asset classes distributed amongst technologies as represented by the upper right corner bar graph in the figure below (the risk adjusted price is also plotted and labeled “NE optimal”). For the sole purpose of reducing price volatility, the optimal risk-adjusted price to risk portfolio is less natural

[15] A Monte Carlo simulation is a mathematical technique that allows people to account for risk in quantitative analysis and decision making.

gas, less nuclear, more wind, more hydro, more biomass (asset 1 = natural gas, asset 2 = nuclear, asset 3 = wind, asset 4 = hydro, asset 5 = biomass). This analysis qualitatively indicates which direction long-term contracts should go to reduce price volatility. The mean-variance analysis focusses on reducing price volatility and does not address engineering and operational feasibility of high amounts of wind, hydropower and biomass on the New England system. Nonetheless, it is clear that more renewable resources acquired at competitive prices brings price volatility reductions benefits to ratepayers.[16]

[16] *See* Dr. Mark Cooper, *Capturing the Value of Offshore Wind, A multi-criteria, portfolio approach to shaping the UK's future electricity generation mix,* Mainstream Renewable Power, October 2012, located at *http://www.mainstreamrp.com/content/reports/capturing-the-value-of-offshore-wind.pdf*, (providing more information on the application of mean-variance portfolio theory as applied to electrical generation portfolios). Dr. Cooper writes "Putting assets, such as coal and gas, that covary strongly and that are price-volatile into the UK's generation portfolio increases the risk of dramatic price spikes, which recent history shows are passed on directly to UK consumers. Providing consumer support for renewable technologies like offshore wind helps reduce that risk, and lowers the overall cost of energy." *Id*. at 6; "For gas, the cost of capital and learning are not very important, but the future price of fuel is. For wind, the cost of capital and learning are of great importance. The learning lowers the cost estimate by as much as £50/MWh. Reducing risk (i.e. the discount rate) lowers the costs as much as £20/MWh." *Id*. at 15. *See also* Shimon Awerbach & Spencer Yang, *Efficient Electricity Generating Portfolios for Europe: Maximising Energy Security and Climate Change Mitigation*, EIB Papers, ISSN 0257-7755, Vol. 12, Iss. 2, pp. 8-37, 2007, located at *http://hdl.handle.net/10419/44888*, provided in cooperation with the European Investment Bank. ("By ignoring diversification effects, engineering risk studies yield a portfolio risk estimate that is systematically biased upwards.").

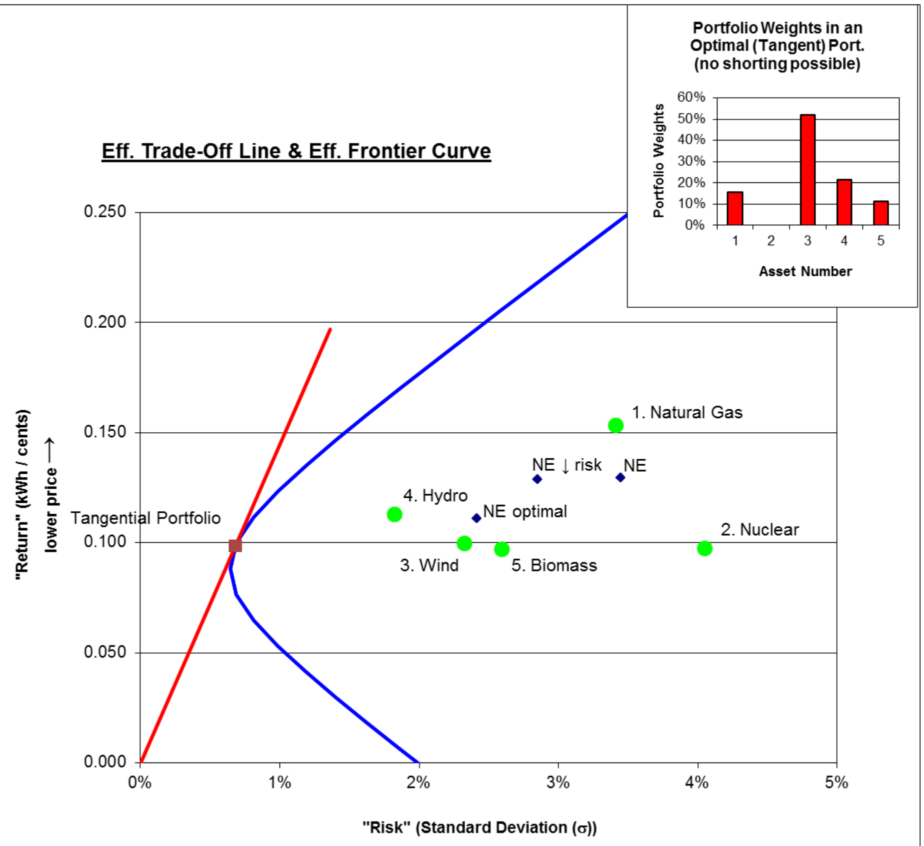

Figure 1: Portfolio Diversity Benefit in the New England Market (Dr. J.Rauch, MPUC 2013)

A less complex risk management model is put forth by researchers at the King Abdullah Petroleum Studies and the Nicholas Institute at Duke University called Least-Risk Planning for Electric Utilities. *See* P. Bean & D. Hoppock, *Least-Risk Planning for Electric Utilities*, Nicholas Institute, Working Paper, NI WP 13-05, August 2013. These researchers focus on establishing a least-risk metric to assure low risk costs by minimizing the maximum regret. The method is simple: Step 1, calculate the present value of the current system for each investment option across all scenarios; Step 2, create a matrix of total costs in every scenario and determine the least-cost option in each scenario, Step 3, calculate the regret score for each option across all scenarios by subtracting the least-cost option from each investment scenario to create a matrix of regret scores. Step 4, determine maximum regret of each investment option by selecting maximum regret score for each option across all scenarios and then determine the investment option with the lowest maximum regret. *Id.* at 6.The authors use the example of the Shoreham nuclear plant in New York that took 20 years to build, ran 100 times over budget and was mothballed before entering service as a "regret" their analysis would identify and eliminate. *Id.* at 3-4. For brevity, I observe this analysis would allow us to put cost and risk in perspective, such as identifying retirements of a major nuclear unit, and provide multiple analyses to lead to better decision making. This is a less quantitative risk management technique than mean-variance theory and likely to avoid only the biggest cost mistakes rather than marginally improve the risk-adjusted price paid by ratepayers.

4. System Integration Costs

System integration costs are system-wide costs to incorporate an intermittent technology such as wind, hydro, tidal or solar. These costs are generally associated with three different time frames in the operation of generation on the system: regulation—from seconds to a few minutes; load-following—tens of minutes to a few hours; and unit commitment—out to the next day or two. Generation developers in New England pay for generator-lead lines and transmission upgrades at substations to connect new wind farms to the grid for example. These system integration costs are added to the project's direct costs because they are additional costs such as the need to keep additional generators on-line to ramp up if the wind dies off. System integration costs are estimated using data reported by the U.S. Energy Department's Wind Technologies Market Report.

5. Greenhouse Gas Emission Reductions

OPA states that federal greenhouse gas regimes should not be part of the Commission's consideration or pricing evaluation. Since carbon reductions are explicitly identified as part of the statutory standard, the OPA's suggestion is contrary to the statute which directs the Commission to consider greenhouse gas reductions.

Nonetheless, to be conservative and ensure the value of greenhouse gas reductions does not become so overstated as to dominate the selection analysis, the Commission adopts staff's approach to estimating the value of greenhouse gas reductions. The LEI model using the RGGI carbon prices moderates any tilt toward too high of a carbon price. The LEI RGGI carbon scenario is conservative because RGGI has the lowest carbon emission pricing of any major carbon market worldwide. The RGGI price is lower than most academic and governmental valuation studies that calculate the economic costs of abatement or the social costs of climate change so some argue that RGGI costs are too low. Using the RGGI costs as the best selection scenario consistent with the statute represents a conservative pricing assumption for the price of carbon to ensure this factor does not drive the selection of specific projects.

The second LEI carbon scenario assumes a federal carbon system and is valuable because it shows the value with a higher price of carbon emissions consistent with the U.S. government and some academic pricing analysis for climate changes economic impacts over global-scale and long time frames. The U.S. Government by inter-agency task force calculates the price of carbon dioxide emissions at $11 to $102 per ton of CO2 emitted with a central value of $36 in 2013. The U.S. Government calculates the central value rising to $43 in 2015 and $71 in 2050 with a high estimate of $221 per ton. There are quite a few academic studies of the cost of climate change on global economies. Academic economic analysis of the cost of carbon emissions put a mean value of $23 per ton of carbon emitted with a certainty-equivalent of $25 per ton of carbon. There is however a 1% probability that the cost could be greater than $78 per ton of carbon.[17]

Since the U.S. Government and academic estimates are notably higher than the RGGI carbon price even as projected in the future, there is value to considering a somewhat higher price carbon for reference in the Commission's analysis. The value assumed in the LEI high-carbon price scenario is nonetheless at low end of the federal and academic estimates of carbon pricing.

B. Adding it all up: Price – Price Suppression – Price Hedge – Portfolio Hedge + System Integration = Ratepayer Value through Full Price Cost

One method to lower ratepayer costs is pricing at a discount from the daily price of electricity. That is the approach of Downeast Wind. In addition, to the discount from the daily price of electricity, there is the additional price suppression effect and hedge value that staff were able to quantify and a non-quantified volatility reduction benefit from a portfolio hedge. We are required to look at greenhouse gas reductions by the statute as well. Downeast Wind will reduce greenhouse gas emissions by the emissions of the marginal unit(s) displaced with the emissions from spinning reserves attributable to this resource added back.

Downeast Wind would sell energy at a guaranteed discount from the Maine clearing price for energy subject to only a low price floor. This wind project would further decrease prices through the "market suppression effect" by roughly $9 million in reduced energy prices for Maine's ratepayers in addition to the direct energy discount. These customer price reductions are better than offered by existing natural gas plants, an existing nuclear plant and an existing natural gas plant.

A second contract method can reduce volatility for ratepayers for energy and capacity at fixed prices. To make sense, the initial pricing must be close to market as it is for Project 3. This is the nature of a direct long-term hedge against price increases with price floors and price ceiling. This hedge value against rising prices is more valuable when markets are at a low point in energy prices, precisely the time one can lock-in low priced contracts for energy and capacity prices with predictable 20 and 25-year contracts Project 3 at far below what any suppliers offered in the past, below what a natural gas and nuclear plant offered, and likely below prices that would be offered when the markets rise.

The Project 3 would provide favorable pricing with predictable increases for the life of the contract. This wind project would also suppress electricity prices by a mid-point value of more than $26 million**.** The Project 3 would provide a hedge values with a midpoint value of roughly $15 million. Against these positive benefits, system integration costs need be added for intermittent resources like wind. System integration costs are

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[17] *See* RSJ Tol, *The Social Cost of Carbon: Trends, Outliers and Catastrophes. Economics Discussion Papers*, Economics E-Journal, 2007, located at *http://www.economics-ejournal.org/economics/discussionpapers/2007-44*.

calculated at several million dollars for Downeast Wind and double that for the Project 3. These costs are subtracted for the project benefits.

In total, Downeast Wind and Project 3 are both worthy of selection. They both meet § 3210-C policy goals of increasing renewable capacity resources and decreasing price, volatility and greenhouse gases. They are beneficial for ratepayers within a reasonable range of scenarios from high to low energy prices and high to low carbon prices. Taking ranges of pricing for energy and capacity, offered discounts where applicable, price suppression benefits, hedging value, volatility reductions benefits, and system integration costs they provide the most value to ratepayers over their contract terms. As new wind projects located in Maine they are prioritized for selection both by statute and the Commission’s rules. Finally, both projects move the state towards its greenhouse gas emission reduction policies and Wind Power Act goals. Accordingly, I conclude that these two of the six proposed projects should be approved.

Dissenting Opinion of Commissioner Vannoy

I respectfully dissent from the majority decision to approve a long-term contract. I would decline from entering into any of the proposed long-term contracts as put forward by the bidders under the RFP. I do not find that any of the contracts are necessary for reliability purposes nor are they likely to achieve, under a broad range of possible futures, cost savings for ratepayers.

Clearly, the Commission has authority to enter long-term contracts per the statutory language in 35-A M.R.S. § 3210-C. The Commission's statutory authority was granted by the Legislature as a backstop to implement the state policy outlined in 35-A M.R.S. § 3210-C.2(A)(C). This policy has as its stated goals to increase renewable capacity resources to 10% by 2017, decrease electric prices, price volatility and greenhouse gas emissions, and finally, to develop new capacity or reduce demand to mitigate effects of federal or regional capacity resource mandates.

Coupled with these policy objectives the statute outlines a number of requirements concerning long-term contracts. Some of these requirements are permissive (allowing action but not mandating that action). For instance the statute indicates that the Commission may enter long-term contracts for interruptible, demand response, or energy efficiency capacity resources. There are also direct prohibitions in the statutory language of 35-A MRS § 3210-C(3), for example, "that capacity resources contracted under this subsection may not exceed the amount necessary to ensure the reliability of the electric grid of this State,… or to lower customer costs." This presents a clear prohibition on contracting for excess resources or entering into contracts that, in the Commission's determination, are not necessary to lower costs.

The statute also cautions the Commission with respect to the term of contracts. Under 35-A MRS § 3210-C(5), the contract term "may not be for more than 10 years, unless the commission finds a contract for a longer term to be prudent". In utility regulatory terms the word "prudency" carries significant weight.[18] The threat of a prudency investigation of a utility's actions/decisions with respect to plant investment and operations is a significant one and ultimately is a protection of ratepayers.

I highlight these aspects of the statute because they provide the Commission with the background on how, as a Commission, we are to apply and utilize the long-term contracting tool. While we as a Commission have the authority to enter into contracts, it is not always prudent to exercise that authority and I believe this is an instance where restraint is the correct approach.

[18] The basis of the prudency principle is fundamental in regulatory law. It is based on the concept that, "if a competitive enterprise tried to impose on its customers costs from imprudent actions, the customers could take their business to a more efficient provider. A utility's ratepayers have no such choice. A utility's motivation to act prudently arises from the prospect that imprudent costs may be disallowed." *See Gulf State Utils. Co. v Louis. Pub. Serv. Comm'n*, 578 So. 2d 71 at 85 n.6.

From a financial standpoint, the Commission's track record with respect to long-term contracting is certainly a question for debate. The fact is that Maine consumers are still paying for prior decisions in the form of stranded costs that are embedded in their electricity bills. Those past contracts should serve as a cautionary tale about the risks inherent in the forecasting required to ascertain whether a long-term contract proposal presents a sufficient value proposition to the ratepayers. That value must offset the inherent risk of guaranteeing payments for products produced many years in the future.

In thinking about long-term contracts in general, I found the Commission's restructuring report to the Legislature back in 1996 quite helpful. One of the guiding principles behind the restructuring of electric markets was the following: "Where viable markets exist, market mechanisms should be preferred over regulation and the risk of business decisions should fall on investors rather than consumers." Restructuring Report 95-462 (Dec 31,1996).

In light of the objectives of restructuring, I view the long-term contracting statute as a backstop to carry out the State's policy goals. If we are having difficulty in achieving the policy goals of 35-A M.R.S. §3210-C through existing viable markets then the Commission should interject itself into the electricity market to further the state policy objectives. After examining the proposals and analysis provided by Staff and our consultants, I do not find this to be the case at this point in time. Based on REC price trends we are exceeding demand for renewables and meeting our RPS mandates.[19] Regionally we are exceeding greenhouse gas reduction goals as evidenced by RGGI's recent action to ratchet down on carbon allowances. Finally, capacity resource adequacy is being met and actually exceeded through the current regional Forward Capacity Market. So the question becomes are any of these contracts necessary to lower consumer costs?

The contract the majority has chosen to award is a 20-year contract. As the majority acknowledges, it is very difficult to predict what electricity prices will look like in 20 years. Such an evaluation must start with the marginal unit, which in today's market is a natural gas unit. Accordingly, most evaluations of future electricity pricing are based on analysis of the pricing of natural gas futures. For benefits to accrue to the ratepayers, the calculation is that gas prices will rise significantly in the out years of the contract. If gas prices do not rise substantially, then customers will be left with stranded costs. It is important at this point to reiterate that by statute a long-term contract should not exceed 10 years unless the Commission finds a contract for a longer term to be prudent. Four of the five proposals we have considered propose contract terms over 10 years. I think it is a reasonable expectation that the Commission may be able to evaluate futures out a couple of years particularly if the contract has

[19] I recognize the OPAs argument here that RECs are a consumption driven metric and not a production metric. Maine Class I REC certified production capacity is 3,316,790 MWh. In order to meet the 2017 mandate of 10%, production capacity required will be approximately 1,090,000 MWh. Therefore Maine's current certified Class I capacity is roughly 3 times that which is mandated by the statute in 2017.

large near term returns (i.e. more immediate benefits for ratepayers). It becomes much more difficult to look out beyond 10 years; to do so becomes pure speculation.

The evaluation of these proposed terms sheets is dependent on one's long-term view of natural gas pricing. We have consultant views that vary widely pending on gas capacity and pricing changes and speculation on more stringent carbon regimes. The low end projections would see losses in all the contracts. The high end coupled with a high price of carbon will see benefits in almost all the proposals. In my judgment a long-term contract entered under the cost saving clause of the statute should see benefit under a very broad range of futures, including the more conservative. Focusing on the statutory requirement that in the absence of a necessity to enter into contracts to assure grid reliability or sufficient funding for efficiency programs, long-term contracts may only be executed to lower costs to ratepayers, therefore I cannot vote to enter into any of these contracts.[20]

Although I would decline to authorize the execution of any of these contracts based on my fundamental concern with the actual proposed rates, I would like to address some of the other factors the majority used in reaching its decision. The calculation of hedge value is based on existing futures contracts and the difference between thinly traded long-term futures contracts and price projections of long-term pricing of natural gas. Such an undertaking is speculative at best. Moreover, a long-term hedge may actually have less value in a low priced gas market than it does in a relatively higher priced gas market. See Dr. Jason Rauch, *The Effect of Different Market Conditions on the Hedge Value of Long-Term Contracts for Zero-Fuel Renewable Resources*, The Electricity Journal, May 2013, at 44, 45.

Typically, a business or investor holds a hedge position to mitigate a risk (paying a premium to do so). For example, when a company like Google builds a new server farm, their largest variable operational cost over the life of the facility is electricity. As a market participant, they see value in fixing the long-term operational cost so that they can have stable predictable operating costs. For a premium, in other words the cost of the hedge, they enter a long-term contract with a zero fuel cost generation source thereby stabilizing that electricity price. The stable price allows them to predict cash flow by eliminating the biggest variable in the operations and maintenance costs to run a server farm. The stabilization of cash flow in their business judgment is worth the premium cost of the hedge. In other words, hedge positions and their associated value

[20] Regarding the Downeast Wind pricing structure, the price paid is based on the DALMP with a price floor. The ratepayers would experience losses if the price drops below the floor. Additionally as noted above, the characteristics or shape of the generation curve (time of day) is important to this contract because of the floor price. Customer losses depend on how often you are operating below the floor. Wholesale markets regularly trade below the floor during off peak hours and shoulder months. Intermittent generation of the type proposed is not dispatchable and is likely to operate off-peak at a greater frequency then on-peak making the price floor a significant part of the contract structure and adversely affecting ratepayers.

are heavily dependent on the particulars of the business involved coupled with their analysis of risk.

If the Commission were to enter long-term contracts based on hedge value, whose interest do we claim to represent? If the answer is residential consumers, or small business owners, what type of analysis have we performed to understand their particular risks? We have a market full of competitive electricity providers (CEPs) looking to serve the consumer. If a long-term hedge provided value that consumers were looking for, would not the market, in the form of CEPs, enter that hedge position and offer a long-term product to their customers? I believe the same is true for our bigger industrial users. They have full-time employees dedicated to obtaining energy supply as efficiently as possible. Based on their own business risk analysis, if they see value in paying a premium to guarantee a stable price they can take that hedge and enter into long-term contracts with generators. In other words, I do not see a market failure in the ISO-NE region of the State that militates for our action. Electricity prices are relatively stable. There is no need for the Commission to enter speculative hedge positions on behalf of Maine ratepayers.

In conclusion, in this circumstance I cannot find that it is prudent to enter into a 20-year contract term, nor do I think the contract pricing is robust enough to conclude that through a likely range of possible futures Maine ratepayers will realize any reduction in electricity pricing. The result of the majority's decision to enter a long-term contract is to needlessly shift risk from investors and shareholders to the Maine ratepayer.

NOTICE OF RIGHTS TO REVIEW OR APPEAL

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

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

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

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

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