STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Mark A. Vannoy
CHAIRMAN

R. Bruce Williamson
Randall D. Davis
COMMISSIONERS

Harry Lanphear
ADMINISTRATIVE DIRECTOR

December 20, 2017

Honorable David C. Woodsome, Senate Chair
Honorable Seth A. Berry, House Chair
Energy, Utilities and Technology Committee
100 State House Station
Augusta, Maine 04333

Re: Annual Report on Long-term Contracts

Dear Senator Woodsome and Representative Berry:

During the 2017 session, the Legislature enacted An Act to Increase Investment and Regulatory Stability in the Electric Industry (Act).[1] Section 2 of the Act, now codified as 35-A M.R.S. § 3210-C, sub-§3, provides in part that:

> By January 1st of each year, the commission shall submit a report to the joint standing committee of the Legislature having jurisdiction over energy and utilities matters on the procurement of transmission capacity, capacity resources, energy and renewable energy credits in the preceding 12 months under this subsection, the Community-based Renewable Energy Act and deep-water offshore wind energy pilot projects under Public Law 2009, chapter 615, Part A, section 6, as amended by Public Law 2013, chapter 369, Part H, sections 1 and 2 and chapter 378, sections 4 to 6. The report must contain information including, but not limited to, the number of requests for proposals by the commission for long-term contracts, the number of responses to requests for proposals pursuant to which a contract has been finalized, the number of executed term sheets or contracts resulting from the requests for proposals, the commission's initial estimates of ratepayer costs or savings associated with any approved term sheet, actual ratepayer costs or savings for the previous year associated with any procurement, the total ratepayer costs or savings at the time of the report and the megawatt-hours, renewable energy credits or capacity produced or procured through contracts. The report must also include a plan for the succeeding 12 months pertaining to the procurement of capacity resources, energy and

[1] P.L. 2017, c. 134.

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renewable energy credits, including dates for requests for proposals, and types of resources to be procured.

Attached is the Commission's report. If you have any questions, please do not hesitate to contact us.

Sincerely,

Mark A. Vannoy, Chairman

On behalf of the Chairman
R. Bruce Williamson, Commissioner
Randall D. Davis, Commissioner
Maine Public Utilities Commission

Attachment
cc: Energy, Utilities and Technology Committee Members
Deirdre Schneider, Legislative Analyst

MAINE PUBLIC UTILITIES COMMISSION

ANNUAL REPORT ON LONG-TERM CONTRACTS

Presented to the
Joint Standing Committee on
Energy, Utilities and Technology
January 1, 2018

TABLE OF CONTENTS

I. INTRODUCTION

During its 2017 session, the Legislature enacted an Act to Increase Investment and Regulatory Stability in the Electric Industry (Act).[1] Section 2 of the Act, now codified as 35-A M.R.S. § 3210-C, sub-§3, provides in part that:

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The Commission hereby submits its report to the Energy, Utilities and Technology Committee regarding long-term contracts.

II. LONG-TERM CONTRACTS

A. Competitive Solicitations Pursuant to 35-A M.R.S. §3210-C

During 2017, the Commission did not conduct any competitive solicitations.

Section §3210-C(6) directs the Commission to conduct a competitive solicitation no less often than every three years if the Commission determines that the likely benefits to ratepayers resulting from any contracts entered into as a result of the solicitation process will exceed the likely costs. The Commission last issued a Request for Proposals (RFP) in February 2015. The Commission expects to issue its findings and conclusions in connection with its Inquiry into the Goals and Objectives for Long-Term Contracting Pursuant to 35-A M.R.S. Section 3210-C in Docket No. 2015-00058 early in 2018. At that time, and prior to issuing an RFP, the Commission will consider

[1] P.L. 2017, c. 134.

market conditions and the potential for beneficial contracts and determine whether it is reasonably likely that the result of conducting a competitive solicitation in 2018 will be beneficial to ratepayers.

1. Prior Competitive Solicitations Pursuant to 35-A M.R.S. §3210-C

Since 2008, the Commission has conducted five competitive solicitations pursuant to Section 3210-C as outlined below. Specific information regarding the contracts and their terms are set forth in Attachment 1.

On December 3, 2008, in Docket No. 2008-00104, the Commission issued an RFP for long-term contracts for capacity and associated energy. Proposals were permitted from new and existing resources, renewable and non-renewable supply side resources and demand-side resources. Multiple bidders submitted proposals by the April 7, 2009 deadline and Commission Staff engaged in proposal discussions with each bidder. On October 8, 2009, the Commission issued an Order directing Central Maine Power (CMP) and Bangor Hydro Electric Company (now Emera Maine) to enter into long-term contracts for capacity and energy with Evergreen Wind Power III, LLC, a subsidiary of First Wind Holdings, LLC, for the output of the 60 megawatt (MW) Rollins Wind Project in Penobscot County. The Commission rejected all other bids. The Rollins Wind contracts were executed in March 2010 and the project achieved commercial operations in the summer of 2011.

On February 22, 2010, in Docket No. 2010-00066, the Commission issued a second RFP seeking proposals from qualified resources for capacity and associated energy. Proposals were permitted from new and existing resources, renewable and non-renewable supply side resources and demand-side resources. Subsequent to the issuance of the RFP but before the April 16, 2010 deadline for proposal submissions, the Legislature enacted a change to 35-A M.R.S. § 3210-C(3)(C), which allowed the Commission to authorize long-term contracts that included renewable energy credits (RECs) provided that the cost of the RECs is below market value or the purchase of the RECs adds value to the transaction.[2] Numerous proposals were submitted by the April deadline. On September 28, 2010, the Commission approved the term sheet for a five-year contract for the capacity and RECs associated with the Verso Bucksport LLC's renewable capacity project located at the Bucksport Mill. The Commission rejected all other bids. The Verso Bucksport contract was effective at the beginning of 2012. On June 30, 2015, the Commission approved the early termination of the Verso Bucksport contract.

On October 24, 2012, in Docket No. 2012-00504, the Commission issued a third RFP seeking proposals from qualified resources for capacity and associated energy. Proposals were permitted from new and existing resources, renewable and non-renewable supply side resources and demand-side resources. The Commission received more than a dozen proposals by the March 1, 2013 deadline. On December 18, 2013, the Commission approved a term sheet for capacity and energy with Apex

[2] P.L. 2009, c. 518.

Clean Energy Holdings, LLC for the output of the 90 MW Downeast Wind project planned for Washington County. The Commission did not approve any other proposals. Apex Clean Energy Holdings LLC has not sought to negotiate or execute a contract. The Downeast Wind project is still in the development stage.

On February 5, 2014, in Docket No. 2014-00024, the Commission issued a targeted solicitation for proposals for long-term contracts for capacity and associated energy from qualifying new renewable resource projects. To qualify for this RFP, the Commission required that a project must: (1) have an in-service date after January 1, 2014 and (2) rely on one or more of the following resources or technologies: fuel cells; tidal; solar; wind; geothermal; biomass (including landfill gas, but not including municipal solid waste); or hydroelectric generation that meets all applicable state and federal fish passage requirements. Numerous proposals from new renewable resources, were received by the April 4, 2014 deadline. On January 8, 2015, the Commission approved the term sheets for long-term contracts for the capacity and associated energy for two projects located in Maine, the Weaver Wind Project, a 99 MW facility proposed for Hancock County and the Highland Wind Project, a 44 MW facility proposed for Somerset County. On February 25, 2015, the Commission voted to reconsider the approved term sheets in light of recent changes in the energy markets. On May 4, 2015, Weaver Wind notified the Commission that it was withdrawing its proposal. On July 13, 2015, the Commission approved an amended term sheet for the Highland Wind project. The developer has not sought to enter final contract negotiations. The Highland Wind project remains in the development stage.

Finally, on February 2, 2015, in Docket No. 2015-00026, the Commission issued an RFP seeking long-term contract proposals from qualified new or existing resources for capacity and associated energy. The Commission received multiple timely submissions by the due date of May 1, 2015. On December 17, 2015, the Commission approved a term sheet with Dirigo Solar, LLC for the purchase of capacity and energy for up to 75 MW of newly developed solar photovoltaic arrays located in the CMP and Emera Maine service territories. The Commission did not approve any other proposals. The Dirigo Solar contract, consisting of a master agreement and the form of the individual project agreements, was approved by the Commission on December 12, 2017. Dirigo Solar expects the first project developed under this agreement to achieve commercial operations by the end of 2019.

2. Current and Forward Market Prices

The Commission considers current and expected market prices in evaluating whether a proposed contract is reasonably likely to result in ratepayer benefits and uses energy market forecast data in the analysis of bidder proposals. Current trading prices for futures contracts and other energy market derivative products provide useful market information regarding future prices. For example, settlement prices as of December 15, 2017 for peak electricity prices at the ISO New England

Mass Hub as settled through CME Group[3] indicate that the locational marginal price (LMP) for electricity during peak hours over the next several years is expected to be in the $70-$80 per MWh during January and February and in the $30-$40 per megawatt hour (MWh) in May.

3. Ratepayer Costs or Savings Associated with Prior Solicitations Pursuant to 3210-C

As noted in Attachment 1, only two contracts have been executed and the projects achieved commercial operations. The Verso Bucksport contract became effective in early January 2012. In 2015, the Commission approved a contract termination effective July 2015 after 3.5 years of the approved five-year term. Overall, through the term of the contract, the cumulative benefit to ratepayers totaled $584,000. The early termination of the contract was taken to ensure some benefit to ratepayers accrued. REC pricing forwards indicated continued operation of the contract would erode ratepayer benefits and would likely end with above market costs.

The Rollins wind project achieved commercial operations in 2011. The contract pricing is subject to a floor price and wholesale market prices have been below the contract floor for several years. From the beginning of commercial operations through February 2017, the date of the most recent stranded cost filings from CMP and Emera Maine, the cumulative above-market cost of the contract is approximately $16 million. Projections provided by CMP and Emera Maine of future above-market costs indicate an on-going cost to ratepayers of approximately $1 million annually. For the most recent stranded cost year ended February 28, 2017, the Rollins Wind contract resulted in above-market costs to CMP and Emera Maine combined of approximately $2.9 million.

B. Competitive Solicitations Pursuant to the Community-Based Renewable Energy Pilot Program

During 2017, the Commission did not conduct any competitive solicitations for the Community-Based Renewable Energy Pilot Program. The Commission's authority to award contracts governed by this program expired on December 31, 2015. No future solicitations are planned.

1. Prior Competitive CBRE Program Solicitations

Since 2010, the Commission has conducted three competitive solicitations pursuant to the Community-Based Renewable Energy Pilot Program (CBRE Program) as outlined below. Specific information regarding the contracts and their terms are set

[3] CME Group is comprised of four Designated Contract Markets (DCMs), the Chicago Mercantile Exchange (CME), the Chicago Board of Trade (CBOT), the New York Mercantile Exchange (NYMEX) and the Commodity Exchange, Inc. (COMEX). The applicable data set code and description is U6—ISO New England Mass Hub 5 MW Peak Calendar-Month Day-Ahead LMP Futures.

forth in Attachment 2. It should be noted that the CBRE Program contained a provision whereby projects of 1 MW or smaller could enter into a contract without submitting bids in a competitive solicitation. The contracts with Exeter Agri-Energy (Phase 1) and Goose River Hydro shown on Attachment 2 were authorized in this fashion.

On April 28, 2011, in Docket No. 2011-00150, the Commission issued an RFP for community-based renewable energy projects. On October 14, 2011, the Commission issued an Order authorizing the terms of a long-term contract between Bangor Hydro Electric Company (now Emera Maine) and Pisgah Mountain, LLC, for a 9 MW wind facility in Clifton, Maine. This Order also authorized the terms of two additional contracts, Jonesport Wind, LLC, a 4.8 MW wind facility in Jonesport and Lubec Wind, LLC, a 4.8 MW wind facility in Lubec. The Jonesport Wind and Lubec Wind proposals were later combined in the 2013 RFP.

On March 21, 2013, in Docket No. 2013-00207, the Commission issued a RFP for community-based renewable energy projects. On May 28, 2013, the Commission approved the terms of contracts with Jonesport Wind, LLC, a 9.6 MW wind facility in Jonesport and a 2 MW expansion of the Exeter Agri-Energy project in Exeter. On August 27, 2013, the Commission authorized the term of a contract with Maine Woods Pellet Company, LLC (now Athens Energy) for a 7.1 MW wood fired biomass facility in Athens.

The Commission conducted one final solicitation for the CBRE Program by issuing its 2015 RFP for community-based renewable energy projects on September 30, 2015 in Docket No. 2015-00299. By Orders issued December 22, 2015 and January 29, 2016, the Commission authorized the terms of contracts with four projects: a 9.9 MW solar project in Pittsfield to be developed by Clear Energy, LLC and Cianbro Development Corporation; a 7.5 MW biomass plant in Searsmont to be developed by Georges River Energy, LLC; a 310 kW hydroelectric power plant and 85.68 kW solar array in Dover-Foxcroft to be developed by Mayo Mill, LLC; and a 1.0 MW wind facility in Limestone, Maine to be developed by Shamrock Partners, LLC.

2. <u>Rate Payer Costs or Savings Associated with Prior Solicitations in the CBRE Program</u>

Only four projects that have received contract awards pursuant to the CBRE Program have achieved full or partial commercial operations by the end of 2017: Pisgah Mountain wind project, Phase 1 of the Exeter Agri-Energy project (1 MW), the initial phase of the Goose River hydro project and the Athens Energy project. As this program was designed to provide incentives for the development of small renewable energy projects, the contract prices are significantly above current wholesale energy market prices and the revenues received by CMP and Emera Maine from the resale of the energy fall significantly short of the payments to the generators. The transmission and distribution (T&D) utilities recover the above-market component of the cost of these contracts through stranded cost proceedings. During the most recent stranded cost year ended February 2017, the total above-market cost to CMP and Emera Maine of the CBRE Program totaled slightly over $1 million.

C. Competitive Solicitations Pursuant to the Deep-water Offshore Wind Energy Pilot Program

During 2017, the Commission did not conduct any competitive solicitations. The Commission currently has no plans to conduct a competitive solicitation during 2018.

1. Prior Competitive Solicitations

As directed by the enabling legislation[4], the Commission issued an RFP for long-term contracts for deep-water offshore wind energy pilot projects and tidal energy demonstration projects on September 1, 2010, in Docket No. 2010-00235. Proposals were due on May 2, 2011 and numerous submissions from both offshore wind and tidal projects were received.

On April 27, 2012, the Commission approved the term sheet for a contract with Ocean Renewable Power Corporation (ORPC) for the output from a 5 MW tidal project located in Eastport. The term sheet contained an initial price of $215/MWh with escalation at 2% per year. The ORPC contract was effective January 1, 2013. During the spring of 2013, the initial phase of the project was in-service and delivered a modest amount of energy to Emera Maine. In April 2013, the project was taken out of service because the electric generator component experienced salt-water infiltration. The project is not expected to re-commence operations until mid-2019.

On February 26, 2013, the Commission approved the term sheet for a contract with the 12 MW Statoil Hywind Maine Project, a floating wind project to be located in the Gulf of Maine. The term sheet contained an initial price of $270/MWh with escalation at a rate equal to 1% plus the yearly growth in the aggregate retail sales to distribution voltage customers. By letter to the Commission dated July 3, 2013, Statoil withdrew its project.

During its 2013 session, the Maine Legislature enacted An Act To Provide for Economic Development with Offshore Wind Power, P.L. 2013, c. 378, which directed the Commission to conduct a second competitive solicitation for proposals for offshore wind projects. On July 9, 2013, the Commission issued a Supplemental RFP. By Orders dated February 13, 2014 and February 19, 2014, the Commission approved a term sheet for a contract with the Maine Aqua Ventus (MAV) project. The term sheet contains an initial price of $230/MWh with escalation at 2.25% per year.

2. Rate Payer Costs or Savings Associated with Prior Solicitations

As noted, the Statoil project has been withdrawn, the MAV project is not

[4] P.L. 2009, c. 615, Part A, Section 6 (Ocean Energy Act).

expected to reach commercial operations for several years and the ORPC project, after operating for a few months, has been out of service since 2013. Thus, there have been no ratepayer costs or benefits associated with these contracts for several years. See Attachment 3. As provided by the Ocean Energy Act, the Commission may not approve any offshore wind or tidal contracts that would result in an increase in electric rates in any customer class that is greater than $1.45/MWh times the sum of T&D's total retail sales to distribution voltage customers measured in megawatt-hours during that year. Based on total sales to distribution voltage customers for CMP and Emera Maine, the total ratepayer funds available to support the above-market costs of all contracts authorized pursuant to the Ocean Energy Act would average approximately $13 million per year.

Competitive Solicitations pursuant to 35-A M.R.S. §3210-C

Attachment 1

Docket No.	RFP Issue Date	Commission Order	Developer	Resource	Installed Capacity	Pricing Terms	Term (Years)	Initial Commission Cost/Benefit Analysis	Quantity Delivered and Above Market Costs (Twelve Months Ending 2/28/17)	Comments
2015-26	2/2/2015	12/17/2015	Dirigo Solar	solar PV	75 MW	Initial bundled price of 3.4 cents per kWh with escalation at 2.5% per year.	20	Present value of net benefits to ratepayers ranges from $3 to $26 million annually over a wide range of future scenarios.	N/A	Form of Master Agreement and Project Agreement approved by the Commission in December 2017. First project under this agreement is expected to achieve commercial operations by the end of 2019.
2014-24	2/5/2014	1/8/2015	Weaver Wind	wind	99 MW	N/A	20	N/A	N/A	Proposal withdrawn in May 2015.
2014-24	2/5/2014	1/8/2015	Highland Wind	wind	96.6 MW	Initial bundled price of $43.80 per MWh with escalation at 2.5% per year.	25	Concurring opinion of Commissioner Littell indicate ratepayer benefits fo $10-$50 million. Concurring opinion of Commissioner McLean indicates net present value benefit/cost range from positive $28 million to negative $35 million.	N/A	Under development.
2012-504	10/24/2012	12/18/2013	Downeast Wind	wind	90 MW	Energy and capacity at 88% of LMP with floor price of $45/MWh (escalating 1.5% per year) and ceiling price of $110/MWh	20		N/A	Under development.
2010-66	2/22/2010	9/28/2010	Verso Bucksport	Biomass RECs	35 MW	REC price of $22 in 2012-3, $21 in 2014, $18 in 2015 and $15 in 2016.	5	Based on London Economics forecast of REC prices, Commission concluded ratepayer benefit was reasonably likely.	N/A	Contract terminated after 3.5 years in 2015 with cumulative benefit to ratepayers of $584,000.
2008-104	3/30/2009	10/8/2009	Rollins Wind	wind	60 MW	Energy and capacity at LMP minus $10-$15/MWh with floor price of $55/MWh (escalating $1/year) and ceiling price of $110/MWh.	20	Based on London Economics forecast of future LMP prices, the contract was expected to have a small benefit in the early years. Benefits were likely to continue to increase in outer years given the trajectory of projected wholesale prices.	$2.9 million	Operating. Contract ends 2031. From the date of commercial operations in 2011 through February 2017, the cumulative above-market costs to ratepayers are approximately $16 million. Recent stranded cost case forecast of future above-market costs are approximately $1 million annually.

Competitive Solicitations: Community-Based Renewable Energy Pilot Program									Attachment 2

Note: For contracts authorized pursuant to the CBRE Program, the Commission did not perform an initial cost/benefit analysis. The program authorized the Commission to award contracts at a price that did not exceed $0.10 per kWh. Proposals were evaluated on the basis of whether they met the pricing requirement.

Docket No.	RFP Issue Date	Commission Order	Developer	Resource	Installed Capacity (MW)	Pricing Terms (cents per kWh)	Term (Years)	Above Market Costs (Twelve Months Ending 2/28/17)	Comments
2013-207	3/21/2013	5/28/2013	Jonesport Wind	wind	9.6	8.5	20	N/A	Under development.
2011-150	4/28/2011	10/14/2011	Pisgah Mountain	wind	9.0	9.3	20	N/A	Achieved COD late in 2016. Revenues and expenses have not yet been included in stranded cost filings by the utility.
2013-207	3/21/2013	8/27/2013	Athens Energy	biomass	7.1	9.9	20	$698,417	Operating.
2015-299	9/30/2015	12/22/2015	Shamrock Wind	wind	1.0	8.3	20	N/A	Under development.
Phase 1: N/A Phase 2: 2013-207	Phase 1: N/A Phase 2: 3/21/2013	Phase 1: N/A Phase 2: 5/28/2013	Exeter Agri-Energy	anaerobic digestion	3.0	Phase 1: 10.0 Phase 2: 8.5	20	$325,405	1 MW in Phase 1 operating. Expected COD Phase 2 early 2018.
2015-299	9/30/2015	12/22/2015	Georges River	biomass	7.5	9.9	20	N/A	Under development.
2015-299	9/30/2015	12/22/2015	Pittsfield Solar	solar PV	9.9	8.45	20	N/A	Under construction. Expected COD mid-2018
N/A	N/A	N/A	Goose River Hydro	hydro	375 kV	10.0	20	$4,931	Phase I operating.
2015-299	9/30/2015	12/22/2015	Mayo Mill	solar PV, hydro	395 kV	10.0	20	N/A	Under development.

Competitive Solicitations: Deep-Water Offshore Wind Energy Pilot Program

Attachment 3

Docket No.	RFP Issue Date	Commission Order	Developer	Resource	Installed Capacity (MW)	Pricing Terms	Term (Years)	Initial Commission Cost/Benefit Analysis	Quantity Delivered During Prior Year Ended 2/28/17	Comments
2010-235	9/1/2010	4/27/2012	Ocean Renewable Power Corporation	tidal	5	Initial price of $215/MWh with escalation at 2% per year.	20	NRELJEDI model estimates indicate $22 million in economic output during construction phase and $1.1 million in economic output per year during operating phase. Commission estimate of total above-market costs stated in Order was $16 million on an NPV basis and $37.5 million nominally.	N/A	Currently not operating, expected restart 2019.
2010-235	9/1/2010	2/26/2013	Statoil	floating wind	12	Initial price of $270/MWh with escalation at 1% per year.	20	REMI modeling indicates $23.1 million in economic output during construction phase and $2 million per year during operating phase. Above-market costs estimated in Order were in the range of $52-$76 million on an NPV basis and $190 nominally.	N/A	Proposal withdrawn on July 3, 2013.
2010-235	7/9/2013	2/13/2014	Maine Aqua Ventus	floating wind	12	Initial price of $230/MWh with escalation at 2.25% per year.	20	Gabe Study (IMPLAN model) estimates indicate economic output of $37-$52 million during construction phase and $1.9 million annually during operations. Above-market costs estimated in Order were $49-$78 million on NPV basis and $172-$187 million nominally.	N/A	The Commission is expected to consider the form of the long-term contract in January 2018. Project contruction is contingent on receipt of additional federal DOE grants. DOE decision is expected by the fall of 2018.

ATTACHMENT 4

REDACTED

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2015-00026

December 17, 2015

MAINE PUBLIC UTILITIES COMMISSON
Long-Term Contracting

ORDER APPROVING
TERM SHEET

VANNOY, Chairman; McLEAN and WILLIAMSON, Commissioners

I. SUMMARY

Through this Order, the Commission approves a Term Sheet for the purchase of capacity and associated energy from up to 75 MW of newly developed solar photovoltaic arrays located in the Central Maine Power Company (CMP) or the Emera Maine (EME), Bangor Hydro District service territories. The projects are to be developed by Dirigo Solar, LLC (Dirigo). The Staff is directed to work with Dirigo, CMP, and EME to develop a final contract consistent with the provisions of the approved Term Sheet. The Commission will determine the utility contractual counterparty(ies) during the process of approving the final contract(s).

II. STATUTORY AUTHORITY

A. Capacity Resource Adequacy, Section 3210-C

Section 3210-C of Title 35-A, Capacity Resource Adequacy, contains a statement of State policy: 1) 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; 2) 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 3) 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).

In promotion of these policies, the Statute provides the Commission with the authority to direct investor-own transmission and distribution (T&D) utilities to enter into long-term contracts for capacity and energy under specified circumstances. Such contracts, under Statute, must occur as a result of a competitive solicitation and contract negotiation. 35-A M.R.S. §3210-C(3)and(6).

The Statute also specifies that the Commission select proposals that are competitive and the lowest cost relative to similar bids. Among such proposals, the Statute provides the following priority order: (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, with a 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, with a preference to capacity resources with no net emission of greenhouse gases; and (6) other capacity resources. 35-A M.R.S. § 3210-C(4).

Finally, the Statute specifies that the long-term contracts may not be for more than ten years, unless the Commission finds that a longer term to be prudent. 35-A M.R.S. § 3210-C(5).

B. Implementing Rules

The Commission's long-term contracting implementing rule (Chapter 316) states 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 rule states 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 rule further states 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.

Chapter 316, section 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.

III. PROPOSAL SOLICITATION

On February 2, 2015, the Commission issued a Request for Proposals for Capacity and Associated Energy and Renewable Energy Credits (RFP) pursuant to 35-A M.R.S.§ 3210-C and Chapter 316 of the Commission rules. Pursuant to the RFP, initial proposals were due on or before May 1, 2015. The Commission received multiple timely submissions.

After Staff discussions and exchanges of alternative proposals with the RFP respondents and consistent with the requirements of the RFP, the respondents submitted their best and final offers. The Term Sheets for the following five proposals were issued for comment to the Office of the Public Advocate (OPA), CMP, and EME. Upon receipt of comments and reply comments from proposal proponents, the Term

Sheets regarding the following proposals were submitted to the Commission for formal consideration:

1. Dirigo Solar, LLC- Up to 75 MW of energy and capacity from solar photovoltaic arrays located in CMP or Emera Maine, Bangor Hydro Districts' service territories.[1]

2. [redacted]

3. [redacted]

4. [redacted]

5. [redacted]

Public Description of Proposals

	Project ID	Location	Vintage	Type	Product	MW Size
Dirigo Solar	1	Maine	new	renewable	energy and capacity	medium
	2	Maine	existing	renewable	capacity	range of quantities
	3	outside of Maine	existing	non-renewable	energy and capacity	large
	4	Maine	new	renewable	energy and capacity	large
	5	Maine	new	renewable	energy	small

III. COMMENTS

The Commission received comments from the OPA and CMP.

A. Office of the Public Advocate

Dirigo Solar [Project #1]

The OPA observed that the economic analysis prepared by Staff indicates that the contract will provide significant ratepayer benefits under all the scenarios examined.

[1] The initial proposal was for a single project. The proposal was revised to allow for several projects at distinct locations.

Moreover, the OPA noted that because the proposed project is a relatively small facility with a low capacity factor, the overall risk to ratepayers is limited. The OPA further stated that the approval of a contract for this project would move in the direction of a balanced, diverse mix of resources that is likely to reduce costs to ratepayers.

The OPA suggested that, if the Commission approves the Term Sheet, clear project timelines should be developed, both for final contract approval and within the power purchase agreement itself. Specifically, the OPA noted that, in addition to being best practice for long-term contracts, the development of project timelines is of particular importance with respect to this project because of the aggressive pricing and uncertainty regarding facility development, as well as the contingency of obtaining a contract for the sale of renewable energy credits (RECs). Subject to that limitation, the OPA stated that the Term Sheet is consistent with Section 3210-C and should be approved.

[redacted] [Project #2]

The OPA stated that, as a contract for capacity only, this proposal is consistent with the original intent of Section 3210-C to mitigate the impact of the financial risk of the ISO-NE forward capacity market. As a capacity-only contract, however, the OPA noted that the benefits rest solely on projections of capacity prices and that the capacity market is a particularly uncertain market. Given the volatility in the capacity market, the OPA stated that this proposal offers a small, but meaningful hedge that would provide value to ratepayers and supports approval of the Term Sheet at the [redacted] MW level.

[redacted] [Project #3]

The OPA observed that Staff's analysis shows that this proposed contract would provide only minimal ratepayer benefit under the most favorable scenario and would increase costs to ratepayers under all other scenarios. The OPA, therefore, recommended that the Commission reject this proposed Term Sheet.

[redacted] [Project #4]

The OPA commented that Staff's analysis shows a "mixed bag" of results and the scenarios that involve qualification in the forward capacity market show the greatest ratepayer benefits. In general, the OPA commented that it would be unwise to enter into contracts of greater than 10 years to obtain structural advantages in a regional capacity market that is less than 10 years old. The OPA observed that this would be [redacted] and, given its size, the OPA urged a cautious approach and did not support approval of the proposed Term Sheet.

[redacted] [Project #5]

The OPA observed that Staff's analysis of this proposed Term Sheet would not provide ratepayer benefit even under the most favorable scenarios and, therefore, recommended its rejection.

B. Central Maine Power Company

As a general comment, CMP noted that the Term Sheets lack detail on several terms that have been important in prior long-term contract negotiations, including: facility operational requirements; change in law provisions; force majeure events; remedies upon breach; assignment rights; indemnification and dispute resolution procedures. Thus, CMP stated, the Term Sheets should be viewed as conditional, subject to Commission approval of the final contract.

CMP noted that pursuant to the enactment of "An Act to Ensure Equitable Support for Long-Term Energy Contracts", P.L. 2014 Chapter 454, all costs from long-term contracts are to be allocated between CMP and Emera Maine based on relative kWh sales. Thus, CMP suggested that rather than having both utilities responsible for administering a portion of a proposed purchase, the Commission allocate 100% of the purchase obligation to the utility in whose service territory the project will be located. Other than with respect to the issue of which utility should be responsible for day-to-day contract administration issues, CMP stated that there is no substantive effect of having either Emera Maine or CMP sign a particular long-term contract.

Dirigo Solar [Project #1]

CMP noted that, although it lacks sufficient information to estimate whether congestion, local transmission charges and line loss adjustments would be a significant concern, the Term Sheet should be clear that any such charges would be the responsibility of the project sponsor and not passed on to utility customers. Additionally, because the Term Sheet provides for either 50% or 100% of the capacity value of the facility, CMP suggested that the Commission require that commercially reasonable efforts be made to maximize the capacity value of the facility. Finally, CMP stated that the proposed Term Sheet would appear to offer the likelihood of lowering customer costs, as shown in the Staff's analysis, and that it generally concurs with Staff's analysis that there would be ratepayer value.

[redacted] [Project #2]

CMP observed that the proposal is for a financial transaction structured as a contract for differences and notes that Section 3210-C provides that the Commission may permit, but may not require a utility to enter into contracts for differences that are intended to buffer ratepayers from negative impacts of transmission development. CMP stated that the proposed contract appears to be more focused on hedging customers from the risks of uncertain future capacity prices rather than the impacts of transmission development and, thus, does not fit within the limitations of Section 3210-C. CMP further noted that it is not aware of any reliable methodology for predicting future capacity market clearing prices. Given the uncertainty of future prices and based on Staff's analysis and its own scenario analysis, CMP concluded that it is not reasonably likely that this proposal would provide an appropriate level of benefits to customers and that it poses an unreasonable risk.

[redacted] [Project #3]

CMP noted that the Term Sheet provides asymmetrical risk in that it contains provisions that favor the bidder to the detriment of ratepayers, specifically the provision regarding [redacted]; provisions regarding the seller's right to retire the generation source and to deliver power not sourced from the generation unit; and, the financial responsibility for capacity availability penalties that are imposed on the buyer. CMP also stated that the Staff's analysis shows that the proposed contract would result in negative customer value in each year of the contract term.

[redacted] [Project #4]

CMP observed that the Term Sheet does not specify a delivery point for the energy so it is difficult to estimate whether congestion, local transmission charges and line loss adjustments would be a significant concern. CMP noted that the capacity provisions in the Term Sheet make the utility financially responsible for performance penalties associated with real-time scarcity event performance relative to FCM obligations. CMP stated that customers should not assume the financial risk of performance penalties and the facility that has undertaken the relevant capacity obligations should more appropriately bear those risks. CMP concurred with Staff's financial analysis that the proposed Term Sheet would offer some likelihood of lowering customer costs, but noted that the proposed pricing is dependent on federal legislation extending the production tax credit (PTC) and the Term Sheet is silent on what would occur if the PTC is not extended.

[redacted] [Project #5]

CMP stated that, based on the plain language of Section 3210-C, capacity is a required component of any long-term contract. Because the Term Sheet would provide that all capacity would be retained by [redacted] CMP noted that it is not clear how this transaction would meet the statutory requirements. In addition, based on review of the Staff's financial analysis, CMP stated it does not appear that the transaction would provide benefits to ratepayers.

IV. DISCUSSION AND DECISION

A. Long-Term Contract Review

Section 3210-C provides the Commission with the discretionary authority to direct T&D utilities to enter into long-term power contracts as a means to achieve and promote the stated policies contained in the statute. These policies include promoting new renewable resource development in the State, reducing electric prices and price volatility and reducing greenhouse gas emissions from electricity generation. The Commission's review of long-term contract proposals focuses on a comprehensive quantitative analysis of the likely impacts on electricity rates and on a consideration of the extent to which proposed contracts will promote the policies in Section 3210-C.

As the Commission has stated previously, a long-term contract with a creditworthy counterparty such as a utility can be very valuable to developers of generation resources and may be necessary to obtain financing for new projects. *See, e.g., Order Directing Utility to Enter into Long-Term Contracts,* Docket No. 2014-00024 at 2 (Feb. 6, 2015). Project developers may, therefore, be willing to offer utilities favorable contractual pricing terms that would result in lower rates. Moreover, by allowing for the financing of projects and subsequent development that might not otherwise occur, long-term contracts could facilitate the construction of renewable generation facilities in Maine in furtherance of stated policies to reduce greenhouse gases, to lower capacity costs, and enhance reliability.

However, the Commission emphasizes that there is an inherent risk to long-term contracts in that an assessment of their economics depends on projections of future electricity and capacity prices (over 5, 10, and 20 years) and a comparison of those projections with the proposed long-term contract prices. Any such long-term forecasts are dependent on numerous projections and are inherently uncertain. In recognition of this uncertainty, it is important to consider long-term contracts under a broad range of possible futures. The ultimate goal is to assess whether the potential benefits and costs of a proposal are sufficiently robust under a variety of future scenarios.

B. Dirigo Solar [Project #1]

The Dirigo Solar project consists of up to 75 MW of new solar photovoltaic array facilities located in various areas within CMP and EME (located in ISO New England) service territories. The products provided under the contract are the energy and the capacity value of the facilities. Regarding the purchase of capacity, the Commission is provided with two options: 1) Option 1-100% of the capacity and 2) Option 2-50% of the capacity. The term of the contract is 20 years and commercial operation is expected to occur by the fourth quarter 2017. The contract price is: Option 1-bundled price of \$35/MWh in Contract Year 1, with 2.5% annual escalation, and Option 2-bundled price of \$34/MWh in Contract Year 1, with 2.5% annual escalation.

Upon review, the Commission concludes that the Dirigo Solar proposal is likely to provide significant rate benefits over a variety of future scenarios and would promote the policies specified in Section 3210-C. Accordingly, the Term Sheet (attached to this Order) is approved.

Specifically, Staff analysis shows net benefits to ratepayers across a wide range of future scenarios, and due to its modest size, the Term Sheet presents relatively low risk exposure to ratepayers. Under the scenarios analyzed, the present value of the net benefit ranges from $3 to $26 million. Additionally, the project is a new renewable capacity resource located in Maine and would create no net emission of greenhouse gases and, therefore, ranks highly under the prioritization criteria outlined in section 3210-C(4).

Based on the level of the starting price and relatively low escalator, the Commission concludes that, consistent with 35-A M.R.S. § 3210-C(5), the 20-year contract term is prudent.

With respect to the capacity and pricing options contained in the Term Sheet, the Commission elects the 50% capacity option and the corresponding lower price. This allocation of capacity benefits will provide Dirigo with a significant financial incentive to act to maximize the benefit of the project's capacity value.

Finally, to ensure that the developer acts to finalize a contract within a reasonable timeframe, the approval of the Term Sheet will expire one year from the date of this Order if a final contract has not been executed. Moreover, we expect that the final contract will contain required development milestones to ensure that the project will reach commercial operations within a reasonable time frame.

C. Analysis of the Remaining Proposals

The Commission finds that the analysis of the costs and benefits of the other long-term contract proposals do not present a sufficiently high probability of ratepayer benefit that would warrant further consideration of a utility long-term contract under our section 3210-C statutory authority.

[redacted] [Project #2]

The proposal is for [redacted] MW of qualified capacity from [redacted] existing [redacted] resources located in Maine. The proposal is structured as a financial contract for differences at a fixed price with an escalator. If the forward capacity market clears above that price ratepayers would benefit, but if the market clears below the contract price, ratepayers would bear the associated cost. The Commission notes that the ISO-New England forward capacity market continues to evolve and is far from stable, which presents further uncertainty and risk.

The economic analysis performed by Staff indicates that this proposed contract may provide small ratepayer benefits over the term of the contract, but that the first five years of the contract would result in net costs. Staff estimates a present value net benefit of approximately $3 million at [redacted] MW of capacity, although the contract would not provide consistent net benefits on an annual basis until 2024, which is the 6th year of a 10-year term. Thus, the Commission concludes that potential ratepayer benefits are not sufficiently certain to support a long-term contract. The Commission also notes that the proposal involves existing facilities that rank relatively lower in the statutory priority order.

[redacted] [Project #3]

The proposed contact would be for energy and capacity for [redacted] MW from the [redacted] The Staff's economic analysis provided to the T&D Utilities and OPA for comment indicates that the contract would not provide significant ratepayer benefits under any of the market scenarios, and could result in significant ratepayer costs under some scenarios. Under the scenarios analyzed for the pricing terms submitted to the utilities and OPA for comment, the present value of the net benefits ranges from a negative $95 million to a positive $1 million. Moreover, [redacted]. This, coupled with the fact that [redacted] is an existing facility and is located outside of Maine, results in the proposal ranking relatively low on the statutory priority list.

[redacted] [Project #4]

The proposed project is a [redacted] MW [redacted] power project located in [redacted] The economic analysis performed by Staff indicates that the net costs / benefits of the proposed contract vary over future scenarios with benefits in the range of negative $3 million to positive $135 million. However, under the scenarios analyzed, the contract would not provide consistent net benefits on an annual basis until 2028, which is the 10th year of a 20-year term. Further, a significant portion of projected benefits arise from capacity market revenues (real-time scarcity payments and/or forward capacity market revenues) under lower energy price forecast scenarios. A reliance on such projections contains enhanced risks given the level of uncertainty in the form and structure of the continually evolving capacity market in New England. In addition, because this project is of such a large scale [redacted], a contract would create substantial ratepayer financial exposure to a single project. On balance, the Commission concludes that the risks of such a large contract outweigh the potential benefits and, therefore, decline to approve the proposed Term Sheet.

[redacted] [Project #5]

The proposed project is a new [redacted] MW [redacted], Maine. The proposal is for energy only and is of relatively small size. Although the proposal presents an interesting project, the Staff's economic analysis indicates the contract will not provide ratepayer benefits in any of the scenarios considered. Under the scenarios analyzed, the present value of the net benefit ranges from approximately negative $6 million to negative $2 million. Accordingly, the Commission declines to adopt the proposed Term Sheet.

Accordingly, the Commission

ORDERS

1. That the Dirigo Solar proposed Term Sheet, attached to this Order, is hereby approved;

2. That Staff initiate discussions with Dirigo Solar, Central Maine Power Company and Emera Maine on the terms of a long-term contract consistent with the approved Term Sheet and this Order;

3. That Central Maine Power Company and Emera Maine actively participate in good faith in the long-term contracting process with the project proponent;

4. That the final contract include interim milestones applicable to the development of the individual solar PV installations to be covered by the long-term contract;

5. That the approval of the Term Sheet will expire one year from the date of this Order if a final contract has not been executed; and

6. That, upon completion of such discussions, the long-term contract be filed in this Docket for subsequent deliberations by the Commission to determine the consistency of the contract with the terms as approved and clarified herein.

Dated at Hallowell, Maine, this 17th day of December 2015.

BY ORDER OF THE COMMISSION

/s/ Harry Lanphear
Harry Lanphear
Administrative Director

COMMISSIONER VOTING FOR: Vannoy
McLean
Williamson

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.

Maine Public Utilities Commission
Docket No. 2015-00026
Proposed Term Sheet for
Long-Term Contract under 35-A M.R.S. §3210-C

Dirigo Solar LLC

November 5, 2015

This Term Sheet describes the essential terms for a potential long-term contract between Dirigo Solar LLC (Dirigo) and Emera Maine and/or Central Maine Power Company (Utilities) subject to approval by the Maine Public Utilities Commission (Commission).[1]

Facilities: The proposed Dirigo, fixed axis and/or tracking photovoltaic arrays located in CMP and that portion of Emera Maine located in ISO New England.

Nameplate Capacity: Up to 75 MW

Products: Energy on a physical basis; Capacity on a financial basis. Specifically, for all capacity value received in the ISO-NE capacity market, either through participation in the FCM directly or through performance payments or any successor capacity program adopted by the ISO-NE. Seller retains RECs and other environmental attributes.

Option 1: 100% of Energy and Capacity produced by the Facility to Buyer.

Option 2: 100% of Energy and 50% of Capacity produced by the Facility to Buyer.

Under both Options, Seller retains RECs and/or other environmental attributes.

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1 **This Term Sheet does not constitute a legally binding obligation of any party hereto or an agreement by any party to negotiate in any particular manner, or at all, or to consummate the transaction(s) described herein. The definitive terms for the transaction(s) described herein, if same should occur, will be set forth in a definitive agreement between Dirigo and one of the Utilities. No legally binding obligation between the parties will exist until such time that the terms contained herein are formally approved by the Commission AND a formal agreement containing such is also formally approved by the Commission and executed by the relevant parties. Either Dirigo or the Commission may, at any time prior to execution of a definitive agreement, unilaterally terminate all negotiations pursuant to this term sheet, for any reason or for no reason, without any liability whatsoever to the other party.**

Term: 20 years beginning at Facility commercial operations date (COD), as such will be defined by the long-term contract, if any, resulting from this term sheet.

Expected COD: On or before the end of Q4 2017

Delivery Point: Facility located at the former Worcester Biomass plant and other sites within Maine. Interconnection at pool transmission facility- LD. Deblois 34.5, Unit ID – 10178.

Contract Price:
Option 1: Bundled price of $35/MWh in Contract Year 1, with 2.5% annual escalation thereafter.

Option 2: Bundled price of $34/MWh in Contract Year 1, with 2.5% annual escalation thereafter.

REC Contingency

Contingent upon Dirigo making separate arrangements outside of this RFP for the disposition of renewable energy credits on terms satisfactory to Dirigo.

Election between Option 1 and Option 2 is at Commission's discretion at the time of Term Sheet Approval, if any.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2014-00024

July 13, 2015

MAINE PUBLIC UTILITIES COMMISSON

ORDER APPROVING TERM SHEET

Request for Proposals of Long-Term Contracts Under 35-A M.R.S. 3210 Pertaining to Central Maine Power and Emera Maine

VANNOY, Chairman; LITTELL, McLEAN Commissioners

I. SUMMARY

Through this Order, and consistent with the Commission's April 2, 2015 Order on Reconsideration (April 2nd Order), the Commission approves an amended term sheet for the Highland Wind Project to reflect the revised terms approved at the May 20, 2015 Deliberations.[1,2]

II. 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) authorizes 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 its long-term contract authority (Chapter 316).

Section 3210-C authorizes the Commission to direct investor-owned utilities to enter into such contracts when they are expected to reduce electric prices and price volatility for the State's electricity consumers. As stated in past decisions directing long-term contracting, the Commission's view has been that the underlying purpose of the authority 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.

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1 As revised subsequent to the April 4th Order, the Highland Wind Project is a 96.6 MW facility proposed to be located in Somerset County.

2 Commissioners Littell and McLean concur and Chairman Vannoy dissents. The concurring opinions and dissent are attached.

Chapter 316, § 5.B. provides that the Commission may solicit bids for long-term contracts with capacity resources through the issuance of a request for proposals (RFP) that contains all standards, procedures and requirements for the solicitation process, as well as a standard form contract. On February 5, 2014, the Commission issued an RFP seeking proposals from new renewable capacity resource projects pursuant to 35-A M.R.S.§ 3210-C and Chapter 316 of the Commission rules. Pursuant to the RFP, initial proposals were due on or before April 4, 2014. The Commission received multiple timely submissions. After Staff discussions of initial proposals with the RFP respondents, three proposals were put out for comment to the Office of the Public Advocate (OPA), CMP, and EME and submitted to the Commission for formal consideration. At Deliberations held on December 16, 2014, the Commission approved term sheets for proposals from the Weaver Wind and Highland Wind projects and directed one or both of the state's investor owned transmission and distribution utilities to negotiate in good faith a long-term contract consistent with the approved terms for final review and approval by the Commission.[3] On January 8, 2015, the Commission issued the Order Part I followed by the Order Part II on February 6, 2015 (Contract Order).[4]

On February 18, 2015, the Commission issued a Request for Comment seeking input from interested parties on whether the Commission should reconsider the Contract Order in light of recent changes in the energy market. Comments were received from multiple entities. The Commission considered the matter at a Deliberation session held on February 25, 2015, at which the Commission voted 2-1 (Littell dissenting) to reconsider the previously approved term sheets.

The Commission obtained a revised market forecast from its consultant in April 2015. On May 4, 2015, Sun Edison filed a letter in this Docket withdrawing the Weaver Wind project from consideration for a long-term contract in this procurement. On May 15, 2015, Highland Wind filed a revised proposal, proposing to increase the size of the project from 44 MW to 96.6 MW and extending the term from 20 to 25 years, in addition to changes to and options for pricing terms in response to the Commission's April 2nd Order on Reconsideration. This revised proposal was considered at a Deliberations held on May 20, 2015.

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

3 Then Chairman Welch and Commissioner Littell approved two term sheets and entering into long-term contracts with the projects and Commissioner Vannoy dissented.

4 Chairmen Welch retired from the Commission on December 31, 2014 and did not take part in the drafting of the Orders.

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, reduce price volatility, and otherwise benefit Maine ratepayers. A long-term contract with a 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 and energy 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. DECISION

As further discussed in the attached concurring opinions, pursuant 35-A M.R.S. § 1320, and consistent with the Commission's April 4, 2015 Order on Reconsideration, the Commission approves (Vannoy dissenting) an amended term sheet for the Highland Wind Project with the terms approved at the May 20, 2015 Deliberations. The approved term sheet is attached to this Order. The Commission delegates to Staff the negotiation and development of a long-term contract consistent with the approved terms. The Commission shall review and approve the final contract reflecting the terms approved at the May 20, 2015 Deliberations to ensure that the contract is consistent with the approved terms.

Accordingly, we

ORDER

1. That one or more of Maine's investor-owned transmission and distribution utilities will enter into long-term contract(s) for capacity and energy with NextEra Energy Resources LLC, for the output of Highland Wind according to the terms approved herein;

2. That the transmission and distribution utility/utilities actively participate in good faith in the long-term contracting process with the project proponents and Staff;

3. The Commission delegates to Staff the negotiation and development of a long-term contract consistent with the approved term sheet and this Order;

4. That, upon completion of such negotiations, the long-term contract be filed in this Docket for subsequent deliberations by the Commission to determine the consistency of the contract with the terms as approved and clarified herein.

Dated at Hallowell, Maine, this 13th day of July 2015.

BY ORDER OF THE COMMISSION

/s/Harry Lanphear

Harry Lanphear
Administrative Director

COMMISSIONER VOTING FOR: Littell
McLean

COMMISSIONERS DISSENTING: Vannoy

CONCURRENCE OF COMMISSIONER LITTELL[1]

I. SUMMARY

The terms offered by Highland Wind as well as the terms approved herein offer power and capacity purchase agreements well below market pricing. The pricing offered is substantially lower than current retail prices – and in particular much lower than prices for the standard offer. That is so even allowing for a mark-up from wholesale to retail pricing. The pricing approved is the equivalent of less than 4.4 ¢ per kilowatt-hour while the standard offer is currently at approximately 6.5 ¢ per kilowatt-hour for residential service.

No other entities whether renewable, natural gas, nuclear or other generators can or are offering guaranteed energy and capacity prices this low for a 20 or 25 year period. In short, this pricing offered is inexpensive and guaranteed for 25 years without price volatility. So much so that even accounting for the wholesale to retail markup, the offered prices is substantially lower than current standard offer prices. Accordingly, locking in this pricing for 25 years would ensure low prices for Maine ratepayers for 25 years for approximately 3 percent of projected electricity needs.

When the totality of the additional benefits of the capacity, potential performance payments, hedging benefits, and price suppression plus costs associated with renewable energy credits, the production/investment tax credit, system integration, are included, the value of the three newly revised scenarios presented is high for ratepayers ranging from tens of millions to hundreds of millions of net ratepayer benefits. Benefits are particularly high when the costs of carbon emission reductions are accounted upwards of more than 100 million dollars positive with carbon emissions benefits calculated. But even without carbon emission benefits, the other costs and benefits are positive with mid-point valuations in the three primary scenarios presented range from millions of dollars and tens of millions of dollars positive without carbon benefits once hedging and price suppression benefits are included, even without those tangible benefits the value of the pricing offered by NextEra presents tens of millions of dollars under the current EIA Annual Energy forecast. These terms make the offered and approved contract a clear winner for Maine ratepayers. These benefits exist before the additional terms proposed by Commissioner McLean are factored into the value.

To attain a majority and therefore a Commission decision; I vote with my colleague on modifications to the term sheet offered at deliberations, to do otherwise eliminate the favorable pricing terms and lose substantial ratepayer value in a long-term contract. Accordingly, by accepting these unilateral modifications proposed by Commissioner McLean the possibility of reaching a contract as these below market prices remains alive. That said, some of the terms modifications were related to the

[1] Due to his departure from the Commission, Commissioner Littell finalized this opinion without reviewing the concurring opinion of Commissioner McLean nor the dissenting opinion of Commissioner Vannoy.

Commission as challenging in negotiations with the bidders so unfortunately the possibility remains that the Commission will fail to reach a final contract agreement with these exceptional prices due to the modifications today. I join in the modifications in the hope that some arrangement might still be reached so that they are acceptable to the project developer and a formal contract may be executed.

These additional unilateral amendments are not necessary to achieve substantial ratepayer benefit. This would be made clear through the Commission releasing the assortment of forecasts and sensitivities used during this process. As I have articulated in my dissent to the May 20th decision asking the Commission to release this information, the pricing scenarios should be public, including the newest scenario based on the U.S. Energy Information Agency's 2015 Annual Energy Outlook. The new scenario based on U.S. EIA's 2015 Annual Energy Outlook is closest to the Commission's practices and methodologies prior to revisions in2015. With that, there are at least 14 energy basic scenarios calculated in this Docket. There are many more sensitivities being calculated off of the basic 14 scenarios. None have been made public including the most relevant ones.

Given the re-engineering of assumptions and proliferation of scenarios from a few to now 14 with more and more sensitivities being run – there are now 14 choices of electricity pricing, natural gas pricing, and basis differential numbers the Commission can use in this decision. According to the latest scenarios, the pricing numbers for electricity pricing, natural gas pricing, and basis differential numbers have changed dramatically from even five months ago and in my opinion are low. With Electricity prices having increased by 14 percent from 2013 to 2014 – from $58.14/MWh to $66.25/MWh in 2014[2] – the projections for prices falling to nearly half the 2014 average cost of electricity in New England are very optimistic and should be known publicly. I reiterate my request for the Commission to release a general summary of these pricing scenarios, (only annual average electricity, natural gas and basis differential) when the Commission makes each decision and when the Commission should logically be accountable for the reasoning of its decisions.

Nonetheless, even without including the project's carbon benefits, the vast preponderance of 14 scenarios show between ten and fifty million dollars in ratepayer benefits. Again all of the 14 scenarios in this docket show millions of ratepayer benefits. Once factoring in the social cost of carbon these numbers can rise above $100 million in value depending on the scenario. In addition, 2 of 14 scenarios that that show the lowest benefits are those based on a consultant who the Commission did not until recently even use for such forecasts. These forecasts are by consultant closely associated with the gas and oil industry. These numbers are biased toward a particular industry and those numbers are simply not appropriate to be injected into proceedings that the public expects to be based on impartial and objective analysis. Accordingly, I approve the Commission entering into a long-term contract for energy and capacity from

[2] *See* ISO-NE, ISO New England Internal Market Monitor, 2014 Annual Markets Report, Table 1-2 at p. 3 (May 20, 2015).

Highland Wind and urge the Commission to continue to work to ensure that a formal agreement is reached to assure the exceptional value being offered to Maine ratepayers is realized.

II. DISCUSSION

A. The Commission should approve this project: the energy price offered even before the price modification at deliberations is below market and provides even lower pricing than the version approved in December of 2014.

This contract is below market. These terms represent the lowest priced wind power ever offered (at least to date) in New England. The company has reduced its pricing even more from the term sheet pricing approved in December of 2014 to make it more favorable for ratepayers.

As discussed above, the pricing offered is substantially lower than current retail prices – and in particular much lower than prices for the standard offer – at approximately 75 percent of the current standard offer. The standard offer itself is quite low right now. The pricing options offers for this project are low even allowing for a mark-up from wholesale to retail pricing as cited by Commissioner Vannoy. Again, this pricing offered for this roughly 100 MW wind farm is inexpensive, below market, and locks in for 25 years to ensure low prices for Maine ratepayers for roughly three percent of Maine electricity consumer load.

This project makes sense based solely on the proposed energy and capacity price; however, as further discussed below that aspect does not capture the full extent of the benefits and opportunities provided under the Commission's approved terms.

i. When full ratepayer costs and benefits are accounted – including price suppression – the project provides over many millions of dollars in public and ratepayer benefits.

Economics tells us that when the supply of a good increases, the goods' price decreases. It is the same for electricity. It is more so for electricity from a renewable resource like wind with no fuel cost. When the wind moves, there is virtually no marginal cost to bringing wind-driven electricity onto the electricity grid.

And for facilities that qualify for the federal investment tax credit (PTC) or federal investment tax credit (ITC), those facilities receive an electricity-production tax benefit that allows them to bid into the New England electricity market at below zero – this directly drives down consumers' prices. Since the ISO-NE instituted negative pricing in fall of 2014, the prices have been allowed to go negative. This means electricity producers pay to generate electricity to the grid and prices can be set at a negative clearing price. This can happen when the wind is blowing generating very inexpensive or indeed no cost electricity for consumers. Energy prices have dipped below zero approximately ten times since negative pricing was instituted in the fall of 2014.

This effect of increasing supply, with zero fuel costs, and negative pricing creates a strong price suppression effect as more wind facilities come onto the New England electricity grid. The Mid-Continent System Operation (MISO) already experiences these negative prices in the Midwest. ISO-NE studied this wind price suppression effect in 2011 Economic Study.[3] The ISO-NE study concluded that wind provided distinct price suppression benefits that increased with wind's level of grid penetration.

The price suppression factor for the Maine zone of the New England grid is high because the wind price suppression has its greatest impact in the zone in which it is generated. The price suppression was calculated by Staff using the ISO-NE Economic Study Gridview Results methodology. It is not a developer calculated number and the calculated value in the benefits total undercounts these savings by about half to be conservative. So the actual benefits from reducing prices when wind comes onto the electricity system are understated in the Commission's economic analysis.

When the additional benefits and cost of capacity, performance payments, renewable energy credits, the production/investment tax credit, hedging benefits, system integration, and price suppression are accounted, the value of even the revised three pricing scenarios is high for ratepayers ranging from tens of millions to hundreds of millions of net ratepayer benefits, particularly when the costs of carbon emission reductions are counted. To reiterate, even without carbon emission benefits, the other costs and benefits are positive with mid-point valuations in the three revised scenarios at millions of dollars to tens of millions of dollars positive without carbon benefits and more than 100 million dollars positive with carbon emissions benefits calculated.

ii. The contract reduces the volatility of Maine's electricity supply under the long-term contracting statute.

As representing roughly three percent of the electricity consumed by Maine consumers, Highland Wind's guaranteed low-priced electricity and capacity is a hedge in Maine's electricity portfolio to reduce the volatility of electricity prices for consumers. The three percent added to other approved projects remains less than 10 percent of the electricity used by Maine consumers after the withdrawal of the Weaver Wind project.

Ten percent itself was found to be a reasonable and relatively low hedge in both December and again in May by the Commission. In its approvals of the project in December of 2014, the Commission opined and later wrote that 10 percent of electricity consumed under stable and low-priced electricity contracts is a reasonable hedge. Ten percent or less is a relatively small hedge. It is akin to having a mixed investment portfolio of high-price and low-priced and high-risk and low-risk financial investments.

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3 ISO-NE, 2014. 2011 Economic Study. Available online at http://www.isone.org/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2014/2011_eco_study_final.pdf

The stability of the pricing and low pricing make this a particularly attractive hedge against future energy price increases.

This satisfies one of the explicit goals of the statute. 35-A M.R.S. §3210-C(2)(B) ("It is the policy of this State: [to] reduce . . . price volatility for the State's electricity consumers. . .")

iii. The price escalator is below market price increase expectations.

Based on the pricing scenarios produced for the next 25 twenty years, the price escalator in the contract is below what both the U.S. Energy information office and the Commission staff and Commission consultant projections for increases in electricity and natural gas prices delivered to New England. So in addition to starting at a low price, the escalators are projected to stay below the projected cost of energy increases for both electricity and natural gas in New England. The escalators are therefore reasonable and further benefit ratepayers assuming these projections are correct.

iii. The effort to label non-market economic benefits as externalities is contrary to statute.

The long-term contracting statute explicitly considers volatility reduction and carbon reductions. Among the three goals of the long-term contracting statute, codified law on the Commission's authority declares it the policy of the State to reduce electricity prices and price volatility and to reduce greenhouse gas emissions:

It is the policy of this State:

. . .

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 . . .

35-A M.R.S. §3210-C(2)(B). The statute further specifies that any long-term contract must be consistent with the goals for greenhouse gas reduction under both Title 38, Section 576 and the regional greenhouse gas initiative in Title 38, Section 577. 35-A M.R.S. §3210-C(3).

The statute specifies a priority of resources that includes projects such as this in priorities two and three:

Among capacity resources meeting the standard in paragraph A [competitive and lowest price when compared to other offers for a capacity resource], the commission shall choose among capacity resources in the following order of priority:

. . .

(2) New renewable capacity resources located in this State;

(3) New capacity resources with no net emission of greenhouse gases; . . .

35-A M.R.S. §3210-C(4)(B). Thus the economic analysis that Staff have performed for hedge benefits, price suppression and greenhouse gas benefits are integral to the economic calculations under the governing statute. These factors are more than "additional benefits" or "add-ons", they are statutory considerations. For this reason, I caution against labeling them as externalities which suggests the Commission can neglect to account for these calculations. In fact, these calculations are integral to the long-term contract calculations and considerations under the law.

iv. Specific Sheets items

Under the options proposed by the project developer, I would approve either option 1 or option 2. For purposes of achieving a Commission decision, I agree to the amendments to the submitted terms proposed by Commissioner McLean.

Specifically, I approve purchase of 25 percent of capacity to be credited to the buyer on a financial basis. By crediting 25% of capacity value to buyer, the ratepayers will benefit directly or through performance payments or through similar capacity programs adopted by ISO-NE for the capacity value from this project. I agree having the seller retain all obligations with respect to the ISO-NE capacity market to provide that the developer would have a strong incentive to obtain ISO-NE Forward Capacity Market qualification and to maximize the value of the facility in the ISO-NE Forward Capacity Markets.

Though I would have accept the already low pricing proposed rather than risk killing the offered price, I also agree with Commission McLean to reduce the purchase price for energy an additional $1 to $43.80 per MWh in contract one, escalated by 2.5% per year. I certainly agree and adopt the buyer's hedge bucket which allows buyers to avoid paying for energy for up to 0.5 percent of annual generation when the price of energy is lowest or negative. This provision benefits ratepayers.

Furthermore, the proposal to constrain the physical curtailment cap at 6% for years one through three and then reduce to 3% thereafter is sound. This limits ratepayer risk.

The reserve account is an innovative mechanism developed by staff to track credits and costs from the buyer's hedge against unknown physical curtailments. I am concerned with the Deemed Energy provisions both from the ratepayer risk perspective but also the modification to this provision. But the overwhelming value in the energy and capacity pricing make the risks in the Deemed Energy provisions worthwhile.

Finally, given the favorable pricing in the contract for energy and pricing, it is reasonable to share some production and curtailment risk. Again for purposes of reaching a Commission decision, I approve the terms as modified at deliberations which are attached hereto.

B. The newly revised and re-engineered pricing scenarios set a very high bar for non-gas projects.

Moving from the specifics of the Highland proposal, I would like to revisit some overarching concerns I have with this process in the context with this concurrence. Under the baseline scenario utilized pursuant the May 20th Order, electricity prices in immediate future years are much lower than even 2014 – almost half the 2014 New England energy prices -- and lower than the prior staff prepared baseline scenario used just five months ago in December of 2014. This is obviously not necessarily bad news. If the re-engineered baseline is at all in the ballpark, then wholesale prices and the standard offer prices will likely continue to decline. And natural gas prices in New England are lower than national gas prices measured at the Henry Hub.

While state officials stated the January electricity standard offer price reduction was a lucky break against a backdrop of increasing energy prices, the price projections labelled confidential by the Commission indicate that electricity price reductions will continue to decrease for three to four years and then only gradually increase. That is great news for consumers if it plays out that way. The opposite will be true if those forecasts are wrong.

C. Bidder pricing is properly confidential unless or until projects are approved or denied and then the pricing and terms should become public.

It very unfortunate and unfair to the bidders to reconsider the December 16th approval after the bid prices and other details of this offer and another were made public following the Commission's December 2014 approval. A third project, Downeast Energy which guarantees a discount to local energy prices with a floor price, could also be at risk of being reconsidered after its pricing is made public. This is what occurred with the approved Statoil project as well. In all, two and perhaps four projects had their confidential pricing disclosed publicly only to be later forced to withdraw which a public disclosure of their confidential bids. This is not the way the Commission should conduct business on behalf of the people of Maine.

Acquiring land rights, engineering, planning and permitting energy price and capacity projects to submit to the Commission requires substantial business resources. Companies could devote those human and financial resources to other states in New England as well as elsewhere in the world. And of course, many of these companies are offering to invest capital and human resources in Maine that produce construction and long-term jobs at these facilities. This public humiliation of project developers who engage in good faith by submitting projects is the antithesis of a positive business climate. It is a hostile business climate. The basis for the Commission's decisions should be public and the bidder information when the Commission decides in good faith to move forward with that project developer.

i. The pricing and methodologies should be available after each project decision and make a substantial difference in project valuations; without a *public discussion and analysis of how the Commission makes these decisions, the Commission process is simply a black box.*

With this most recent review on May 20, 2015, the Commission now has started to call certain scenarios non-current or out-of-date. Both the Commissioners and Staff oddly considered all of what staff now label as out-of-date to be valid in December of 2014 - and staff and most parties did as well as recently as February of 2015. I am concerned with the suggestion that some or some modified versions or non-current scenarios would be released with no explanation for what was relied up, how relied upon and in what way. But to the basic point, the relevant information of public interest is what the Commission uses to review each project. As I previously wrote, I believe it best to release after each project approval or denial. Since the Commission majority apparently believes these scenario outlooks quickly become outdated, I do not understand the reluctance to release them when they are fundamentally non-confidential and the very basis of the Commission's decisions.

Market-based value of the project developer's options measure on the latest U.S. EIA Outlook is positive in all cases. This new case called Case 3 is comparable to previous scenario 2 but uses updated EIA pricing. Both are baselines scenarios (scenarios from which sensitivities are run) using official U.S. government price projections, this project shows benefits to ratepayers by multiple tens of millions of dollars on market-based values before taking into account other statutory valuations. When hedging, price suppression, greenhouse gas reduction and system integration costs are considered, the U.S. EIA based forecast (new case 3) yields a high ratepayer benefit calculation.

On the other hand, the two revised methodologies introduced pursuant to the majority's February vote on Reconsideration (published April 2 Order) (*see* April 2nd Order on Reconsideration), yielded a different valuation on market benefits. So the assumptions and methodology makes a big difference. This sea change in methodological approach has not been peer reviewed, nor even academically vented, nor publically released or discussed. Nonetheless, when hedging, price suppression, greenhouse gas reduction and system integration costs are considered, these benefits calculations are also strongly positive as they were in December. Value for this project under all three methodologies ranges from a low of about $65 million to over $115 million between the three cases staff consider most current. Again the public should see this.

ii. Switching labels and numbers on pricing scenarios between different projects in the same docket makes it impossible for those without access to the numbering or outside knowledge to follow or understand what the Commission is doing.

As I note in my dissent to the May 20th Order, switching scenarios effectively changes the grading scheme because it changes the projected electricity pricing, natural gas pricing, and relationship between those numbers. The change in pricing matters because the savings or losses on an energy/capacity contract are relative (value is comparative) to the price of electricity and natural gas each day in the future for 25 years. So in comparison, the shift in that pricing directly changes the cost comparison of other resources including energy efficiency, renewables and natural gas infrastructure. Changing future energy pricing changes the grading scheme for these energy resources.

In addition to switching between scenarios, the Staff are now using overlapping numbering of scenarios. What they have labelled scenario 12 in April of 2015 is now case 1 in May of 2015 – even though there is a scenario 1 in this docket which can confuse anyone without inside knowledge. And what was scenario 13 in the past is now case 2. And the new scenario based on the U.S. Energy Information Office's Annual Energy Outlook 2015 is labelled case 3. This case 3 is actually the 14th scenario developed by staff in this docket and bears no relationship to scenario 3 previously referenced in December 2014, February of 2015 and April of 2015 in the same docket.

This renumbering of scenarios will make it very difficult for anyone to ever figure out in retrospect what the Commission was looking at – or to compare the pricing differences between scenarios. Only one with inside knowledge would even realize that the former scenario 12 is now case 1, the former scenario 13 is not case 2 and that case 3 is really a new 14 scenario. This numbering change all happened in a few months in the same case and appears to disregard any consideration for clearly setting forth a clear record. It creates complexity so only those in the know understand how the decision is made.

iii. Full disclosure of the pricing scenarios and forecasts will show that the Natural-Gas-Industry-Consultant's Scenario is prominent.

As I have previously stated it is most troubling that at least two scenarios are based on a natural gas industry consultant's admittedly favorable projections to the gas industry (low gas prices). This consultant does substantial work for the natural gas industry, or the oil & gas industry as it is known nationally because of the commonality among many of the oil and gas companies. The company, IHS is a large consulting firm. It is also known to have a clientele that is predominantly oil and gas interests nationally and internationally. The IHS projections are invariably optimistic for oil and gas and the Commission's review have traditionally not used such apparently industry-favorable sources. Pricing scenarios from inputting industry-favorable pricing is neither impartial nor objective.

This natural-gas-industry-consultant based pricing was formerly scenario 13 and is now relabeled and identified in case 2. The backdrop is that at no point before 2015 did the Commission accept any industry pricing projections nor any developer pricing. Yet now the Commission is considering scenarios as legitimate based directly on favorable prices projections by a primary consultant to the oil and gas industry. This is new reliance on industry favorable numbers in the last six months alters pricing assumptions and projections.

When these numbers were injected into the December 2014 decisions at the last moment after the utilities and the OPA reviewed the more traditional projections, the Commission did not find these projections based on industry-consultant prices to credible and explicitly rejected them. *See* Docket 2014-00024 Directing Utility to Enter into Long-Term Contracts Order Part I (Jan. 8, 2015) and Order Part II (Feb. 6, 2015); Order Part II at 10, fn. 11 (Chairman Welch, Comm. Littell majority, Comm. Vannoy dissenting).

I continue to be troubled by the very recent and new injection of industry-favorable numbers into confidential pricing scenarios used to accept or reject energy projects as well as the uses of new modeling and new assumptions for purposes of long-term contracting that represent a significant divergence with past practice and methodologies.

CONCURRENCE OF COMMISSIONER McLEAN

I. SUMMARY

The term sheet for the Highland Wind project, as amended by the Commission at the May 20, 2015 Deliberations, provides the opportunity for significant and likely benefits over the life of the contract while at the same time providing safeguards to offset risks to Maine ratepayers. Accordingly, it is appropriate for the Commission to enter into a long-term contract pursuant the modified term sheet attached to this Order.

II. BACKGROUND

Title 35-A, Section 3210-C authorizes the Commission to direct investor-owned utilities to enter into long-term contracts for capacity and energy under certain circumstances. Contracts should reduce electric prices and price volatility for the State's electricity consumers and reduce greenhouse gas emissions from the electricity generation sector. The Commission has determined in past decisions regarding long-term contracting, that the underlying purpose of the authority 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. Due to the benefits and value a long-term contract has for developers and owners of generation, project developers and owners may be willing to offer utilities contractual terms that would be beneficial to electricity ratepayers. *See* 35-A M.R.S. § 3210-C(6).

The Commission is to select proposals that are competitive and the lowest cost relative to similar bids. 35-A M.R.S. § 3210-C(4). Priority is placed upon new resources and renewable resources. *Id.* Further, the Commission's implementing rules specify that contracts for capacity resources may not exceed the amount necessary to ensure reliability of Maine's grid or to lower customer costs and that the contract price is below expected market value. 35-A M.R.S. § 3210-C(3). The Commission's rules authorize associated energy contracts to fulfill the State's new renewable resource policy and the prices are not expected to be higher than market prices. *Id.*

Section 3210-C provides broad latitude to the Commission to exercise, within its sound judgment, the authority to direct such contracts. The Legislature has directed a balance between costs and risks on the one hand and other policy goals and benefits on the other, such as price volatility and greenhouse gas reduction. *See* 35 M.R.S. § 3210-C.

Further, Section 3210-C(8) requires the Commission ensure that all eligible costs and benefits associated with long-term contracts are allocated to ratepayers. Hence, ratepayers will enjoy the benefits and pay for the costs. It is for this reason that identification and reduction of risk is so important, as any downside that flows from long-term contract pricing will be borne by ratepayers.

On March 3, 2015, the Commission voted to reconsider approval of two term sheets. The Commission did so pursuant to its authority contained in Section 1321 which authorizes the Commission to rescind, alter or amend any order at any time. The reason for reconsideration hinged upon new information having been identified. Specifically, the Commission considered whether the observed decline in energy prices (between projected prices and actual prices), prices upon which the future projections underpinning the Commission's conclusions were based, amounted to a substantial enough change to call into question the financial costs and benefits expected to flow from the previous Order in this docket. Subsequent to the reconsideration, the Commission obtained new natural gas and wholesale electricity price projections from its consultant, London Economics International (LEI), that showed that the price changes that the Commission based its reconsideration decision upon did not appear to have been anomalies, but possibly an indication that a major shift may be occurring in the natural gas and electricity markets. As a consequence of these new price projections, Staff analyzed the Highland Wind Project (Highland) using a set of updated forecast scenarios. The analysis depicted a range of possible costs and benefits that may result over the life of the contract proposal. The updated analysis indicated a net present value benefit/cost range from positive $40 million to negative $31 million.[1] The range highlights the challenge the Commission faces in considering long-term contract proposals.

The Highland proposal offers pricing that is substantially lower than current retail prices and much lower than prices for the standard offer—at approximately 75% of the current standard offer. This project makes sense based upon the proposed energy and capacity pricing; however, it has unprecedented and new approaches to containing investor risks that pose substantial uncertainties as to ratepayer benefit. Although there is a significant opportunity to realize value for the ratepayers through the progressive pricing scheme, there is unbounded and unrestrained risk that might have the impact of rendering void the pricing benefits and resulting in large ratepayer costs. These concerns were shared by all three Commissioners in the December 16th, 2014 Order approving the later reconsidered terms sheets and were the focus of comment from a majority of commenting parties. Accordingly, I would approve a contract, as further discussed below, that achieves an acceptable balance of value and risk for both the ratepayers and the project developer.

III. DISCUSSION

The term sheet here outlines pricing, together with options on curtailment provisions and options on capacity value. First, standing alone, the pricing offered in the proposal is attractive. The pricing hinges upon the right blend of improved wind technology, a strong renewable energy credit (REC) price, federal production tax credits for which the project has qualified, energy and capacity market outcomes, and the reduced risk that a long-term contract with the utilities, as directed by this Commission, will bring to investors. Inherent in that last point is the notion that a certain degree of risk

[1] With the revised terms outlined below, it is estimated that the net present value benefit/cost ranges from positive $23 million to negative $35 million.

is contained in the contract terms and depending on a range of potential future outcomes may be borne by the ratepayers or the project developer depending on contract structure.

The second key component of the proposal is a curtailment provision, a provision not previously approved in any long-term contract in Maine. Curtailment occurs when a generator is able and willing to provide electricity but is prevented from doing so by the independent system operator (ISO). This provision existed in the previous iteration of this term sheet and has been revised here to provide more clarity and to mitigate the risk of the provision to Maine ratepayers.

Public comment received on the curtailment provision directed further clarity and specificity of this previously unseen contract term. To that end, and subsequent to the reconsideration decision in early March 2014, Staff has embarked on that work and has come a long way toward comprehending and mitigating the curtailment provision risk. The Commission's concern centers on whether a knowable or unknowable set of events exist that would lead to high curtailment levels and thus significant ratepayer costs. On this point I move forward by approving the term sheet with the following terms included but with direction to Staff to investigate additional mechanisms to further contain the risk to the ratepayers associated with curtailment.

There are several proposed options on pricing contingent upon treatment of the curtailment and locational marginal pricing (LMP) hedge provisions, as well as the capacity value included in the contract. Based on the current term sheet, I approve a contract price of $43.80 MWh, escalated at 2.5% per year over a 25-year term, a 0.5% LMP "Hedge Bucket", subject to an average LMP floor of $150/MWh, and a 50/50 arrangement on capacity value. With respect to the physical curtailment provision, I approve a provision with a Physical Curtailment Cap equal to 6% in contract years 1 through 3, and 3% thereafter. The physical curtailment provision is described in more detail below, including the components of the reserve account, which are vital to the approval of the term sheet. The reserve account should function to accrue revenue in years where curtailment does not exceed 3% (or 6% in the first three years) of the average annual generation and will be available to pay for curtailments in future years should it become necessary. Any payment resulting from curtailments made by the utility will be reimbursed from the revenue that would accrue in the reserve account. Accordingly, the balance of the reserve account may become negative in one year but may be replenished in a future year where curtailment does not exceed 3% of the average annual generation. The mechanics of this provision should be further refined.

Any payments made as a result of curtailments that exceed at any point in time an amount that has accumulated in the reserve account and are made by the utility directly, rather than from the amount contained in the reserve account, will include only the items purchased and sold under this contract, and will not include payment of any amount for RECs or tax credits that the seller is not otherwise receiving due to curtailment.

For the first three years of the contract where the curtailment is not expected to exceed 1%, the generator would guarantee a contribution of at least 3% into the reserve account for any actual curtailment below 3%. For actual curtailment which occurs in the first three years above 3% the contribution would be reduced incrementally until 6% (i.e. a 2% contribution if actual curtailment is 4% of expected annual output). The utilities would not be responsible for reimbursement for deemed energy during the first three years until actual curtailment exceeds 6%. Finally, any monies remaining in the reserve account would be paid to the seller at the end of the term of the contract.

These provisions added by the Commission will address the significant concerns presented by the curtailment provision and identified by this Commission as well as, the T & D utilities and OPA during the comment period for the original term sheet. These safeguards are essential to protect ratepayer interests and form the basis for my approval today.

Accordingly, with those considerations incorporated into the final terms and clarity brought to the mechanics and logistics of the arrangement, I approve the term sheet.

DISSENT OF CHAIRMAN VANNOY

I. SUMMARY

I respectfully dissent. I would decline to enter into a long-term contract either under the terms put forth by the bidder or as amended by the Commission. In this circumstance, I cannot find that it is prudent to enter into a 25 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.

II. DISCUSSION

The Commission certainly has authority to enter into 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 M.R.S. § 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 consumer costs.

The statute also cautions the Commission with respect to the term of contracts. Under 35-A M.R.S. § 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.[2]

These particular aspects of the statute provide the Commission with the background on how the Commission should apply and utilize the long-term contracting

[2] 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." *Gulf State Utils. Co. v. Louis. Pub. Serv. Comm'n*, 578 So. 2d 71 at 85 n.6.

tool. While we, as a Commission, have the authority to enter into long-term contracts, it is not always prudent to exercise that authority and I believe this is an instance where restraint is the correct approach.

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 rates 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.

In conducting this analysis, the Commission's 1996 restructuring report to the Legislature is quite helpful. One of the guiding principles behind the restructuring of Maine's electric markets is 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." *Electric Utilities Industry Restructuring Study*, Docket 95-462, Report to the Legislature (Dec. 31,1996). In light of the objectives of restructuring, I view the long-term contracting authority as a backstop to meet the policy goals of M.R.S. § 3210-C, to be used where existing viable markets are found insufficient to lower customer costs or properly assign risk. 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. Regionally, we are exceeding greenhouse gas reduction goals as evidenced by RGGI's recent action to ratchet down on carbon allowances. So the question becomes are any of these proposed contracts necessary to lower consumer costs or decrease volatility?

In my judgment, a long-term contract entered under the cost saving clause of M.R.S. § 3210-C should see benefit under a very broad range of futures. 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 and reduce volatility to ratepayers. With respect to volatility, Chapter 316, section d.1.b of the Commission rules caveats the volatility criteria for evaluation by stating: that such contracts should not increase costs to ratepayers. This leaves us with primarily cost as the determining factor under this statute and rule. In my view, the partial term sheet that we have before us, even as amended, is unlikely to meet this requirement.

The energy landscape in New England is undergoing a fairly rapid transition. New capacity market reforms are providing the sustained price signal for investment in new highly efficient combined cycle gas turbines with heat rates that are 35% less than the fleet average. The transition away from older oil and coal plants continues. Marcellus shale gas continues to change the way that gas flows in North America. These changes in gas flows are having an effect on energy pricing in New England. Our analytic tools need to reflect these changing conditions. As soon as thermal loads on the natural gas supply in New England dropped off in March and April of 2015, we immediately saw New England day-ahead and real-time pricing drop and trade on average in the $25 MWh range. In March 2015, pricing was 46% lower than in March 2014 and pricing in April 2015 was 35% lower than in April 2014. This pricing reflects Marcellus shale gas flow and is a reality in New England whenever pipeline transportation is not constrained.

The question we are faced with today is what does the future look like? Are we seeing the beginning of a future of relatively low prices for the next 10 years or is this simply the low side of temporary volatility? Will New England electricity pricing reflect Marcellus shale gas supplies or will it be something else? My view is that in the coming years electricity pricing will begin to reflect the pricing of Marcellus shale gas supplies. Energy infrastructure will be required to make that a reality. In that future energy view, this contract will cost ratepayers significant above market premiums over its 25 year life.

I appreciate the project developer's willingness to negotiate and look at creative ways to lower the pricing of the project. In my analysis, the tradeoffs made to achieve the current pricing offer, which on its face may appear attractive, were a longer term extending from 20 years to 25 years, increasing the escalator to achieve a lower starting price, and developing a curtailment provision which shifts risk from the project developer to ratepayers. These tradeoffs could easily have the cumulative impact of making this contract more expensive rather than less over the term of the agreement.

We have no urgent need to enter into this contract. In fact, last year's renewable energy production in Maine totaled roughly 65% of overall production. A contract under 35-A M.R.S. § 3210-C should lower cost at minimal risk to Maine ratepayers. Moreover, we also have a robust capacity market with no obvious need for government intervention. The recent Forward Capacity Auction results point to new capacity supply obligations of 2,075 MW at an investor cost of roughly $2.3 billion.[3] Maine ratepayers are not at risk for these investments. If their production becomes uneconomical, they will simply be replaced by market forces. We have no capacity shortage in Maine; in fact, we are a net exporter of electricity.

Turning to a potential volatility reduction benefit, recent changes to the ISO New England market rules, which allow for negative pricing, have added complexity to how one might try to quantify the benefit of reduced market volatility. Under the old construct, the bottom of the market was capped at zero. In the New England market, the value of generated electricity is heavily dependent on the time of day, the season, and the geographic location in which it is produced. While we pay a fixed price to the generator under a contract, our ability to recoup value for the electricity generated is dependent on what the market clearing price is at the time electricity is generated. The volatility benefit was seen because we paid a fixed price even when energy market prices increased while our downside exposure was limited because of the zero floor in the market. The zero floor was eliminated in December and the market has a new floor of negative $150/MWh.

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3 *See* http://www.iso-ne.com/static-assets/documents/2015/02/fca9_finalresults_final_02272015.pdf

Because this change was implemented only recently, we have very limited data to assess what future negative pricing may look like. Under a long-term contract, ratepayers will be exposed to this negative pricing because we will be obligated to sell electricity produced during these periods into the market. In essence, we will be obligated to pay the market to take this generation. The market construct of negative pricing was developed to provide an economic signal to generators not to generate. A long-term contract insulates the generator from this market signal because ratepayers will carry the burden and, as such, encourages irrational production behavior such as producing electricity during times when it is not needed. While there may be a volatility benefit from long-term contracts with a zero floor, this value is eroded with negative pricing and ratepayers will be burdened with paying for production during periods of negative pricing. Although the revised term sheet does provide for an offset allowance to allow the utility be reimbursed for the lowest 0.5% of the hours with the largest downside discrepancy between the contract and nodal price. The so called "LMP Hedge Bucket" is a step in the right direction, but does not go far enough to mitigate the ratepayer risk exposure.

The provision that raises the most concern for me, however, involves the risk shift being proposed through the term sheet's curtailment provision. Taking on this risk, which does not lend itself to mathematical quantification because there are too many variables and unknowns involved, would result in unbounded exposure of Maine ratepayers to potential costs. The revised term sheet submitted by the proponent contains a curtailment provision that would have Maine ratepayers make the company whole for not just the contracted energy that was curtailed, but also for the renewable energy credits and the production tax credit. This in my view is completely unacceptable. A good contract assigns risk to the party who has the best ability to control and manage the risk. Accompanying the assignment of risk is compensation in payment for the risk. With limited ability to quantify the risk, I requested that Staff ask the developer what contract price starting point they would need to eliminate the curtailment provision. Based on my understanding from Staff, the developer put the added price at $20 MWh. Due to our inability to quantify the risk or manage the risk from an operational standpoint; I believe this is the best way to value the risk. Therefore, the true cost of entering this contract is the starting price at $43.80 plus an additional $20. The real exposure to ratepayers is a starting price of $63.80. This is clearly not a competitive price and will lead to significant above market costs.

Commissioner Littell places significant reliance on the proposed market suppression effect of price taking resources in the energy market as a justification for entering into this contract. In my view, any analysis that simply looks at the energy market and does not look at the capacity market is incomplete. The two markets work together. If you reduce energy market prices and reduce the capacity factor of dispatchable generating units, ultimately you will have to pay these resources more in the capacity market for them to remain financially viable. They need to remain financially viable so that they are available to carry load and maintain a reliable power supply when the intermittent resource is not producing. These effects and the increases must be factored into any analysis of market suppression.

Finally, this project is not a small undertaking for Maine ratepayers. The commitment that is required of Maine ratepayers over the term of the contract is a large one in excess of $400 million for a term of 25 years. The revenues flowing to the generator include not just the long-term contract price, but also the ability to sell the attributes of the generation, the RECs, into the New England market (likely Massachusetts which is currently trading at a premium in excess of $65), and capitalizing on the federal production tax credit. Taking all of these revenue streams into account—the Commission's agreed upon price of $43.80, the $65 REC price, and the $22 production tax credit—puts first year revenue stream for the project at roughly $130.80 MWh.

In conclusion, entering into a long-term contract for a remotely located intermittent resource needlessly shifts market risk from shareholders to ratepayers. In addition, the majority has taken on a curtailment risk meaning that ratepayers will be obligated to pay for power that may never be produced. Locating generation in remote parts of the grid, away from load, is a growing problem in the region. State contracts that enable this development without including the transmission upgrades to enable delivery do not adequately reflect the true costs to ratepayers. This contract is not a good deal. Any value contained in the energy price approved today is more than offset by the risk of the curtailment provision. My hesitancy is strengthened by the fact, as discussed above, that we are not obligated to enter into any contract under 35-A M.R.S. 3210-C at this time and therefore, the rationale for taking on this additional risk is lacking. Accordingly, given the totality of these factors, I cannot approve a long-term contract for this project.

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).

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Maine Public Utilities Commission Docket No. 2014-00024— Highland Wind Approved Term Sheet

May 20, 2015

This Term Sheet describes the essential terms for a long-term contract with NextEra Energy Resources ("NEER") for the Highland Wind Project, located in Somerset County, ME.

Quantity: 96.6 MW Nameplate; 100% of facility output of Energy; 25% of the value of the facility Capacity in the ISO-NE capacity market.

Products: Energy on a physical or financial basis; Capacity on a financial basis. Specifically, for all capacity value received in the ISO-NE capacity market, either through participation in the FCM directly or through performance payments or any successor capacity program adopted by the ISO-NE, 25% of this capacity value shall be credited to the Buyer.

Capacity Obligation: Seller retains all obligations with respect to the facility Capacity in the ISO-NE market and commits to using commercially reasonable efforts to maximize the value of the facility Capacity in such markets.

Term: 25 years.

Contract Price: Bundled price of $43.80/MWh in contract year 1, escalated at 2.50% per year.

Buyer's LMP Hedge Bucket: To hedge against nodal LMPs below the per MWh contract price then in effect, Buyer has the option to sell 1,762 MWh (equal to 0.5% of average annual generation) back to Seller and get reimbursed for costs to the Buyer, defined as the difference between the contract price and the average nodal LMP of those MWh sold back to Seller, subject to an average LMP floor of $-150/MWh. For example, if in year one the nodal LMP for those MWh averaged $-150.00/MWh, Buyer would be reimbursed the difference between the contract price of $45.80 and the average nodal LMP of $-150.00 for a total reimbursement of $195.80 / MWh, or $345,000. If the LMP averaged $10, the reimbursement would be $45.80 - $10 = $35.80 / MWh, or $63,080.

Physical Curtailment Cap: The Physical Curtailment Cap is 6% of average annual generation, or 21,146 MWh for contract years 1-3 and 3%, or 10,573 MWh, for the remainder of the term. NEER expects Physical Curtailments, defined as a reduction or dispatch off of facility output by the ISO-NE, to be less than 1% of annual generation.

Reserve Account: The Reserve Account is created to provide Buyer a hedge against unknown future Physical Curtailments. The revenue generated by the facility associated with the MWh difference between the amount of MWh that are physically curtailed by ISO-NE (Actual Curtailment) and the Physical Curtailment Cap, will be credited to a Reserve Account. Reserve Account revenue is calculated as the sum of: the Contract Price + REC price + production tax credit revenue received by the Seller for the MWh between Actual Curtailments and the Physical Curtailment Cap. For years 1-3, funding of the Reserve Account shall occur as further described in "Partial Guaranteed Contribution in Years 1-3" below. The Reserve Account shall be a physical account held at a qualified financial institution or other mutually agreed upon institution and shall be funded according to an agreed upon schedule.

Seller shall be obligated to contribute to the Reserve Account the value received from contract payments ,the sale of RECs, and the production tax credit for all MWh between Actual Curtailment and the 3% Physical Curtailment Cap. At the conclusion of the Contract Term, any amounts remaining in the Reserve Account after settlement of any outstanding Deemed Energy reimbursement to Buyer shall be project revenue of the Seller.

Partial Guaranteed Contribution in Years 1-3: Seller is confident that actual curtailment will be no more than 1 % in Contract years 1 -3 and is willing to guarantee a contribution into the Reserve Account of up to 3% for each of those years up to the 6% Physical Curtailment Cap. Accordingly, if Actual Curtailment in Year 1 is 0% the Seller will contribute 3% to the Reserve Account, if the Actual Curtailment is 1, 2 or 3% the Seller will contribute 3 %. If Actual Curtailment is 4% Seller would Contribute 2% to the Reserve Fund for years 1-3 of the contract etc. If Actual Curtailment reaches 6% Seller would make no contribution but Buyer would have no Deemed Energy obligation. Buyer would be responsible for Deemed Energy payments for Actual Curtailments in excess of 6% and above for years 1- 3. For clarification, contributions to the Reserve Account in years 1-3 will occur as follows:

Actual Curtailment	Contribution to Reserve Account by Seller	Deemed Energy Payment by Buyer
0%	3%	0%
1%	3%	0%
2%	3%	0%
3%	3%	0%
4%	2%	0%
5%	1%	0%
6%	0%	0%
7%	0%	1%

Bilateral Nature of the Reserve Account: In the event that insufficient funds are available in the Reserve Account to cover any Deemed Energy payment due to Seller in a given period Buyer shall be obligated to make those payments when due. Subsequent contributions to the Reserve Account shall first be applied to reimburse Buyer for any payments made by Buyer for Deemed Energy.

Deemed Energy: Deemed Energy shall be defined as: in each year, the physically curtailed MWh the Seller is *available* to generate that exceed the Physical Curtailment Cap. The Reserve Account shall be utilized to make Seller whole for all Deemed Energy including REC + tax credits associated with the Deemed Energy. In the event that Deemed Energy payments exceed the Reserve Account value, Buyer shall pay Seller for remaining Deemed Energy at the contract price only, i.e., exclusive of REC and tax credits.

Account Settlement: True up of the "LMP Hedge Bucket" and the Reserve Account will occur at the end of the contract year or on an alternative mutually agreed schedule.

Curtailment Risk Limitation: In developing the final contract, the parties will consider potential transmission constraints that might lead to Curtailment, and seek to include in the contract provisions to define and limit ratepayer exposure to curtailment to ensure that adequate protections are in place such that the provision will not erode the ratepayer value of the contract.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2014-00024

January 8, 2015

MAINE PUBLIC UTILITIES COMMISSON
Request for Proposals of Long-Term Contracts under M.R.S. 3210-C Pertaining to Central Maine Power and Emera Maine

ORDER APPROVING TERM SHEETS (PART ONE)

WELCH, Chairman[1]; LITTELL and VANNOY, Commissioners

Through this Part One Order, we approve the term sheets for long-term contracts for the capacity and associated energy for two projects located in Maine; the Weaver Wind Project, a 99 MW facility proposed to be located in Hancock County and the Highland Wind Project, a 44 MW facility proposed to be located in Somerset County.[2] [3] A detailed description of the background, analyses and reasoning underlying this decision will be provided in the Part Two Order to issue subsequently.

The Commission approves the attached term sheets for Weaver Wind and Highland Wind, respectively, because we find that both proposals satisfy all of the policy goals outlined in section 3210-C(2) and are the most advantageous of those received under the prioritization criteria outlines in section 3210-C(4). These projects present 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 these projects provide benefits to ratepayers across the widest range of future scenarios, and present relatively low risk exposure to ratepayers. Additionally, the projects present 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).

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1 Chairman Welch took part in this decision during a Deliberation Session held on December 16, 2014 in which the Commission voted two to one in favor of approving these two term sheets. Chairman Welch retired from the Commission on December 31, 2014 and was replaced as Chairman by Commissioner Vannoy.

2 Commissioner Vannoy dissented in this decision.

3 The Weaver Wind Project is being undertaken by Weaver Wind LLC, a wholly-owned subsidiary of First Wind holdings, LLC. The Highland Wind Project is being undertaken by NextEra Energy Resources LLC.

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 Weaver Wind LLC for the output of Weaver Wind and NextEra Energy Resources LLC for the output of Highland Wind;

and,

2. That the transmission and distribution utility/utilities actively participate in good faith in the long-term contracting process with Weaver Wind LLC, NextEra Energy Resources LLC and Staff.

Dated at Hallowell, Maine, this 8th day of January 2015.

BY ORDER OF THE COMMISSION

/s/Harry Lanphear

Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Littell

COMMISSIONERS VOTING AGAINST: Vannoy

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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 CO2 emissions (0.53 kg CO2/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.
>
> 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.
>
> B. Among capacity resources meeting the standard in paragraph A, the commission shall choose among capacity resources in the following order of priority:
>
> (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

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[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]

1. Price Suppression Effect

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

[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

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[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]

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[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.").

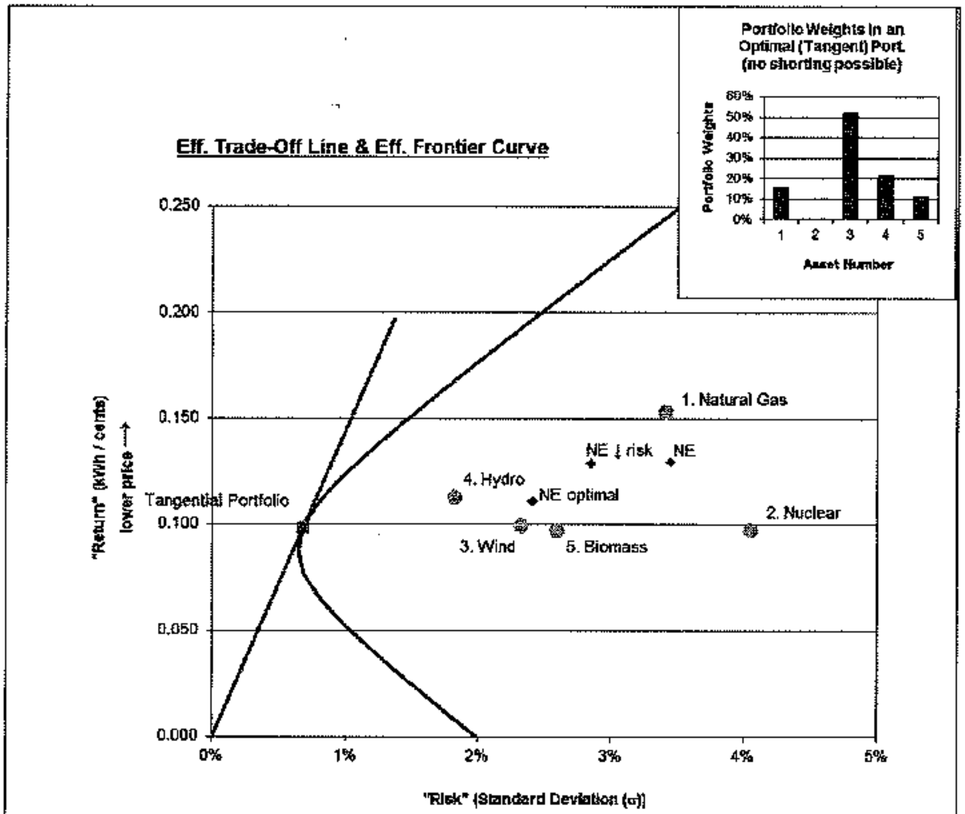

Figure 1: Portfolio Diversity Benefit in the New England Market (Dr. J.Rauch, MPUC 2013)

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.

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[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.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2010-66

January 3, 2011

MAINE PUBLIC UTILITIES COMMISSION
Long-Term Contracting Bidding Process

ORDER DIRECTING UTILITY TO ENTER INTO LONG-TERM CONTRACT

CASHMAN, Chairman; VAFIADES AND LITTELL, Commissioners

I. SUMMARY

Through this Order, we direct Central Maine Power Company (CMP) to enter into a long-term contract[1] for the capacity value and renewable energy credits (RECs) associated with Verso Bucksport LLC's ("Verso Bucksport") Renewable Capacity Project (VRC Project).[2] The VRC Project, which is located at Verso Bucksport's paper mill in Bucksport, Maine, will include the modification of one of the boilers at the mill and the installation of a new steam turbine generator and associated equipment that will result in a total Project output of approximately 40 MW. We direct CMP to enter into a five-year long-term contract with Verso Bucksport for 35 MWhs per hour equivalent of RECs and the financial equivalent of 21 MW of capacity associated with the VRC Project (Agreement). The Agreement may be extended by CMP for an additional five-year term at the direction of the Commission.[3]

II. PROCEDURAL BACKGROUND

Title 35-A M.R.S.A. § 3210-C authorizes the Commission to direct investor-owned transmission and distribution (T&D) utilities to enter long-term contracts for capacity resources and associated energy.

In the Second Regular Session of the 124th Maine Legislature, the Legislature enacted an Act to Enhance Maine's Clean Energy Opportunities (Clean Energy Opportunity Act). P.L. 2010, Ch. 518. Section 3 of the Clean Energy Opportunity Act

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[1] The Commission directs CMP to execute the contract substantially in the form of the Agreement for the Purchase and Sale of Capacity Value and Renewable Energy Credits filed on December 22, 2010 by Verso Bucksport.

[2] Commissioner Vafiades dissents in part to this Order. The dissenting opinion is attached to this Order.

[3] If CMP extends the Agreement at the direction of the Commission, Verso will provide the financial equivalent of 24 MW of capacity during the second five-year term.

(codified at 35-A M.R.S.A. § 3210-C(3)(C)) authorizes the Commission to direct T&D utilities to enter long-term contracts for available RECs associated with capacity resources. RECs may be included as part of the long-term contract provided that the cost of the RECs is below market value or the purchase of the RECs adds value to the transaction.

The Commission's rules for implementing the long-term contract statute are set forth in Chapter 316. Section 5(B) of Chapter 316 requires the Commission to solicit bids for capacity resources through the issuance of a request for proposals (RFP) that contains all standards, procedures and requirements for the long-term contract solicitation process, as well as a standard form contract.

On February 22, 2010, the Commission issued an order in Docket No. 2010-66 approving and issuing the 2010 long-term contract RFP for Capacity and Associated Energy. *Order Approving Request for Proposals,* Docket No. 2010-66 (February 22, 2010) (2010 Long-Term Contract RFP). The 2010 Long-Term Contract RFP did not include a request for long-term contract proposals for RECs because the RFP was issued prior to the enactment of the Clean Energy Opportunity Act, but the Commission has considered such proposals pursuant to the authority conferred in the Act.

On April 16, 2010, Verso Bucksport submitted an Initial Proposal for a ten-year contract for capacity and RECs associated with the VRC Project. Staff worked with Verso Bucksport to agree upon a Term Sheet outlining the initial terms of a ten-year contract for capacity and RECs from the VRC Project, with an option for the Commission to order the utility to opt out of the last five years of the contract. CMP, Bangor Hydro Electric Company (BHE) and the Public Advocate filed comments on the proposed Term Sheet. Additionally, with the assistance of the Commission's consultant, London Economic International, LLC (LEI), Staff conducted an economic analysis of the terms of the long-term contract reflected in the Term Sheet. Based upon reasonably derived market price forecasts as of July 2010, the pricing structure contained in the proposed Term Sheet showed a modest positive benefit to ratepayers. The capacity proposal provided a discount to ratepayers for the cost of capacity requirements and the REC proposal contained in the Term Sheet provided value to the overall transaction by allowing the VRC Project to move forward.

The Commission deliberated the Term Sheet on September 7, 2010. After considering the economic projections and inherent uncertainty of REC Market forecasts, the Commission approved the Term Sheet conditioned upon: (i) the successful negotiation and approval of the final long-term contract with Verso Bucksport for capacity and RECs associated with the VRC Project; (ii) the amendment of the Term Sheet to provide for an initial term of five years with the option for CMP, pursuant to Commission direction, to extend the contract term for an additional five-year period; (iii) agreement upon the amount and form of the Project and Performance Security prior to engaging in further contract negotiations; and (iv) CMP's active and good faith participation in the long-term contract negotiations between Staff and Verso Bucksport.[4]

[4] The Term Sheet was deliberated prior to Commissioner Littell joining the Commission and, accordingly, he did not participate in the decision to conditionally approve the Term Sheet.

Over the next several months following the Commission's conditional approval of the Term Sheet, Staff, with the participation of CMP, continued to negotiate the terms of the final long-term contract with Verso Bucksport. Verso requested and the Staff agreed to present two different sized Agreements to the Commission: the original Agreement that requires CMP to purchase RECs at a 30 MWhs per hour level and a larger Agreement that requires CMP to purchase RECs at a 40 MWhs per hour level. Late in the negotiations, Verso Bucksport indicated that if the Commission approved the Agreement at the 30 MWhs per hour level, the VRC Project would likely not be built and that approval of the larger Agreement was required for Verso to move forward on the Project. After additional negotiations with Staff, Verso agreed to consideration by the Commission of a mid-sized Agreement that requires CMP to purchase 35 MWhs per hour of RECs from the VRC Project.

On December 21, 2010, the Commission deliberated the three different sized Agreements. After substantial discussion, the Commission suspended its deliberations and directed Staff to further negotiate several provisions of the Agreement that would help mitigate any additional ratepayer risk associated with purchasing additional RECs under the contract. On December 28, 2010, the Commission resumed deliberations and approved an Agreement for 35 MWhs per hour RECs, and the financial equivalent of 21 MW of Capacity for the first five-year term and 24 MW of capacity for the second five-year term with additional modifications as described below.

III. CONTRACTING AUTHORITY

1. Overview

As stated above, section 3210-C of Title 35-A, provides the Commission with the authority to direct investor-owned utilities to enter into long-term contracts for capacity, energy and RECs that are consistent with Maine statute and the Commission's rules. In the Commission's view, the underlying purpose of this authority is to take advantage of opportunities to use long-term contracts for capacity, energy and RECs with utilities as a means to lower capacity and energy costs or otherwise benefit Maine ratepayers. A long-term contract with a creditworthy counterparty such as a utility can be valuable to developers or owners of generation resources and may be necessary to obtain financing for new projects or for upgrades to existing facilities. This is especially the case in the current financial climate. 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, energy and RECs at a discount off of expected future 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, and promote the State's renewable energy development policies. *See* 35-A M.R.S.A. § 3210-C (2).

2. Statute

Title 35-A, 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.A. § 3210-C(3). Additionally, section 3210-C authorizes the Commission to direct investor-owned T&D utilities to enter into long-term contracts for RECs associated with capacity resources to the extent that the price of the RECs is below market value or the purchase of the RECs adds value to the transaction. The statute specifies that the Commission select proposals that are in the best interest of customers, and that are competitive and the lowest cost relative to similar bids. Among such proposals, the statute provides a priority order that establishes new renewable resources as a high priority in the selection of proposals. 35-A M.R.S.A. § 3210-C(4).

Section 3210-C also specifies that the long-term contracts should be no more than ten years, unless the Commission finds that a longer term to be prudent. The section states that the Commission may not require utilities to enter into "contracts for differences" that are designed to buffer ratepayers from negative impacts from transmission development, but does not otherwise restrict the Commission's authority to direct utilities to enter into financial transactions.[5] 35-A M.R.S.A § 3210-C (3). 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.

3. Implementing Rules

The Commission's rules for implementing the long-term contracting authority are contained in Chapter 316. Chapter 316 provides that the Commission may not contract for capacity resources that exceed the amount necessary to ensure the reliability of Maine's grid or to lower customer costs. Specifically, the rule states that the Commission may authorize a contract for capacity 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 then market prices; or 3) the contract prices are significantly below expected market value. Although the existing Chapter 316 does not address the Commission's authority to contract for RECs associated with capacity resources because it was adopted prior to the enactment of the REC amendment in the long-term contracting statute, the Commission recently issued an Order provisionally adopting amendments to Chapter 316 that include authorization for the Commission to enter into a contract for RECs associated with a contract with a capacity resource. *Order Provisionally Adopting Rule and Statement of*

[5] Financial transactions are agreements in which only money (rather than a physical delivery of the capacity and energy commodity) is exchanged among the contracting parties. Such transactions mirror exactly the financial consequences of a physical transaction, but can do so in a way that reduces transaction costs and risks for utilities.

Factual Policy Basis, Docket No. 2010-260 (November 10, 2010). The provisionally adopted rule authorizes the Commission to contract for "any available renewable energy credits associated with capacity resources" to the extent that "the cost of the renewable energy credits is below market value or the purchase of the renewable energy credits adds ratepayer value to the transaction." Although the provisional rule is not yet in effect because it has not been approved by the Legislature,[6] the language contained in the provisionally adopted rule regarding how to determine ratepayer value expresses the Commission's general practice of evaluating long-term contract proposals. As stated in the provisionally adopted rule, the Commission evaluates long-term contracts in terms of the their potential to provide benefits to ratepayers, including contracts that provide capacity, energy or RECs at costs that are reasonably likely to be below their market value or contracts that are reasonably likely to reduce price volatility without increasing costs to ratepayers.

IV. PROPOSED LONG-TERM CONTRACT

The proposed Agreement is for a long-term contract between Verso Bucksport and CMP for the annual REC equivalent of 35 MWhs per hour and the financial equivalent of 21 MW of capacity from Verso Bucksport's VRC Project in the first term, and, if the Commission directs CMP to exercise its option to extend, the financial equivalent of 24 MW of capacity in the second term.

The term of the proposed Agreement is for five years commencing on January 1, 2012, regardless of whether the VRC Project is commercially operational as of that date.[7] Near the conclusion of the first term of the Agreement, CMP has an option to extend the Agreement for an additional five year term at the direction of the Commission. The Commission may choose to direct CMP to exercise this option if, at that time, the Agreement is still in the public interest and remains consistent with the applicable long-term contracting criteria.

Under the Agreement, CMP will purchase RECs at a base price that is preset for each contract year. The REC base price starts at $22 per REC for contract years one and two and decreases over time to $15 per REC in contract year five. If CMP exercises its option to extend the Agreement for the second term at the direction of the Commission, the base price of $15 per REC in contract year six decreases to $10 per REC in contract year ten. If, after the second year of the Agreement, the average cost

[6] Pursuant to 35-A M.R.S.A. § 3210-D, Chapter 316 is a major substantive rule and therefore the amendments to the rule have been submitted to the Legislature for review and authorization for final adoption.

[7] Although the VRC Project is expected to begin commercial operation in or about the first quarter of 2012, if the VRC Project does not achieve commercial operation by December 31, 2013, or if Verso Bucksport ceases to pursue in good faith the VRC Project at any time, CMP may terminate the Agreement and may recover any losses it may have incurred under the Agreement up until that point.

per Maine Class I REC (ACPR)[8] is greater than the REC base price, then Verso Bucksport will receive 75% of the ACPR for each REC transferred under the Agreement.

Although the Agreement is primarily for RECs from the VRC Project, if the VRC Project is unable to generate the amount of RECs required for the applicable contract year, Verso Bucksport may purchase Maine Class I RECs from other generation sources (hereinafter referred to as Replacement RECs) and deliver the Replacement RECs to CMP to fulfill Verso's obligations under the Agreement and keep the Agreement in effect. If it is not in the best interest of ratepayers to accept Replacement RECs, CMP has the ability to decline Replacement RECs associated with electricity generation in contract years two through five in the first term, and for the entire second term if the Agreement is extended. Also, if the Commission directs CMP to exercise its option to extend the Agreement, Verso Bucksport will be required to generate a minimum average amount of 26.25 MWhs per hour of RECs for each contract year of the second term, or CMP will have the right to terminate the Agreement.

The capacity component of the Agreement is a financial transaction in which CMP receives a payment for capacity value from Verso Bucksport during thirty of the sixty months of the first term of the Agreement. The capacity value is firm, which means that Verso Bucksport must provide it under the contract regardless of how the capacity from the VRC Project actually fares in the ISO-NE forward capacity market. Under the Agreement, from June 1, 2014 to November 30, 2016, Verso Bucksport will pay CMP the monthly financial equivalent of 21 MW[9] multiplied by 10% of the forward capacity auction capacity clearing price.[10] This provides CMP with the financial equivalent of purchasing capacity at a 10% discount and reselling that capacity at full market value without burdening CMP or ratepayers with any market transaction risk. If CMP exercises its option to extend the Agreement at the direction of the Commission, Verso Bucksport will pay CMP capacity value in the amount of 24 MW multiplied by 5% of the forward capacity auction capacity clearing price for every month of the second term of the Agreement. This provides CMP with the financial equivalent of purchasing capacity at a 5% discount and reselling that capacity at full market value without burdening CMP or ratepayers with any market transaction risk. Additionally, the Agreement provides that Verso Bucksport will use commercially reasonable efforts to qualify the capacity created by the VRC Project in the forward capacity auction, as well as increase Verso Bucksport's participation in ISO-NE's demand response programs as a result of any

[8] The average cost per REC is calculated by the Commission using Maine Class I renewable portfolio standard compliance costs (not including alternative compliance payments) for the prior contract year.

[9] This capacity amount represents the portion of the entire expected capacity value of the VRC Project (after it is qualified as capacity resource in the forward capacity market), prorated in a similar ratio as the amount of RECs contracted for under the Agreement in relation to the entire REC output of the VRC Project.

[10] For all other months during the initial five-year term of the Agreement, Verso Bucksport is not obligated to pay CMP for capacity value.

increased opportunity for demand response created by the development of the VRC Project.

The Agreement requires Verso Bucksport to post an initial form of security and replace it with a permanent form of security once Verso Bucksport has provided a minimum amount of RECs to CMP. Specifically, Verso Bucksport must deliver to CMP a $300,000 initial letter of credit within one month of the Agreement becoming effective that will remain in place until Verso Bucksport has delivered 58,000 RECs to CMP (hereinafter referred to as the REC Base Volume). Once CMP has received the REC Base Volume, it will release the letter of credit, convert the REC base volume into cash and hold the cash value of the REC Base Volume as security for Verso Bucksport's performance under the Agreement. Beginning in July 2013, CMP will release 20% of the security back to Verso Bucksport on an annual basis as long as Verso Bucksport has fulfilled its obligations under the Agreement for the previous contract year. If the Commission directs CMP to extend the Agreement for a second term, CMP will not release the last 20% deposit payment until Verso Bucksport has delivered an additional REC Base Volume to CMP to serve as security for the second term of the Agreement. Similar to the first term, CMP will release 20% of the cash value of the REC Base Volume back to Verso Bucksport each contract year of the second term of the Agreement as long as Verso Bucksport has performed its obligations under the Agreement. CMP is not required to post security unless it falls below investment grade or the equivalent.

V. DECISION

We direct CMP to enter into the long-term contract for 35 MWhs per hour of RECs, and 21 MW of capacity value and associated with the VRC Project in the first five-year term, and 24 MW of capacity value during the second term, if the Commission directs CMP to enter into the second term of the Agreement. For the reasons discussed below, we find that the Agreement is reasonably likely to be beneficial to ratepayers and will promote the State's energy policy as expressed in 35-A M.R.S.A. § 3210-C and elsewhere in Maine statutes.

At the outset, we note that there is an inherent risk to any long-term contract for RECs because the economics of the contracts depend on future projections of REC prices which are difficult to forecast and are sensitive to market and regulatory influences. It is for this reason that we take into account both quantitative economic analyses (including sensitivity analyses), as well as more qualitative considerations in evaluating this REC and Capacity Value Agreement.

As a preliminary matter, the Commission finds that the price for the capacity resource as part of this long-term contract will never exceed market prices over the term of the Agreement and will provide a financial benefit to ratepayers, because the Agreement provides the financial equivalent of a 10% discount on the forward capacity auction clearing price in the first term, and a 5% discount in the second term, which is a significant discount on the cost of capacity requirements. In effect, the contract mirrors the financial results of buying capacity at a discount off of market prices and reselling that capacity at market prices. Additionally, the Commission finds that this long-term contract is necessary for the VRC Project to be built and the development of the VRC project, combined with Verso's commitment to use commercially reasonable efforts to qualify capacity created by the VRC Project in the forward capacity market, will increase available capacity resources in Maine. This will help mitigate the effects of regional capacity resource mandates on Maine ratepayers.

We recognize that this Agreement presents risks to ratepayers associated with the difficulty of accurately forecasting REC prices over a five year period, and potentially over a ten-year period. With the assistance of the LEI, Staff completed an analysis of the proposed contract and gave the proposed price provisions serious consideration in light of reasonably derived market price forecasts. Using the LEI projections, the pricing structure for capacity and RECs shows a modest positive benefit to ratepayers on a present value basis compared to market forecasts. The use of other forecasts and sensitivity analyses reveal differing results that vary from substantial ratepayer benefits to significant ratepayer costs. We are also cognizant of a significant drop in REC prices subsequent to the negotiation and approval of the Term Sheet. Nevertheless, we find that it is reasonably likely that the REC prices contained in the Agreement will be below their market value over the term of the Agreement. However, given the inherent uncertainty, the Commission has limited the term of the Agreement to only five years, with the option of an additional five-year term if the Commission finds that a second term of the Agreement will benefit ratepayers. Additionally, as discussed above, if the VRC project does not achieve commercial operations by the end of the second contract year, CMP may terminate the Agreement and recover any costs which serve to put the ratepayers in the same position as if the Agreement had never existed.

On a more qualitative basis, the Agreement provides a ratepayer hedge against a future of higher than expected renewable portfolio standard (RPS) compliance prices. Because the price of compliance with Maine's RPS is built into the energy supply price of the competitive energy providers that serve Maine load, Maine ratepayers would be impacted by high costs of compliance with Maine's RPS. Since, as stated above, the REC prices in the Agreement are reasonably likely to be below market prices over time, especially in the outer years of the Agreement, the Agreement provides a functional hedge against potentially high and volatile REC prices without increasing costs to ratepayers. We acknowledge that the Agreement will have lower or negative benefits if future REC prices turn out to be lower than expected. In that event, however, any such costs will occur in an environment of generally lower REC prices which will reduce the overall cost of electricity supply by reducing the cost of compliance with Maine's RPS. This will mitigate some of the adverse effect of the Agreement upon ratepayers in the event that the Market does not behave as expected.

Additionally, Verso Bucksport has represented that this Agreement is necessary for the VRC project to obtain financing and is necessary for the Bucksport Mill to remain competitive in the industry. Thus, this Agreement will result in additional renewable generating capacity being built in Maine, helping to contribute to lower capacity prices within the State and to the State meeting its renewable capacity goals.[11] This

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[11] As a general matter, the more generation that is constructed in the region, the lower the regional capacity prices. Moreover, new generation capacity built in Maine could result in lower capacity costs in Maine than the rest of the region.

Agreement promotes clearly articulated State energy policy of encouraging the development of new renewable generation resources in Maine.

On balance, the Commission finds that this Agreement is reasonably likely to be beneficial to the ratepayers by providing for the development of an increased capacity and demand resource, as well as a reasonably likely benefit from the purchase and disposition of RECs from the VRC Project based upon reasonably derived forecasts from LEI.

Finally, the Commission finds that this long-term contract is consistent with the State's goals for greenhouse gas reduction and the regional greenhouse gas initiative because it will support the development of a project that has demonstrated an anticipated reduction in annual greenhouse gas emissions associated with the Bucksport Mill. Therefore, the Agreement is consistent with the State's goals for greenhouse gas reduction under Title 38, section 576 and the regional greenhouse gas initiative as described in the state climate action plan required by Title 38, section 577.

In accordance with provisions in statute and the rule, 35-A M.R.S.A. § 3210-C(8) and Chapter 316, section 8, the Commission will allow CMP to recover in rates the costs of this contract. In particular, CMP will be allowed to: (i) recover in rates through full reconciliation all costs paid for RECs under the Agreement net of any value realized from Verso's capacity payments and any value above the contract price obtained by CMP from the sale of the RECs to a third party; (ii) defer and recover in rates all prudently incurred incremental costs associated with the administration of the contract; and (iii) recover in rates any impact on their cost of capital that results from the entering into these contracts.

Finally, through future order, we will direct CMP as to the disposition of the contracted for resources consistent with statute and rule. 35-A M.R.S.A. § 3210-C(7) and Ch. 316, § 7.

Dated at Hallowell, Maine, this 3rd day of January, 2011.

BY ORDER OF THE COMMISSION

Karen Geraghty
Administrative Director

COMMISSIONERS VOTING FOR: Cashman
Littell

COMMISSIONER CONCURRING
IN PART AND DISSENTING IN PART: Vafiades

Dissenting Opinion of Commissioner Vafiades

I support the Agreement to purchase RECs and capacity value from the Verso Renewable Capacity (VRC) Project as outlined in the August, 2010 Draft Term Sheet with the contractual provisions as provided in this Commission's Order except for the amount of RECs to be purchased under the Agreement.

In the course of negotiating the contractual terms of the Agreement, Verso indicated to the Staff that it wished the Commission to consider an increase in the amount of RECs from the Project that would be purchased under the Agreement. Verso requested that the Agreement incorporate an increase from 30 MWhs per hour to 40 MWhs per hour of RECs purchased. Shortly before the Commission deliberated the final Agreement, Verso informed the Staff that it needed the Commission to approve the Agreement at the 40 MWhs per hour level in order for the VRC project to move forward and that approval of the Agreement at the 30 MWhs per hour level would likely result in the abandonment of the Project. In final negotiations, Verso agreed that it could make the VRC Project work with approval of the Agreement at a 35 MWhs per hour level.

In considering Verso's proposal to increase the amount of RECs purchased under the Agreement, I was concerned that the existing market for Maine RECs had dropped in value significantly from the estimates this summer and the volatility of the market could harm ratepayers over the long term. The Commission agreed to continue the matter and requested Staff to reinitiate discussions with Verso regarding, at a minimum, an increase in demand response participation, replacement RECs obligations in years one and two, and reduction in REC Cap prices.

After the completion of negotiations, the Commission was presented with a commitment of 21 MW of capacity in contract years 1-5 and 24 MW in years 6-10 and 35 MWhs per hour of RECs. Verso responded positively to a number of the issues of concern, but would not consider an adjustment in REC Cap prices even in the final five years of the contract term. I concluded that adjusting the calculation of the REC Cap price as provided in the Agreement so that the Contract Price paid for RECs would be reduced from 75% of the average of the cost per REC paid by all load serving entities to 50 % for the last five years of the contract term would result in a significant potential increase in the value of the contract to ratepayers. I included in my analysis an adjustment for the recent substantial drop in REC prices from the Commission's approval of the VRC Project in August as reflected in the current market. Without this adjustment and with the continuing volatility in the REC market, I cannot support increasing the requirement to purchase RECs from the mill by the additional 5 MWhs per hour. The increased risk to ratepayers is not sufficiently mitigated without this additional adjustment.

I strongly urge the Commission to review carefully the values of RECs purchased over the first five-year term at the time it is considering an authorization of an extension of the contract for the additional five-year term.

NOTICE OF RIGHTS TO REVIEW OR APPEAL

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1. Reconsideration of the Commission's Order may be requested under Section 1004 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.

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.A. § 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.A. § 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.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2008-104

October 8, 2009

MAINE PUBLIC UTILITIES COMMISSON
Resource Planning and
Long-Term Contracting

ORDER DIRECTING
UTILITIES TO ENTER
INTO LONG-TERM
CONTRACT

REISHUS, Chairman; VAFIADES and CASHMAN, Commissioners

I. SUMMARY

Through this Order, we direct Central Maine Power Company (CMP) and Bangor-Hydro-Electric Company (BHE) to enter into long-term contracts for capacity and energy with Evergreen Wind Power III, LLC (EWP), a subsidiary of First Wind Holdings, LLC (First Wind), for the output of the Rollins Wind Project. The Rollins Wind Project is a 60 MW wind facility to be constructed in Penobscot County, Maine. We direct CMP to enter into a contract for 80% of the output of the Project and BHE to enter into a contract for 20% of the output of the contract.

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.A § 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 capacity resources through the issuance of a request for proposals (RFP) that contains all standards, procedures and requirements for the long-term contract solicitation process, as well as a standard form contract. On December 3, 2008, the Commission issued an order approving and issuing the first long-term contract RFP.

The RFP called for Stage 1 Proposals (Bidder Registration) to be submitted by January 7, 2009 and Stage 2 Proposals (Comprehensive Proposals and Indicative Pricing) to be submitted by April 7, 2009. Since the submission of Stage 2 proposals, Staff and the Commission's consultant, London Economic Inc. (LEI), have conducted economic analyses of the various proposals, and have been working with a short-list of bidders and the utilities to develop commercial and contractual terms for long-term contracts that would be beneficial to ratepayers. The Staff has also consulted on a regular basis with the Public Advocate and the Department of Environmental Protection on the details of potential contractual arrangements.

Over recent weeks, the Staff and EWP, with substantial input from the utilities, worked to finalize contracts that could be presented to the Commission for its consideration. CMP, BHE, EWP and the Public Advocate filed comments on the proposed contracts. On October 7, 2009, the Commission deliberated the matter.

II. CONTRACTING AUTHORITY

1. 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 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. This is especially the case in the current financial climate. 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 off of expected future prices. Such contracts may also provide a low-cost hedge against rising electricity prices (resulting from increases in natural gas 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, and promote the State's renewable energy development policies. *See* 35-A M.R.S.A. §3210-C (2).

2. 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.A § 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 renewable resources as a high priority in the selection of proposals. 35-A M.R.S.A § 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. The section states that the Commission may not require utilities to enter into "contracts for differences" that are designed to buffer ratepayers from negative impacts from transmission development, but does not otherwise restrict the Commission's authority to direct utilities to enter into financial transactions.[1] 35-A M.R.S.A § 3210-C (3). 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.

3. Implementing Rules

The Commission's long-term contracting implementing rules (Chapter 316) state that contracted 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 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 then 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.

III. PROPOSED LONG-TERM CONTRACT

The proposal under consideration is for a long-term contract between EWP and CMP and BHE for the entire energy output and capacity value of the Rollins Wind Project. The Rollins Wind Project is a 60 MW wind generating facility proposed to be developed in the Penobscot County towns of Lincoln, Winn, Lee and Burlington, Maine. The project is expected to begin commercial operation at the end of 2011.

The contract is for a twenty year term. The term begins with the commercial operation of the facility.[2] The energy under the contract is priced at the hourly real time locational marginal price at the ISO-NE internal hub (hub LMP) minus $10/MWh when the hourly real time locational marginal price for energy for the applicable node (node LMP) is within 10% of the hub LMP, and hub LMP minus $15/MWh when the node LMP is more than 10% lower than the hub LMP. Because the value of the energy under the contract will reflect the node LMP applicable to the Rollins facility, the two-tiered formula structure is intended to mitigate the risk of divergence between the node LMP and the

[1] Financial transactions are agreements in which only money (rather than a physical delivery of the capacity and energy commodity) is exchanged among the contracting parties. Such transactions mirror exactly the financial consequences of a physical transaction, but can do so in a way that reduces transaction costs and risks for utilities.

[2] Either party may terminate the contract if the facility is not in commercial operation by December 31, 2013.

hub LMP. Due to congestion and line losses, the node LMP has tended to be lower than the hub LMP, creating a risk that the $10/MWh discount off the hub LMP will be higher than the value of the energy. It is for this reason that the discount off hub LMP drops to $15/MWh if the differential between the hub LMP and nodal LMP is greater than 10%.

The energy price has a hourly floor of $55/MWh in the first year that escalates by $1/MWh per year until it reaches $65/ MWh in the eleventh year and remains at the level through the remaining years in the term. The contract also has an hourly energy price cap of $110/MWh.

The capacity component of the contract is a financial transaction in which the utility, essentially, obtains the capacity value of the facility for no addition cost above the energy costs. The capacity value is firm in that EWP must provide it under the contract regardless of how the capacity from the Rollins facility actually fares in the regional capacity market. This is a key feature of the contract because, although EWP expects that the Rollins project will in the future realize capacity value in the ISO-NE Forward Capacity Market (FCM), the facility is not currently qualified to participate in the Forward Capacity Auction (FCA). To provide for a capacity benefit prior to qualification, the contract specifies that, prior to qualification, EWP will pay CMP and BHE the financial equivalent of 17.91 MW[3] multiplied by the market value of capacity.[4] When the facility is qualified in the FCA, the contracts provide that EWP will pay to the utilities an amount equal to the qualified capacity value of the facility multiplied by the market value of capacity, with a capacity floor of 17.91 MW. After initial qualification, if the facility no longer has a capacity value under the regional rules, the contracts specify that EWP will pay to the utilities the financial equivalent of 17.91 MW multiplied by the lesser of (1) the market value of capacity or (2) and floor equal to $3.50/kW-month until May 2019 and $5.00/kW-month thereafter.

For security, the contracts require EWP to deliver to the CMP/BHE a second lien on the facility with the caveat that any first priority lien or security interest in the aggregate will not exceed 80% the capital cost or the appraised value of the facility, whichever is higher. EWP has the option of replacing the second lien with a letter of credit or cash in the amount of $4 million. The utilities are required to post security only if certain financial indicators show the utilities to be below investment-grade or the equivalent. The amount of security in the aggregate would be $8 million, with the amount apportioned to the utilities based on their contracted-for percent of the output of the facility. The utilities are not required to post any security if they remain rated at investment grade or the equivalent.

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[3] This capacity amount represented the expected capacity value of the facility after it is qualified as capacity resource in the forward capacity market.

[4] The market value price is capped at $5/kW-month until May 2015, than increases by $1/kW-month every five years, until it reaches $8/kW-month.

IV. COMMENTS

A. Utilities' Comments

On October 1, 2009, CMP and BHE submitted comments expressing concerns regarding the EWP contract, with CMP recommending that the Commission not direct it to enter into contract. As a general matter, the utilities note that that an evaluation of long-term contracts involve forecasts of future energy and capacity prices, which is a difficult task that carries certain inherent risk. With respect to the proposed contracts, the utilities state that the analysis also includes assumptions regarding the future differential in locational prices between the contract delivery point (node LMP) and the index pricing point (hub LMP). CMP indicated that its analysis of the contract over the first ten years of the term shows that the proposal would produce a net cost to ratepayers of several hundred thousand dollars per year over the first five years and a net present value loss of over $1.5 million for the 10-year period (assuming CMP contracts for the entire output of the facility). BHE's analysis shows a small marginal benefit to customers over the 20-year term (assuming a 20% allocation of the output to BHE). The utilities note that there would be more favorable results if market energy prices rise above current expectations or if the node LMP and hub LMP converge. Conversely, they note that the results would be worse for ratepayers if future prices are lower than projected and the LMPs do not converge.[5]

In addition, the utilities express concern that credit support provisions of the contracts are asymmetrical. The contracts provides for a second lien on the EWP facility that may be replaced at any time with cash or a letter of credit in the amount of $4 million, while the utilities must post $8 million if they fall below investment grade. The utilities state that the $4 million credit support is inadequate relative to the long term of the contract, possibly allowing EWP to take advantage of favorable economics in the first few years, but then decide to abandon the contract if market prices rise so that the performance is no longer attractive to EWP. Moreover, the utilities state that a second lien is not standard in the industry, is difficult to quantify, and is much less desirable than a liquid asset in securing the obligation.

BHE adds a concern regarding possible costs of administering the contract. BHE states that if the output of the facility is settled in the day-ahead or real-time market, there would be a cost of approximately $20,000 annually and a requirement for BHE to comply with FERC's standards of conduct that would cost approximately $25,000 in start-up costs. In the event BHE is allowed to contract for administration with its affiliate, Emera Energy, the cost would be approximately $10,000 annually.

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[5] CMP states that, because the Maine/New England price differential is largely a function of losses, not congestion, there is no reason to expect that convergence to a significant degree will occur.

Finally, BHE states there is a risk that the utilities may have to pay local transmission charges. This would occur if BHE's Keene Road upgrade is not completed as scheduled or if ISO-NE PTF designation does not occur prior to the facility's commercial operation date.

B. Evergreen Wind Power

On October 5, 2009, EWP submitted comments in response to the utilities' filings. EWP states that the proposed contracts will provide ratepayers with substantial savings and protection from price instability. Specifically, EWP states that the contracts will provide ratepayers a substantial discount from energy costs they would otherwise face, and provides the financial equivalent of the full capacity value of the facility at no additional cost to ratepayers. EWP also states that it retained a consultant to analyze the future differential between the node LMPs and the hub LMPs, and that the analysis found that there will be a general decrease in the future LMPs differential due to reduced congestion.[6]

With respect to security, EWP argues that a second lien is commercially reasonable under this circumstance in that in the current financial environment, EWP and its affiliates have found it extremely expensive to obtain letters of credit for a wind project. Thus, a second lien is far more cost-effective and has a secured value that is more than sufficient to secure the ratepayers' benefit. Moreover, according to EWP, the amounts that utilities are required to post in the event they fall below investment grade or the equivalent is necessary for the project to be financed in that it secures for the lender a certain cash flow under the contract for at least as year.

C. Public Advocate

As mentioned above, the Staff has consulted with the Public Advocate (as well as the DEP) throughout the contract evaluation process, including the provision of the economic analyses of the proposed contracts. The Public Advocate has submitted comments in general support of the approval of the EWP contracts. Specifically, the Public Advocate states his view that the contracts are reasonably likely to be beneficial over their 20 year terms.

V. DISCUSSION

We direct CMP and BHE to enter into the long-term contracts for capacity and energy with EWP for the entire output of the Rollins Wind Project. We direct CMP to enter into a contract for 80% of the output of the Project and BHE to enter into a contract for 20% of the output of the contract. For the reasons discussed below, we find that the contracts are reasonably likely to be beneficial to ratepayers and would clearly

[6] EWP commented that this analysis is conservative in that it assumed no reduction in losses, when such reductions will occur with transmission upgrades.

promote State energy policy as expressed in 35-A M.R.S.A. §3210-C and elsewhere in Maine statutes.

At the outset, we note our agreement with the utilities that there is an inherent 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 economics are 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.

As mentioned, Staff has discussed pricing and contractual terms with EWP and the utilities for several months. Staff and its consultant, LEI, have reviewed and analyzed the proposed prices and the terms of the capacity and energy contracts using reasonably derived market price forecasts. The structure of these contracts with the value of the capacity purchased through energy prices negates a separate analysis of the capacity and associated energy components of the contracts.[7]

The contract is structured as a discount off of market prices, but contains a price floor. If market prices are primarily above the floor, the contractual structure provides a benefit in that the price is a discount off of market prices. The Staff/LEI's analysis (which analyzes the first 12 years of the contract) indicates that the contracts will likely have a small benefit in the early years of the contract that grows over time as electricity and capacity prices are forecasted to increase. These benefits are likely to continue to increase in the outer years of the contract given the trajectory of projected wholesale prices.

The Staff/LEI's analysis included sensitivities around various levels of differentials between the node LMPs and the hub LMPs. This analysis shows that the benefits decrease with higher assumed differentials. However, the analysis shows positive ratepayer benefits, even when a constant 15% differential is assumed. In addition, we note that the EWP analysis shows significantly greater ratepayer benefits due primarily to a higher natural gas price forecast, suggesting that that the Staff/LEI analysis may be conservative to some degree.

On a more qualitative basis, the contracts provide a ratepayer hedge against a future of higher than expected market prices. Maine's ratepayers are generally at risk of high and volatile market prices. Because the contracts contain a firm price ceiling of \$110/MWh, they provide a hedge against high and volatile prices over their 20 year term. We acknowledge that the contracts will have lower or negative benefits if future prices turn out to be lower than expected. However, the potential cost of the hedge is

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[7] To the extent that our review is inconsistent with that contemplated by Chapter 316, we waive, for good cause, any inconsistent provisions pursuant to Chapter 316, § 10. Such a waiver is appropriate because the approach contemplated by the rule is not mandated by statute and a waiver in this case, if necessary, will promote the policies of section 3210-C.

relatively low in that the contracts are small relative to the size of the utilities. In the event that market prices are lower than the expected, any costs of the contracts will occur in an environment of generally lower prices, thus reducing the impact of the contracts on ratepayers.

With respect to the utilities concerns regarding credit support provisions, we agree that second lien is less desirable than more liquid security, and liens are not standard in the industry. As such, we do not favor this type of security. However, we recognize that the letters of credit are difficult to obtain and are very expensive in the current financial environment, especially for wind projects and conclude that this security provision does not warrant rejecting the contracts.[8] Moreover, the provisions that require the utilities to post security if they fall below investment grade or the equivalent is consistent with our long-standing approach with standard offer arrangements and were authorized in our December 3, 2008 order approving the RFP. Although the specific amounts of the security provision may not be ideal, they are not unreasonable and appear necessary for the financing of the project.

In response to BHE's concern regarding local transmission charges, BHE has provided a memorandum, in consultation with its FERC counsel, that states that effective on or about June 30, 2010 it will place into service a new Keene Road substation (long before the expected commercial operation of the Rollins project), which it expects to be classified by the ISO-NE as a PTF facility. Thus, we view the risk that the utilities may have to pay local transmission charges as minimal.

Finally, EWP has represented that the contracts are necessary for the projects to obtain financing and, as such, these contracts are necessary for the construction of the Rollins facility. Thus, these contracts will result in new generating capacity being built in Maine, helping to contribute to lower capacity prices within the State[9] and increase the diversity of the resource mix in the State and in the region. Moreover, as necessary to develop a wind facility in Maine, the contracts promote clearly articulated State energy policy of encouraging the development of wind facilities in Maine.[10]

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[8] We note that the contracts provide that any first priority lien or security interest may not exceed 80% of the capital cost or appraised value, whichever is larger and, therefore will secure a relatively large amount compared to the expected ratepayer benefit.

[9] As a general matter, the more generation that is constructed in the region, the lower the regional capacity prices. Moreover, new generation capacity built in Maine could result in lower capacity costs in Maine than the rest of the region.

[10] For example, Maine's Legislature has established wind energy development goals in the State of at least 2000 MW by 2015 and at least 3000 MW by 2020. 35-A M.R.S.A. § 3404(2).

As a wind facility, there will be no carbon air emissions associated with the generation of electricity. Thus, the long-term contracts are consistent with the States goals for greenhouse gas reduction and the regional greenhouse gas initiative, as required by statute.

The major benefits of these contracts occur over the 20 year term. As such, we find that contracts of 20-year terms are, in this case, prudent and in the ratepayer's interest as required by statute and rule.[11]

Consistent with provisions in statute and the rule, 35-A M.R.S.A. § 3210-C (8) and Ch. 316, § 8, the Commission will allow CMP and BHE to recover in rates the costs of this contract. In particular, the utilities will recover in rates through full reconciliation all costs paid for capacity and energy under the contracts net of any value realized from the disposition of the resources; will be allowed to defer and recover in rates all prudently incurred incremental costs associated with the administration of the contracts; and will be allowed to recover in rates any impact on their cost of capital that results from the entering into these contracts.

Finally, through future order, we will direct CMP and BHE as to the disposition of the contracted for resources consistent with statute and rule. 35-A M.R.S.A. § 3210-C (7) and Ch. 316, § 7.

Dated at Augusta, Maine, this 8th day of October, 2009.

BY ORDER OF THE COMMISSION

____
Karen Geraghty
Administrative Director

COMMISSIONERS VOTING FOR: Reishus
Vafiades

COMMISSIONER ABSENT: Cashman

[11] The standard for authorizing contracts beyond 10 years in statute is "prudent." 35-A M.R.S.A. SEC 3210-A (5). The standard in the implementing rules is "ratepayer interest." The Commission views the two standards as essentially the same.

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STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2015-00299

January 29, 2016

MAINE PUBLIC UTILITIES COMMISSION
Community-Based Renewable Energy Projects
Request for Proposals (2015 Issuance)

ORDER – PART II

VANNOY, Chairman; MCLEAN and WILLIAMSON, Commissioners

I. SUMMARY

Pursuant to 35-A M.R.S. § 3604, the Commission directs Central Maine Power Company to enter into long-term contracts for energy output with three Community-Based Renewable Energy Projects: Clear Energy, LLC and Cianbro Development Corporation, a 9.9 MW solar project in Monroe, Maine; Georges River Energy, LLC, a 7.5 MW biomass plant in Searsmont, Maine; and Mayo Mill, LLC, a 310 kW hydroelectric power plant and 85.68 kW solar array in Dover-Foxcroft, Maine. The Commission also directs Emera Maine to enter into a long-term contract for energy output with Shamrock Partners, LLC, a 1.0 MW wind facility in Limestone, Maine. On December 22, 2015, the Commission issued its Part I Order describing the Commission's decision in the above-captioned proceeding. This Part II Order provides the background, analyses, and reasoning underlying the Commission's decision.

II. STATUTORY AUTHORITY

During its 2009 session, the Maine Legislature enacted An Act to Establish the Community-based Renewable Energy Pilot Program (Act), P.L. 2009, ch. 329. Part A of the Act establishes a community-based renewable energy pilot program, to be administered by the Commission, to encourage sustainable development of community-based renewable energy. 35-A M.R.S.A. § 3602.

The projects chosen to participate in the pilot program must generate electricity from an eligible renewable resource, which includes fuel cells; tidal power; solar, wind and geothermal installations; hydroelectric generators; biomass generators fueled by wood, wood waste or landfill gas; and anaerobic digestion of by-products of waste from animals or agricultural crops, food or vegetative material, algae or organic refuse. These projects must be "locally owned electricity generating facilities," which means that 51% or more of the facility must be owned by "qualifying local owners." The total installed generating capacity in the pilot program is limited to 50 MW.

On June 22, 2015 the Legislature adopted P.L. 2015 ch. 232, An Act to Amend the Community-Based Renewable Energy Program (2015 Amendment).

The Amendment makes several changes to the existing Community-based Renewable Energy Program. Among other changes, Section 5 of the Amendment directed the Commission to review all certified program participant projects that have not yet reached commercial operations to determine whether the projects are reasonably likely to achieve commercial operations within a 3-year period and, to the extent there is less capacity contracted than is allowed under Title 35-A, section 3603, subsection 2 after the removal of nonviable projects, to conduct an expedited request for proposals to select community-based renewable energy projects to become program participants and enter into long-term contracts.

III. VIABILITY ASSESSMENT AND REQUEST FOR PROPOSALS

The Commission completed its viability assessments and identified approximately 21 MW of capacity available for contract awards. On September 30, 2015, the Commission issued its 2015 Request for Proposals for community-based renewable energy projects. Pursuant to the RFP, proposals were due on or before November 6, 2015.The Commission received bids from multiple entities, totalling approximately 80 MW to fill the 21 MW of capacity available for contract awards. The proposals were for projects of varying sizes, different generator types, and located in various regions of the state. Staff reviewed all proposals and supporting documentation. One proposal was withdrawn prior to review by the Commission and all remaining proposals were submitted to the Commission for consideration.

The projects submitted for consideration included three solar photovoltaic projects, two biomass projects, three wind projects, an anaerobic digestion project and a hydro/solar PV project. The size of the projects ranged from less than 1 MW to 10 MW and the proposed pricing ranged from 6.7 cents/kWh to 10 cents/kWh. All projects proposed a 20-year contract term.

IV. DECISION

As noted, the Commission received proposals from projects that total well in excess of the capacity available for contract awards. The 2015 Amendment directs the Commission to select projects that provide the most benefit to ratepayers; that have contract pricing levels below $0.10 per kilowatt hour within each contract year; and to meet the maximum pilot program allowance of 50 MW.

The Commission is given broad discretion in determining which projects will bring the most benefit to ratepayers. The community-based pilot program currently includes contract awards for projects totaling slightly more than 29 MW. Of this amount of capacity, 18.6 MW is with wind projects, 7.1 MW with biomass, 3 MW with a farm-based anaerobic digester and less than 1 MW with hydro. In this instance, the Commission notes that given that this program is a pilot, a broad diversity of generation technologies and regional representation is especially beneficial. Additionally, in considering the proposals, the Commission takes into account issues of viability; permitting status; price; engineering and design status; and state and local economic benefits. Finally, the Commission considers issues related to whether the proposed project meets the specific requirements of the pilot program such as obtaining a resolution of support from the municipal legislative body in the municipality in which the project is to be located and whether the project meets the requirement for 51% qualifying local ownership.

Based on these factors, the Commission finds that the following project proposals best fulfill the criteria and appear to have a clearer development path with fewer impediments to achieving success:

1. Clear Energy-Monroe. Clear Energy- Monroe is a 9.9 MW AC capacity, solar PV facility to be located in Monroe, Maine. It would interconnect to the CMP system at a 12.47kv distribution line 5,800 feet from the facility. The project would be 30% equity owned by Clear Energy, LLC and 70% equity owned by Cianbro Development Corporation, both Maine companies. The Selectmen of the Town of Monroe passed a resolve in support of the project on October 30, 2015. A resolution of support from the municipal legislative body is still needed. The developers have project development ability and experience with permitting and constructing solar installations. The COD is anticipated in the autumn of 2016. The proposed price is $0.0845 per kWh for a 20-year term;

2. Georges River Energy, LLC. Georges River is a 7.5 MW net capacity, wood-fired biomass cogeneration system located at the Robbins Lumber sawmill in Searsmont. It will use a locally-sourced blend of bark, hog fuel, sawdust and wood chips as biomass fuel. The proposed plant would use fuel produced by the Robbins sawmill and pine pulpwood produced by logging contractors in Waldo and Knox County. Waste heat produced in the biomass plant would be used to dry lumber and heat the mill buildings. Georges River is a Maine LLC wholly owned by Robbins Lumber, a family owned mill that has been in operation since 1881. Robbins Lumber is 100% owned by members of the Robbins family, all Maine residents. The Selectmen passed a resolve in support of the project. A resolution of support from the municipal legislative body is still needed. The developers have general project development ability and experience. COD is expected Q1 2018. The proposed price is $0.099 per kWh for a 20-year term;

3. Mayo Mill, LLC. Mayo Mill is a 310 kW hydroelectric and 85.68 kW DC (396 kW total capacity) solar PV facility to be located in Dover-Foxcroft, Maine. It would interconnect to the CMP system at the 1908 American Woolen Mill at the Riverfront Redevelopment

Project II at 5 East Main Street. The project is owned by the Town of Dover-Foxcroft, which has granted a lease to Mayo Mill LLC (75% owned by Charles Arnold of Topsham, Maine) to manage and operate the project. At a Special Town Meeting Referendum on November 3, 2015, the Town of Dover-Foxcroft voted to authorize the Board of Selectmen to petition the Commission for certification. The COD is October 2016. The proposed price is $0.10 per kWh for a 20-year term; and

4. Shamrock Partners, LLC. Shamrock Wind is a 1 MW wind (1 turbine) project to be located on farm fields in Limestone. The proposal represents a re-located (outside of Fort Fairfield) and significantly re-sized wind project that has been certified by the Commission. The new site is directly north of the original site by 1 mile on 100 acres of farm land. Ownership remains the same as the original proposal. A resolution of support from the municipal legislative body has not yet been obtained. COD is expected in late 2017, or no later than late 2018. The proposed price is $0.083 per kWh for a 20-year term.

The Commission notes that these projects have not yet been certified as Community-Based Renewable Energy Projects consistent with the requirements of Chapter 325. However, the proposals contain sufficient information to determine that the projects would meet the pilot program eligibility requirements contained in Section 4(A) of Chapter 325. Each project must obtain such certification prior to execution of any contract with a T&D utility.

Accordingly, the Commission

ORDERS

1. That Central Maine Power Company enter into the following long-term contracts:

   a. Clear Energy, LLC, a 9.9 MW utility scale solar array in Monroe, Maine, for a 20-year term at a price of $0.0845 per kWh;

   b. Georges River Energy, LLC, a 7.5 MW net generating capacity biomass plant located on the grounds of the Robbins Lumber mill in Searsmont, Maine, for a 20-year term at a price of $0.099 per kWh; and

   c. Mayo Mill, LLC, a 310 kW hydroelectric power plant and a 85.68 kW solar photovoltaic array located at the Riverfront

Redevelopment Project in Dover-Foxcroft, Maine, for a 20-year term at a price of $0.10 per kWh.

2. That Emera Maine enter into the following long-term contract:

   a. Shamrock Partners, LLC, a 1.0 MW wind generator located in Limestone, Maine, for a 20-year term at a price of $0.083 per kWh.

Section 107(4) of Title 35-A provides that the Commission may delegate to its staff such powers and duties as the Commission deems proper. Pursuant to this authority, the Commission hereby grants to the Director of Electric and Gas Utility Industries the authority to approve proposed modifications to the terms and conditions of the standard form contract for the Community-Based Renewable Energy Pilot Program and the authority to certify any project as a Community Based Renewable Energy Project consistent with the requirements of Section 4 of Chapter 325 of the Commission's Rules.

Consistent with provisions in statute and the rule, 35-A M.R.S.A. § 3604(8) and Ch. 325, § 6, the Commission will allow CMP and Emera Maine to recover in rates all costs of the contracts entered into, including but not limited to any effects on the utilities' cost of capital.

Dated at Hallowell, Maine, this 29th day of January, 2016.

BY ORDER OF THE COMMISSION

Harry Lanphear

Harry Lanphear,
Administrative Director

COMMISSIONERS VOTING FOR: Vannoy
McLean
Williamson

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).

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STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2015-00299

December 22, 2015

MAINE PUBLIC UTILITIES COMMISSION
Community-Based Renewable Energy Projects
Request for Proposals (2015 Issuance)

ORDER – PART 1

VANNOY, Chairman; MCLEAN and WILLIAMSON, Commissioners

I. SUMMARY

By this Order – Part 1, and pursuant to 35-A M.R.S. § 3604, the Commission directs Central Maine Power Company to enter into long-term contracts for the energy output only with three Community-Based Renewable Energy Projects: Clear Energy, LLC and Cianbro Development Corporation, a 9.9 MW solar project in Monroe, Maine; Georges River Energy, LLC, a 7.5 MW biomass plant in Searsmont, Maine; and Mayo Mill, LLC, a 310 kW hydroelectric power plant and 85.68 kW solar array in Dover-Foxcroft, Maine. The Commission also directs Emera Maine to enter into a long-term contract for the energy output only with Shamrock Partners, LLC, a 1.0 MW wind facility in Limestone, Maine.

II. BACKGROUND

A. Order in Parts

Pursuant to Chapter 110, § 11(C)(2) of the Commission's Rules, the Commission may issue an order in two parts. This Part I Order describes the Commission's decision in the above-captioned proceeding. A Part II Order providing the background, analyses, and reasoning underlying the Commission's decision will be issued in the near future.

B. Procedural Summary

During its 2009 session, the Maine Legislature enacted An Act to Establish the Community-based Renewable Energy Pilot Program (Act), P.L. 2009, ch. 329. Part A of the Act establishes a community-based renewable energy pilot program, to be administered by the Commission, to encourage sustainable development of community-based renewable energy. 35-A M.R.S.A. § 3602.

The projects chosen to participate in the pilot program must generate electricity from an eligible renewable resource, which includes fuel cells; tidal power; solar, wind and geothermal installations; hydroelectric generators; biomass generators fueled by wood, wood waste or landfill gas; and anaerobic digestion of by-products of waste from animals or agricultural crops, food or vegetative material, algae or organic refuse. These projects must be "locally owned electricity generating facilities," which means that 51% or more of the facility must be owned by "qualifying local owners." The total installed generating capacity in the pilot program is limited to 50 MW.

On June 22, 2015 the Legislature adopted P.L. 2015 ch. 232, An Act to Amend the Community-Based Renewable Energy Program (Amendment). The Amendment makes several changes to the existing Community-based Renewable Energy Program. Among other changes, Section 5 of the Amendment directed the Commission to review all certified program participant projects that have not yet reached commercial operations to determine whether the projects are reasonably likely to achieve commercial operations within a 3-year period and, to the extent there is less capacity remaining than is allowed under Title 35-A, section 3603, subsection 2 after the removal of nonviable projects, to conduct an expedited request for proposals to select community-based renewable energy projects to become program participants and enter into long-term contracts.

The Commission completed its viability assessments and identified approximately 21 MW of capacity that is available for contract awards. On September 30, 2015, the Commission issued its 2015 RFP for community-based renewable energy projects.

The Commission received bids from multiple entities, totalling approximately 80 MW to fill the 21 MW of capacity available for contract awards. The projects were of varying sizes, different generator types, and are located in multiple regions of the state.

III. DECISION

In determining which project proposals should be chosen to participate in the community-based renewable energy pilot program, the Amendment requires that the Commission select projects that provide the most benefit to ratepayers and that have contract pricing levels below $ 0.10 per kilowatt hour within each contract year. In addition, the Amendment directs the Commission to select projects to provide for a total net generating capacity for all projects to meet the maximum allowance of 50 MW.

As noted, the Commission received proposals from projects that total well above the available capacity. The Commission is given broad discretion in determining which projects will bring the most benefit to ratepayers. In this instance, the Commission notes that given that this program is a pilot, a broad diversity of generation technologies and regional representation is especially beneficial. Additionally, the Commission took into account issues of viability and state and local economic benefits. Based on these factors, the Commission finds that four project proposals specified best fulfill these criteria.

As noted above, the Commission will issue a Part II Order in the near future that will provide the background, analyses, and reasoning underlying the Commission's decision.

Accordingly, the Commission

ORDERS

1. That Central Maine Power Company enter into the following long-term contracts:

    a. Clear Energy, LLC and Cianbro Development Corporation, a 9.9 MW utility scale solar array in Monroe, Maine, for a 20-year term at a price of $0.0845 per kWh;
    b. Georges River Energy, LLC, a 7.5 MW net generating capacity biomass plant located on the grounds of the Robbins Lumber mill in Searsmont, Maine, for a 20-year term at a price of $0.099 per kWh; and
    c. Mayo Mill, LLC, a 310 kW hydroelectric power plant and a 85.68 kW solar photovoltaic array located at the Riverfront Redevelopment Project in Dover-Foxcroft, Maine, for a 20-year term at a price of $0.10 per kWh

2. That Emera Maine enter into the following long-term contract:

    a. Shamrock Partners, LLC, a 1.0 MW wind generator located in Limestone, Maine, for a 20-year term at a price of $0.083 per kWh

Dated at Hallowell, Maine, this 22nd day of December, 2015

BY ORDER OF THE COMMISSION

/s/ Harry Lanphear
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Vannoy
McLean
Williamson

NOTICE OF RIGHTS TO REVIEW OR APPEAL

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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).

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STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2013-00207

August 27, 2013

MAINE PUBLIC UTILITIES COMMISSION
Request for Proposals for Community-Based Renewable Energy Projects
(2013 Issuance)

ORDER APPROVING LONG-TERM CONTRACTS

WELCH, Chairman; LITTELL and VANNOY, Commissioners

I. SUMMARY

Pursuant to 35-A M.R.S.A. § 3604, we direct Central Maine Power Company (CMP) to enter into a long-term contract for energy from a 7.1 MW wood fired biomass cogeneration system to be developed by Maine Woods Pellet Company, LLC, and we direct Maine Public Service Company (MPS) to enter into a long-term contract for 4 MW of the energy produced by a 10 MW wind facility to be developed by Shamrock Partners, LLC.

II. BACKGROUND

During the 2009 session, the Legislature enacted An Act To Establish the Community-based Renewable Energy Pilot Program (Act), P.L. 2009, ch. 329. Part A of the Act establishes a community-based renewable energy pilot program, to be administered by the Commission, to encourage the sustainable development of community-based renewable energy. The Act provides incentives, on a pilot program basis, for the development of community-based renewable projects that qualify for participation in the program. The projects must generate electricity from an eligible renewable resource, which includes fuel cells; tidal power; solar, wind and geothermal installations; hydroelectric generators; generators fueled by landfill gas; and biomass generators whose fuel includes anaerobic digestion of agricultural products, byproducts or wastes. These projects must be "locally owned electricity generating facilities," which means that 51% or more of the facility must be owned by "qualifying local owners." An individual project must not exceed 10 MW and the total installed generating capacity of all program participants in the pilot program combined may not exceed 50 MW. The pilot program is repealed on December 31, 2015. 35-A M.R.S. §§ 3601-3609.

The incentive mechanisms provided by the Act are either: 1) a long-term contract for the output of the facility with a transmission and distribution (T&D) utility; or 2) a renewable energy credit (REC) multiplier in which the value of the REC is 150% of the amount of the produced electricity. Projects electing the REC multiplier are responsible for negotiating their own transactions for energy, capacity or RECs. Certified projects of less than 1 MW that elect a long-term contract can complete a standard form contract with the T&D utility at a price per kWh that has been established by the Commission.

For certified projects with generating capacity of 1 MW and larger, the Act provides that the Commission shall periodically conduct a competitive solicitation to select projects that will be awarded a long-term contract with the T&D utility. The Commission has conducted two competitive solicitations for Community -Based Renewable Energy Projects. On April 28, 2011, the Commission issued a Request for Proposals for Community-Based Renewable Energy Projects of 1 MW or larger. Bids were due on May 31, 2011 and on October 14, 2011, the Commission issued an Order directing BHE to enter into long-term contracts for energy with three Community-Based Renewable Energy Projects: Jonesport Wind, LLC, a 4.8 MW wind facility to be constructed in Jonesport, Maine; Lubec Wind, LLC, a 4.8 MW wind facility to be constructed in Lubec, Maine; and Pisgah Mountain, LLC, a 9 MW wind facility to be constructed in Clifton, Maine. *Maine Public Utilities Commission*, Docket No. 2011-150, Request for Proposals for Community-Based Renewable Energy Projects, Order Approving Long-Term Contracts (October 14, 2011).

On March 21, 2013, the Commission issued a second Request for Proposals for Community-Based Renewable Energy Projects. Bids were due on April 5, 2013. On May 28, 2013, the Commission directed BHE to enter into contracts with the re-sized 9.6 MW Jonesport Wind project and with a planned 2 MW expansion of the EAE anaerobic digester project. *Maine Public Utilities Commission*, Docket No. 2013-207, Request for Proposals for Community-Based Renewable Energy Projects (2013 Issuance), Order Approving Long-Term Contracts (May 28, 2013). Two additional proposals were received in response to this RFP, a proposal from Maine Woods Pellet for a 7.1 MW wood fired biomass cogeneration system located in Athens, Maine, and a proposal for a 10 MW wind generator located in Fort Fairfield, Maine from Shamrock Partners, LLC.

III. DISCUSSION AND DECISION

At the outset, we note that the Legislature, in establishing the Community-Based Renewable Energy Pilot Program, has established the objective of encouraging the sustainable development of community-based renewable energy projects up to the 50 MW overall capacity limit statewide by the time the pilot program ends on December 31, 2015. Our role in administering the pilot program is to ensure that the projects meet the standards for program participation established by the Legislature, and to ensure that in any contract entered into: 1) the average price per kilowatt-hour does not exceed 10 cents, and 2) the cost of the contract does not exceed the cost of the project plus a reasonable rate of return on investment as determined by the Commission.

Both of the projects have submitted bids that comply with the requirement that the price per kilowatt-hour may not exceed 10 cents. Maine Woods Pellet bid a fixed price for a 20-year term of 9.9 cents per kilowatt-hour. Shamrock Partners provided two alternative structures: a bid for the entire output of the 10 MW project for a 20-year term at a fixed price of 9.5 cents per kilowatt-hour, or a bid for the output of 4 MW of the project for a 20-year term at a fixed price of 9.9 cents per kilowatt-hour. Each of the bidders submitted complete project financial information and return calculations that were analyzed by Staff. The indicated rates of return are within a range that is reasonable for stand-alone project developments and indicate that the developers are not receiving a "windfall" return from the projects.

We continue to be sensitive to the potential burden that the Community-Based contracts may place on ratepayers. Chapter 325 § 3.D.3 contains utility service territory limitations on the total installed generating capacity for projects that has the effect of allocating the above-market costs proportionately among the T&D utilities. Specifically, the limit for the MPS service territory is 4 MW. Although we recognize the intermittent nature of a wind generator, the burden on MPS ratepayers that would be created by a 10 MW contract would be disproportionately large.

Accordingly,

- We direct CMP to enter into a long-term contract with Maine Woods Pellet, for energy only, for 20 years to begin at the commercial operation date of the project, at a fixed price throughout the term of 9.9 cents per kWh.

- We direct MPS to enter into a long-term contract with Shamrock Partners, LLC, for energy only, for 20 years to begin at the commercial operation date of the project, at a fixed price throughout the term of 9.9 cents per kWh for 4 MW of the output of the facility.

We delegate to the Director of Electric and Gas Utility Industries the authority to approve proposed modifications to the terms and conditions of the standard form contract for the Community-Based Renewable Energy Pilot Program.

Consistent with provisions in statute and the rule, 35-A M.R.S.A. § 3604 (8) and Ch. 325, § 6, the Commission will allow CMP and MPS to recover in rates all costs of the contracts entered into, including but not limited to any effects on the utilities' cost of capital.

Dated at Hallowell, Maine, this 27th day of August, 2013.

BY ORDER OF THE COMMISSION

/s/ Harry Lanphear
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Littell
Vannoy

NOTICE OF RIGHTS TO REVIEW OR APPEAL

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1. Reconsideration of the Commission's Order may be requested under Section 1004 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.A. § 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.A. § 1320(5).

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STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2013-00207

May 28, 2013

MAINE PUBLIC UTILITIES COMMISSION
Request for Proposals for Community-Based Renewable Energy Projects (2013 Issuance)

ORDER APPROVING LONG-TERM CONTRACTS

WELCH, Chairman; LITTELL and VANNOY, Commissioners

I. SUMMARY

Pursuant to 35-A M.R.S.A. § 3604, we direct Bangor Hydro Electric Company (BHE) to enter into long-term contracts for energy with two Community-Based Renewable Energy Projects: Jonesport Wind, LLC, a 9.6 MW wind facility to be constructed in Jonesport, Maine and the 2 MW expansion of the Exeter Agri-Energy, LLC (EAE) anaerobic digester to be constructed in Exeter, Maine.

II. BACKGROUND

During the 2009 session, the Legislature enacted An Act To Establish the Community-based Renewable Energy Pilot Program (Act), P.L. 2009, ch. 329. Part A of the Act establishes a community-based renewable energy pilot program, to be administered by the Commission, to encourage the sustainable development of community-based renewable energy. The Act provides incentives, on a pilot program basis, for the development of community-based renewable projects that qualify for participation in the program. The projects must generate electricity from an eligible renewable resource, which includes fuel cells; tidal power; solar, wind and geothermal installations; hydroelectric generators; generators fueled by landfill gas; and biomass generators whose fuel includes anaerobic digestion of agricultural products, byproducts or wastes. These projects must be "locally owned electricity generating facilities," which means that 51% or more of the facility must be owned by "qualifying local owners." An individual project must not exceed 10 MW and the total installed generating capacity of all program participants in the pilot program combined may not exceed 50 MW. The pilot program is repealed on December 31, 2015. 35-A M.R.S.. §§ 3601-3609.

The incentive mechanisms provided by the Act are either: 1) a long-term contract for the output of the facility with a transmission and distribution (T&D) utility; or 2) a renewable energy credit (REC) multiplier in which the value of the REC is 150% of the amount of the produced electricity. Projects electing the REC multiplier are responsible for negotiating their own transactions for energy, capacity or RECs. Certified projects of less than 1 MW that elect a long-term contract can complete a standard form contract with the T&D utility at a price per kWh that has been established by the Commission. For certified projects with generating capacity of 1 MW and larger, the Act provides that the Commission shall periodically conduct a competitive solicitation to select projects that will be awarded a long-term contract with the T&D utility. On April 28, 2011, the Commission issued a Request for Proposals for Community -Based Renewable Energy Projects of 1 MW or larger. Bids were due on May 31, 2011 and on October 14, 2011, the Commission issued an Order directing BHE to enter into long-term contracts for energy with three Community-Based Renewable Energy Projects: Jonesport Wind, LLC, a 4.8 MW wind facility to be constructed in Jonesport, Maine; Lubec Wind, LLC, a 4.8 MW wind facility to be constructed in Lubec, Maine; and Pisgah Mountain, LLC, a 9 MW wind facility to be constructed in Clifton, Maine. *Maine Public Utilities Commission*, Docket No. 2011-150, Request for Proposals for Community-Based Renewable Energy Projects, Order Approving Long-Term Contracts (October 14, 2011).

On March 21, 2013, the Commission issued a second Request for Proposals for Community-Based Renewable Energy Projects. Bids were due on April 5, 2013. Among the bids received were a proposal to combine the previously approved long-term contracts for Jonesport Wind and Lubec Wind into one contract for an expanded Jonesport Wind project and a proposal for a long-term contract for a planned 2MW expansion of the EAE anaerobic digester project.

III. DISCUSSION AND DECISION

At the outset, we note that the Legislature, in establishing the Community-Based Renewable Energy Pilot Program, has indicated the objective of encouraging the sustainable development of community-based renewable energy projects up to the 50 MW overall capacity limit statewide by the time the pilot program ends on December 31, 2015. Our role in administering the pilot program is to ensure that the projects meet the standards for program participation established by the Legislature, and to ensure that in any contract entered into: 1) the average price per kilowatt-hour does not exceed 10 cents, and 2) the cost of the contract does not exceed the cost of the project plus a reasonable rate of return on investment as determined by the Commission.

Both of the projects have submitted bids that comply with the requirement that the price per kilowatt-hour may not exceed 10 cents. Jonesport bid a fixed price for a 20-year term of 8.5 cents per kilowatt-hour and expressly relinquished the rights of Lubec Wind with respect to both the certification as a Community-Based Renewable Energy Project and our prior award of a long-term contract. EAE has proposed a structure in which the contract for the existing .98 MW project will remain in effect at \$0.10 per kilowatt-hour and the output from the planned 2 MW expansion will be at a fixed price of \$0.085 per kilowatt-hour for a 20 year term beginning on the commercial operations date of the expansion. Each of the bidders submitted complete project financial information and return calculations that were analyzed by Staff. The indicated rates of return are within a range that is reasonable for stand-alone project developments and indicate that the developers are not receiving a "windfall" return from the projects.

We continue to be sensitive to the potential burden that the Community-Based contracts may place on BHE ratepayers. In approving this contract with the larger

Jonesport Wind project, there is no incremental burden created for ratepayers since the proposal specifically provides that the previously granted certification and approved long-term contract for the Lubec Wind project are relinquished by the developer. With the 2 MW expansion of the EAE project, the total installed capacity certified for the Community-Based Renewable Projects in the BHE service territory is 21.58 MW and the total installed capacity subject to long-term contracts is 21.58 MW. Although we assess the additional burden to ratepayers of approving the proposed EAE contract as relatively modest, we note that the overall ratepayer burden associated with the Community-Based Renewable Energy Pilot Program long-term contracts is being borne exclusively by BHE ratepayers and we may be reluctant to approve additional certifications or contracts in the BHE service territory in the future.

Accordingly, we direct BHE to enter into the following long-term contracts:

- Jonesport Wind, LLC, for energy only, for 20 years to begin at the commercial operation date of the project, at a fixed price throughout the term of 8.5 cents per kWh.

- Exeter Agri-Energy, LLC, for the energy produced by the planned 2 MW expansion, for 20 years to begin at the commercial operation date of the project, at a fixed price throughout the term of 8.5 cents per kWh.

The Lubec Wind, LLC contract award and certification is, hereby rescinded...

We delegate to the Director of Electric and Gas Utility Industries the authority to approve proposed modifications to the terms and conditions of the standard form contract for the Community-Based Renewable Energy Pilot Program.

Consistent with provisions in statute and the rule, 35-A M.R.S.A. § 3604 (8) and Ch. 325, § 6, the Commission will allow BHE to recover in rates all costs of the contracts entered into, including but not limited to any effects on BHE's costs of capital.

Dated at Hallowell, Maine, this 28th day of May, 2013.

BY ORDER OF THE COMMISSION

/s/ Harry Lanphear
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Littell
Vannoy

NOTICE OF RIGHTS TO REVIEW OR APPEAL

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1. Reconsideration of the Commission's Order may be requested under Section 1004 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.A. § 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.A. § 1320(5).

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STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2011-150

October 14, 2011

MAINE PUBLIC UTILITIES COMMISSION
Request for Proposals for Community-Based Renewable Energy Projects

ORDER APPROVING LONG-TERM CONTRACTS

WELCH, Chairman; VAFIADES and LITTELL, Commissioners

I. SUMMARY

Pursuant to 35-A M.R.S.A. § 3604, we direct Bangor Hydro Electric Company (BHE) to enter into long-term contracts for energy with three Community-Based Renewable Energy Projects: Jonesport Wind, LLC, a 4.8 MW wind facility to be constructed in Jonesport, Maine; Lubec Wind, LLC, a 4.8 MW wind facility to be constructed in Lubec, Maine; and Pisgah Mountain, LLC, a 9 MW wind facility to be constructed in Clifton, Maine.

II. BACKGROUND

During the 2009 session, the Legislature enacted An Act To Establish the Community-based Renewable Energy Pilot Program (Act), P.L. 2009, ch. 329. Part A of the Act establishes a community-based renewable energy pilot program, to be administered by the Commission, to encourage the sustainable development of community-based renewable energy. The Act provides incentives, on a pilot program basis, for the development of community-based renewable projects that qualify for participation in the program. The projects must generate electricity from an eligible renewable resource, which includes fuel cells; tidal power; solar, wind and geothermal installations; hydroelectric generators; generators fueled by landfill gas; and biomass generators whose fuel includes anaerobic digestion of agricultural products, byproducts or wastes. These projects must be "locally owned electricity generating facilities," which means that 51% or more of the facility must be owned by "qualifying local owners." An individual project must not exceed 10 MW and the total installed generating capacity of all program participants in the pilot program combined may not exceed 50 MW. The pilot program is repealed on December 31, 2015. 35-A M.R.S.A. §§ 3601-3609.

The incentive mechanisms provided by the Act are either: 1) a long-term contract for the output of the facility with a transmission and distribution (T&D) utility; or 2) a renewable energy credit (REC) multiplier in which the value of the REC is 150% of the amount of the produced electricity. Projects electing the REC multiplier are responsible for negotiating their own transactions for energy, capacity or RECs. Certified projects of less than 1 MW that elect a long-term contract can complete a standard form contract with the T&D utility at a price per kWh that has been established by the Commission. For certified projects with generating capacity of 1 MW and larger, the Act provides that the Commission shall periodically conduct a competitive solicitation to select projects that will be awarded a long-term contract with the T&D utility.

On January 27, 2010, the Commission adopted a rule implementing the community-based renewable energy pilot program. *Maine Public Utilities Commission Community-Based Renewable Energy Pilot Program (Chapter 325)*, Docket No. 2009-363, Order Adopting Rule and Statement of Factual and Policy Basis (January 27, 2010). On March 8, 2011, the Commission approved the standard form contract for the Community-Based Renewable Energy Pilot Program. *Order Approving Community-Based Renewable Pilot Program Standard Contract*, Docket No. 2010-118 (March 8, 2011). On April 28, 2011, the Commission issued a Request for Proposals for Community -Based Renewable Energy Projects. The RFP required the bidders to include:

- Project description
- the proposed pricing terms;
- indicative customer prices on a cents per-kilowatt-hour basis, not to exceed 10 cents per kilowatt;
- full project cost disclosure;
- expected revenue sources in addition to the long-term contract;
- Commission order certifying the project as a community-based renewable energy project pursuant to Section 4 of Chapter 325 (if certified) or petition for certification.

Bids were due on May 31, 2011 and were received from the following three bidders:

- Jonesport Wind ("Jonesport"), a 4.8 MW wind project[1];
- Lubec Wind ("Lubec"), a 4.8 MW wind project[2].; and
- Pisgah Mountain, LLC ("Pisgah"), a 9.0 MW wind project[3].

Staff discussed pricing and structuring terms with the bidders throughout the summer and bidders were asked to submit a best and final pricing offer. It is those best and final offers we consider here.

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[1] See *Jonesport Wind Power, LLC*, Docket No. 2011-50, Request for Certification of a Community-Based Renewable Energy Project, Order Approving Certification (March 1, 2011).

[2] See *Kean Energy, LLC, Lubec Wind Power, LLC*, Docket No. 2011-178, Request for Certification of a Community-Based Renewable Energy Project, Order Approving Certification (March 22, 2011).

[3] See *Pisgah Mountain, LLC*, Docket No. 2011-154, Request for Certification of a Community-Based Renewable Energy Project, Order Approving Certification (September 14, 2011).

III. DISCUSSION AND DECISION

At the outset, we note that the Legislature, in establishing the Community-Based Renewable Energy Pilot Program, has indicated the objective of encouraging the sustainable development of community-based renewable energy projects up to the 50 MW overall capacity limit statewide by the time the pilot program ends on December 31, 2015. In response to the Request for Proposals, the Commission received proposals from bidders for projects totaling 18.6 MW in installed capacity. When these proposed wind projects are combined with the two other community-based projects that are already program participants, the total capacity of all pilot program participants is slightly over 24 MW[4]. Our role in administering the pilot program is to ensure that the projects meet the standards for program participation established by the Legislature and, to ensure that in any contract entered into: 1) the average price per kilowatt-hour does not exceed 10 cents, and 2) the cost of the contract does not exceed the cost of the project plus a reasonable rate of return on investment as determined by the Commission.

All three of the projects have submitted bids that comply with the requirement that the price per kilowatt-hour may not exceed 10 cents. Lubec and Jonesport bid a fixed price for a 20-year term of 8.5 cents per kilowatt-hour. Pisgah bid a fixed price for a 20-year term of 9.3 cents per kilowatt-hour. In addition, each of the bidders submitted complete project financial information and return calculations that were analyzed by Staff. The indicated rates of return are within a range that is reasonable for stand-alone project developments and indicate that the developers are not receiving a "windfall" return from the projects.

We are sensitive to the potential burden that these contracts may place on BHE ratepayers.[5] The proposed contract prices are above current wholesale market prices

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[4] *Exeter Agri-Energy, LLC (fka Stonyvale, Inc.)* Docket No. 2010-141, Request for Certification of a Community-Based Renewable Energy Project, Order Approving Certification (November 23, 2010) and *Fox Islands Wind, LLC,* Docket No. 2010-65, Request for Certification of a Community-Based Renewable Energy Project, Order Approving Certification (April 14, 2010).

[5] By approving all three proposals, the total MW for the Community-Based Renewable Projects in BHE territory will exceed the total anticipated in the Commission's rules. Chapter 325, § 3(D)(2). As indicated in those rules, however, the Commission may modify those "shares" based on program experience. Chapter 325, § 3(D). *Pisgah Mountain, LLC*, Docket No. 2011-144, Request for Reallocation of Utility Territory Specific Capacity Limits for Community-Based Renewable Energy Pilot Program, Order (October 3, 2011). In light of the paucity of proposals to this point, and the relatively modest burden imposed by the proposals we accept today, we will allow all these projects to go forward in BHE territory. While we will take into account the extent of projects now approved for BHE in any future consideration of projects proposed for BHE or other utilities' territories, we reach no conclusion today on any "reallocation" of the shares contemplated by the rule.

for electricity and the difference between contract prices and the price at which BHE will be able to sell the electricity into the wholesale market will be borne by BHE ratepayers. We note, however, that these projects are relatively small wind projects with projected capacity factors below the capacity factors of other potential renewable energy projects such as biomass. Although the incentive rate per kilowatt-hour permitted as part of the community-based pilot program exceeds current wholesale prices, the lower capacity factor associated with wind projects serves to mitigate the overall economic impact in the BHE service territory when compared to alternative community-based renewable project development.

Accordingly, we direct BHE to enter into the following long-term contracts:

- Jonesport Wind, LLC, for energy only, for 20 years to begin at the commercial operation date of the project, at a fixed price throughout the term of 8.5 cents per kWh.

- Lubec Wind, LLC, for energy only, for 20 years to begin at the commercial operation date of the project, at a fixed price throughout the term of 8.5 cents per kWh; and

- Pisgah Mountain, LLC, for energy only, for 20 years to begin at the commercial operation date of the project, at a fixed price throughout the term of 9.3 cents per kWh.

We delegate to the Director of Electric and Gas Utility Industries the authority to approve proposed modifications to the terms and conditions of the standard form contract for the Community-Based Renewable Energy Pilot Program.

Consistent with provisions in statute and the rule, 35-A M.R.S.A. § 3604 (8) and Ch. 325, § 6, the Commission will allow BHE to recover in rates all costs of the contracts entered into, including but not limited to any effects on BHE's costs of capital.

Dated at Hallowell, Maine, this 14th day of October 2011.

BY ORDER OF THE COMMISSION

Karen Geraghty
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Littell

LIMITED DISSENT: Vafiades

Dissent of Commissioner Vafiades in Docket 2011-150, Request for Proposal for Community-Based Renewable Energy Projects, Consideration of Bids

I respectfully dissent on the limited issue of the acceptance of the Pisgah Mountain project's bid proposal.

The overall purpose of the community-based renewable energy pilot program is to encourage sustainable development of community-based renewable energy in the State. The three project bidders have been certified as meeting the statutory requirements to qualify for the pilot program and have elected to enter into a long term contract for energy as a program incentive. The Commission initiated a competitive solicitation process for long term contracts for these community-based renewable energy projects as provided by Title 35-A Section 3604. The statute requires that the contracts may not be for more than 20 years, the annual average kWh price does not exceed 10 cents and the overall cost of the project does not exceed the project cost plus a reasonable rate of return on investment. The statute anticipates that the process will be competitive and that the Commission will negotiate with program participants regarding the contract terms including assuring that such contracts are commercially reasonable. In addition the Commission is directed to select program participants that are competitive and lowest price when compared to comparable bids. (35-A section 3604, sub 6)

All the proposals received by the Commission in May of this year were for wind projects with contract terms of 20 years and all bid prices were under 10 cents. These are small projects and the energy bids are above market rates as anticipated by the terms of the pilot project enabling legislation. The project bid price received from Pisgah Mountain was greater than the other two bidders. Based on statutory guidance and Commission discretion to engage in negotiations, I would have rejected the Pisgah bid and directed the staff to negotiate with the project for a lesser price.

I agree with my fellow Commissioners that the Commission has discretion in accepting terms for long term contracts but with the additional statutory guidance provided for this pilot program, I would have rejected the Pisgah contract bid. I respectfully dissent on this limited issue.

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 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 1004 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.

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.A. § 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.A. § 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.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2010-235

February 19, 2014

MAINE PUBLIC UTILITIES COMMISSON
Ocean Energy
Long-Term Contracting

ORDER APPROVING TERM SHEET (PART TWO)

WELCH, Chairman; LITTELL and VANNOY, Commissioners

I. SUMMARY

Through this Order Part Two, we provide further detail concerning on our approval of the term sheet for a Long-Term Contract for the capacity and associated energy of the Maine Aqua Ventus Project (the Project) with Maine Aqua Ventus I GP LLC (MAV) dated December 4, 2013 as contained in the Order Approving Term Sheet Part One, dated February 13, 2014.[1]

II. BACKGROUND

A. Ocean Energy Act

During its 2010 session, the Maine Legislature enacted An Act To Implement the Recommendations of the Governor's Ocean Energy Task Force (Ocean Energy Act). P.L. 2009, ch. 615. Section A-6 of the Ocean Energy Act directed the Maine Public Utilities Commission (Commission), in accordance with Title 35-A, section 3210-C of the Maine Revised Statutes, to conduct a competitive solicitation for proposals for long-term contracts to supply installed capacity, associated renewable energy and renewable energy credits (RECs) from one or more deep-water offshore wind energy pilot projects or tidal energy demonstration projects.

As specified in the Ocean Energy Act, the Commission may authorize one or more long-term contracts for an aggregate total of no more than 30 megawatts of installed capacity and associated renewable energy or RECs from deep-water offshore wind energy pilot projects or tidal energy demonstration projects as long as no more than 5 megawatts of the total is supplied by tidal energy demonstration projects. The Ocean Energy Act specified a "deep-water offshore wind energy pilot project" as a wind energy development, as defined by Title 35-A, section 3451, subsection 11, that is connected to the electrical transmission system located in the State and employs one or more floating wind energy turbines in the Gulf of Maine at a location 300 feet or greater in depth and no less than 10 nautical miles from any land area of the State other than

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[1] Commissioner Vannoy dissents in this decision.

coastal wetlands, as defined by Title 38, section 480B, subsection 2, or an uninhabited island.

Specifically, the Ocean Energy Act states that the Commission may direct one or more transmission and distribution (T&D) utilities, as appropriate, to enter into a long-term contract pursuant to a request for proposals (RFP) only if it determines that the bidder:

A. Proposes sale of renewable energy produced by a deep-water offshore wind energy pilot project or a tidal energy demonstration project as defined in the RFP;

B. Has the technical and financial capacity to develop, construct, operate and, to the extent consistent with applicable federal law, decommission and remove the project in the manner provided by Title 38, section 480HH, subsection 3, paragraph G;

C. Has quantified the tangible economic benefits of the project to the State, including those regarding goods and services to be purchased and use of local suppliers, contractors and other professionals, during the proposed term of the contract;

D. Has experience relevant to tidal power or the offshore wind energy industry, as applicable, including, in the case of a deep-water offshore wind energy pilot project proposal, experience relevant to the construction and operation of floating wind turbines, and has the potential to construct a deep-water offshore wind energy project 100 megawatts or greater in capacity in the future to provide electric consumers in Maine with project-generated power at reduced rates;

E. Has demonstrated a commitment to invest in manufacturing facilities in Maine that are related to deep-water offshore wind energy or tidal energy, as applicable, including, but not limited to, component, turbine, blade, foundation or maintenance facilities; and

F. Has taken advantage of all federal support for the project, including subsidies, tax incentives and grants, and incorporated those resources into its bid price.

Additionally, the Act provided that long-term contracts authorized pursuant to the RFP could not, in the aggregate, result in increased electric rates for any customer class that is greater than the amount of the assessment charged under Title 35-A, section 10110, subsection 4 at the time that the contract is entered into. *P.L. 2009*, ch. 615. § A-6. Based on the prior version of the law, the Commission concluded that the Legislature intended that customers that take service at transmission and subtransmission voltage would not have a rate impact resulting from any ocean energy long-term contracts. *Order on Rate Impact Limitation*, Docket No. 2010-235, (September 28, 2010).

As required by the Ocean Energy Act, the Commission initiated an initial competitive solicitation by issuing a Request for Proposals for Long-Term Contracts for Deep-Water Offshore Wind Energy Pilot Projects and Tidal Energy Demonstration Projects (2010 RFP) on September 1, 2010. Responses to this RFP were received on May 2, 2011. Commission Staff performed an initial review of all proposals received, prioritized proposals and conducted in-depth discussions with several bidders. Projects were evaluated based on cost considerations, overall project viability, including financial, environmental and other site approvals, construction schedule, operational characteristics and the evaluation criteria as required in the Ocean Energy Act. The Commission authorized long-term contracts with Ocean Renewable Power Company (ORPC) and Statoil North America Inc. (Statoil) for the Hywind Maine Project through Orders dated April 27, 2012 and February 26, 2013 respectively.[2]

During its 2013 session, the Maine Legislature enacted An Act To Provide for Economic Development with Offshore Wind Power, P.L. 2013, ch. 378. that supplemented and amended the Ocean Energy Act (Supplemental Act). The Supplemental Act made several changes to the long-term contracting process as outlined in the Ocean Energy Act. First, the Supplemental Act called for the Commission to conduct a second competitive solicitation of proposals under the Ocean Energy Act with proposals due no later than September 1, 2013. Second, the Supplemental Act expanded the definition of "deep-water offshore wind energy pilot project" to include offshore wind projects located within the University of Maine Offshore Wind Test Site off the southern coast of Monhegan Island (UMaine Test Site). *P.L. 2013* ch. 378, § 4.

Third, Supplemental Act amended the rate impact limitation language to state that the impact on any customer class could be no greater than $1.45 per MWh, removing the statutory reference to section 10110. The Commission issued a request for comments on October 10, 2013 concerning the impact of this amendment on how the rate impact should be calculated under the amended law and whether the costs of the contracts under the Ocean Energy Act should be allocated to all customer classes. *P.L. 2013* ch. 378, § 5.

As instructed by the Supplemental Act, the Commission issued an additional RFP on July 9, 2013 requiring proposals to be submitted by August 30,

[2] ORPC's Cobscook Bay Tidal Energy Project began operation in September of 2012 and the long-term contract with Bangor Hydro Electric Co. was approved by the Commission on December 21, 2012. *Order Approving Contract*, Docket No. 2010-235 (December 21, 2012). On October 28, 2013, while in the process of negotiating the language of its long-term contract, Statoil filed a letter with the Commission stating it had decided to close down the Hywind Maine Project and withdraw its proposal for a long-term contract from the Commission.

2013. MAV's submission was the only proposal received by the Commission. After discussions with Commission Staff, MAV submitted a proposed term sheet on December 4, 2013 containing the essential terms of a long-term power purchase agreement for a 12 MW offshore wind pilot project located in the UMaine Test Site (Proposed Term Sheet). The Commission issued a request for comments on the Proposed Term Sheet and received over 200 submissions between December 4 and December 20, 2013. MAV submitted responses to comments on December 31, 2013.

B. Project Proposal

The Project comprises two floating wind turbines with a total nameplate capacity of 12 MW, located in state waters in the Gulf of Maine at a location 2.5 miles off the southern coast of Monhegan Island's Lobster Cove and 12 miles off the coast of the mainland. The transmission interconnection is presently contemplated to occur in the Pemaquid Point region at the CMP substation in Bristol, Maine.

The Project is to be located in the designated UMaine Test Site, which measures approximately 2.1 miles by 1.1 miles with water depths ranging from approximately 210 to 350 feet. This site was selected by the State of Maine in 2009 to be one of three priority locations for testing offshore wind technology. Consistent with the Project's location in a designated offshore wind testing site, it will be eligible for an expedited 60 day DEP review.

As stated by MAV, "the goal of these pilot projects is to demonstrate the technological feasibility of these technologies at full grid-scale, and to help optimize the technologies in preparation for commercial-scale projects. Commercial development will only follow successful pilot demonstration. Commercially competitive project financing for grid-scale development will only follow successful full-scale technology demonstration".[3] The Project "offers Maine the opportunity to invest in and benefit substantially from the development of transformative technology capable of significantly reducing the cost of electricity provided by offshore wind, creating Maine jobs, and simultaneously making a long term commitment to reducing both society's carbon dioxide emissions and our reliance on fossil fuels."[4] Fundamentally, this Project intends to establish Maine as a worldwide leader in the offshore wind industry through the deployment of the first commercial-scale floating wind turbine technology in North America. As part of this goal, the final long-term contract executed by CMP and MAV (Contract) will provide that all ocean energy test and pilot demonstration results will be provided to, and retained by, the University of Maine (UMaine) for the benefit of the State of Maine.

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[3] MAV, *Business Case for a Pilot 12 MW Deepwater Offshore Wind Farm in the Gulf of Maine,* November 20, 2013.

[4] MAV, *Offshore Wind Proposal*, August 30, 2013 at 3-4.

III. TERM SHEET

The Proposed Term Sheet was the result of several months of discussions between MAV and Commission Staff to structure the Contract for the Project. The essential components of the Proposed Term Sheet are as follows:

1. Contracting Parties. The proposed contract would be between MAV and Central Maine Power Company (CMP).

2. Term. The proposed contract term is twenty (20) years from the Project's commercial operations date, which is expected to occur in 2017.

3. Products and Quantities. The contract products to be purchased and sold under the Contract are the entire quantity of energy generated by the Project and delivered to the delivery point (Energy) and the Project's electrical capacity (Capacity) (collectively, the Contract Products). The Energy purchased and sold under the Contract must be produced by the Project and delivered to the ISO-NE energy market. Renewable Energy Credits (RECs) are to be retained by MAV.

4. Pricing. The contract price shall apply to all energy produced by the Project up to the annual energy cap of 43,099 MWh. The Contract price for all energy produced up to the cap is $230/MWh for energy provided during the initial contract year. The contract price in each subsequent contract year will increase by 2.25% percent of the prior year's contract price. The price for energy produced by the Project in excess of the energy cap shall be the applicable hourly Day-Ahead or Real-Time Locational Marginal Price in the ISO-NE wholesale energy market.

5. Grant Sharing. MAV will retain all grant proceeds from the DOE Wind and Water Program's Advanced Technology Demonstration Program under FOA-DE-FOA-41 0 (DOE Solicitation) and any other grants and/or subsidies, for example, any investment tax credit (ITC), identified in the Project's final financing plan to be submitted before the execution of the Contract. For all subsequent grants and subsidies the contract price will be reduced by an amount equal to 50% of the net grant proceeds realized. If however, the ITC is not extended and MAV is unable to obtain eligibility under the current safe harbor provision, the Project will be able to retain 100% of all subsequent grants necessary to offset the loss of the economic benefits to MAV associated with the ITC.

6. Economic Development Commitments. MAV commits to use commercially reasonable efforts to:
   a. Contract with Maine-based entities for the majority (greater than 50%) of the total capital expenditures of the project.

b. Require that the majority (greater than 50%) of contract expenditures for construction period activities be performed by Maine-based entities.
c. Contract with Maine-based entities for not less than 50% of operations and maintenance (O & M) related expenditures.
d. Provide electric energy to the Monhegan Plantation Power District for the entire duration of the Contract term or provide benefits in an alternative form that are acceptable to MAV and approved by the Commission.
e. Pay for and install a fiber optic cable to Monhegan.
f. Develop and implement a program in collaboration with the University of Maine to attract K-12 students to science, engineering and business programs as well as a similar program in collaboration with Maine Maritime Academy and the community college system geared toward college students.
g. Implement a workforce training program.
h. Institute contractor and supply chain preferences for Maine-based entities.
i. Continue use of Maine-based entities for environmental and metocean studies, including issuing contracts to the University of Maine for project related research and development and testing programs of not less than $7 MM.
j. Adopt the same preference for Maine-based entities in the development of a large 100-500 MW wind farm to be located in the Gulf of Maine.

7. Payment for Non-performance of Economic Development Commitments. If, after notice and an opportunity for hearing, the Commission determines that MAV has failed to comply with one or more of its economic development obligations, the Commission may assess a reasonable penalty, the amount of which is within the Commission's sole discretion, provided that penalties assessed by the Commission shall not exceed 7% of the revenue from energy payments in any given year.

8. Commission Termination Provisions. At a time determined by MAV but before the commencement of construction of the Project, MAV shall submit a report outlining the status of and likelihood of successful compliance with the economic development commitments. As evidence and support of MAV's statements on the status and likelihood of successful compliance, MAV shall include with the report evidence of commitments that it will meet its obligation including but not limited to executed contracts, financial letters of commitment, and/or affidavits that demonstrate the likelihood of compliance. If, after notice and hearing, the Commission determines that MAV has not demonstrated that it is likely to achieve its obligation, the Commission may either a) declare the Contract terminated, and MAV and CMP shall have no further obligations to one another under the Contract; or b) if requested by MAV, grant an extension of time for MAV to demonstrate that it has or is likely to achieve the Local Benefit Obligations.

9. MAV Termination Provisions. MAV may terminate the contract:

a. If notwithstanding MAV's good faith efforts, MAV is unable to obtain all necessary State and Federal permits by January 1, 2016; or
b. If prior to January 1, 2016, the federal investment tax credit or any Department of Energy support which may have been awarded to MAV to develop the Project are materially adversely modified with respect to the Project or have not been extended to cover the full expected construction period of the Project; or
c. If the boards of directors of the MAV partners decide by January 1, 2016 for any reason not to go forward with the project.

IV. PUBLIC COMMENTS

The Commission received approximately 210 public comments regarding the Project. Comments in favor of the approval of the term sheet emphasized the unique opportunity this presented to the State of Maine, the economic impacts outlined by UMaine Professor Todd Gabe (Gabe Study) and opportunities for UMaine and the state's workforce in general. Comments opposed to the Project focused on the proximity of the Project to Monehgan Island and the associated potential for noise and visual impacts, impacts on migratory birds, scale of the turbines, impacts on lobstering, the schedule for the process and Monhegan as a unique and historic location in Maine and the world. There were comments both in favor of the provision of electricity to the island and those who felt the benefits of connecting the community did not outweigh the potential negative impacts on fishing and tourism.

The Commission received letters of support from Maine legislative leaders in both parties, the chairs of the Energy and Utilities Committee, the Governor's Energy Office (as well as former Director Ken Fletcher), Congressman Michaud and Senator Angus King in his private capacity, the Town of Old Town and the Chairs of the Ocean Energy Task Force. Many year round residents also submitted comments which ranged from supportive to opposed or simply raised concerns on impacts to quality of life, fishing and tourism. Several year round residents raised questions on the importance of giving Monehgan a voice in the process and a mechanism for assuring their interests were valued. Of year round residents, most expressed interest in the provision of electricity from the Project but also raised several concerns regarding costs and long term impacts on the community. The Town of Bristol's Wind Advisory Task Force submitted comments as well. Approximately 75 summer residents and visitors to the Monhegan submitted comments mostly in opposition to the Project as a whole and not raising specific issues within the Commission's purview or concerning the Proposed Term Sheet. Over two dozen students from the University of Maine system submitted comments, which were unanimously in favor. In addition, supportive comments were received from over 15 different business interests, the Northern Maine Community College system, Natural Resources Defense Council, the Ocean Energy Institute, Conservation Law Foundation, E2Tech, and the Maine Ocean and Wind Industry Initiative.

V. DISCUSSION

A. Statutory Criteria

We assess the proposed terms of a long-term contract as outlined in the Proposed Term Sheet in accordance with the requirements of the Ocean Energy Act and the Supplemental Act and as informed by the Final Report of the Ocean Energy Task Force.[5] In enacting the legislation, the Legislature recognized the public benefits that could accrue to the State by providing economic incentives to encourage the development of offshore wind, tidal and wave power energy resources. The Ocean Energy Act envisions these projects as technology demonstration projects that would: (i) provide direct economic benefits of research, testing, and development occurring in Maine; (ii) lay a foundation for Maine to be global leader in offshore wind and tidal technology development; and (iii) develop Maine's own indigenous natural resources. The economic incentives inherent in a long-term power purchase agreement are intended by the Ocean Energy Act to support the development of a limited number of technology demonstration projects by providing for above-market prices to be paid for electricity produced by such projects. The Ocean Energy Act limits the impact on ratepayers by limiting the overall impact on rates.

1. Supplier Requirements

Pursuant to the Ocean Energy Act, the Supplemental Act and as provided in the Commission's RFP, the Commission may order a long-term contract only if it determines that the potential supplier satisfies several specified criteria. The Project's compliance with each of these statutory criteria is analyzed below:

a. Supplier proposes sale of renewable energy produced by a deep-water offshore wind energy pilot project or a tidal energy demonstration project as defined in this RFP.

We find that the Project proposed is a deep-water offshore wind energy pilot project as defined by the Act as amended by the Supplemental Act. *P.L. 2013* ch.378 § 4. The Supplemental Act states that an offshore wind project located in the UMaine Test Site qualifies as a deep-water offshore wind energy pilot project. As discussed above, the Project as proposed will be located within the UMaine Test Site off the coast of Monhegan Island. We also find that it is a pilot project as it employs an innovative proprietary floating concrete base and composite tower design that is not commercially available and has the potential to be the first floating offshore wind farm in the United States.

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[5] Maine Ocean Energy Task Force, 2009. *Final Report of the Ocean Energy Task Force to Governor John E. Baldacci.* Available online at: http://www.maine.gov/spo/specialprojects/OETF/.

b. Supplier has the technical and financial capacity to develop, construct, operate and, to the extent consistent with applicable federal law, decommission and remove the project in the manner provided by Title 38, section 480HH, subsection 3, paragraph G.

We find that MAV has the technical and financial capacity to develop, construct, operate, and decommission and remove the Project. MAV is a partnership of three entities with a wealth of relevant technical experience that together represents a world class technical team. Cianbro Corporation (Cianbro) is an industry leading construction company with annual capital revenue generation of over $650 million and experience with over 50 major capital energy projects in the US. Of specific relevance, Cianbro has fabricated and deployed semi-submersible oil drilling vessels (including two 12,000 ton Amethyst drilling rigs), giving Cianbro experience in semi-submersible floating platform construction. Cianbro has additional experience with concrete construction from its work on the Penobscot Narrows Bridge. Further, Cianbro has aided construction of various land-based wind farms across northern New England, including the Fox Islands Wind Project (three 1.5 MW turbines located on Vinalhaven Island) and was recently selected to design and build the electrical services platform for the Cape Wind Project.

Emera Inc. (Emera), with $2.1 billion in revenue in 2012, has managed and developed both conventional and renewable energy projects including involvement and investment through subsidiaries in the deployment of complex hydrokinetic energy devices in the Bay of Fundy and is currently developing a 500 MW HVDC subsea transmission line connecting Newfoundland and Nova Scotia. Emera, the parent company of Emera Maine-Bangor Hydro District and Emera Maine-Maine Public Service District, has invested $500 million in transmission and distribution infrastructure in Maine and has partnered with wind developer First Wind on several on-shore wind projects in the state.

UMaine is recognized nationally as a leading research institution in wind power technologies. Resources include the Advanced Structures and Composites Center and the Offshore Wind Laboratory. The laboratory offers the longest structural testing floor in the US and a reinforced concrete test stand capable of testing wind blades, towers, and floating foundations up to 70 m in length. UMaine has deployed a 1/8th scale semi-submersible floating offshore wind prototype. In addition, UMaine has engaged in significant environmental and resource assessment activity on the project site for several years and has previous experience ocean energy siting and impact quantification as a partner in ORPC's Cobscook Bay Energy Project.

We also find that MAV has the financial capacity to develop, construct, and operate the Project. The Commission recognizes that the Project is at a different phase of its development lifecycle than the projects previously reviewed under the Ocean Energy Act and is proposed by a special purpose entity backed by three unaffiliated organizations. Although the three members of MAV have, to date, made only limited financial commitment to the venture, they have demonstrated significant commitment to the Project in terms of in-kind contributions and technical and analytical assistance. In addition, the Project is one of six projects currently under consideration for an award in the DOE Solicitation and a selection under that program will significantly contribute to the long-term economic viability of the Project. The commitment of the Governor's Energy Office to support the Project in securing additional state and federal funding also contributes to our finding of financial capacity. Accordingly, we find that the statutory standard for financial capacity has been met at this preliminary stage of the Project. We require, however, that MAV report to the Commission annually to provide an update on Project financing, with the first report due within thirty (30) days of the execution of the Contract. In light of the preliminary nature of MAV's capitalization and financial structure, these reports will enable the Commission to confirm that the Project is successful in the DOE Solicitation and in procuring the financial capacity for the construction, operation and decommissioning of the Project.

c. Supplier has quantified the tangible economic benefits of the project to the State, including those regarding goods and services to be purchased and use of local suppliers, contractors and other professionals, during the proposed term of the contract.

As described by MAV, the project would provide Maine jobs and benefit the Maine economy in both the short and long term. In the near term, the project would create direct jobs and stimulate economic activity though a "multiplier" effect. MAV has presented information in support of the proposed term sheet that attempts to quantify those near term benefits. In the longer term, the project would improve Maine's ability to compete with other companies, and with other regions, in constructing and locating large off-shore projects. Finally, there are likely additional benefits from the Project resulting in knowledge creation in the state.

As part of MAV's August 30, 2013 proposal, MAV commissioned the Gabe Study, which utilized the IMPLAN Model analysis tool, to quantify the Project's economic impact on the State of Maine. Professor Gabe estimated that the construction phase of the project would result in \$37.4 to \$51.9 million of output (341-475 construction jobs) and \$1.9 million / year in output over the 20 years of operations (14 jobs / year) in Maine. Staff estimates from these results the total economic benefit to Maine as \$107-\$143 million (NPV@7%) (\$150-\$194 million nominal). MAV has estimated that 59% of the total project expenditures would be in Maine.

Accordingly, we conclude that the Project has quantified the tangible economic benefits of the Project to the State.

d. Supplier has experience relevant to tidal power or the offshore wind energy industry, as applicable, including, in the case of a deep-water offshore wind energy pilot project proposal, experience relevant to the construction and operation of floating wind turbines, and has the potential to construct a deep-water offshore wind energy

<u>project 100 megawatts or greater in capacity in the future to provide electric consumers in Maine with project-generated power at reduced rates</u>.

We find that MAV has the experience relevant to floating wind turbines to construct and operate the Project. MAV, through its partners, especially UMaine, has developed expertise regarding the design, manufacture, and deployment of the VolturnUS project, a 1/8th scale demonstration project of the technology to be used for the Project. As the proponent states, "VolturnUS builds off a track record of R & D and testing experience with the offshore wind technology by UMaine as the principal member of the DeepCWind Consortium".[6]

MAV's Project partners also provide experience that covers much of what is required to develop, construct, and deploy a floating offshore wind farm, particularly one composed of a concrete floating base and a composite tower. Project partners have significant experience with complex infrastructure construction as well as maritime experience.[7]

We also find that MAV has the potential through economies of scale to construct a larger offshore wind project of greater than 100 MW at significantly lower cost per megawatt-hour relative to the pilot project that may provide consumers in Maine with project-generated power at reduced rates. Although there are significant risks and unknowns regarding the viability of the larger project, the Ocean Energy Act does not seek a guarantee that such a project will occur, only that the potential supplier has the relevant experience to construct such a project. Thus, considering the potential for significant technological improvements in the field of off shore wind resulting from the VolturnUS technology and the strength of the team, we find that MAV has the potential to construct a larger offshore project and meets the statutory threshold.

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[6] The DeepCwind Consortium is a UMaine led consortium includes universities, nonprofits, and utilities; a wide range of industry leaders in offshore design, offshore construction, and marine structures manufacturing; firms with "expertise in wind project siting, environmental analysis, environmental law, composites materials to assist in corrosion-resistant material design and selection, and energy investment; and industry organizations to assist with education and tech transfer activities." Available at: http://www.deepcwind.org/about-the-consortium/about-deepcwind-consortium.

[7] Cianbro has related experience working on project involving semi-submersible drilling rigs, undersea cables, on shore wind, bridge projects and was recently selected as a subcontractor for the Cape Wind Project. *See,* MAV Proposal (August 30, 2013) at Appendix ; *see also,* http://www.offshorewind.biz/2013/12/24/cianbro-subcontracted-for-cape-wind-project-usa/. Emera was been involved in complex experimental tidal energy project in the Bay of Fundy in 2009. Other partners listed in the Project's proposal have other significant relevant experience but their specific roles in the Project are not defined.

e. Supplier has demonstrated a commitment to invest in manufacturing facilities in Maine that are related to deep-water offshore wind energy or tidal energy, as applicable, including, but not limited to, component, turbine, blade, foundation or maintenance facilities.

We find that MAV has demonstrated a commitment to invest in manufacturing and other facilities in the State of Maine. MAV's substantial Maine presence and the track record of the MAV partners in the State provide sufficient commitment to investing in manufacturing facilities in Maine to meet the statutory criteria. The commitment is further outlined in the local benefit obligations in the Proposed Term Sheet and the termination rights provided to the Commission help ensure that the commitment will be met as intended. In addition, in its proposal dated August 30, 2013, MAV states its intention to develop an Integrated Manufacturing and Assembly Facility on the Maine coast to produce and launch the estimated 83 x six MW VolturnUS hulls, towers, and possibly additional components, needed for the 500 MW farm.[8] Finally, in its comment letter dated December 12, 2013, MAV's composite tower supplier, Ershigs Inc., states the following, "(it) is our plan to establish a large scale manufacturing facility in the state of Maine to build future towers for subsequent offshore floating wind farms that will be the end result of success with the (Project)."[9]

f. Supplier has taken advantage of all federal support for the project, including subsidies, tax incentives and grants, and incorporated those resources into its bid price.

MAV's proposal includes recognition of the $4 million DOE grant that has already been received and the expectation that it will receive an additional $46.7 million in the second round of DOE awards. The financing structure anticipates availability of the ITC. The Proposed Term Sheet includes the commitment to use commercially reasonable efforts to pursue and acquire additional State, Federal or other grant and subsidy opportunities and to apply 50% of any additional net proceeds to reducing the contract cost. MAV has reserved the right to retain grant proceeds to offset the loss of any ITC assumed in the structure.

Accordingly, MAV has sufficiently demonstrated that it has taken advantage of, and will continue to take advantage of, all available federal support for the Project, and has incorporated reasonably expected federal funding into its bid price.

2. Rate Impact Limitation

[8] *MAV Offshore Wind Proposal*, Docket 2010-235, (August 30, 2013) at 12-13.

[9] *Letter of Tom Pilcher, President Ershig Inc.*, Docket 2010-235 (December 12, 2013).

Under the prior Ocean Energy Act, the rate impact limitation was set with reference to Title 35-A, section 10110, subsection 4 as the base electricity system benefit charge (SBC). The SBC is charged only to customers taking service at distribution voltage, and cannot be charged to customers at sub-transmission and transmission voltages, i.e., the large industrial customers. Accordingly, the statutory rate impact cap for the combined impact of all long-term contracts entered into pursuant to the Ocean Energy Act was the SBC for distribution voltage customers and zero for sub-transmission and transmission voltage customers. *Order on Rate Impact Limitation Provision,* Docket 2010-235 (September 28, 2010).

The Supplemental Act amended the rate impact limitation applicable to long-term contracts approved under the Ocean Energy Act from the SBC to a flat $1.45 per MWh and removed the language referencing Title 35-A, section 10110, subsection 4. *P.L. 2009*, ch. 615. Section A-6. The plain language of the Supplemental Act is clear and load in all customer classes is included in the calculation of the amount of the rate cap, regardless of whether the customer takes service at the transmission or distribution level.[10] The Proposed Term Sheet, however, explicitly limits the calculation of the cap to retail sales to distribution customers of CMP[11], which would shift costs to residential and small business class ratepayers and exempt large ratepayers who take service directly at the transmission level. *Proposed Term Sheet* at 2. Current law supports an allocation across all rate classes.[12] The Term Sheet includes a provision for an internal tracking mechanism referred to as the Available Ratepayer Funds (ARF) Tracking Account that incorporates a methodology by which the ratepayer funds available under the rate impact limitation are tracked throughout the term of the Contract based on a maximum subsidy level as calculated using only the retail sales to distribution voltage customers.

Based on the projections and scenarios provided by Commission Staff, we find that the actual Project costs are reasonably likely to fall below the rate impact limitation, as the cap is defined in the Proposed Term Sheet. The calculation of available ratepayer funds employed by Commission Staff was based on estimated load for distribution voltage customers of CMP times the statutory cap of $1.45/MWh. In addition, the ARF Tracking Account provides for a true-up mechanism that will require MAV to essentially repay to ratepayers at the end of the term of the Contract any funds that may have been paid to MAV in excess of the rate impact cap. MAV will also be required to provide financial assurance throughout the term to secure their obligation to pay under the ARF Tracking Account methodology.

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[10] All three commissioners agree on this point.

[11] At deliberations, Chair Welch stated that there is no need to decide at this time the question of how to allocate the actual costs incurred under this Contract across rate classes, as the Project is not scheduled to come online until 2017.

[12] At deliberations, Commissioner Littell stated that the Commission should decide how to allocate the actual costs incurred under this Contract based on the current law for purposes of transparency and to provide clarity to ratepayers on how much each class would pay.

In analyzing whether the Proposed Term Sheet meets this requirement, Commission Staff considered various market price scenarios that reflected a range of assumptions about natural gas prices, carbon programs and compliance costs, and locational effects on the nodal LMP. Commission Staff assumed no ratepayer funding before 2016, when MAV is assumed to be in service. The Commission's conclusion, based on its analysis of net contract costs and available subsidy amounts over a range of market prices, is that the rate impact test is unlikely to be exceeded.

B. Economic Analysis

In approving of the Proposed Term Sheet, we also consider the likely economic benefits of the Project to the State. The Ocean Energy Act does not require that the economic benefits to Maine must equal or exceed the ratepayer costs, but gives the Commission discretion, to be exercised consistent with the articulated Legislative intent, to determine whether to direct Maine utilities to enter into a long-term contract once all statutory criteria are satisfied, and we consider the relationship of the net benefits of the contract to the costs as an important factor in making that decision.[13]

Based on the analysis described above, we estimate the present value (NPV) of the above-market costs of the MAV long-term contract to range from $49 million to $78 million[14] or $172 to $187 million nominally. The Project will involve investment of just over $167 million initially in 2013-2017 to build the Project and then just over $1.7 million annually in operations and maintenance expenses for 20 years.

The proposed 12 MW pilot project is conceived as an R&D project and a necessary stepping-stone to a larger project. The potential long-term economic development benefits to the State resulting from the development of a commercial scale offshore wind project in the Gulf of Maine are not easily quantified and depend on the emergence of a technologically and economically viable offshore wind industry. In its August 30, 2013 proposal, MAV identified a path from the pilot project to full commercialization which would include the development of a commercial-scale park of about 500 MW in the Gulf of Maine in the 2020-2024 time period. Professor Gabe estimates the park would cost $1.8 billion to plan and construct. MAV proposes to develop an integrated manufacturing and assembly facility on the Maine coast to produce 83 x six MW VolturnUS hulls and towers. It also will work with State and other Maine entities to attract a turbine manufacturer to Maine.

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[13] Because of the uncertainty inherent in this type of forward-looking analysis, Staff examined costs over various market price scenarios. With respect to assumptions about load, Staff's analysis reflects flat growth, which is consistent with the latest ISO-NE CELT load forecast for Maine.

[14] Staff calculated a range of present values based on four different scenarios of future energy prices using discount rates of 10% and 7%; $49 to $78 million represented the range across the future scenarios and discount rates.

In the Proposed Term Sheet, MAV specifically commits to using commercially reasonable efforts to: 1) locate the Project in the Gulf of Maine; 2) develop an integrated manufacturing and assembly facility within Maine; 3) issue 50% of all contracts to Maine-based entities; 4) work with the State of Maine and other Maine-based Entities to attract a turbine manufacturer to Maine; and 5) issue contracts for operations and maintenance which maximizes the participation of Maine-based entities.

The commitments in the Proposed Term Sheet that require MAV to develop Maine-based contractors and supply chain and to collaborate with the UMaine ensure that a significant portion of the knowledge creation benefits from the development of the Project will accrue in Maine. The participation of UMaine is especially relevant as it provides further assurance that centers of knowledge and training in this globally cutting-edge field will be centered within the State. In addition, the VolturnUS technology will be licensed from UMaine, and MAV will continue to invest in commercially reasonable research and development at UMaine. In addition to the direct, quantifiable spending on the R&D collaboration, a significant, but unquantifiable external benefit of an offshore wind project such as this is the social benefit of knowledge creation from technological development the will accrue to the State of Maine.

Finally, there is an unquantifiable, but nevertheless important, economic value associated with establishing Maine on the forefront of offshore wind development. This Project is the kind of investment contemplated by the Ocean Energy Act as the foundation for building a strong offshore wind industry in Maine. In addition, projects such as this establish Maine as a center for cutting edge development of this emerging technology and may capture the imagination and generate excitement among a new generation of talented professionals attracted to Maine. Retaining this young talent in Maine could only have a positive effect on Maine's demographic and economic future.

In sum, considering the level of expenditures made in Maine that the Project is likely to achieve and based on total project capital investment of $167.7 million, the direct quantified economic benefits from the pilot project using data from the Gabe Study, as interpreted by Commission Staff, would be $69 million nominal and $52 million on a present value basis with 475 peak construction phase jobs and 14 operational jobs. Investments in Maine's knowledge base, commercial and labor expertise for work on offshore floating platforms and advanced wind and composites technologies may be perhaps the most significant economic benefit. Based upon all of these factors, we find that there is tangible economic benefit from the Project and additional potentially significant intangible economic benefit that weighs in favor of approving the Proposed Term Sheet. Although we recognize that there is an inherent risk in approving the proposal in that Maine may not see all of the economic benefit that is promised, that is a risk that the Legislature was aware of when it passed the Ocean Energy Act and approved the use of ratepayer money for the purpose of facilitating the development and operation of offshore wind power and tidal power projects. In light of the Act and the proposal before us, it is a reasonable risk to take to achieve the potential benefits that are the goals of the Ocean Energy Act.

D. Other Matters and Commenter Issues

Several other issues are raised by the review of the Proposed Term Sheet through public comments and filings by CMP, Emera Maine (T & D Utilities) and the Office of the Public Advocate (OPA). These are discussed below.

1. Monhegan Benefits

MAV has proposed certain commitments to Monhegan Island, concerning the provision of electricity, interconnection of the island to the grid, and providing fiber optic access to Monhegan Plantation. The exact form of these benefits is still under discussion between representatives of Monhegan Plantation, the Monhegan Power District and MAV and will be memorialized in a memorandum of understanding to be completed before execution of the Contract. We find it sensible and appropriate that MAV has undertaken discussions both with Monhegan and the Town of Bristol, where the Project's grid interconnection will occur. However, we find that the Proposed Term Sheet meets the statutory criteria irrespective of any specific benefit arrangement with these communities.

We have no objection to the structure of the Proposed Term Sheet as it is currently drafted, or to additional community benefits that are included in the final contract as appropriate and will await the results of discussions between MAV and island representatives.

2. Project Siting and Environmental Concerns

The majority of the public comments received in this process concerned matters of environmental impact and project siting issues which are not within the Commission's authority pursuant to the Ocean Energy Act. Although the Commission is sensitive to the issues raised through these comments, the Ocean Energy Act designates the Department of Marine Resources, the Department of Environmental Protection and/or the Maine Land Use Regulation Commission as the jurisdictional entities to address these potential impacts.

3. Future Grants

CMP expresses concern that the mechanism of how any future grants will be applied to reducing the costs of the contract is not specified in the Proposed Term Sheet. This matter will be addressed during the development of the Contract.

4. Enforcement Responsibility

CMP prefers that the non-pricing terms not be included in the Contract, because it should not be CMP's responsibility to monitor and enforce the non-pricing term provisions.

We understand CMP's concern in this regard. We do not expect CMP to have significant responsibilities regarding the enforcement of the non-pricing terms. The specific details of the enforcement responsibilities of the parties and the Commission will be a subject during contract discussions.

5. Operation of Available Ratepayer Funds (ARF) Tracking Account

Comments were received from the T & D Utilities and the OPA concerning the purpose and operation of the ARF tracking mechanism, including potential ratepayer impacts and the timing of its "true-up provisions". The ARF mechanism is an administrative tracking account designed to provide a system for monitoring the availability of ratepayer funds calculated at the rate impact limit in relation to the payments made to the Project throughout the term of the Contract. It is not intended to be used to set the actual rate that would be charged to customers to collect revenues to support the contract payments to MAV. We anticipate that the actual rate to be charged to customers for the costs of this Contract would likely be determined in a Commission proceeding similar to the current stranded cost proceedings used to set rates that allow the T & D Utilities to recover any costs associated with other long-term power purchase agreements.[15] Thus, we do not share the concern that the operation of the ARF Tracking Account would have the effect of causing customer rate volatility.

Both CMP and the OPA commented that the ARF Tracking Account should be subject to true-up or reconciliation on an annual or periodic basis. Since the ARF Tracking Account described in the Proposed Term Sheet includes a provision for annual accounting reconciliation, we interpret this comment to recommend that, should a negative balance exist in the ARF Tracking Account at the end of any Contract Year, MAV would be required to pay that amount to the utility. Introducing such a provision would potentially create an unpredictable and uncertain cash flow structure for MAV and increase the difficulty in structuring acceptable financing. We are satisfied that the ARF Tracking Account mechanism provides the appropriate rate impact protections.

Additionally, CMP commented that the Proposed Term Sheet should clarify that the Annual Energy Shortfall provisions do not allow MAV to receive payments at the Contract Price after the Term has expired and that any negative

[15] Any above-market costs incurred by the T&D Utilities that are associated with existing QF contracts entered into under PURPA or long-term contracts authorized under the Commission's long-term contracting authority are currently recovered through stranded costs proceedings and per kWh stranded cost rates charged to customers.

balances in the ARF Tracking Account should accrue interest. We agree with both these comments but note that obligations pursuant to the operation of the ARF Tracking Account may extend beyond the term of the Contract. We leave the development of specific contract provisions to address these issues to contract negotiations.

8. Commercial Operations Deadline

CMP commented that the Proposed Term Sheet allowed MAV to choose its Commercial Operation Date (COD) with too much discretion. *Comments of CMP* at 5 (Dec. 20, 2013). The Proposed Term Sheet states that the COD is the date designated in writing from MAV to CMP after a number of requirements such as interconnection are complete and all permits and approvals are received as necessary for the Project to begin Operations. *Proposed Term Sheet* at 1. The Commission concludes that the COD process is more appropriately addressed in the Contract itself and is subject to a number of requirements by both the ISO and CMP. CMP's additional requirements can be incorporated into the Contract.

9. Selection of Real Time versus Day-Ahead Pricing

Finally, CMP raised an issue concerning MAV exercising discretion as to whether it would receive the applicable Day-Ahead or Real-Time Locational Marginal Price for energy that is in excess of the Annual Energy Cap. Again this is an issue more appropriately addressed in the structure of the Contract, but it is logical that MAV would have to select one settlement process for a specified period of time.

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Accordingly, we

ORDER

1. That the initial contract provisions contained in the Proposed Term Sheet, as amended by the Commission, are approved, for negotiation of the Contract with MAV;

2. That in the event MAV is unsuccessful in the DOE Solicitation, MAV shall return to the Commission to make a new financial capacity demonstration;

3. That MAV shall report to the Commission annually to provide an update on Project financing beginning upon the execution of the Contract and continuing through its COD and the Commission may modify or rescind this Order if sufficient financing is not procured to construct, operate and decommission the Project; and

4. That CMP actively participate in good faith in the Contract negotiations with Staff and MAV.

Dated at Hallowell, Maine, this 19th day of February, 2014.

BY ORDER OF THE COMMISSION

/s/ Harry Lanphear
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Littell

COMMISSIONERS VOTING AGAINST: Vannoy

Dissenting Opinion of Commissioner Vannoy

The Ocean Energy Act is an economic development statute. In part, it permits the State to invest money in a particular type of energy generation technology – offshore wind turbines. The mechanism for funding this economic development program, as authorized by Ocean Energy Act, is the creation of a subsidy that is funded wholly with money obtained from Maine consumers through the rates that they pay for electricity. The Ocean Energy Act assigns the responsibility of implementing this economic development program to the Commission. Thus funds will be used, in concert with other government and private investment, to underwrite the construction of an offshore wind pilot project that would not be built if financing were sought entirely through the private capital markets. The intent of the statute is that the subsidization of a pilot offshore wind project will produce a host of economic development benefits to the State and will lead to the development of a new industrial sector in the Maine economy, offshore ocean wind power.

The Ocean Energy Act directs the Commission to evaluate proposals for an offshore wind pilot project using several economic development criteria. Only if the Commission finds that a specific proposal meets each of these criteria may it direct one of Maine's transmission and distribution utilities to enter into a long-term contract at above market prices. Of the various factors that we must consider, I depart from the majority in my evaluation of the one factor that most directly implicates the Commission's fundamental area of expertise – the prospect that the pilot project will lead to the development of a large scale offshore wind farm capable of producing electricity at reduced[16], or at least market, prices. My analysis leads me to the conclusion that it is highly unlikely that the seed investment in the Project will spur the private sector investment that is needed to finance the construction of a future, large scale offshore wind farm capable of providing a financial return to private investors and benefits to Maine ratepayers in the form of lower electricity costs. Consequently, I would exercise the discretion the Ocean Energy Act provides the Commission and not use the ratepayer funds entrusted to the Commission by the Ocean Energy Act to fund the pilot project.

To be clear, the question before us is not one of the size or amount of the demonstration project subsidy. The Ocean Energy Act plainly contemplates such subsidization. Moreover, based upon its description of the technologies and expertise that will be brought to bear, the MAV team has sufficiently demonstrated to me that there is a reasonable likelihood that its pilot project will perform as designed. From an engineering perspective, I applaud the MAV team for its innovative design approach to addressing cost drivers that are specific to a marine environment and which, if not

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[16] *P.L. 2009*, Ch. 615. § A-6 (D) reads in part, "Has experience relevant to . . .the offshore wind industry. . .and has the potential to construct a deep-water offshore wind energy project 100 megawatts or greater in capacity in the future to provide electric consumers in the State with project-generated power at reduced rates."

addressed, become an impediment to cost competitiveness. This project addresses some of these cost issues by (a) maximizing the size of the turbine on each structure thereby minimizing the number of structures, (b) developing a semisubmersible structure that is fitting to Maine bathymetry and thereby improving constructability and minimizing the need for special equipment, and (c) specifying the use of a composite tower and concrete structure in order to minimize the heightened costs of construction and operation typically experienced in projects built for the ocean environment.

Nonetheless, the MAV team fails to demonstrate that, even if its pilot project performs precisely as it is designed, the anticipated engineering success of the Project will precipitate the financing and construction of an economically viable large scale offshore wind farm that is capable of generating electricity without further subsidy by Maine ratepayers. This deficiency is not a new one in the arena of ocean energy transformation projects. Ocean energy transformation historically has not been a question of technical capability; but rather it is a problem of economic viability. To be economically competitive with other sources of energy in the New England wholesale energy market, offshore wind generation must overcome substantial and self-evident impediments. It relies on a low density, intermittent source of energy (sometimes the wind blows, sometimes it doesn't). It must be located in a place (offshore) where there exist significant and costly siting limitations. Energy generation technologies that do not depend on an intermittent resource are dispatchable, and therefore have a significant "capacity value," because they can be relied upon when they are needed to satisfy demand. Wind technologies on the other hand, have a low capacity value and, from an economic perspective, are more accurately viewed as fuel savers.

The economics at play can be analogized to those involved in the economic calculus that a consumer would bring to the purchase of a hybrid vehicle. Such vehicles achieve superior gas mileage capabilities due to the fact that they possess two distinct drive trains: one electric driven and one fossil-fuel driven. The electric drive train is a fuel saver. Whether the greater up-front increased sticker price of a hybrid car will be offset over the life of the vehicle through improved fuel efficiency depends on what the price of fuel will be over the life of the vehicle. A purchaser's confidence in calculating the "break-even" point of a hybrid vehicle is a direct function of their confidence in estimating how much fuel will cost in the future.

Although the electric drivetrain certainly complements the fuel drivetrain to optimize fuel consumption, on its own it is insufficient to ensure, in most cases, that a driver will be able to get to his destination. If one were to drive from Portland to Bangor with sufficient fuel in the tank, arriving in Bangor is a reasonable certainty. However, if you were to leave Portland without sufficient fuel in the tank, there is little likelihood of reaching Bangor regardless of how much fuel optimization is contributed by the electric drivetrain. An electric drivetrain in a hybrid vehicle is simply insufficient to supply, on its own, the needed energy to make the trip from Portland to Bangor. Similarly, an intermittent energy resource such as an offshore wind farm will help to reduce the amount of fuel that is necessary to supply the demand for electricity over time. Wind generation is a fuel-saver technology. However, offshore wind is not capable of reliably supplying our electricity needs at a given moment in time because it is not dispatchable. For this, a dispatchable source of electricity, such as a gas turbine, is required.

The stated goal of the Project is to achieve a levelized cost of electricity of 10 cents/kWh.[17] The economic study submitted by MAV contemplates the future construction (after the pilot project is built and shown to be operationally effective) of a 500 MW offshore wind farm to be completed and placed into service by 2025. The capital cost of this anticipated future offshore wind farm would be roughly $1.8 billion. It is expected to have a capacity factor of 41%.[18] Ongoing operating and maintenance costs are estimated at $40/MWh. It will therefore cost $72 million per year to run the facility. At the 7.6 MMBTU marginal heat rate published by ISO New England in 2011, this anticipated future offshore wind farm would save 13,648,080 MMBTU in fuel each year.[19] Over a 20 year period, and taking into account the nominal capital cost of constructing the wind farm, the operating and maintenance costs, but without factoring into the analysis any return to investors or the financing costs of the project, the monetary value of this fuel savings equates to approximately $12/MMBTU. By comparison, most projections of the price of gas futures 20 years out are between 30% and 50% lower than $12/MMBTU, thereby offsetting substantially the expected net value of the fuel savings that the wind farm would achieve.

According to one projection prepared by a consultant retained by the Commission, electricity rates will not cross the 10 cent/kWh threshold that Maine Aqua Ventus hopes a future large scale offshore wind farm will achieve (on a levelized basis) until approximately 2031 and they will flatten out at 11 cents/kWh through 2037. Even this projection is based on a key assumption that (all else being equal) enhances the economics of such a future project – that the United States will implement a significant tax on the carbon emitted by generators that rely on fossil fuels (or RGGI carbon caps will result in a significant increase in carbon compliance costs). Other consultants, applying other assumptions, estimate that electricity rates will flatten out to 8 cents/kWh through 2037. The conclusion that I draw from these projections is that it would take 17 years, and likely longer, before the hypothetical 500 MW offshore wind farm that might be built following a demonstration of the operational success of the pilot project could produce electricity at a competitive cost. Further, due to the significant multiplier effect that is associated with a large 500 MW facility, any failure to actually achieve the 10

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[17] The levelized cost of electricity is an interesting metric which is really a holdover from the days of vertically integrated utilities where integrated resource planning was used to perform economic comparisons of different dispatchable generation technologies. The method has shortcomings in the context of our modern competitive market where wholesale prices often fluctuate significantly through the course of a day and dispatchable generators may be able to realize a significant portion of their annual revenue needs through a handful of high priced events.

[18] A capacity factor is the ratio of the expected actual output of a generating facility to the facility's rated nameplate capacity.

[19] System Planning Department, ISO New England Inc., *2011 ISO New England Electric Generator Air Emissions Report*, (February 2013) at 5 ft.nt. 3.

cent/kWh goal will have significant financial ramifications. For every penny above MAV's assumed cost of 10 cent/kWh, the annual costs to ratepayers will increase by $18 million. A partial success – one that achieves only a 15 cent/kWh levelized cost – would increase the annual cost by $90 million. In light of the extremely long period before even the most hopeful break-even point, I simply do not believe that there will be much private appetite for the $1.8 billion investment required to construct the future 500 MW offshore wind farm that Maine Aqua Ventus hopes will be built following the pilot project and upon which the Ocean Energy Act premises the Commission pilot approval.

Moreover, MAV's goal of achieving a 10cent/kWh levelized cost of electricity is a "best-case" scenario that depends upon the substantial assumption that the costs of actually building a 500 MW offshore wind farm will benefit from both scale (the large farm) and the existence, at the time that it is built, of a mature manufacturing market.[20] The assumed existence of such a mature manufacturing sector is what is necessary to drive the per unit base energy price of 23 cent/kWh that is set forth in the Proposed Term Sheet that the majority approves, to the 10 cent/kWh goal upon which MAV's projections are based. However, the manufacturing efficiencies that could make this possible will only be realized if numerous large scale offshore wind farms are developed to provide the throughput necessary for private investment in manufacturing facilities. Private investment in manufacturing facilities will not take place unless a future stream of orders is assured. The manufacturing efficiencies that MAV assumes in order to be able to meet a $0.10/kWh price point are predicated on the existence of a mature, competitive manufacturing sector. I am simply not persuaded that such a market will have developed during the relevant timeframe.

Even if a mature manufacturing market for the construction of offshore wind farms were to develop in time to yield the unit costs upon which MAV's analysis is premised, it is important to recognize that the existing manufacturing market for fuel-based electricity generation will continue to evolve over the same, two-decade period. Slowly, but steadily, unsubsidized improvements in technology will continue to be deployed, so as to continue historical gains in the efficiency of fuel-based generators. Recent history reflects the inevitability of improved efficiency. For instance, in 1999, the marginal heat rate achieved in the ISO NE region was roughly 10 MMBTU/MWh produced.[21] By 2011 the heat rate dropped to 7.6 MMBTU/MWh, an improvement of

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[20] As I observed in my Dissent from the Commission's February 26, 2013 Order approving the term sheet for the Hywind Maine project submitted by Statoil North America, Inc., the mature market assumption depends upon a product that can achieve a lower cost than the wholesale New England market. The appetite for renewable energy credits to the south of us is simply insufficient to meet the volume requirements of a mature market. *Order Approving Term Sheet*, Docket 2010-235, (February 23, 2014) at 20.

[21] ISO New England Inc., *2011 ISO New England Electric Generator Air Emissions Report,* (February 2013), at 20. Available at http://www.iso-ne.com/genrtion_resrcs/reports/emission/2011_emissions_report.pdf.

24%.[22] New combined cycle plants, deploying existing technologies, are capable of combined heat rates of 5.6 MMBTU/MWh and represent a 44% fuel savings over 1999.[23] Such incremental technological improvements will certainly continue over time, and while any given improvement in efficiency may not be revolutionary, combined, such fuel-saving technologies will tend to diminish the economic significance of the fuel-saving characteristics of a future 500 MW offshore wind farm. Moreover, these technological improvements will be developed and implemented without resort to above market costs imposed on Maine ratepayers.

The majority's approval of the Proposed Term Sheet commits Maine ratepayers to above market costs of between $8 million and $10 million each year for the next 20 years. The investment is to demonstrate the technical viability of an offshore wind generator. I find it unlikely, given the economics of the industry, that upon the successful demonstration of the technology, private investors will commit $1.8 billion in private capital, to invest in a future large scale 500 MW offshore wind farm, when such an undertaking is unlikely to produce electricity at a competitive cost for at least 17 years, and perhaps longer. For this reason, I do not find it prudent to invest ratepayer funds for such a technology demonstration.

Indeed, I am concerned that today's investment of ratepayer funds will be followed by a future request, after the pilot project is completed, for additional ratepayer subsidization in order to support the capital requirements of constructing the contemplated, 500 MW offshore wind project. I see the term sheet today as a first step down the path of ever increasing demands on the Commission for long-term contracts to support a Maine-centric energy development that will result in higher electricity prices that will, in turn, contribute to the continued erosion of Maine's manufacturing and industrial base. In short, I would pass on the opportunity to invest in the MAV venture because I do not believe that the funding of this particular demonstration project is reasonably likely to lead to reduced electricity prices for Maine consumers nor is it likely to lead to a new Maine industry. While I applaud the success story of the Advanced Structures and Composites Center at UMaine, I simply do not think that Maine's electricity consumers will be well served by the pursuit of this particular application of composites technology.

I respectfully dissent.

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[22] *Ibid*; *see also*, Energy Information Administration, *Average Tested Heat Rates by Prime Mover and Energy Source, 2007 - 2012*. Available online at http://www.eia.gov/electricity/annual/html/epa_08_02.html.

[23] For example, R.W. Smith *et al.*, *Advanced Technology Combined Cycles,* GE Power Systems, at 2. Available at http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger3936a.pdf.

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.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2010-235

February 13, 2014

MAINE PUBLIC UTILITIES COMMISSON
Ocean Energy
Long-Term Contracting

ORDER APPROVING TERM SHEET (PART ONE)

WELCH, Chairman; LITTELL and VANNOY, Commissioners

I. SUMMARY

Through this Part One Order, we approve the term sheet for a Long-Term Contract for the capacity and associated energy of the Maine Aqua Ventus Project (the Project) with Maine Aqua Ventus I GP LLC (MAV) dated December 4, 2013 subject to the conditions and clarifications described in this Order and as further described in the Part Two Order to be issued subsequently.[1]

During its 2010 session, the Maine Legislature enacted An Act To Implement the Recommendations of the Governor's Ocean Energy Task Force (Ocean Energy Act). P.L. 2009, ch. 615. Section A-6 of the Ocean Energy Act directed the Maine Public Utilities Commission (Commission), in accordance with Title 35-A, section 3210-C of the Maine Revised Statutes, to conduct a competitive solicitation for proposals for long-term contracts to supply installed capacity, associated renewable energy and renewable energy credits (RECs) from one or more deep-water offshore wind energy pilot projects or tidal energy demonstration projects. Pursuant to the Ocean Energy Act the Commission issued a series of solicitations and received submissions from several proposed projects including the Project.

The Project comprises two floating wind turbines with a total nameplate capacity of 12 MW, located in state waters in the Gulf of Maine at a location 2.5 miles off the southern coast of Monhegan Island's Lobster Cove and 12 miles off the coast of the mainland. The transmission interconnection is presently contemplated to occur in the Pemaquid Point region at the CMP substation in Bristol, Maine.

II. DECISION

In making its decision to approve the proposed term sheet, the Commission determined that the project met or exceeded the following statutory criteria outlined in the Ocean Energy Act. *P.L. 2009*, ch. 615. Section A-6.

1. The Project proposed to sell energy from an offshore wind pilot project.

[1] Commissioner Vannoy dissents in this decision.

2. MAV has the technical and financial capacity to develop, construct, operate and decommission the project subject to further compliance filings, deadlines and findings by the Commission to be fully set forth in the Part Two Order

3. The Project as proposed would provide tangible economic benefits to the State of Maine.

4. MAV has experience relative to the construction and operation of floating wind turbines and demonstrates the potential to construct an offshore wind project of 100 MW or greater in the future to provide consumers in Maine with power at reduced rates

5. The Project as proposed would take advantage of other sources of funding to mitigate the cost to Maine ratepayers.

In addition to meeting the statutory criteria, the Commission determines the Project presents sufficient economic benefits to Maine in terms of direct and indirect investment, environmental benefits, innovation and development of knowledge base within the state to merit awarding a contract at above market rates. Finally, the Commission determined that the Project's costs were below the statutory rate cap set by P.L. 2013, ch. 378 Pt. A § 4.

Accordingly, we

ORDER

1. That the initial contract provisions contained in the Proposed Term Sheet, as amended by the Commission, are approved, for negotiation of the final Long-Term Contract with MAV;

2. That in the event MAV is unsuccessful in the DOE Solicitation MAV shall return to the Commission to make a new financial capacity demonstration. In addition, MAV shall report to the Commission on a twelve month basis to provide an update on Project financing beginning upon the execution of the Contract and continuing through its commercial operations date and the Commission may modify or rescind this Order if sufficient financing is not procured.

3. That CMP actively participate in good faith in the Long-Term Contract negotiations with Staff and MAV.

Dated at Hallowell, Maine, this 13th day of February, 2014.

BY ORDER OF THE COMMISSION

/s/Harry Lanphear
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Littell

COMMISSIONERS VOTING AGAINST: Vannoy

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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).

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STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2010-00235

February 26, 2013

MAINE PUBLIC UTILITIES COMMISSON
Ocean Energy
Long-Term Contracting

ORDER APPROVING TERM SHEET

WELCH, Chairman; LITTELL and VANNOY, Commissioners

I. SUMMARY

Through this Order, we approve the Term Sheet for a Long-Term Contract for the capacity and associated energy of Statoil North America, Inc.'s (Statoil) Hywind Maine Project dated January 14, 2013 (Term Sheet) subject to the conditions and clarifications described in this Order.[1]

II. BACKGROUND

A. Ocean Energy Act

During its 2010 session, the Maine Legislature enacted An Act To Implement the Recommendations of the Governor's Ocean Energy Task Force (Ocean Energy Act). P.L. 2009, ch. 615. Section A-6 of the Ocean Energy Act directed the Maine Public Utilities Commission (Commission), in accordance with Title 35-A, section 3210-C of the Maine Revised Statutes, to conduct a competitive solicitation for proposals for long-term contracts to supply installed capacity and associated renewable energy and renewable energy credits (RECs) from one or more deep-water offshore wind energy pilot projects or tidal energy demonstration projects.

For purposes of the competitive solicitation, "deep-water offshore wind energy pilot project" means a wind energy development, as defined by Title 35-A, section 3451, subsection 11, that is connected to the electrical transmission system located in the State and employs one or more floating wind energy turbines in the Gulf of Maine at a location 300 feet or greater in depth and no less than 10 nautical miles from any land area of the State other than coastal wetlands, as defined by Title 38, section 480B, subsection 2, or an uninhabited island. "Tidal energy demonstration project" has the same meaning as in Title 38, section 636A, subsection 1, paragraph A. Specifically, a "tidal energy demonstration project" means a hydropower project that uses tidal action as a source of electrical power that has a total installed generating capacity of 5 megawatts or less and is proposed for the primary purpose of testing tidal energy generation technology, which may include a mooring or anchoring system and

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[1] Commissioner Vannoy dissents in this decision.

transmission line, and collecting and assessing information on the environmental and other effects of the technology.

As specified in the Ocean Energy Act, the Commission may authorize one or more long-term contracts for an aggregate total of no more than 30 megawatts of installed capacity and associated renewable energy and RECs from deep-water offshore wind energy pilot projects or tidal energy demonstration projects as long as no more than 5 megawatts of the total is supplied by tidal energy demonstration projects.

As required by the Ocean Energy Act, the Commission initiated a competitive solicitation by issuing a Request for Proposals for Long-Term Contracts for Deep-Water Offshore Wind Energy Pilot Projects and Tidal Energy Demonstration Projects (RFP) on September 1, 2010. Responses to the RFP were received on May 2, 2011, including a proposal from Statoil for the Hywind Maine Project. Commission Staff performed an initial review of all proposals received, prioritized proposals and conducted in-depth discussions with several bidders. Projects were evaluated based on cost considerations, overall project viability, including financial, environmental and other site approvals, construction schedule, operational characteristics and the following evaluation criteria as required in the Ocean Energy Act.

Specifically, the Ocean Energy Act states that the Commission may direct one or more transmission and distribution (T&D) utilities, as appropriate, to enter into a long-term contract pursuant to the RFP only if it determines that the bidder:

A. Proposes sale of renewable energy produced by a deep-water offshore wind energy pilot project or a tidal energy demonstration project as defined in this RFP;

B. Has the technical and financial capacity to develop, construct, operate and, to the extent consistent with applicable federal law, decommission and remove the project in the manner provided by Title 38, section 480HH, subsection 3, paragraph G;

C. Has quantified the tangible economic benefits of the project to the State, including those regarding goods and services to be purchased and use of local suppliers, contractors and other professionals, during the proposed term of the contract;

D. Has experience relevant to tidal power or the offshore wind energy industry, as applicable, including, in the case of a deep-water offshore wind energy pilot project proposal, experience relevant to the construction and operation of floating wind turbines, and has the potential to construct a deep-water offshore wind energy project 100 megawatts or greater in capacity in the future to provide electric consumers in Maine with project-generated power at reduced rates;

E. Has demonstrated a commitment to invest in manufacturing facilities in Maine that are related to deep-water offshore wind energy or tidal energy, as applicable, including, but not limited to, component, turbine, blade, foundation or maintenance facilities; and

F. Has taken advantage of all federal support for the project, including subsidies, tax incentives and grants, and incorporated those resources into its bid price.

As required by the Ocean Energy Act, long-term contracts authorized pursuant to the RFP may not, in the aggregate, result in increased electric rates for any customer class that is greater than the amount of the assessment charged under Title 35-A, section 10110, subsection 4 at the time that the contract is entered. That assessment is currently $1.45 per MWh.[2]

As required by the Ocean Energy Act, the Commission consulted with the University of Maine, Department of Industrial Cooperation, Office of Research and Economic Development (University) and the Department of Economic and Community Development (DECD) in developing the RFP and evaluating proposals submitted.

After reviewing all of the RFP responses, the Commission Staff identified a subset of bidders with the strongest proposals from a technical and financial standpoint and began negotiations with these bidders, including Ocean Renewable Power Corp. (ORPC) and Statoil. On March 28, 2012, the Commission approved a Term Sheet with Ocean Renewable Power Corp. (ORPC) containing the essential terms of a long-term power purchase agreement for a 5 MW hydrokinetic facility to be constructed in tidal waters off the coast of the towns of Perry, Eastport and Lubec. *Order Approving Term Sheet*, Docket No. 2010-235 (April 27, 2012). On December 21, 2012, the Commission approved the Agreement Related to Capacity Resource between Bangor Hydro Electric Company and ORPC Maine, LLC (Agreement) and directed Bangor Hydro Electric Company (BHE) to enter into the Agreement and to allocate a pro-rata share of the costs of the contract to Maine Public Service (MPS). *Order Approving Contract,* Docket No. 2010-235 (December 21, 2012).

B. Project Proposal

The Statoil Hywind Maine Project (Project) is a 12 MW deep-water floating offshore wind facility to be constructed in the Gulf of Maine at a location 300 feet or

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[2] The Commission has previously concluded that the Legislature intended that customers that take service at transmission and sub-transmission voltage would not have a rate impact resulting from any ocean energy long-term contracts. *Order on Rate Impact Limitation Provision,* No. 2010-235 (Sept. 28, 2010). Accordingly, the costs of the contract will be allocated to customers taking service at the distribution level.

greater in depth and no less than 10 nautical miles from any land area of the State of Maine. The transmission interconnection to Maine is presently contemplated to occur in the Boothbay region. The Project is expected to begin commercial operation sometime in 2016.

Statoil's Hywind Project identifies the following objectives:

1. Demonstrate scalability of costs, building credibility in the market for the commercialization of floating wind parks;

2. Utilize the Hywind demonstration experience to demonstrate a more cost efficient design;

3. Reduce the technical, time and cost risks associated with a large park development;

4. Build a domestic industry and strengthen the ability of the U.S. and Maine supply chains to deliver according to industry expectations;

5. Generate public acceptance of offshore wind turbines;

6. Prove environmental feasibility for a large scale deployment; and

7. Test and prove the interface and controls in a wind farm configuration of Statoil's' ocean turbine angle-of-attack control system which compensates for both wind speed and sea state by controlling each turbine's continuous adjustment to the wind conditions and stability of the floating platform.

C. Initial Term Sheet

Following several months of negotiations between Statoil and the Commission Staff, on August 15, 2012, Statoil proposed a Term Sheet containing the essential terms of a Long-Term Contract for energy and capacity from the Project (Long-Term Contract) for Commission consideration (Initial Term Sheet). The Initial Term Sheet included two different pricing options, one with a starting contract price of $290/MWh with a fixed annual escalator of 1% and a yearly adjustment for the annual rate of change in the aggregate retail sales of distribution voltage customers of Central Maine Power Company (CMP), BHE and MPS (Rate of Change), and a second pricing option with a starting contract price of $320/MWh, no fixed escalator, and a yearly Rate of Change adjustment. The term of the contract was for 20 years, and the amount of energy to be purchased at the contract pricing was capped at 41 GWh/year. CMP, BHE, MPS (collectively referred to as Utilities), the University, DECD, and the Office of the Public Advocate (OPA) were given the opportunity to comment on the Term Sheet. All but the DECD provided comments by September 5, 2012. Statoil provided a letter in support of its proposal as well as responsive comments on the Utilities', University's, and OPA's comments. The Commission Staff solicited comment from the general public regarding the Initial Term Sheet. The Commission received 46 comments from individuals, businesses and business associations and 14 comments from non-profits, academic institutions, governmental entities and elected officials. The large majority of the comments that were filed voiced support for the Project and the proposed Term Sheet.

On October 4, 2012, the Commission deliberated Statoil's Initial Term Sheet and tabled its deliberation of the matter pending further discussions between Commission Staff and Statoil to address the comments that the Commissioners made at deliberations. The concerns raised by the Commissioners included the viability of the Hywind technology to achieve the long-term cost reduction curve purported by Statoil, the cost of the contract relative to the expected benefits, and the lack of a commitment by Statoil to share any benefits of a future larger park with Maine ratepayers.

III. PROPOSED REVISED TERM SHEET

On January 14, 2013, Statoil proposed a Revised Term Sheet for a Long-Term Contract for the Project that lowered the energy price from that contained in the Initial Term Sheet and included language indicating a commitment to using Maine contractors and suppliers in a future Northeast offshore wind park. (See Revised Term Sheet attached hereto as Attachment 1).

The Revised Term Sheet provides for a contract term of twenty (20) years beginning on the Commercial Operations Date (COD)[3] and contains an initial price of \$270/MWh for energy provided during the first year of the contract. No Payments under the Long Term Contract would occur until the COD is achieved by Statoil. For each subsequent Contract Year over the contract term, the contract energy price escalates at 1.0% per year plus the yearly growth in the aggregate retail sales to distribution voltage customers. The quantity of energy to be purchased under the Long-Term Contract is subject to an annual cap of 41 GWh. To the extent the actual energy produced by the Project is less than the annual energy cap, the difference between the cap and the quantity produced may be carried forward and sold as part of the Long-Term Contract, in addition to the annual energy cap, for up to three successive Contract Years.

As provided in the Revised Term Sheet, the capacity component of the proposed Long-Term Contract is a pass-through transaction whereby Statoil would receive a price for any capacity it provides based on the prevailing market value for such capacity. Statoil must use commercially reasonable efforts to qualify the capacity of the facility in the ISO-NE market.

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[3] The COD is not set, but by statute, must occur within five years of the date of execution of the contract, unless the Commission and Statoil mutually agree to a longer period.

The Revised Term Sheet states that Statoil will use commercially reasonably efforts to pursue and acquire state, federal, non-profit organization, for-profit organization, and other grant and subsidy opportunities applicable to the Project. The Project will retain any and all funds stemming from the Department of Energy (DOE) Funding Opportunity Announcement Number DE-FOA-0000410. The acquisition or failure to acquire these particular DOE funds will not change the Contract Price. The Revised Term Sheet provides that any additional grants that Statoil acquires will be applied toward reducing the costs of the Long-Term Contract to ratepayers, unless Statoil proposes, and the Commission agrees to, an increase in the Project scope. This provision, however, is subject to an exception for changes to the Investment Tax Credit (ITC) program. In the event the current federal ITC is materially adversely modified or otherwise unavailable with respect to the Project, Statoil is entitled to retain any additional grant proceeds to the extent necessary to offset the loss of the economic benefits to Statoil associated with the ITC.

The Revised Term Sheet also includes numerous non-pricing terms intended to ensure that economic benefits expected to accrue to the State as a result of the Project will be realized. These terms include a commitment by Statoil to use commercially reasonable efforts to expend at least 40% of the capital investments and 40% of the operating expenditures for the Project in Maine and to establish and maintain the Operations Center for the Project in Maine. The Revised Term Sheet commits Statoil to continue to engage at least 20-25 local consultants through the development period of the Project, including using commercially reasonable efforts to allocate front end engineering and design studies to Maine-based companies. The terms also commit Statoil to employ at least 150 persons in Maine, directly or indirectly through its suppliers, during the peak construction period of the Project. The Revised Term Sheet also commits Statoil to an extended supplier development process as described in the Term Sheet, to a research and development Collaboration Program with the University of Maine, and to use good faith, diligent efforts to award contracts in a future larger Northeast park representing not less than the lessor of 10% of capital expenditures or $100 million to qualified Maine-based contractors. In the event that Statoil fails to deliver on these economic commitments, the Revised Term Sheet provides for financial payments not to exceed 7% of total revenue from the Project in any given year. The Revised Term Sheet also contains a provision permitting the Commission to terminate the Contract prior to the commencement of construction if the Commission determines that Statoil is not likely to achieve a significant portion of the economic benefits associated with capital expenditures, employment, local content, supplier development and research and development collaboration.

The Commission solicited comment on the Revised Term Sheet and received comments from the Utilities, the OPA, the Governor's Energy Office, the Industrial Energy Consumers Group (IECG), nine comments from public or former public officials, and over 50 comments from organizations, businesses and individuals. The large majority of the comments filed by the general public expressed support for the Project and the proposed Revised Term Sheet. The Utilities, the Governor's Energy

Office and the IECG expressed substantial concerns primarily related to the increase in electricity rates that would result from the Statoil long-term contract.

IV. DISCUSSION

A. Statutory Criteria

We assess the proposed terms of a long-term contract as outlined in the Revised Term Sheet in accordance with the requirements of the Ocean Energy Act and as informed by the Final Report of the Ocean Energy Task Force.[4] In enacting the legislation, the Legislature recognized the potential public benefits that could accrue to the State by providing economic incentives to encourage the development of offshore wind, tidal and wave power energy resources. The Ocean Energy Act envisions these projects as technology demonstration projects that would: (i) provide direct economic benefits of research, testing, and development occurring in Maine; (ii) lay a foundation for Maine to be global leader in offshore wind and tidal technology development; and (iii) develop Maine's own indigenous natural resources. The economic incentives inherent in a long-term power purchase agreement are intended by the Ocean Energy Act to support the development of a limited number of technology demonstration projects by providing for above-market prices to be paid for electricity produced by such projects. The Ocean Energy Act limits the impact on ratepayers by limiting the overall impact on rates.

1. Supplier Requirements

As noted above, pursuant to the Ocean Energy Act and as provided in the Commission's RFP, the Commission may order a long-term contract only if it determines that the potential supplier satisfies several specified criteria. Each of these statutory criteria is analyzed below:

a. Supplier proposes sale of renewable energy produced by a deep-water offshore wind energy pilot project or a tidal energy demonstration project as defined in this RFP.

We find that the Project proposed is a deep-water offshore wind energy pilot project. Consistent with the statutory definition, Statoil's 12 MW deep-water wind farm will be constructed in the Gulf of Maine at a location 300 feet or greater in depth and no less than 10 nautical miles from any land area of the State of Maine. In October 2011, Statoil submitted a request for a commercial wind lease on the outer continental shelf (OCS) offshore Maine to the Bureau of Ocean Energy Management (BOEM) identifying the proposed location of the Project as a 22.2 square mile area located 12 nautical miles from the coast and 18 nautical miles from Boothbay Harbor. A map of the

[4] Maine Ocean Energy Task Force, 2009. *Final Report of the Ocean Energy Task Force to Governor John E. Baldacci.* Available online at: http://www.maine.gov/spo/specialprojects/OETF/

area proposed by Statoil can be found at: http://www.boem.gov/Renewable-Energy-Program/State-Activities/Maine.aspx .[5] We also find that it is a pilot project as it is employing a novel spar buoy design and has the potential to be the first floating offshore wind farm in the United States.

b. Supplier has the technical and financial capacity to develop, construct, operate and, to the extent consistent with applicable federal law, decommission and remove the project in the manner provided by Title 38, section 480HH, subsection 3, paragraph G.

We find that Statoil has the technical and financial capacity to develop, construct, operate, and decommission and remove the Project. Statoil North America, Inc. (Statoil) is a wholly owned subsidiary of Statoil ASA and Statoil's proposal indicates that the full weight of Statoil ASA's knowledge and financial resources will be applied to Statoil's development, construction and operation of the Project.

Statoil's proposal indicates that Statoil is among the most technically capable companies in the world with respect to off-shore wind development. In 2009, Statoil ASA deployed the world's first full-scale, floating wind turbine off the coast of Norway and that turbine continues to operate today. Additionally, Statoil ASA committed to develop the 315 MW Sheringham Shoal (fixed-bottom) offshore wind farm in the UK and is one of four partners developing the Dogger Bank farm in the UK. We find this qualified experience and these activities, combined with Statoil ASA's financial resources described below, demonstrate that Statoil has the technical capability to develop, construct, and operate the Project.

We also find that Statoil, as a wholly owned subsidiary of Statoil ASA, has the financial capacity to develop, construct, and operate the Project. Statoil ASA is an international energy company, headquartered in Norway and majority owned by the Norwegian Government, with 20,000 employees and operations in 34 countries. Statoil ASA's current market capitalization exceeds $85 billion. Statoil ASA is rated Aa2 by Moody's and AA- by Standard & Poor's.

Although the Revised Term Sheet does not address decommissioning and removal of the Project, any commercial lease authorized by BOEM must contain provisions for decommissioning and site clearance procedures and requires the applicant to demonstrate the financial ability or post a surety bond to meet the estimated decommissioning costs. The final long-term contract, which must be approved by the Commission, will also include decommissioning and site clearance requirements. We find that the evidence in the record, combined with Statoil ASA's experience in the

[5] On December 19, 2012, BOEM issued a Notice of Determination of No Competitive Interest (DNCI) for Proposed Commercial Wind Lease Offshore Maine. BOEM will now proceed with the noncompetitive lease issuance process outlined at 30 CFR 585.231.

offshore oil and gas industry and its significant financial resources, establish that Statoil has the technical and financial capability to decommission and remove the project and will be required to do so by BOEM.

c. Supplier has quantified the tangible economic benefits of the project to the State, including those regarding goods and services to be purchased and use of local suppliers, contractors and other professionals, during the proposed term of the contract.

As outlined in Statoil's comments filed on August 15, 2012, Statoil provided two separate analyses of the potential economic benefits to Maine, one produced by Dr. Charles Colgan of the University of Southern Maine using a set of econometric models of the Maine economy developed by Regional Economic Models Inc. (REMI) of Amherst, Massachusetts and maintained by the University of Southern Maine's Center for Business and Economic Research, and the other produced by the National Renewable Energy Laboratory (NREL) using a version of their Jobs and Economic Development Impact (JEDI) model.

Using the REMI model, Dr. Colgan estimates that the Project would result in $17.4 million in earnings and $23.1 million in economic output during the five-year construction phase and $1.8 million per year in earnings and $2 million per year in economic output during the subsequent 20-year operating phase. Dr. Colgan estimates that during the construction phase, the Project will create up to 292 jobs in Maine, 233 of which would be direct jobs, with another 59 induced jobs. During the operation phase, the Project is anticipated to create 30 new jobs annually in Maine, comprising 20 direct jobs and 10 indirect jobs. These estimates incorporate the assumption that the expenditures made by Statoil in Maine reach but do not exceed the level committed to by Statoil in the Revised Term Sheet of 40% of the capital investments and 40% of the operating expenditures. A higher level of spending by Statoil for the Project in Maine would generate higher economic benefits. Statoil's May 2nd proposal included an analysis by Dr. Colgan that assumed Project spending in Maine of 57% of capital expenditures. Based on this higher level of capital spending, Dr. Colgan estimated the Project would create up to 345 jobs during the construction phase.

The NREL JEDI model results, while confidential and preliminary due to the ongoing development of the JEDI model for offshore wind, affirm or exceed these quantified economic benefits. Statoil has also committed in the term sheet to partner with the University of Maine to use the Advanced Structures and Composite Center's (AEWC) capabilities in materials development and testing. Specifically, Statoil states that it has developed a technology development program with the University that began in June 2012 and will continue for the next five years with a quantified and specific amount of support. Statoil states that the University will have ten personnel involved in the collaboration including senior level researchers, technicians, and graduate students as well as five undergraduate students. Statoil has also committed to establish a mid-coast Maine facility for operations and maintenance with a Maine-based full-time operations staff. The operations center will have facilities for offices, storage and workshops and function as the main operational base for the project.

Finally, under the Revised Term Sheet, Statoil has committed to use good faith, diligent efforts to award contracts to qualified Maine-based contractors and suppliers representing at least $100 million or 10% of capital expenditures (whichever is smaller) in a future Northeast Hywind park. This is a further quantification of economic benefits to Maine flowing from a future Statoil investment that is not reflected in the REMI or JEDI economic models.

Accordingly, we conclude that Statoil has quantified the tangible economic benefits of the Project to the State.

d. Supplier has experience relevant to tidal power or the offshore wind energy industry, as applicable, including, in the case of a deep-water offshore wind energy pilot project proposal, experience relevant to the construction and operation of floating wind turbines, and has the potential to construct a deep-water offshore wind energy project 100 megawatts or greater in capacity in the future to provide electric consumers in Maine with project-generated power at reduced rates.

We find that Statoil has the experience relevant to floating wind turbines to construct and operate the Project. Statoil ASA has more than 40 years of experience in offshore oil and gas and has developed extensive resources, engineering and purchasing competence, and a wide range of specialized technical disciplines. Statoil ASA resources, experience, and expertise from the offshore oil and gas industry are transferable to the development of the offshore wind sector. Additionally, as stated above, Statoil ASA is a global leader in the deep-water offshore wind industry, having been the first entity to deploy a full-scale floating offshore wind turbine in 2009. We also find that Statoil has the potential through economies of scale to construct a larger offshore wind project of greater than 100 MW at significantly lower cost per megawatt-hour relative to the pilot project that may provide consumers in Maine with project-generated power at reduced rates.

e. Supplier has demonstrated a commitment to invest in manufacturing facilities in Maine that are related to deep-water offshore wind energy or tidal energy, as applicable, including, but not limited to, component, turbine, blade, foundation or maintenance facilities.

We find that Statoil has demonstrated a commitment to invest in manufacturing and other facilities in the State of Maine. Statoil, unlike ORPC, which is further along in project development, has not yet invested in manufacturing or other facilities in Maine. However, we find that Statoil's numerous commitments outlined in the non-pricing terms of the Revised Term Sheet demonstrate Statoil is committed to invest in the State of Maine on a going-forward basis. Under the terms of the Revised Term Sheet, Statoil has committed to locating the operations center for the Project in Maine, to implementing an extended supplier development process with the goal of maximizing the use of Maine-based suppliers and contractors on the Project, and to using good faith, diligent efforts to award contracts representing at least 10% of capital expenditures in a future Northeast park or $100 million (whichever is less) to qualified Maine-based suppliers and contractors.

Statoil's proposed term sheet contains an extended supplier development process which is designed to facilitate local suppliers and contractors providing goods and services during the construction and operation of the Project and which is designed and likely to result in investment in manufacturing facilities in Maine. One Statoil commitment is to prequalify and nominate Maine suppliers to allow them to bid to provide goods and services for the Project for all components in which local capabilities exist. A second Statoil commitment is to award contracts to Maine based contractors and suppliers who have provided a bid whenever a technically acceptable bid is present on commercially reasonable terms and at a cost that is not materially in excess of alternative goods or services. This commitment provides Maine suppliers with a modest advantage in winning subcontracts including for manufacturing facility work.

Statoil performed two construction studies in 2010 and three assembly studies in 2011 with potential Maine suppliers and an "Extended Supplier Development Program for Hywind Maine" is underway with Maine companies to assess Maine companies' abilities to undertake foundation and assembly, marine operations, metal fabrication and other contractor work on the project. Statoil has preliminarily concluded that Maine companies can construct the floating substructures, although specific suppliers must go through Statoil's prequalification, nomination and selection process before they can be considered to participate in the construction of the Hywind project.

In addition, the Revised Term Sheet includes a provision whereby Statoil is required to file with the Commission, prior to commencement of construction, a Pre-Construction Report documenting Statoil's performance in achieving the local economic benefits. If, in evaluating this report, the Commission determines that Statoil is not likely to achieve a significant portion of the economic benefits associated with capital expenditures, employment, local content, supplier development and research and development collaboration, the Commission may terminate the contract.

f. Supplier has taken advantage of all federal support for the project, including subsidies, tax incentives and grants, and incorporated those resources into its bid price.

Statoil has taken advantage of, and has committed in the Revised Term Sheet to continue to pursue, federal support for the Project. Statoil has been awarded a $4 million Department of Energy (DOE) grant to commercialize the Hywind technology and intends to pursue further funding available through the Department of Energy Funding Opportunity Announcement Number DE-FOA-0000410. Statoil has assumed that it will receive a significant amount of DOE funding and has reflected this assumption in their projected contract revenues and the proposed Contract Price. The Revised Term Sheet provides that the Contract Price for Energy will be reduced to reflect a credit for any net grant proceeds acquired, beyond the DOE funding described above, unless: (i) Statoil proposes, and the Commission agrees to, an increase in the Project scope, or (ii) the current federal Income Tax Credit (ITC), which is assumed as part of the Project revenues, is materially adversely modified or otherwise unavailable with respect to the Project. In the event that the ITC is not extended or is materially changed, Statoil is entitled to retain any additional grant proceeds to the extent necessary to offset the loss of the economic benefits to Statoil associated with the ITC.

Accordingly, Statoil has sufficiently demonstrated that it has taken advantage of, and will continue to take advantage of, all available federal support for the Project, and has incorporated reasonably expected federal funding into its bid price.

2. Rate Impact Limitation

To explicitly limit the rate impact of the economic incentives provided for ocean energy demonstration projects, the Ocean Energy Act contains a rate impact limitation provision that requires that the Commission may not approve long-term contracts pursuant to the Act that would result in an increase in electric rates in any customer class that is greater than the amount of the assessment charged under Title 35-A, section 10110, subsection 4 at the time that the contracts are entered. The current assessment is $1.45 per MWh, which is assessed to customers taking service at distribution voltage and not to large industrial customers taking service at sub-transmission and transmission voltages

The Commission has analyzed the aggregate above-market costs of the ORPC and Statoil contracts by comparing the contract costs to the expected value of the energy they will provide under a range of potential future scenarios. Based on this analysis, we conclude that the Statoil contract, together with the previously authorized ORPC contract, are within the rate impact cap set forth in the Ocean Energy Act.

B. Economic Analysis

In approving of the Term Sheet, we also consider the likely benefits of the Project. The statute does not require that the economic benefits to Maine must equal or exceed the ratepayer costs, but the Ocean Energy Act gives the Commission discretion, to be exercised consistent with the articulated Legislative intent, to determine whether to direct the Utilities to enter into a long-term contract once all statutory criteria are satisfied, and we consider the relationship of the net benefits of the contract to the costs as an important factor in making that decision.

Based on the analysis described above, we estimate the present value (NPV) of the above-market costs of the Statoil long-term contract to range from $52 million to $76 million[6] or $190 million nominally. The Project will involve investment of just over $120 million initially in 2013-2016 to build the Project and then just over $4 million annually in operations and maintenance expenses for 20 years. The quantified economic benefits to Maine for the Project are estimated by Dr. Colgan to be $33 million (NPV) and $63 million (nominal) assuming that the expenditures made by Statoil in Maine reach but do not exceed the level committed to by Statoil of 40% of the capital investments and 40% of the operating expenditures. The quantified economic benefits estimated by Dr. Colgan assuming that Statoil spends 57% of capital expenditures in Maine would be $99 million nominal and $68 million on a present value basis.

The overall Project investment is estimated at $140-150 million dollars on a present value basis.[7] Statoil is financing the initial investment in the Project from its own funds and other sources including U.S. DOE grants. Measured on a present value basis, therefore, the above market costs to be paid by Maine ratepayers of $52-76 million will leverage as much as twice that amount in additional investment in the Maine Project. Payments under the Statoil contract would not begin until the Project is operational and would be made only when the Project is generating electricity. Thus, all of the permitting, development, construction and operational risk is borne by Statoil.

There are also intangible and un-quantified benefits that may occur in relation to the Project. First, Statoil's good faith commitment to utilize Maine suppliers in a future larger Northeast Wind Farm has the potential to bring economic benefits to the Maine economy beyond the scope of this pilot Project. While these benefits are not certain because Statoil may not develop a future park and not all Maine-based suppliers who want to participate in a larger park may be qualified, Statoil's commitment does represent a potentially significant additional benefit to the State.

[6] The present value of the cost to Maine ratepayers of the above market subsidy ranges from $52 million to $76 million in 2012 dollars. Commission Staff calculated a range of present values based on four different scenarios of future energy prices using discount rates of 10% and 7%; $52 to $76 million represented the range across the future scenarios and discount rates. While the Commission has traditionally used a 10% discount rate to evaluate cash-flows from long-term contracts, we note that the private equity markets would currently demand a rate of return closer to 20% for this level of risk. Given the Commission's history, we use 7% as a lower bound of the midrange and 10 % as an upper bound of the midrange for purposes of consistency.

[7] The overall Project investment includes the present value of Statoil's capital expenditures to construct the Project, the bulk of which occur prior to 2016 exceed $100 million and the present value of funds spent on operations and maintenance over the life of the Project, projected at $40 million to $50 million.

Second, there are intellectual and labor force development benefits that flow from Statoil's construction of the Project in Maine. These benefits include the knowledge generation from technological development, especially the knowledge that may be created through the collaboration between Statoil and the University, the training of an expert workforce associated with the various aspects of off-shore wind park development and its associated technological developments, and the experience gained by Maine-based businesses from their participation in the Project.[8] The experience Maine businesses likely will be useful in other marine or energy projects anywhere in the world but primarily on U.S. East Coast.

Finally, there is an unquantifiable, but nevertheless important, economic value associated with establishing Maine on the forefront of offshore wind development. This Project is the kind of investment contemplated by the Ocean Energy Act as the foundation for building a strong offshore wind industry in Maine. In addition, projects such as this establish Maine as a center for cutting edge development of this emerging technology and may capture the imagination and generate excitement among a new generation of talented professionals attracted to Maine. Retaining this young talent in Maine could only have a positive effect on Maine's demographic and economic future.

We find that there is a reasonable possibility that, with support from the federal programs supporting offshore development or programs in other states supporting such development, Statoil could develop a large park. University of Maine Professor Todd Gabe performed an analysis of the benefits of a 500 MW floating offshore wind farm in the Gulf of Maine. Professor Gabe's analysis indicates that state-wide economic output would increase by $270 - 460 million annually for five years of planning and construction and then by $115-145 million annually during a 20 year operational phase. Professor Gabe estimates the 500 MW project would support 2,200 to 3,200 direct and indirect jobs during construction and 550 to 880 direct and indirect jobs during operations. The Revised Term Sheet allows Maine to recapture some of the benefit from a large park developed anywhere from Maine to Maryland.

In sum, depending on the level of expenditures made in Maine that Statoil is able to achieve, direct quantified economic benefits from the pilot project as estimated by Dr. Colgan would range from $63 million to $99 million nominal and from $33 million to $68 million on a present value basis with 292 construction phase jobs and 30 operational jobs assuming Statoil reaches but does not exceed the 40% commitment level. Investments in Maine's knowledge base, commercial and labor expertise for work on offshore floating platforms and advanced wind and composites technologies may be

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[8] The field of economics has recognized that long-term economic growth depends more upon knowledge creation than it does on labor (e.g. job creation) or capital (e.g. lower electricity costs). The commitments in the term sheet for Statoil to develop Maine-based suppliers and to facilitate a collaborative relationship between Statoil, the University of Maine, and private companies and individuals will result in "knowledge creation benefits" from the development of the Hywind Pilot Project accruing in Maine.

perhaps the most significant economic benefits. Based upon all of these factors, we find that there is tangible economic benefit from the Project and additional potentially significant intangible economic benefit that weighs in favor of approving the proposed Revised Term Sheet. Although we recognize that there is an inherent risk in approving the proposal in that Maine may not see all of the economic benefit that is promised, that is a risk that the Legislature was aware of when it passed the Ocean Energy Act and approved the use of ratepayer money for the purpose of facilitating the development and operation of offshore wind power and tidal power projects. In light of the Act and the proposal before us, it is a reasonable risk to take to achieve the potential benefits that are the goal of the Act. Accordingly, we approve the proposed Revised Term Sheet subject to the conditions and modifications discussed below.

C. Other Matters and Commenter Issues

Several other issues are raised by the review of the Revised Term Sheet. These are discussed below.

1. Contract Allocation and Rate Impact Limitation

In their comments, BHE and MPS express concern that the Term Sheet calls for the allocation of the Long-Term Contract to all of Maine's Investor Owned Utilities despite the allocation of the ORPC contract entirely to BHE and MPS ratepayers. We agree with BHE and MPS that they should not participate in this Long-Term Contract, and thus find that this Long-Term Contract will be between Statoil and CMP only.

While our analysis indicates that the Statoil contract will not likely violate the statutory rate impact limitation, the contract should include a provision to address this risk. We leave it to the Commission Staff, CMP and Statoil to determine the mechanism, whether it be through the method used in the ORPC long-term contract as a default or through another method if mutually agreed upon.

2. Contract Products and Structure

The current Revised Term Sheet contemplates that capacity will be included in the long-term contract as a pass through, such that any value associated with the capacity from the project will be passed directly to Statoil. CMP expresses a preference that capacity not be included in the contract because it does not provide any value to CMP or its customers but presents a performance risk for CMP. CMP states that it would be more straight forward and administratively easier for capacity to be excluded.

We conclude that there should be a capacity term in the contract, as the Ocean Energy Act allows the Commission to direct utilities to contract for the "installed capacity and *associated* renewable energy and renewable energy credits of deep-water offshore wind energy pilot projects." However, we do not expect CMP to have any significant role or exposure to risk in matters related to qualifying or bidding the capacity in the ISO-NE market, and direct that the contractual terms regarding capacity ensure that result.

CMP expresses concern that a 3 year period to make up delivery shortfalls is too long. We disagree and find that the 3 year period to make up shortfall deliveries, as outlined in the Term Sheet, is acceptable in this instance.

3. Future Grants

CMP expresses concern that the mechanism of how any future grants will be applied to reducing the costs of the contract is not specified in the Term Sheet. This matter will be addressed during the development of the Long-Term Contract.

4. Enforcement Responsibility

CMP prefers that the non-pricing terms not be included in the contract, because it should not be its responsibility to monitor and enforce the non-pricing term provisions.

We understand CMP's concern in this regard. We do not expect CMP to have significant responsibilities regarding the enforcement of the non-pricing terms. However, we conclude that the non-pricing terms should be included in the contract as there is a provision allowing the Commission to terminate the contract in the event that Statoil is not likely to achieve a significant portion of the economic benefits set forth in the Revised Term Sheet. The specific details of the enforcement responsibilities of the parties and the Commission will be a subject during contract negotiations.

5. Obligation to Perform and Performance Assurance

CMP points out that the Term Sheet is silent on Statoil's obligation to perform, as well as the level and need for financial assurance. Statoil's obligation to perform will be specified in the contract. The Long-Term Contract shall include adequate financial assurance consistent with the requirements of the RFP to secure that obligation. Because the pricing in the contract is above-market, performance assurance would primarily be to secure Statoil's non-pricing obligations.

6. Termination Rights

Under the terms of the Revised Term Sheet, Statoil has the right to terminate the long-term contract if, prior to January 1, 2015: (a) Statoil is unable to obtain all necessary State and Federal permits; (b) the investment tax credit or any DOE support which may have been awarded to Statoil to develop the Project is adversely modified; or (c) the Project fails to obtain the necessary internal Statoil approvals. While we do not alter this termination provision, our approval is conditioned upon a provision in the contract that requires Statoil to elect or waive its termination right within 90 calendar days of being notified of an adverse DOE funding decision with respect to the Project. To the extent that there are multiple funding decisions, Statoil shall give an indication of intent to terminate or waive the termination right as to that event. We leave it to the Commission Staff to determine the best structure to implement this requirement.

7. Reporting Requirements

In addition to the reporting requirements in the Term Sheet, we add a requirement that six months after contract execution and every six months thereafter until commencement of construction, Statoil North America and its parent Statoil ASA indicate to the Commission in writing, their intent to move forward with the Project and provide updates on planning, engineering, and pre-construction activities.

8. Commercial Operations Deadline

Pursuant to the Ocean Energy Act, we require that the Project be constructed and operating within five (5) years of the date the contract is finalized, unless the Commission and Statoil agree to a longer period..

9. Maintenance of Status During Operation

In its comments, the IECG claims that the Revised Term Sheet violates federal law because it attempts to regulate the price for wholesale purchases of energy and is therefore preempted by FERC's jurisdiction under the Public Utilities Regulatory Policies Act (PURPA) or the Federal Power Act (FPA). While we do not believe that IECG's claim is ripe for determination, we do not view our actions as usurping any applicable FERC jurisdiction. To that end, to the extent necessary, we require that Statoil maintain the Facility's status as an exempt wholesale generator at all times after the Commercial Operations Date and shall obtain and maintain, as necessary, any requisite authority to sell the output, including capacity, of the Facility at market-based rates or an exemption from the requirement that it have such authority.

10. Decommissioning

We require the Long-Term Contract to include a provision that indicates that Statoil will comply with directives from any applicable State or Federal agency to decommission the Project consistent with the Ocean Energy Act. In the unlikely event the neither State nor Federal agencies specify decommissioning requirements, the Contract will contain a backup decommissioning requirement.

11. Educational Training

We require Statoil to use commercially reasonable efforts to develop and implement a training program or other training opportunities to benefit the students of Maine academic or technical institutions, colleges, and universities.

12. Future Offshore Wind Development

Statoil proposes to inform the Commission of key aspects of a business case for a large, commercial park in the Gulf of Maine based on floating technology. This information would be useful and we, therefore, condition our approval of the Revised Term Sheet on Statoil's agreement to develop and submit, prior to December 1, 2015, a business case for the development and construction of an offshore wind farm no less than 100 MW in the Gulf of Maine and using Maine qualified suppliers and to provide updates of the business case or plan every two years until the Contract terminates.

In addition, we require that the economic benefit language in the Long-Term Contract contain a modification that would eliminate the ability of local content requirements in another jurisdiction to obviate the good faith requirement to award contracts representing 10% of future park capital expenditures (or $100 million) to Maine-based contractors and suppliers. Maine companies and research institutions will play a significant role in Statoil establishing its renewable energy pilot project in the United States and Maine ratepayers will make a significant commitment to support the Project. While this 10% or $100 million commitment to pursue Maine content on another U.S. East Coast ocean wind project is a good faith requirement only, we expect that Statoil will use good faith efforts to involve qualified Maine companies and research institutions in other ocean energy projects whether in the Gulf of Maine or elsewhere. We direct that any additional language that would provide a further obstacle to Maine receiving this additional benefit be excluded from the Contract. In connection with any future offshore wind development undertaken by Statoil, regardless of the location of the development, we require Statoil to invite any as yet unqualified Maine suppliers to pre-qualify and to nominate Maine based suppliers and contractors that were previously pre-qualified as part of the pilot Project in the contractor and sub-contractor selection processes for the future park.

13. Technology

To afford Statoil flexibility in developing its Project and to allow for changes or development in technology that may occur after the issuance of this Order, we direct Staff and Statoil to include in the long-term contract a clarification that the commitments and obligations under the long-term contract with respect to both the Project itself and to the future, large park commitment, apply to the Hywind technology, as well as to and any other similar or derivative technology should Statoil elect to utilize other similar or derivative technology in this Project which election will be solely within Statoil's discretion under the Contact.

Accordingly, we

ORDER

1. That the initial contract provisions contained in the Revised Term Sheet, as amended in this Order, are approved, for negotiation of the final Long-Term Contract with Statoil;

2. Delegate negotiation of the Long-Term Contract to Staff consistent with this Order; and,

3. That Central Maine Power Co. actively participate in good faith in the Long-Term Contract negotiations between Staff and Statoil.

Dated at Hallowell, Maine, this 26th day of February, 2013.

BY ORDER OF THE COMMISSION

/s/ Nancy Goodwin
Nancy Goodwin
Acting Administrative Director

COMMISSIONERS VOTING FOR: Welch
Littell

COMMISSIONERS VOTING AGAINST: Vannoy

Dissent of Commissioner Vannoy

I respectfully dissent from the majority decision approving the Statoil N.A. Hywind Maine term sheet. The authorizing statute, the Ocean Energy Act,[1] is an economic development statute that seeks to subsidize the development of ocean energy electricity generation technologies. The goal of the Act is to spur research and development that is complimentary with Maine's marine resources and that could lead, ultimately, to the development of a large-scale project that can "provide electric consumers in the State with project-generated power at reduced rates."[2]

There are significant sources of potential energy in the world's ocean, including tidal and wind energy resources. The ocean engineering community has worked for many years on a variety of ocean energy conversion technologies. The commercial development of these ocean energy conversion technologies is not a question of whether or not they are technically feasible, but rather, whether or not they are financially viable. This is a key question that a pilot project should seek to answer.

The Ocean Energy Act clearly allows for a subsidy, but at the same time it leaves to the Commission the responsibility of negotiating a prudent contract that meets the statutory terms, achieves the economic development goals, and advances the potential of a large offshore wind farm. A good contract assigns risk and compensates parties for the risk they assume. The issue before the Commission with respect to the term sheet can be reduced to answering the question as to whether the risk undertaken by Statoil N.A. is commensurate with the above-market subsidy it will receive under the term sheet. Statoil N.A. is the entity that should assume the risk inherent in demonstrating that the proposed pilot farm will advance the technology of the proven Hywind concept to a point where it is economically viable at a large scale. However, rather than encouraging Statoil N.A. to take on this risk to advance to an economically viable commercial technology, the term sheet compensates Statoil, at roughly seven times the current wholesale market rate, for what amounts to merely a conservative reproduction of the Hywind concept.

Statoil N.A. Development Risk

I will briefly outline the risk to Statoil N.A. in the development of this project. The primary risk to Statoil N.A. in the structure of the term sheet is that of the upfront capital to build the project. The primary area of risk in getting the project built, which is outside of Statoil N.A.'s control, is that of permitting. The term sheet mitigates this risk by allowing Statoil N.A. to opt out of the project at any stage prior to December 31, 2015. This allows Statoil N.A. to limit its capital expenditures until all of the external risks are resolved. With those external risks resolved the company can go to

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[1] An Act to Implement the Recommendations of the Governor's Ocean Energy Task Force, P.L. 2009, Ch. 615 (L.D. 1810).

[2] Ocean Energy Act, P.L. 2009, Ch. 615, § A-6.1.D

construction and, with sound project management, can quickly construct the project and move to commercial operation of the pilot project. Upon reaching the commercial operation milestone, Maine ratepayer costs will begin to accrue.

Statoil N.A. argues that there is substantial risk in developing a new supply chain in Maine. The term sheet mitigates this risk by capping Statoil N.A.'s capital expenditure and operations and maintenance expenditure commitments to 40% Maine content and further limiting those commitments by requiring that Statoil N.A. use "commercially reasonable efforts" to satisfy its commitment. The "commercially reasonable efforts" clause will make it very difficult for the Commission to enforce Maine content requirements. Regardless, well respected Maine marine contractors and experienced terrestrial wind contractors will ensure that Statoil N.A. has very little difficulty in developing a new supply chain in Maine.

Maine Ratepayer Risk

There are no real risks to ratepayers in the project development phase of the project. The ratepayer costs do not flow until the project reaches the commercial operation phase and Statoil N.A. starts receiving payment for the electricity that the pilot project produces. At that point, based on the amount of power produced, the above-market payments begin to flow at roughly $9.5 Million a year for twenty years.

Maine Benefits

In its non-pricing terms, Statoil N.A. outlines "Statoil Ambitions" and several tangible economic benefits. These benefits include: significant construction jobs (150 direct jobs) during the peak construction period of the project; 20-25 consultant and attorney jobs during the pre-Financial Investment Decision phase of the Project, siting and staffing a full time operations center in Maine; developing a research and development collaboration with the University of Maine; and, if a large farm is built before 2025 on the Northeast coast utilizing the Hywind technology, a commitment to undertake "good faith, diligent efforts" to include Maine content of 10% of capital expenditures or $100 million (whichever is less) in the large farm construction. None of these tangible benefits are secure. Instead, the enforceability of these commitments is eroded by the definition and process associated with the term "commercially reasonable efforts."

In its majority decision, the Commission agrees with Statoil N.A., and most commenters filing in support of the project, that the real benefit to the State of Maine lies in the potential of a future large scale offshore wind farm somewhere on the East coast. In Statoil N.A.'s filings they point to the goals of the Ocean Energy Act, that by 2020 Maine will realize 300 MW of build-out of generation located in coastal waters, and by 2030, 5000 MW of build-out. Statoil N.A. couples these goals with the Maine Offshore

Wind Report which Statoil characterizes as indicating that such a build-out will attract $20 billion in private investment.[1]

Large Scale Park Economic Viability

For an industry to be sustainable it will have to produce a product at grid parity. Private capital is risk averse and is not interested in reasonable financing rates for projects that depend on government support that may or may not be available or sustainable. If the cost-curve of this technology is not brought down to grid parity by 2020 any difference (above-market prices) is multiplied by significantly higher production capacities making the project untenable. To illustrate this, if one assumes a 500 MW wind farm in 2020, for every penny above market rates, the wind farm will cost Maine ratepayers $17.1 million annually (assuming a 39% capacity factor).

The pilot project term sheet has a starting price of $270/MWh ($0.27/kWh). Under the term sheet, the power produced by the project is sold into the ISO-NE wholesale electricity market. The difference between wholesale market prices for the power produced, at the time of production, and the term sheet price constitutes the above-market subsidy. The average wholesale price in the ISO-NE Market for 2012 was $36.09/MWh ($0.036/KWh), 7.5 times less than the starting contract price for energy contained in the term sheet. While it is true that the average wholesale price in the ISO-NE market is currently extremely low and is likely to rise, the disparity between the price for electricity in the term sheet and the current wholesale market price is significant. Indeed, the difference between Statoil's unsubstantiated goal of achieving a price point of between $0.10-0.15/kWh is a multiple of 3-4 times the current wholesale market rates. Quite simply, if Statoil N.A.'s technology does not break the cost-curve,[2] the future investment upon which the majority in part bases its decision simply will not materialize. Moreover, it will be Maine ratepayers, and not private investors, who will bear the burden in the event that the cost-curve is not broken and a large offshore wind farm is nevertheless constructed.[3]

The United Kingdom has developed significant offshore wind farms and is on the way to developing what might be called a mature industry. The Crown Estates issued its Offshore Wind Cost Reduction Pathways Study because, despite the billions of dollars being spent, they were actually seeing cost escalations rather than seeing

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[1] Statoil Comments on Term Sheet, August 15, 2012, Docket No. 2012-235, page 1.

[2] Technology that breaks the cost curve is referred to as "destructive technology."

[3] These numbers grow much larger at the 2030 goal of 5000 MW, for every penny above market this would be $170.8 Million at a 39% capacity factor.

cost reductions.[1] The study highlights the United Kingdom's goal of £100/MWh by 2020, which is roughly \$0.16/kWh. This report demonstrates how difficult it will be to realize Statoil's goal of a price point of \$0.10/kWh by 2020. The study also identifies a number of pathways to drive down price. Among these pathways two key concepts are discussed: building at scale, and market maturation. Statoil N.A.'s price point goal of \$0.10/kWh is predicated on both building at scale and a mature market. It is important to understand that these concepts are distinct. The development of a mature market will take numerous large scale farms developed over several decades to ensure the volume of throughput necessary to develop competitive manufacturing facilities. It is through these competitive manufacturers that a "mature market" begins to yield the price efficiencies that Statoil N.A. is relying on to meet a \$0.10/kWh price point by 2020. If the United Kingdom has not achieved a mature market despite billions in public investment, how difficult will it be to achieve a "mature market" in New England?

The purpose of a pilot project is to demonstrate a technology at a small scale and test out advances that will make it practical for a larger scale. Statoil N.A. developed and tested the Hywind concept as a single turbine off the coast of Norway. This Hywind concept from a technical standpoint proved very effective. Statoil N.A. states that "The Hywind concept is based upon recognized work methods and equipment from both the marine and oil and gas industries."[2] There is merit in this as the oil and gas industry has a wealth of experience in working in the offshore marine environment. But this leads to a significant question for the industry, based on the more extensive data in the United Kingdom, where the current cost-curve for offshore wind is escalating. What type of destructive technology is necessary to break the cost-curve and, to the point here, is the Statoil Hywind approach a destructive technology? The projects in the United Kingdom to date have been in shallow water using traditional template platforms and jack-up barges. Some would argue that a floating structure is a destructive technology. To a certain degree this is true, it does eliminate the need for jack-up barges, but it does not go far enough. The offshore wind industry and in particular Statoil N.A.'s current proposal, which utilizes a deep draft spar buoy, continues to rely on expensive oil and gas industry equipment for installations. The pilot project before us does not propose any significant changes in construction methodologies that would eliminate deep water assembly and in turn bring the cost-curve down.

This is where the question of Statoil N.A.'s risk enters back into the discussion. Statoil N.A. is suggesting only a conservative increase of its Hywind technology, from the 2.3 MW unit that has already been installed in Norway to the 3 MW

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[1] The Crown Estate "Offshore Wind Cost Reduction Pathways Study," May 2012, page 1 (located at the following link: http://www.thecrownestate.co.uk/media/305094/Offshore%20wind%20cost%20reduction%20pathways%20study.pdf).

[2] Statoil Comments on Term Sheet, August 15, 2012, Docket 2010-235, Attachment 3, Section 3.

units in Maine. In addition, the Company has proposed modifications to the spar buoy structure allowing for some ballasting and de-ballasting due to the relatively shallow depths of Penobscot Bay (in comparison to Norwegian fjords). However, this minimal, and marginal, improvement will not fundamentally change the cost-curve.

There are a number of things that Statoil N.A. could have proposed that would have brought its risk into a more commensurate relationship with its compensation, thereby appreciably impacting the cost-curve. For instance, Statoil N.A. might have maximized generator size per floating structure. Of the recent seven Department of Energy grant winners for offshore wind projects, five have proposed turbines in the 5-6 MW range. In addition, Statoil N.A. might have proposed modifications to the Hywind design that would allow for cost savings in construction methods (for example, a land based assembly process), thereby avoiding the more costly equipment and rates associated with marine work. Further, although the minor modifications to the spar buoy design allows for some ballasting and de-ballasting and thus adds a degree of flexibility to the spar buoy design, it does not truly remedy the issue regarding flexibility and draft. The spar buoy is approximately 100 meters (328 ft.) in length, requiring a draft for erection of the tower and turbine on the order of 300 ft. Clearly this cannot be achieved pier-side in Maine (in contrast to the deep fjords of Norway) and will therefore require costly special equipment and processes.[1]

The Statoil N.A. term sheet falls short in the area of significant advancement beyond the Hywind prototype that demonstrates that the Hywind approach holds the promise of commercial viability through future expansion from a pilot to a full scale farm. Again the ocean engineering world has been working on various ocean energy transformation technologies for many years and has proven that the technologies are not limited by their technical feasibility, but rather by their economic viability.

Another gauge of this project is to consider the "all-in" levelized cost of electricity. This analytical approach calls for consideration of the total lifetime costs of the technology. In this case this would include, the power purchase agreement, the sale of renewable energy credits, the sale of capacity, federal grants, the Investment Tax Credit, and the application of a discount rate to establish a present value. The result is a levelized cost of electricity which can be used to compare different technologies that may receive different levels of state and federal support. This approach does have some limitations because it does not account for the technologies production ramp up rates, or intermittency which might have a significant effect on a developer's view of financial viability. But, for comparison's sake, Statoil N.A.'s Hywind

[1] The offshore oil industry has relied on three different floating structures which include the spar buoy, the tension leg platform (TLP), and the semisubmersible platform. The offshore wind industry has adopted these proven platform designs. While Statoil N.A.'s proposal is a spar buoy platform, the University of Maine, funded by the DOE is pursuing a semi-submersible platform, and Glosten Associates, also funded by the DOE, is pursuing a TLP.

project's levelized cost of electricity is in the range of 4-6 times that of a combined cycle gas turbine.[1]

In interpreting the Statute and its goals, which are primarily geared towards economic development, a balance must be sought between cost, the assignment of risk, and tangible economic benefits. Simply put, the economic development prospects of this term sheet depend on the future economic viability of a large scale park. Statoil N.A. does not undertake the development risks necessary to achieve a future large park that is economically viable. Nor does it ensure that the potential economic benefits of the pilot project are concrete, enforceable, or commensurate with a levelized cost of electricity that is 4-6 times the market rate. For these reasons, I would reject the term sheet.

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[1] Unfortunately in this case, Statoil N.A. considers the levelized cost figures to be confidential. In my view, it would be valuable for all policy-makers to understand the total costs of this project, and I therefore encourage Statoil N.A. to be transparent in this regard. As an example, while Statoil N.A. has released its estimate of Capital Expenditure for the pilot project ($120 million). This figure, which is but a small portion of the total cost of the project, does not begin to approach the sum of the various revenue streams and tax incentives.

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 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 1004 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.

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.A. § 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.A. § 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.

Statoil Proposed Term Sheet

January 14, 2013

The following terms reflect the essential elements of a long-term contract for energy and capacity from the Statoil Hywind Maine Project (the Project) that will be negotiated in good faith by Statoil North America, Inc. (Statoil), the Maine Public Utilities Commission (Commission), and the investor-owned transmission and distribution utilities (T&D Utilities), and is anticipated to be executed by Statoil and the T&D Utilities (hereinafter referred to as the Contract).

Project Description: The Project is as presented in the May 2011 Proposal by Statoil, comprised of four floating wind turbines with a total nameplate capacity of 12 MW, located in the Gulf of Maine at a location 300 feet or greater in depth and no less than 10 nautical miles from any land area of the State of Maine. The transmission interconnection to Maine is presently contemplated to occur in the Boothbay region.

T&D Utilities: Central Maine Power Company (CMP), Bangor Hydro Electric Company (BHE), and Maine Public Service Company (MPS).

Contract Term: The Contract Term is twenty (20) years beginning on the Commercial Operations Date (COD) of the Project as designated by Statoil (Contract Start Date) and ending twenty (20) years after the Contract Start Date (Contract End Date). For purposes of this provision, COD is the date designated in writing by Statoil to the T&D Utilities once all of the following have been completed: (a) 1-4 of the wind turbines at the Project have been commissioned, as evidenced by a commissioning certificate executed by the wind turbine manufacturer and delivered to the T&Ds by Statoil; (b) such wind turbines have been synchronized with the utility grid and are capable of generating Energy that may be delivered to the Delivery Point; (c) Statoil has obtained all permits, approvals and/or authorizations required from any governmental authority to develop, construct and operate the Project other than the T&D Required Permits (Seller Required Permits); (d) the T&Ds have obtained any and all permits, approvals and/or authorizations required from any governmental authority to accept delivery of the Products, including without limitation all required construction and operating permits required to develop, construct, own and operate the Interconnection Facility (T&D Required Permits); and (e) all other requirements necessary under any agreement, including the Project's interconnection agreement, have been met or are otherwise satisfied and the Project is authorized to generate and deliver the Energy and related Contract Products to the Delivery Point, all as set forth in a certificate Statoil shall submit to the T&Ds certifying that the COD has been achieved. All amounts and prices are provided on a Contract Year basis. Contract Year means the 12-month period beginning on the Contract Start Date and each successive 12-month period commencing on the annual anniversary of the Contract Start Date (Contract Year). For example, if the Contract Start Date is October 1, 2016, Contract Year 1 is October 1, 2016 through September 30, 2017 and Contract Year 2 is October 1, 2017 through September 30, 2018. Any adjustments to the Contract Start Date may result in changes to the amounts and prices contained in this term sheet.

Contract Products: The Contract Products to be purchased and sold under the Contract are the energy generated by the Project and delivered to the Delivery Point (Energy) and the Project's electrical capacity (Capacity) (collectively, the Contract Products). The Energy purchased and sold under the Contract must be produced by the Project and delivered to the ISO-NE energy market during the Contract Term. Statoil will use commercially reasonable efforts to qualify, clear and deliver Capacity from the Project in the ISO-NE Forward Capacity Market (FCM) (or successor market) such that Capacity purchased by the T&D Utilities receives full market value at the prevailing adjusted clearing price in the FCM (or successor market). Capacity provided by the Project, if any, will be sold to the T&D Utilities and all value realized in the FCM (or successor market) will flow to Statoil.

Energy and Capacity provided by the Project are the sole Contract Products to be purchased under the Contract. RECs or other market products associated with the environmental attributes of the Project are not included in the Contract and the rights to such attributes are retained by Statoil.

Contract Quantity: The amount of Energy purchased and sold under the Contract shall be the entire generation output produced by the Project. The amount of Energy produced and sold under the contract *at the Contract Pricing provided below* is subject to a 41 GWh Annual Energy Cap applicable to each Contract Year. The price for Energy produced by the Project in excess of the applicable Annual Energy Cap shall be the applicable Day-Ahead or Real-Time (at Statoil's option) LMP in the ISO-NE wholesale energy market (or successor) applicable to the Project.

At the conclusion of a Contract Year, if the Energy produced by the Project is below the Annual Energy Cap (an Annual Energy Shortfall), the number of megawatt-hours of the Annual Energy Shortfall may be carried forward for up to three successive Contract Years and added as a credit (Shortfall Credit) to the Annual Energy Cap for such three successive Contract Years until utilized. Any payment for Energy pursuant to such Shortfall Credit mechanism shall be at the Contract Price in effect during the Contract Year when such Annual Energy Shortfall occurred.

Contract Price- Energy: Contract Prices are specified by Contract Year and are stated in nominal dollar terms. The Contract Price shall apply to all Energy produced by the Project up to the Annual Energy Cap of 41 GWh.

The Contract Price for Energy is \$270/MWh[1] for Energy provided during Contract Year 1. The Contract Price for Energy will change annually during each subsequent Contract Year over the Contract Term at a rate equal to 1% percent plus or minus the applicable annual rate of change in the aggregate retail sales of distribution voltage customers of CMP, BHE and MPS ("Rate of Change"). For any particular Contract Year, the Rate of Change will be calculated as follows:

$$\text{Rate of Change} = \frac{\text{Retail Sales (Contract Year N-1)}}{\text{Retail Sales (Contract Year N-2)}}$$

For purposes of applying this formula, aggregate retail sales of distribution voltage customers shall be determined on a calendar year basis.

Contract Price – Capacity: The Contract Price for Capacity shall be the market value per kW-month at the prevailing clearing price in the FCM (or successor market) received by the T&D Utilities and passed through to Statoil in addition to the Contract Price for Energy.

Grants and Other Sources of Project Revenue: Statoil will use commercially reasonable efforts to pursue and acquire State, Federal, non-profit organization, for-profit organization, and other grant and subsidy opportunities applicable to the Project, including those that provide for the reduction of construction costs, capital or financing costs, and/or operating costs of the Project. The Project will retain any and all funds stemming from the Department of Energy Funding Opportunity Announcement Number DE-FOA-0000410 in their entirety. For any additional grants received by Statoil, the Contract Price-Energy will be reduced for the applicable Contract Year to reflect a credit for the net grant proceeds realized unless Statoil proposes, and the Commission agrees to, an increase in the Project scope which increases the costs of the Project (including, without limitations, use of larger turbines, more extensive test programs or other relevant activities) to the benefit of future offshore wind developments. In the event the current federal Investment Tax Credit is materially adversely modified with respect to the Project or has not been extended to cover the full expected construction period of the Project, and if notwithstanding such event Statoil proceeds to construct the Project, Statoil shall be entitled to retain any additional grant proceeds to the extent necessary to offset the loss of the economic benefits to Statoil associated with the Investment Tax Credit.

Non-Pricing Terms:

Statoil Ambitions:

[1] Prices are given in nominal terms for Contract Year 1. Estimated equivalent 2013 price reference is 254\$/MWh (assuming start-up in 2016, and a yearly 2% growth rate)

Statoil will actively contribute to the building of a renewable energy sector supply chain in Maine. In order to achieve this, Statoil will aim, to the greatest extent possible, to utilize local suppliers in the planning and execution phase of the project. In addition, the main operational base will be located in the State of Maine in order to secure a long term foothold for the project and exposure to the wind industry.

A majority of local jobs will be created by subcontractors. Statoil will, through its bidding documents and procedures, use commercially reasonable efforts to ensure that its contractors and suppliers use Maine-based employees to the maximum extent possible, provided that qualified Maine employees are available. Statoil will use local employment in Maine as a positive ranking factor in the procurement process such that a contractor or subcontractor using local Maine employees will, if otherwise qualified and competitive, have an advantage over other bidders in the evaluation process.

Statoil currently estimates that suppliers to the Project will employ approximately 150 persons full time in Maine during the peak construction period. Additional indirect jobs will result from multiplier effects and are not included in this figure.

Statoil specifically commits to:

1. **Capital Expenditures.** Statoil will use commercially reasonable efforts to spend in Maine and/or allocate to Maine suppliers, at least 40% of the capital expenditures for the Project.

2. **O&M Expenditures.** Statoil will use commercially reasonable efforts to spend at least 40% of the operating and maintenance expenditures for the Project in Maine.

3. **Employment.** Statoil will, either directly or indirectly through its suppliers, employ 150 persons full time in Maine during the peak construction period.

4. **Operations Center in Maine.** The Operations Center for the Project including full-time operations staff will be located in Maine. The base will have facilities for offices, storage and workshops. This will function as the main operational base for the Project where local staff presence is required for preparedness and stand-by. During operations Statoil will use commercially reasonable efforts to utilize local suppliers in order to maximize the presence of local content and efficiency.

5. **Local Content in Pre-FID (Financial Investment Decision) Phase.** Staoil has contracted with an Environmental Impact Assessment (EIA) coordinator with offices in Maine, resulting in a comprehensive survey program by which a number of local vessel owners and specialists will be

engaged. In addition, Statoil has retained other local consultants and attorneys and will continue to engage local consultants. Currently Statoil is actively utilizing approximately 20-25 persons employed by 5 local consultant and law firms, and Statoil commits to utilizing the services of at least this number of local persons and firms through the development period of the Project. Statoil will use commercially reasonable efforts to allocate front end engineering & design (FEED) studies to Maine based companies as part of the Project definition towards the FID.

6. **Supplier Development Activities.** Statoil will apply an extended supplier development process as outlined in Attachment 1 attached hereto with the goal of maximizing local suppliers and contractors providing goods and services during construction and operation of the Project, including:

   - Initiating an early market screening process to systematically identify and assess potential Maine suppliers and contractors.
   - Holding dedicated supplier workshops targeting local suppliers for the Project.
   - Performing studies with Maine suppliers to familiarize the suppliers with the Project, to understand the deliverables, to identify challenges and bottlenecks and to bring forward the suppliers' proposals for methodology improvements and process simplifications.
   - Arranging and conducting tailored training events for parts of the supply chain, including vessels and harbors, steel manufacturing, construction infrastructure, logistics and transport, onshore electrical facilities, marine operations and installation.
   - Statoil commits to nominate local suppliers for all areas in which local capabilities are present or can be developed, and Statoil will prequalify local suppliers for contract tendering to the greatest reasonable extent. In lieu of nomination for direct contracting with Statoil, Maine-based vendors may be nominated as sub-suppliers under Statoil's contracts.
   - During tender evaluation, Statoil will include local content as one of the evaluation criteria. Statoil commits to award contracts to Maine based contractors and suppliers whenever a technically acceptable bid is present on commercially reasonable terms and at a cost that is not materially in excess of alternative goods or services.

7. **R&D Collaboration.** Statoil has established a Collaboration Program within technology development with the University of Maine (UMaine) to use the Advanced Structures & Composites Center's capabilities in materials development and testing. The Program will cover important areas of technology development for establishing a commercially viable offshore wind industry over time. The program was intiated in 2nd half of 2012 and will gradually be extended as the project matures. Statoil foresees the involvement of Maine based manufacturing industries as contributors within this Program. Statoil will enter into an agreement with UMaine through which Statoil will share certain Intellectual Property Rights developed through the program.

8. **Large Park Commitment.** Statoil will involve Maine contractors and suppliers in any large park development utilizing the Hywind technology on the Northeast U.S. coast (Maryland to Maine), which Statoil places into service prior to 2025. Statoil will work actively with Maine contractors and suppliers who were pre-qualified for the Project to assist them to become pre-qualified for the larger project.

   In evaluating contractor and supplier bids for any such future Northeast park, Statoil will first comply with any local content requirements and other legal obligations it is required to meet in order for the project to be successful.

   Subject to such requirements, Statoil will use good faith, diligent efforts to award contracts representing not less than the lessor of 10% of capital expenditures in the future Northeast park or $100 million to qualified Maine-based contractors and suppliers provided that Statoil determines that Maine-based suppliers or contractors have submitted technically acceptable bids on commercially reasonable terms and at a cost that is not materially in excess of alternative goods or services.

For purposes of this Term Sheet, the term "commercially reasonable efforts" as referred to above means good faith diligent efforts to achieve identified local economic benefits provided that qualified local contractors, suppliers or employees are available to provide goods or services that meet Statoil's quality and technical standards at a cost that is not materially in excess of alternative goods or services.

Further, for purposes of this Term Sheet, the terms "capital expenditures" and "O&M expenditures" shall mean expenditures as budgeted per August 2012 (cited in Statoil's letter to the PUC dated August 15, 2012).

Process Outline for Documentation of Local Content

Not later than one year after the Contract is executed by the parties, Statoil shall prepare and file a report (the Initial Local Benefit Report) with the Commission documenting how the project is progressing in achieving the local economic benefits. Statoil shall file an updated version of this report prior to commencement of construction (the Pre-Construction Report). To the extent that Statoil did not achieve the committed local benefits, Statoil's report shall explain why it was not commercially reasonable to do so. Statoil shall further file reports documenting the local benefits in the operational phase, annually for the first 5 years after COD, and every 3 years thereafter during the Contract Term.[2]

If at any time after COD the Commission Staff or the T&D Utilities, at their option, believe that Statoil has failed to comply with its obligation, the Commission Staff and/or the T&D Utilities may convene an informal conference of Parties to remedy the dispute. Statoil shall participate in such informal conference. If the dispute cannot be remedied by the informal conference process, the Commission may, at its option, open a proceeding to determine whether Statoil has complied with the obligations set forth in this provision. Statoil shall have all the due process rights accorded to parties under Chapter 110 of the Commission's Rules, including a right to hearing at which Statoil would have the opportunity to present evidence to support the reasonableness of its efforts. If, after notice and an opportunity for hearing, the Commission determines that Statoil has failed to comply with this provision, the Commission may assess a reasonable payment, the amount of which is within the Commission's sole discretion, provided that payments assessed by the Commission shall not exceed 7% of the revenue in any given year generated within the annual cap of 41 GWh. In reaching a determination of the amount of the payment, the Commission shall consider the magnitude of the deficiency associated with Statoil's failure to comply with its contractual obligation. The Commission may also notify Statoil what actions may be taken by Statoil within a specified timeframe to cure the deficiency and avoid the payment.

The Contract will contain a contract termination provision as set forth herein. Upon Statoil's filing of the Pre-Construction Report, the Commission may initiate an expedited adjudicatory proceeding to evaluate the Pre-Construction Report and to determine whether Statoil has achieved, or is likely to achieve a significant portion of the local economic benefits set forth above. In such a proceeding, which shall be concluded within 90 days of submission of the Pre-Construction Report, Statoil shall have all of the due process rights accorded to parties under Chapter 110 of the Commission's Rules, including a right to hearing at which Statoil would have the opportunity to present evidence. If, after notice and hearing, the Commission finds that Statoil is not likely to achieve a significant portion of the local economic benefits set forth in numbered items 1, 3, 5, 6 and 7 above, the Commission may declare the Contract terminated, and Statoil and the

[2] See Attachment 2 for illustration of this process.

Utilities shall have no further obligations to one another under the Contract. For purposes of the foregoing sentence, a significant portion of the capital expenditure commitment means that Statoil will allocate to Maine suppliers or spend in Maine at least 30% of the capital investments.This commitment is illustrated in Attachment 3. If Statoil disputes the Commission's findings or conclusions, Statoil may appeal to the Maine Supreme Judicial Court. During the pendency of any such appeal, the Contract termination shall be stayed, but Statoil will not initiate construction of the Project pending a final decision. In the event of a termination pursuant to this paragraph, Statoil will not be subject to payment obligations under this section. The Commission may not initiate a termination of the Contract under this paragraph after the commencement of construction of the Project.

Termination Right: In the event that any of the following events occur, Statoil has the right to terminate the Contract by written notice to the T&Ds without any liability or obligation to Statoil or the T&Ds, and upon such termination each Party will return any unused credit support provided as performance security to the issuing Party:

a) notwithstanding Statoil's good faith efforts, Statoil is unable to obtain all necessary State and Federal permits by January 1, 2015,
b) prior to January 1, 2015, the investment tax credit or any Department of Energy support which may have been awarded to Statoil to develop the Project are materially adversely modified with respect to the Project or have not been extended to cover the full expected construction period of the Project,
c) prior to January 1, 2015 the Project fails to obtain the necessary internal approvals from Statoil and its parent Statoil ASA, or
d) the Commercial Operations Date is not achieved on or before the date that is 5 years after the execution date of the Contract.

[Attachments 1-3 Redacted]

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2010-235

April 27, 2012

MAINE PUBLIC UTILITIES COMMISSON
Ocean Energy Long-Term Contracting

ORDER APPROVING TERM SHEET

WELCH, Chairman; VAFIADES and LITTELL, Commissioners

I. SUMMARY

Through this Order, we approve, contingent on the conditions and clarifications described in this Order, the Term Sheet for a Long-Term Contract for the capacity and associated energy of Ocean Renewable Power Company's (ORPC) Maine Tidal Energy Project dated March 28, 2012 (Term Sheet) (attached hereto as Attachment 1).[1] ORPC's Maine Tidal Energy Project (Project) is a less than 5 MW hydrokinetic facility to be constructed in Washington County, Maine in tidal waters off the coast of the towns of Perry, Eastport, and Lubec. The Project is expected to begin commercial operation by the fall of 2012.

II. BACKGROUND

A. Ocean Energy Request for Proposals (RFP)

During its 2010 session, the Maine Legislature enacted An Act To Implement the Recommendations of the Governor's Ocean Energy Task Force (Ocean Energy Act). P.L. 2009, ch. 615. Section A-6 of the Ocean Energy Act directed the Maine Public Utilities Commission (Commission), in accordance with Title 35-A, section 3210-C of the Maine Revised Statutes, to conduct a competitive solicitation for proposals for long-term contracts to supply installed capacity and associated renewable energy and renewable energy credits (RECs) from one or more deep-water offshore wind energy pilot projects or tidal energy demonstration projects.

For purposes of the competitive solicitation, "deep-water offshore wind energy pilot project" means a wind energy development, as defined by Title 35-A, section 3451, subsection 11, that is connected to the electrical transmission system located in the State and employs one or more floating wind energy turbines in the Gulf of Maine at a location 300 feet or greater in depth and no less than 10 nautical miles from any land area of the State other than coastal wetlands, as defined by Title 38, section 480B, subsection 2, or an uninhabited island. "Tidal energy demonstration project" has the same meaning as in Title 38, section 636A, subsection 1, paragraph A.

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[1] Chairman Welch did not participate in this decision.

Specifically, a "tidal energy demonstration project" means a hydropower project that uses tidal action as a source of electrical power that has a total installed generating capacity of 5 megawatts or less and is proposed for the primary purpose of testing tidal energy generation technology, which may include a mooring or anchoring system and transmission line, and collecting and assessing information on the environmental and other effects of the technology.

As specified in the Ocean Energy Act, the Commission may authorize one or more long-term contracts for an aggregate total of no more than 30 megawatts of installed capacity and associated renewable energy and RECs from deep-water offshore wind energy pilot projects or tidal energy demonstration projects as long as no more than 5 megawatts of the total is supplied by tidal energy demonstration projects.

As required by the Ocean Energy Act, the Commission initiated a competitive solicitation by issuing a Request for Proposals for Long-Term Contracts for Deep-Water Offshore Wind Energy Pilot Projects and Tidal Energy Demonstration Projects (RFP) on September 1, 2010. Responses to the RFP were received on May 2, 2011. Commission Staff performed an initial review of all proposals received, prioritized proposals and conducted in-depth discussions with several bidders. Projects were evaluated based on cost considerations, overall project viability, including financial, environmental and other site approvals, construction schedule, operational characteristics and the following evaluation criteria as required in the Ocean Energy Act.

Specifically, the Ocean Energy Act states that the Commission may direct one or more T&D utilities, as appropriate, to enter into a long-term contract pursuant to the RFP only if it determines that the bidder:

A. Proposes sale of renewable energy produced by a deep-water offshore wind energy pilot project or a tidal energy demonstration project as defined in the RFP;

B. Has the technical and financial capacity to develop, construct, operate and, to the extent consistent with applicable federal law, decommission and remove the project in the manner provided by Title 38, section 480HH, subsection 3, paragraph G;

C. Has quantified the tangible economic benefits of the project to the State, including those regarding goods and services to be purchased and use of local suppliers, contractors and other professionals, during the proposed term of the contract;

D. Has experience relevant to tidal power or the offshore wind energy industry, as applicable, including, in the case of a deep-water offshore wind energy pilot project proposal, experience relevant to the construction and operation of floating wind turbines, and has the potential to construct a deep-water offshore wind energy project 100 megawatts or greater in capacity in the future to provide electric consumers in Maine with project-generated power at reduced rates;

E. Has demonstrated a commitment to invest in manufacturing facilities in Maine that are related to deep-water offshore wind energy or tidal energy, as applicable, including, but not limited to, component, turbine, blade, foundation or maintenance facilities; and

F. Has taken advantage of all federal support for the project, including subsidies, tax incentives and grants, and incorporated those resources into its bid price.

As required by the Ocean Energy Act, the Commission consulted with representatives of the University of Maine, Department of Industrial Cooperation, Office of Research and Economic Development and the Department of Economic and Community Development at relevant points in the RFP process, including RFP development and proposal evaluation.

Additionally, as required by the Ocean Energy Act, long-term contracts authorized pursuant to the RFP may not, in the aggregate, result in increased electric rates for any customer class that is greater than the amount of the assessment charged under Title 35-A, section 10110, subsection 4 at the time that the contract is entered. That assessment is currently $1.45 per MWh.[2]

B. Term Sheet

On March 28, 2012, ORPC proposed a final Term Sheet containing the essential terms of a Long-Term Contract for energy and capacity from the Project (Long-Term Contract) for Commission consideration. Central Maine Power Company (CMP), Bangor Hydro Electric Company (BHE), Maine Public Service Company (MPS) (collectively referred to as Utilities), and the Office of the Public Advocate (OPA) were given the opportunity to comment on the Term Sheet, and all provided comments on April 5, 2012. ORPC also provided comments on the Term Sheet on April 5, 2012, followed by April 12, 2012 responsive comments to the Utilities' and OPA's comments. The Term Sheet and comments on the Term Sheet are described in this Order below.

[2] The Commission has previously concluded that the Legislature intended that customers that take service at transmission and subtransmission voltage would not have a rate impact resulting from any ocean energy long-term contracts. *Order on Rate Impact Limitation Provision*, Docket No. 2010-235 (Sept. 28, 2010). Accordingly, the costs of the contract will be allocated to customers taking service at the distribution level.

III. PROPOSED TERM SHEET

The proposal under consideration is a Term Sheet that contains certain contract terms for a Long-Term Contract between ORPC and the Utilities for energy produced by the Project up to the energy quantities specified in the Term Sheet and any capacity value received by the Project in the ISO-NE market.

The Term Sheet provides for a contract term of twenty (20) years beginning on October 1, 2012. The Term Sheet lays out two pricing options for the energy to be purchased under the Long-Term Contract, one of which is to be chosen by the Commission. Pricing Option 1 is an initial price of $215/MWh for energy provided during the first year of the Contract (until September 30, 2013) that escalates at 2.0% per year thereafter for each subsequent contract year over the contract term. Option 2 is an initial price of $266/MWh for energy provided during the first year of the contract (until September 30, 2013) that escalates at the yearly growth in the aggregate retail sales to distribution voltage customers. The quantity of energy to be purchased under the Long-Term Contract is subject to annual, monthly, and hourly caps as outlined in the Term Sheet. To the extent the actual energy produced by the Project is less than the annual energy cap, the difference between the cap and the quantity produced may be carried forward to the following contract year and sold as part of the Long-Term Contract in addition to the annual energy cap in that following contract year only.

As provided in the Term Sheet, the capacity component of the proposed Long-Term Contract is, in essence, a pass-through transaction whereby ORPC would receive a price for any capacity it provides based on the prevailing market value for such capacity. ORPC must use commercially reasonable efforts to qualify the capacity of the Project in the ISO-NE market.

The Term Sheet states that ORPC will use commercially reasonably efforts to pursue and acquire state, federal, non-profit organization, for-profit organization, and other grant and subsidy opportunities applicable to the Project. The Term Sheet provides that 75% of any external grants acquired will apply to reducing the costs of the Long-Term Contract to ratepayers and 25% will be retained by ORPC. This grant sharing does not apply to grants already received by ORPC or to grants or other support anticipated by ORPC and communicated to the Commission Staff during Term Sheet negotiations and incorporated in the proposed pricing contained in the Term Sheet.

The Term Sheet also includes numerous non-pricing terms intended to ensure that economic benefits anticipated to accrue to the State as a result of the Project will be realized. These terms include a commitment by ORPC to maintain or establish manufacturing, assembly, and testing operations in Maine, to continue its partnerships with entities in the Washington County region, and to upgrade distribution lines in Lubec, Maine. The terms also commit ORPC to create and/or retain at least 80 direct full-time equivalent jobs in Maine during the development, construction, and installation of the Project, to create and/or retain at least 12 direct full-time equivalent jobs in Maine during the operation and maintenance phase of the Project, and to use commercially reasonable efforts to expend at least 50% of the capital investments and 50% of the operating expenditures for the Project in Maine. The Term Sheet provides for financial payments for failure to deliver on these commitments not to exceed 7% of total revenue in any given year.

IV. COMMENTS

A. Utilities' Comments

On April 5, 2012, CMP, BHE, and MPS submitted comments expressing concerns regarding the ORPC Term Sheet. As a general matter, the Utilities are concerned the Contract will raise electricity costs for customers, although they recognize that this Contract appears to comply with the provisions of the Ocean Energy Act, specifically that any increase in electric rates in any customer class be no greater than the amount of the assessment charged under Title 35-A, section 10110, subsection 4 at the time that the contract is entered. The Utilities also express concern about not being engaged in the RFP process, resulting in an inability to fully comment on the compliance of the Term Sheet with statutory requirements. Additionally, the Utilities express concern that many of the details associated with the commercial terms of the Contract have not been finalized in the Term Sheet. For instance, the Utilities point out that the Term Sheet is silent on the level and need for financial assurance.

CMP is also concerned about other contractual provisions that are not included in the Term Sheet. CMP suggests the Term Sheet should include a provision that specifies that energy should be transferred through internal bilateral transactions in the market settlement system administered by ISO-NE. CMP expresses further concern that the Term Sheet is silent on ORPC's obligation to perform under the terms of a Long-Term Contract. CMP states that there should also be further clarity on how the proceeds from any future grants are actually conveyed to the Utilities.

CMP expresses a preference that capacity not be included in the Contract, as CMP interprets the statute as allowing the Contract to not include capacity just as the proposed Term Sheet presently does not include RECs. CMP also expresses preference for pricing Option 1. With regard to the non-pricing terms, CMP states that the non-pricing terms should not be included in the Contract on the basis that it should not be CMP's responsibility to monitor and enforce the non-pricing term provisions.

BHE and MPS, who filed joint comments, express concern that the methodology for allocating the energy and capacity among BHE, MPS, and CMP has not been determined in the Term Sheet. BHE and MPS suggest that purchase and resale of energy and capacity be structured as a financial transaction. With regard to grant sharing, BHE and MPS express a preference that 100% of any future grants be applied to reducing the Contract costs. BHE and MPS also express concern that it would be too challenging and burdensome for them to monitor ORPC's compliance with using commercially reasonable efforts to pursue and acquire grants or other subsidies or to comply with the non-pricing terms. BHE and MPS suggest any future Order provide more details on the Commission's and ORPC's responsibilities associated with enforcing compliance for grant and non-pricing related requirements.

BHE and MPS also express individual concerns unique to each utility. BHE states that it is concerned about its ratepayers bearing a disproportionate burden of the costs arising out of long-term contracts, as this Contract with ORPC will add to the above-market contracts that were created as part of the Community-Based Renewable Energy Pilot Program. MPS is concerned that little to no economic development benefits will accrue to MPS ratepayers because the project construction will not be in MPS territory and because MPS is not connected to ISO-NE.

B. OPA Comments

The OPA submitted comments on the Term Sheet on April 5, 2012. The OPA, on the whole, expresses support for the Contract, as the OPA views it as an effective means of fulfilling the Legislature's desire that the Commission pursue long-term contracts for offshore renewable energy projects. The OPA suggests the Term Sheet itself reveals that ORPC has quantified the tangible economic benefits to the State of Maine, and that the Term Sheet also addresses subsection 2.A. of the Ocean Energy Act (requiring supplier to take advantage of future federal support), although the OPA observes that the Term Sheet does not illustrate how provisions of subsection 2.B. are to be addressed (subsection 2.B. of the Ocean Energy Act requires that the Commission use available state funds to mitigate long-term contract impacts on ratepayers). The OPA's significant concern is that the 75%/25% split in allocation between ratepayers and ORPC in any future grant money is too generous to ORPC, and ORPC should be allowed to retain no more than 15% of any future grants. The OPA states this level should still allow for sufficient incentive to developers while relieving as much as possible the burden on ratepayers.

C. ORPC Comments

ORPC submitted comments in support of the Term Sheet on April 5, 2012. ORPC's comments outline recent company and project milestones, including that the Cobscook Bay Tidal Energy Project (CBTEP), a portion of the Maine Tidal Energy Project, that received its Federal Energy Regulatory Commission (FERC) pilot project license in February, 2012. Having received the permit, ORPC deployed its first bottom support frame for a turbine generator unit on March 20, 2012. According to ORPC, it has already created and/or retained 65 full-time equivalent jobs in Maine, and 38 contractors have been providing services at the construction site.

ORPC's comments also quantify the Project's economic benefits to Maine using the Jobs and Economic Development Impact (JEDI) model developed by the National Renewable Energy Laboratory (NREL) of the U.S. Department of Energy (DOE). ORPC states that the Project would result in \$8.1 million in earnings and \$22 million in economic output during the construction phase, and \$0.7 million per year in earnings and $1.1 million per year in economic output during the operating years. The model estimates that the construction phase of the Project will create 125 full-time equivalent jobs in Maine, 23 of which would be direct jobs, with another 67 inter-industry or supply-chain jobs, and 33 induced jobs resulting from increases in household spending. During the operation phase, the model predicts 19 new full-time equivalent jobs annually in Maine, comprising 15 direct jobs, 2 supply chain jobs, and 1 induced job.

ORPC also states it has spent more than $14 million since 2007 in 13 of the 16 counties in Maine and has created or retained more than 100 jobs statewide. This spending includes approximately $4.2 million in the Eastport/Lubec area alone. ORPC indicates that as of 2012, ORPC has worked and is working with 85 Maine businesses, including Perry Marine and Construction, Morris Manufacturing Inc., Newport Industrial Fabrication, and R.M. Beaumont Inc. In addition, ORPC indicates that Hall Spars & Rigging, a global composites manufacturing firm headquartered in Bristol, Rhode Island, plans to open a division in southern Maine for long-term manufacturing of ORPC's turbines.

ORPC's comments discuss ORPC's involvement with ongoing research and development efforts, including seeking federal funding for projects to develop a subsea medium voltage DC network to reduce transmission losses, and to develop a commercially viable RivGen Power System. ORPC states the Maine Tidal Energy Project has generated considerable interest from the scientific community and researchers at the University of Maine, leading to many published papers and presentations.

ORPC also submitted reply comments on April 12, 2012 in response to the comments filed by the Utilities and the OPA. ORPC reiterates the quantification of tangible economic benefits, states that the existing pricing proposal accounts for grants sought and received, including existing funding received from DOE and the Maine Technology Asset Fund. ORPC defends the 75%/25% split between ratepayers and ORPC of any future grants received, asserts that requiring a financial security for the project would create an unnecessary and onerous burden on ORPC, and agrees that the Commission should choose between the pricing options in the Term Sheet, while registering ORPC's preference for Option 2.

V. DISCUSSION

A. Statutory Criteria

We assess the proposed terms of a Long-Term Contract as outlined in the Term Sheet in accordance with the requirements of the Ocean Energy Act and as informed by the Final Report of the Ocean Energy Task Force.[3] In enacting the legislation, the Legislature recognized the potential public benefits that could accrue to the State by providing economic incentives to encourage the development of offshore wind, tidal and wave power energy resources. The Ocean Energy Act envisions these projects as technology demonstration projects that would provide direct economic benefits of research, testing, and development occurring in Maine; lay a foundation for Maine to be global leader in offshore wind and tidal technology development; and develop Maine's own indigenous natural resources. The economic incentives inherent in a long-term power purchase agreement are intended by the Ocean Energy Act to support the development of a very limited number of technology demonstration projects by providing for above-market prices to be paid for electricity produced by the projects. The Ocean Energy Act limits the impact on ratepayers as discussed below by limiting the overall impact on rates. The Ocean Energy Act also specifically requires the Commission to ensure that the Legislature's intent to foster technological development, support job creation and encourage economic development in Maine is honored.

1. Supplier Requirements

As noted above, pursuant to the Ocean Energy Act and as provided in the RFP, the Commission may order a long-term contract only if it determines that the potential supplier satisfies several specified criteria. Each of these statutory criteria is analyzed below:

Supplier proposes sale of renewable energy produced by a deep-water offshore wind energy pilot project or a tidal energy demonstration project:

The project proposed is a tidal demonstration project, employing a novel cross-flow hydrokinetic turbine design. The mooring structure to anchor the turbine generator units is also new, and part of the Project is expected to include ORPC's envisioned OCGen module, that employs a neutrally buoyant generator system tethered to the seafloor.

Supplier has the technical and financial capacity to develop, construct, operate and, to the extent consistent with applicable federal law, decommission and remove the project in the manner provided by Title 38, section 480HH, subsection 3, paragraph G:

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[3] Maine Ocean Energy Task Force, 2009. *Final Report of the Ocean Energy Task Force to Governor John E. Baldacci*. Available online at: http://www.maine.gov/spo/specialprojects/OETF/

We find that ORPC has the technical and financial capacity to develop, construct, operate, and decommission and remove the Project. ORPC has been working in Maine since 2007 and has demonstrated its ability to successful build and test a cross-flow hydrokinetic turbine prototype, attract grant funds, and develop supply chains for the Project. In the summer of 2011, ORPC successfully deployed and tested its prototype in Cobscook Bay. Additionally, ORPC has posted financial security for 100% of the projected decommissioning and removal costs of the Cobscook Bay installation as required by the FERC pilot license issued for the Project on February 27, 2012.

> <u>Supplier has quantified the tangible economic benefits of the project to the State, including those regarding goods and services to be purchased and use of local suppliers, contractors and other professionals, during the proposed term of the contract</u>:

The Commission concludes that ORPC has quantified the tangible economic benefits of the Project to the State. As outlined in ORPC's comments, the NREL JEDI model estimates that the Project would result in $8.1 million in earnings and $22 million in economic output during the five-year construction phase and $0.7 million per year in earnings and $1.1 million per year in economic output during the subsequent 15-year operating phase. The model estimates that during the construction phase, the Project will create 125 full-time equivalent jobs in Maine, 23 of which would be direct jobs, with another 67 inter-industry or supply-chain jobs, and 33 induced jobs resulting from increases in household spending. During the operation phase, the Project is anticipated to create 19 new full-time equivalent jobs annually in Maine, comprising 15 direct jobs, 2 supply chain jobs, and 1 induced job. ORPC has already spent approximately $14 million in Maine since 2007, including approximately $4.2 million in the Eastport/Lubec area alone.

> <u>Supplier has experience relevant to tidal power or the offshore wind energy industry, as applicable, including, in the case of a deep-water offshore wind energy pilot project proposal, experience relevant to the construction and operation of floating wind turbines, and has the potential to construct a deep-water offshore wind energy project 100 megawatts or greater in capacity in the future to provide electric consumers in Maine with project-generated power at reduced rates</u>:

We find that ORPC has the experience relevant to tidal power to construct and operate the Project. ORPC is a global leader in the hydrokinetic tidal industry, and is one of only two developers to have received a FERC pilot license for installation and operation of a hydrokinetic tidal project.

> Supplier has demonstrated a commitment to invest in manufacturing facilities in Maine that are related to deep-water offshore wind energy or tidal energy, as applicable, including, but not limited to, component, turbine, blade, foundation or maintenance facilities:

We find that ORPC has demonstrated a commitment to invest in manufacturing facilities in the State of Maine. As a result of ORPC's development efforts leading to the deployment of the Project, Perry Marine & Construction (PMC) has purchased a site in Eastport with deep-water access, to serve as a location for equipment delivery, storage, component assembly, and overall construction services in support of the Project. Additionally, ORPC has worked with Morrison Manufacturing, Inc. of Perry, Maine to provide other subcontract services, including driving pilings for the Project. ORPC has contracted with Newport Industrial Fabrication of Newport, Maine to fabricate the bottom support chain and chassis for the turbine generator unit. And finally, ORPC indicates that it is working with Hall Spars & Rigging, a global composites manufacturing firm headquartered in Bristol, Rhode Island, on a plan to open a division in Maine for long-term manufacturing of ORPC's turbines.

> Supplier has taken advantage of all federal support for the project, including subsidies, tax incentives and grants, and incorporated those resources into its bid price:

ORPC has taken advantage of, and has committed in the Term Sheet to continue to pursue, federal support for the Project. To-date, ORPC has been awarded a $10 million DOE grant to commercialize their TidGen Power System, a $1.26 million grant from the Maine Technology Asset Fund, and a $900,000 DOE Small Business Technology Transfer Program (STTR) grant for the refinement of their cross flow hydrofoils. ORPC has applied for the U.S. Treasury section 1603 payments in lieu of tax credits for the first phase of the Project, and expects to be able to use investment tax credits for the remainder of the Project and has incorporated these tax credits into its financial model. The second phase of the Project qualifies for the U.S. Treasury New Markets Tax Credit Program, and ORPC has committed to continue to seek additional grants and to allocate 75% of any such grants to defray the cost of the Contract to ratepayers.

2. Rate Impact Limitation

To explicitly limit the rate impact of the economic incentives provided for ocean energy demonstration projects, the Ocean Energy Act contains a rate impact limitation provision that requires that the Commission may not approve any long-term contract that would result in an increase in electric rates in any customer class that is greater than the amount of the assessment charged under Title 35-A, section 10110, subsection 4 at the time that the contract is entered. The current assessment is $1.45 per MWh.

The Commission has conducted economic modeling incorporating the proposed prices and amounts of electricity expected to be purchased under the Long-Term Contract and incorporating electricity price forecasts provided by the Commission's consultant, London Economic Inc. (LEI), to determine that the Long-Term Contract would not result in an increase electric rates in any customer class that is greater than the amount of the assessment. Based on this analysis, we estimate that the total above-market costs that would result from the pricing proposed in the ORPC Term Sheet under pricing Option 1 would be in the range of $16 million on a present value basis or about $37.5 million (nominal undiscounted payments over 20 years). This above-market cost would result in a rate impact of approximately $0.30 per MWh,[4] an amount that is well within the statutory rate impact limitation, and allows for possible future consideration other ocean energy projects contemplated by the statute, specifically for deep water offshore wind projects.

Thus, we conclude that a Long-Term Contract based on the Term Sheet satisfies the stated statutory criteria to limit rate impact.

B. Pricing Options

As described above, the Term Sheet contains two pricing options and contemplates that the Commission determine the option that would be included in the Contract. The two pricing options are: 1) an initial price of $215/MWh for energy provided during the first year of the Contract that escalates at 2.0% per year thereafter for each subsequent contract year over the contract term; and 2) an initial price of $266/MWh for energy provided during the first year of the Contract that escalates at the yearly growth in the aggregate retail sales to distribution voltage customers.

We determine that pricing Option 1 is preferable and select Option 1 to be included in the Long-Term Contract with ORPC. Although we cannot determine with certainty which option would result in lower costs to ratepayers because prices under Option 2 are a function of future load growth, Option 1 starts at a lower price and would result in modestly lower ratepayer costs under our modeling of rate impacts.

C. Economic Analysis

In considering the approval of the Term Sheet, we consider the likely benefits of the Project to the State in relation to the above-market costs resulting from a Long-Term Contract with ORPC. The balance between the tangible economic benefits provided by the Project to Maine and the cost of the economic incentive provided by the

[4] For an average residential Maine ratepayer, assumed to use 500 kWh/month, this rate impact results in an increase of approximately 15 cents per month.

Long-Term Contract can be separated into four categories of economic benefits consistent with the intent of the Ocean Energy Act:

- First, direct wage growth in Maine will benefit from the Project. Based on our modeling, the present value of the projected wage earnings in Maine generated by the Project is roughly commensurate with the present value of the projected above-market costs associated with the pricing contained in Option 1 of the Term Sheet.

- Second, direct investment in Maine will be supported by the Project. The present value of the projected above-market cost of Option 1 is a fraction of the total projected capital expenditures associated with the construction and deployment of the Project that are anticipated to be spent in Maine and the future investment levels that result from ORPC's on-going commitment to expend at least 50% of capital investments and 50% of the operating expenditures in Maine.

- Third, general economic conditions will improve as a result of the Project. The projected additional economic output in the State as a result of the Project approaches twice the present value of the projected above-market costs of Option 1.

- Finally, although not easily quantifiable as the other economic benefits provided by the Project of increases in earnings, capital investment, and general economic activity, the knowledge generation from technological development, the creation of intellectual capital, and the development of an expert workforce that is associated with technological developments such as this Project is at least as valuable a factor in long-term economic growth as increases in labor or capital.[5]

To ensure that the anticipated economic benefits are realized, the Term Sheet includes specific job creation and spending obligations on the part of ORPC for those quantified benefits. The Term Sheet includes a provision that the Commission may impose reparatory financial payments by ORPC that would flow back to ratepayers.

Based upon the preceding analysis and in conformance with the Ocean Energy Act, we approve the Term Sheet with the following conditions and clarifications and delegate to the Director of Electric and Gas Utility Industries the authority to approve the final Long-Term Contract developed in compliance with this Order.

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[5] See, for example, Warsh, David, 2006. *Knowledge and the Wealth of Nations: A Story of Economic Discovery*. W. W. Norton: New York, New York. 320 pp.

D. Other Issues

Several other issues are raised by the review of the Term Sheet. These are discussed below.

1. Contract Allocation

BHE and MPS express concern that the methodology for allocating the purchased energy and capacity between BHE, MPS, and CMP has not been determined. The purpose of the Ocean Energy Act in promoting deep-water offshore wind energy pilot projects or tidal energy demonstration projects is to provide economic benefits to the State generally. Therefore, it is appropriate to allocate the Contract costs to the ratepayers of all three of the Utilities on a pro rata basis. The precise methodology for accomplishing this allocation will be a matter for Contract discussions and will be approved by the Director of the Electric and Gas Utility Industries.[6]

2. Contract Products and Structure

CMP expresses a preference that capacity not be included in the Contract. We conclude that there should be a capacity term in the Contract. However, we do not expect the Utilities to have any significant role or exposure to risk in matters related to qualifying or bidding the capacity in the ISO-NE market.

BHE and MPS suggest that purchase and resale of energy and capacity be structured as a financial transaction. CMP suggests that the Term Sheet include a provision that specifies that energy should be transferred through internal bilateral transactions in the market settlement system administered by ISO-NE. These matters will be addressed during the development of the Contract terms.

3. Future Grants

The Term Sheet provides that 75% of any future external grants acquired will apply to reducing the costs of the Contract, with 25% retained by ORPC. BHE and MPS express a preference that 100% of any future grants be applied to reducing the Contract costs and the OPA suggested ORPC should be allowed to retain no more than 15% of any future grants.

We find that the 75%/25% allocation of future grants represents a reasonable balance in that a substantial amount of any such grants will be used to reduce the costs of the Contract for ratepayers, while ORPC retains a financial incentive to aggressively pursue any future applicable grants. We also note that too great an allocation to ratepayers, as opposed to the Project itself, may put at risk ORPC's ability

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[6] For example, a Long-Term Contract between ORPC and all three Utilities may not be the most efficient means to allocate costs among the Utilities. An alternative approach may be a cost-sharing agreement among two or more of the Utilities.

to secure future grants. Accordingly, we request that ORPC notify the Commission of any barriers in securing future grants due to the structure of the 75%/25% allocation and propose an alternative mechanism to provide ratepayers with comparable benefits.

4. Enforcement Responsibility

CMP prefers that the non-pricing terms not be included in the Contract, because it should not be its responsibility to monitor and enforce the non-pricing term provisions. BHE and MPS also express concern that it would be too challenging and burdensome for them to monitor ORPC's compliance with the non-pricing terms and suggest that the Commission provide more details on the responsibilities associated with enforcing compliance for non-pricing related requirements.

We understand the Utilities' concern in this regard. We do not expect the Utilities to have significant responsibilities regarding the enforcement of the non-pricing terms. However, we conclude that the non-pricing terms should be included in the Long-Term Contract. The specific details of the enforcement responsibilities of the parties and the Commission will be a subject during Contract discussions.

5. Obligation to Perform and Performance Assurance

The Utilities point out that the Term Sheet is silent on ORPC's obligation to perform, as well as the level and need for financial assurance. ORPC's obligation to perform will be specified in the Contract. The Long-Term Contract shall include adequate financial assurance consistent with the requirements of the RFP to secure that obligation. Because the pricing in the Contract is above-market, performance assurance would primarily be to secure ORPC's non-pricing obligations.

As noted above, the Term Sheet does have provisions that obligate ORPC to make payments to the Utilities if it fails to use commercially reasonable efforts to comply with the non-pricing terms. However, the Term Sheet is silent on the consequences of a significant material breach of the non-pricing terms. Thus, the Long-Term Contract should contain a contract termination provision in the event of a significant material breach of the non-pricing terms that is not remedied. The details of this provision will be included in the Long-Term Contract.

6. Decommissioning

As noted above, ORPC's FERC license requires it to have financial security in place to assure the proper decommissioning of the facility. We find the FERC requirement to be sufficient. However, we conclude that the Long-Term Contract should include a provision that indicates that ORPC will comply with directives from any applicable State agency with respect to decommissioning the Project consistent with the Ocean Energy Act.

Accordingly, we

ORDER

1. That the initial Contract provisions contained in the Term Sheet, as amended in this Order, are approved, contingent upon the successful negotiation and approval of the final Long-Term Contract with ORPC;

2. That Central Maine Power Co., Bangor Hydro Electric Co. and Maine Public Service Co. actively participate in good faith in the subsequent Long-Term Contract negotiations between Staff and ORPC;

3. That approval of a final Long-Term Contract with ORPC consistent with the Term Sheet approved by this Order is delegated to the Director of Electric and Gas Utility Industries;

4. That Central Maine Power Co., Bangor Hydro Electric Co., and Maine Public Service Co. enter into a Long-Term Contract with ORPC, or such other arrangement to achieve the cost allocation consistent with this Order, that is approved by the Director of Electric and Gas Utility Industries; and

5. That consistent with RFP, the Term Sheet and the comments on Term Sheet shall be public information.

Dated at Hallowell, Maine, this 27th day of April, 2012.

BY ORDER OF THE COMMISSION

Karen Geraghty

Karen Geraghty
Administrative Director

COMMISSIONERS VOTING FOR: Littell
Vafiades

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 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 1004 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.

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.A. § 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.A. § 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.

ATTACHMENT 1

Proposed Term Sheet for ORPC Long-Term Contract

March 28, 2012

The following terms reflect the essential elements of a long-term contract for energy and capacity from the ORPC Project that will be negotiated in good faith by Ocean Renewable Power Corporation (ORPC), the Maine Public Utilities Commission (Commission), and the investor-owned transmission and distribution utilities (T&D Utilities), and is anticipated to be executed by ORPC and the T&D Utilities (hereinafter referred to as the Contract).

<u>ORPC Project</u>: The Maine Tidal Energy Project (the Project), as presented in the May 2011 Proposal by ORPC, comprised of the Turbine Generator Units and associated facilities placed into service in the Cobscook Bay, Kendall Head, and Western Passage sites.

<u>T&D Utilities</u>: Central Maine Power Company (CMP), Bangor Hydro Electric Company (BHE), and Maine Public Service Company (MPS).

<u>Contract Term</u>: The Contract Term is 20 years beginning October 1, 2012 (Contract Start Date) and ending September 30, 2032 (Contract End Date). All amounts and prices are provided on a Contract Year basis. Contract Year means the 12-month period beginning on the Contract Start Date and each successive 12-month period commencing on the annual anniversary of the Contract Start Date (Contract Year). For example, Contract Year 1 is October 1, 2012 through September 30, 2013 and Contract Year 2 is October 1, 2013 through September 30, 2014. Any adjustments to the Contract Start Date may result in changes to the amounts and prices contained in this term sheet.

<u>Contract Products</u>: The Contract Products to be purchased and sold under the Contract are Energy and Capacity. The Energy purchased and sold under the Contract must be produced by the Project and delivered to the ISO-NE energy market during the Contract Term. ORPC will use commercially reasonable efforts to qualify, clear and deliver Capacity from the Project in the ISO-NE Forward Capacity Market (FCM) (or successor market) such that Capacity purchased by the T&D Utilities receives full market value at the prevailing clearing price in the FCM (or successor market).

Energy and Capacity provided by the Project are the Contract Products. Energy provided by the Project will be sold to the T&D Utilities at the Contract Price. Capacity provided by the Project, if any, will be sold to the T&D Utilities and ORPC will receive market price at such time. RECs or other market products associated with the environmental attributes of the Project are not included in the Contract and the rights to such attributes are retained by ORPC.

<u>Contract Quantity-Energy</u>: The amount of Energy purchased and sold under the Contract is subject to the Annual Energy Cap as shown below. The amount of Energy purchased and sold under the Contract is further subject to an Hourly Energy Cap of 5.0 MWh/hr throughout the Contract Term and a Monthly Energy Cap equal to 1/10 (10%) of the amount of the Annual Energy Cap during the applicable Contract Year.

Contract Year	**Calendar Dates**	**Annual Energy Cap (kWh/Contract Year)**
1	10/1/12 to 9/30/13	65,789
2	10/1/13 to 9/30/14	538,313
3	10/1/14 to 9/30/15	2,521,777
4	10/1/15 to 9/30/16	4,850,155
5	10/1/16 to 9/30/17	9,472,085
6-20	10/1/17 to 9/30/32	11,306,528

At the conclusion of a Contract Year, if the actual energy produced by the Project is below the Annual Energy Cap (hereinafter referred to as an Annual Energy Shortfall), the number of megawatt-hours of Annual Energy Shortfall may be carried forward to the subsequent Contract Year and added to the Annual Energy Cap for only that immediately following Contract Year (Carry Forward Limitation).

Energy produced by the Project in excess of the applicable Annual or Monthly Energy Cap that does not qualify as an Annual Energy Shortfall carried forward to the subsequent Contract Year, will not be purchased or administered by the T&D Utilities and shall be retained by ORPC. Energy produced by the Project in excess of the Hourly Energy Cap will not be purchased or administered by the T&D utilities and shall be retained by ORPC.

<u>Contract Quantity-Capacity:</u> The amount of Capacity purchased and sold under the Contract shall be the amount of Capacity qualified, cleared and delivered in the ISO-NE Forward Capacity Market (FCM) (or successor market).

<u>Contract Pricing</u>: Contract Prices are specified by Contract Year and are stated in nominal dollar terms. As used herein, Contract Year 1 means October 1, 2012 through September 30, 2013.

Contract Pricing-Energy: Subject to the Annual, Monthly and Hourly Energy Caps as previously described, two Contract Pricing options for Energy are outlined below. ORPC must select one of the pricing options for the Contract Term, which option will provide the basis for the final Term Sheet.

Option 1. Contract Price would be $215/MWh for Energy provided during Contract Year 1 and would escalate at 2.0% per year for Energy provided during each subsequent Contract Year over the Contract Term.

Option 2. Contract Price for Energy provided during Contract Year 1 would be set at $266/MWh. Prices for Energy provided in subsequent years of the Contract Term would be established by reference to yearly variations in the aggregate retail sales of distribution voltage customers of CMP, BHE and MPS in accordance with the following formula:

$$\textbf{Price/MWh (Year N)} = \textbf{Price/MWh (Year N-1)} \times \frac{\textbf{Retail Sales (Year N-1)}}{\textbf{Retail Sales (Year N-2)}}$$

For purposes of applying this formula, aggregate retail sales of distribution voltage customers shall be determined on a calendar year basis.

Contract Pricing-Capacity: The Contract Price for Capacity shall be the market value per kW-month at the prevailing clearing price in the FCM (or successor market) received by the T&D utilities and passed through to ORPC in addition to the Contract Price for Energy.

Grants: ORPC will use commercially reasonable efforts to pursue and acquire State, Federal, non-profit organization, for-profit organization, and other grant and subsidy opportunities applicable to the Project, including those that provide for the reduction of capital or financing costs, or construction and/or operating costs of the Project. For any such grants received, ORPC will apply 75% of the amount realized (after tax) as a Credit to Ratepayers against the costs of this Contract. The timing of such Credits to Ratepayers shall be consistent with the timing of the amounts received by ORPC for Grants. This provision does not apply to any new funding that is obtained that requires repayment, such as a loan.

Non-pricing terms:

- ORPC will maintain or establish in Maine, concentrated in the Eastport-Lubec, Maine area, operations, monitoring, manufacturing, fabrication, assembly, testing, inspection, maintenance and repair service base for its tidal energy power systems to the extent practicable, including system components and related sub-assemblies. If practicable, ORPC will expand this local service base over the Contract Term.

- During the development, construction and installation of all phases of the Project, ORPC will use commercially reasonable efforts to create and/or retain at least 80 direct full-time equivalent jobs in Maine. Jobs created or retained by the Project from May 2, 2011 to the date of the execution of the Contract shall be considered retained jobs as of the date of the Contract for purposes of calculation of the number of jobs created and/or retained. At the conclusion of the installation of all phases of the Maine Tidal Energy Project, ORPC shall file a Report documenting the 80 direct full-time equivalent jobs in Maine that were created and/or retained by the Project during the development, construction and installation phases. To the extent that ORPC did not create and/or retain at least 80 direct full-time equivalent jobs in Maine, ORPC's Report shall explain why it was not commercially reasonable to do so. If the Commission Staff or the Utilities, at their option, believe that ORPC has failed to comply with its obligation pursuant to this provision, the Commission Staff and/or the Utilities may convene an informal conference of Parties to remedy the dispute. ORPC shall participate in such informal conference. If the dispute cannot be remedied by the informal conference process, the Commission may, at its option, open a proceeding to determine whether ORPC has complied with the obligations set forth in this provision. ORPC shall have all of the due process rights accorded to parties under Chapter 110 of the Commission's Rules, including a right to hearing at which ORPC would have the opportunity to support the reasonableness of its efforts. If, after notice and an opportunity for hearing, the Commission determines that ORPC has failed to comply with this provision, the Commission may assess a reasonable payment, the amount of which is within the Commission's sole discretion, but is subject to the aggregate cap discussed below. In reaching a determination of the amount of the payment, the Commission shall consider the magnitude of the deficiency associated with ORPC's failure to comply with its contractual obligation. The Commission may also notify ORPC what actions may be taken by ORPC within a specified timeframe to cure the deficiency and avoid the payment.

- During the operation and maintenance phase of the fully built out Project, ORPC will use commercially reasonable efforts to create and/or retain at least 12 direct full-time equivalent jobs in Maine. These jobs will be created and/or retained by the commencement of Contract Year 6 and will continue to be retained throughout the Contract Term. ORPC shall provide annual reports to the Commission commencing July 1, 2016 specifying the number of created and/or retained direct full-time equivalent jobs in Maine. To the extent ORPC did not create and retain at least 12 direct new full-time equivalent jobs in Maine by the commencement of Contract Year 6, it shall explain why it was not commercially reasonable to do so. If the Commission Staff or the Utilities, at their option, believe that ORPC has failed to comply with its obligation pursuant to this provision, ORPC shall have a reasonable cure period to remedy such failure. If

ORPC does not remedy the failure within the applicable cure period and ORPC disputes that it has failed to comply with this provision, the Commission Staff and/or the Utilities may convene an informal conference of Parties to remedy the dispute. ORPC shall participate in such informal conference. If the dispute cannot be remedied by the informal conference process, the Commission may, at its option, open a proceeding to determine whether ORPC has complied with the obligations set forth in this provision. ORPC shall have all of the due process rights accorded to parties under Chapter 110 of the Commission's Rules, including a right to hearing at which ORPC would have the opportunity to support the reasonableness of its efforts. If, after notice and an opportunity for hearing, the Commission determines that ORPC has failed to comply with this provision, the Commission may assess a reasonable payment, the amount of which is within the Commission's sole discretion, but is subject to the aggregate cap discussed below. In reaching a determination of the amount of the payment, the Commission shall consider the magnitude of the deficiency associated with ORPC's failure to comply with its contractual obligation. The Commission may also notify ORPC what actions may be taken by ORPC within a specified timeframe to cure the deficiency and avoid the payment.

- ORPC will use commercially reasonable efforts to expend at least 50% of the capital investments for the Project in Maine. ORPC will provide annual reports to the Commission specifying the percentage of capital investments for the project in Maine. If the Commission Staff or the Utilities, at their option, believe that ORPC has failed to comply with its obligation pursuant to this provision, ORPC shall have a reasonable cure period to remedy such failure. If ORPC does not remedy the failure within the applicable cure period and ORPC disputes that it has failed to comply with this provision, the Commission Staff and/or the Utilities may convene an informal conference of Parties to remedy the dispute. ORPC shall participate in such informal conference. If the dispute cannot be remedied by the informal conference process, the Commission may, at its option, open a proceeding to determine whether ORPC has complied with the obligations set forth in this provision. ORPC shall have all of the due process rights accorded to parties under Chapter 110 of the Commission's Rules, including a right to hearing at which ORPC would have the opportunity to support the reasonableness of its expenditures. If after notice and an opportunity for hearing, the Commission determines that ORPC has failed to comply with this provision, the Commission may assess a reasonable payment, the amount of which is within the Commission's sole discretion, but is subject to the aggregate cap discussed below. In reaching a determination of the amount of the payment, the Commission shall consider the magnitude of the deficiency associated with ORPC's failure to comply with its contractual obligation. The Commission may also notify ORPC what actions may be taken by

ORPC within a specified timeframe to cure the deficiencies and avoid the payment.

- ORPC will use commercially reasonable efforts to expend at least 50% of operating or other expenditures related to the Project on Maine suppliers, contractors and academic institution resources for permitting, construction and operation tasks related to the Project for each Contract Year over the Contract Term. ORPC shall provide annual reports to the Commission specifying all suppliers, contractors and academic resources used for the permitting, construction and operation of the Project over the last year. The Annual Report shall also provide, for the prior Contract Year and for the life of the Project to-date, the total operating or other expenditures related to the Project and the operating or other expenditures related to the Project expended on Maine suppliers, contractors and academic institution resources for permitting, construction and operation tasks related to the Project. To the extent that ORPC has not expended at least 50% of the operating or other expenditures related to the Project in any Contract Year on Maine suppliers, contractors and academic institution resources, ORPC shall explain in its Annual Report why it was not commercially reasonable to do so. If the Commission Staff or the Utilities, at their option, believe that ORPC has failed to comply with its obligation pursuant to this provision, ORPC shall have a reasonable cure period to remedy such failure. If ORPC does not remedy the failure within the applicable cure period and ORPC disputes that it has failed to comply with this provision, the Commission Staff and/or the Utilities may convene an informal conference of Parties to remedy the dispute. ORPC shall participate in such informal conference. If the dispute cannot be remedied by the informal conference process, the Commission may, at its option, open a proceeding to determine whether ORPC has complied with the obligations set forth in this provision. ORPC shall have all of the due process rights accorded to parties under Chapter 110 of the Commission's Rules, including a right to hearing at which ORPC would have the opportunity to support the reasonableness of its expenditures. If, after notice and an opportunity for hearing, the Commission determines that ORPC has failed to comply with this provision, the Commission may assess a reasonable payment, the amount of which is within the Commission's sole discretion, but is subject to the aggregate cap discussed below. In reaching a determination of the amount of the payment, the Commission shall consider the magnitude of the deficiency associated with ORPC's failure to comply with its contractual obligation. The Commission may also notify ORPC what actions may be taken by ORPC within a specified timeframe to cure the deficiency and avoid the payment.

- Payments assessed by the Commission pursuant to the four previous provisions shall not, in the aggregate, exceed 7% of total revenue in any given year.

- ORPC will continue its partnerships and collaborative relationships with the City of Eastport, the Town of Lubec, Washington County, the Eastport Port Authority, the Sunrise County Economic Council, local contractors and suppliers, and others to support the continued development of the tidal energy economic cluster in Maine over the Contract Term.

- ORPC will construct an on-shore station in North Lubec for the Cobscook Bay portion of the project, which will include upgrades to approximately three miles of distribution lines in North Lubec.