Recommended Criteria and Process for the Evaluation and Selection of Offshore Wind Applications

prepared for

the Maryland Public Service Commission Staff

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Table of Contents

Acronyms and Definitions 1

Introduction and Overview 5

- OWEA and Commission Regulations 5
- Project Location 6
- Overview of Recommended Process 7

Best Practices and Lessons Learned from Offshore Wind Projects 13

- Best Practices – General Principles 13
- Lessons Learned from Other RFP and Power Procurements 14
- Lessons Learned – Transmission Upgrades 19
- Lessons Learned – Surplus ORECs 21
- Lessons Learned – COD Delays 22
- Other Best Practices and Lessons Learned Applied to Maryland's OWEA Process 23

Application Requirements 27

- Applicant Background and Contact Information 28
- Project Description 29
- Commercial Operations Date 31
- Maryland Business Impacts 32
- Financial Information 33
- Project Analyses 34
- Proposed OREC Price Schedule 35
- Proposed OREC Amount 36
- Confidential Information 37

Step 1: Pre-Application Tasks and Application Period 39

- Pre-Application Tasks 39
- Application Period Commencement and Duration 40

Step 2: Application Completeness Review 42

Step 3: Minimum Threshold Criteria Screening 43

- Reasons to Use Levelized Calculations 43
- Minimum Threshold Criteria 44
- Clarifying Questions 46

Step 4: Quantitative and Qualitative Evaluations 47

- Qualitative Evaluation 48
- Quantitative Evaluation 55
- Evaluation of Net Environmental, Health, and Economic Impacts 57

Step 5: OREC Application and OREC Price Schedule Selection 60
Approved OREC Amount and RPS OREC Percentage 60
Approved OREC Amount and Expected OREC Generation 61
Selection of Project and OREC Price Schedule 61
Failure of Any Project to Satisfy the Rate Caps 62
Additional Round of OREC Applications 62
Recommended Findings to Be Included in a Commission Order 64

Appendix 1 – Maryland Offshore Wind Energy Act – Transmission Upgrade Whitepaper
Appendix 2 – Connecticut RFP Summary
Appendix 3 – Delaware RFP Summary
Appendix 4 – Massachusetts Green Communities Act
Appendix 5 – Maryland RFP for Generation Capacity
Appendix 6 – New Jersey Offshore Wind Economic Development Act
Appendix 7 – Rhode Island: Block Island Offshore Wind Project
Appendix 8 – Maryland Offshore Wind Energy Act – Financial Calculations
Appendix 9 – Maryland Offshore Wind Energy Act – Levelized Constant Dollar Price Concept

Acronyms and Definitions

Act or OWEA	Maryland Offshore Wind Energy Act of 2013
Administratively Complete	An application that the Commission has determined contains the all of the information required by the Regulations.
Administrator	The administrator of the Escrow Account
Applicable Load	The portion of Maryland retail electric sales subject to the RPS OREC Percentage, i.e., excluding sales in excess of (i) 75,000,000 kWh/year for industrial process customers and (ii) 3,000 kWh/month for agricultural customers who file an IRS Form 1040, Schedule F, per PUA § 7-703(a)(3).
Application Period	The period of time starting when the first application for a Qualified Offshore Wind Project is received and determined to be Administratively Complete, during which time other applications may be submitted, and closing no less than 90 days afterwards per PUA § 7-704.1(a)(2)(ii).
Approved OREC Amount	The maximum quantity of ORECs to be purchased during a year per a Commission Order from a Qualified Offshore Wind Project.
BOEM	DOI Bureau of Ocean Energy Management
BPU	New Jersey Board of Public Utilities
CfD	Contract for Differences
CFR	U.S. Code of Federal Regulations
Commission	Maryland Public Service Commission
COD	Commercial Operation Date
DEEP	Connecticut Department of Energy and Environmental Protection
Delmarva	Delmarva Power (previously known as Delmarva Power & Light)
DNV GL	DNV GL, technical consultants to the Commission
DOI	U.S. Department of Interior
EDC	Electric Distribution Company

Electricity Supplier	A licensed electric company, broker, or aggregator that sells electricity, electric supply services, competitive billing services, or competitive metering services; or purchases, brokers, arranges, or markets electricity or electricity supply services for sale to a retail electric customer per the Code of Maryland Regulations, Title 20 Subtitle 51 Chapter 1 Definitions.
EPA	U.S. Environmental Protection Agency
Escrow Account	A financial account to receive and transfer OREC payments per PUA § 7-704.2(b).
Estimated Project COD	The COD specified in an application
FERC	U.S. Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GATS	PJM's Generation Attribute Tracking System
GWh	Gigawatt-hour, equal to one thousand MWh
H&S	Health and Safety
IC or Independent Consultant	The independent consultant to be retained by the Commission to evaluate and compare applications per PUA § 7-704.1(d)(2) and to calculate the net benefits to the State, per PUA § 7.704.1(e)(2)(i).
IFRS	International Financial Reporting Standards
kV	kilovolt, a measure of electrical force used to rate electrical cables and substations.
LAI	Levitan & Associates, Inc., commercial consultants to the Maryland Public Service Commission Staff.
Levelized OREC Price	The levelized 2012 constant dollar price per OREC equivalent on a PV basis to an applicant's OREC Price Schedule.
Long-Term Composite Treasury Bond Rate	The unweighted average of bid yields on all outstanding fixed-coupon bonds neither due nor callable in less than ten yeas as published by the U.S. Department of the Treasury.
LSE	Load serving entity

Minimum Threshold Criteria	The minimum project characteristics required for an application to be given further consideration by the Commission.
MWh	Megawatt-hour, a unit of electric energy or of ORECs
NARUC	National Association of Regulatory Utility Commissioners
Net Ratepayer Cost	The projected net direct cost to Applicable Load ratepayers of a project or combination of projects, including (i) payments for ORECs under the OREC Price Schedule, (ii) less the market revenues for Power Products generated by the project that would be credited to ratepayers, (iii) less the market cost of avoided Tier 1 RECs, and (iv) any effect on market prices of Power Products and RECs.
O&M	Operations and maintenance
Offshore Wind Energy	The energy generated by a Qualified Offshore Wind Project per PUA § 7-701(f).
OREC or Offshore Wind Renewable Energy Credit	A Renewable Energy Credit equal to the generation attributes, i.e., Power Products, and the environmental attributes of 1 MWh of electricity derived from Offshore Wind Energy per PUA § 7-701(h).
OWEDA	New Jersey's Offshore Wind Economic Development Act
PJM	PJM Interconnection LLC, the Regional Transmission Operator of the bulk power system in the Mid-Atlantic region (including Maryland).
Power Products	Energy, capacity, and ancillary services as recognized by PJM.
PPA	Power Purchase Agreement
Proposed OREC Amount	The total ORECs per year offered by an applicant associated with a Proposed OREC Price Schedule within an application.
Proposed OREC Price Schedule	An applicant's proposed price of Offshore Wind Energy sold as ORECs.
PSC	Public Service Commission
PUA	Public Utilities Article, Annotated Code of Maryland

Public Information Act	Maryland Code Annex, State Government Article, Title 10, Subtitle 6
PV or Present Value	An equivalent financial value discounted at the appropriate discount rate
Qualified Offshore Wind Project	A wind turbine electricity generation facility, including the associated transmission–related interconnection facilities and equipment, that (1) is located on the outer continental shelf of the Atlantic Ocean in an area that (I) the United States Department of the Interior designates for leasing after coordination and consultation with the State in accordance with § 388(a) of the Energy Policy Act of 2005; and (II) is between 10 and 30 miles off the coast of the State; (2) interconnects to the PJM Interconnection grid at a point located on the Delmarva Peninsula; and (3) the Commission approves under § 7–704.1 of this subtitle, per PUA § 7-701(k).
REC	Renewable Energy Credit
Regulations	The comprehensive set of regulations the Commission is required to adopt by July 1, 2014 to implement OWEA per PUA § 7-704.2(f).
Retail Electric Customer	A purchaser of electricity for end use in the State as defined in PUA.
RFP	Request for Proposal
RPS	Renewable Energy Portfolio Standard
RPS OREC Percentage	The percentage of Maryland's RPS to be provided by ORECs, up to 2.5% of Maryland's retail electricity sales (adjusted for large industrial process and agricultural loads) commencing in 2017, per PUA § 7-703(b)(12).
Surplus ORECs	Project output exceeding the Approved OREC Amount in any year that is banked as ORECs in the Administrator's GATS Account for retirement and payment in a future year.

Introduction and Overview

Offshore wind resources have been developed throughout northern Europe over the past two decades. Since the first offshore wind project was developed off the coast of Denmark, more than 2,000 turbines with a combined capacity of over 6,500 MW have been installed globally, predominantly in the North Sea and Baltic Sea off the coasts of the United Kingdom, Denmark, Belgium, Germany, the Netherlands, and other northern European nations. A handful of offshore wind projects have also been installed in Asia, with China leading that market. The US has considerable offshore wind potential, but only a few projects have been approved and no full-scale units have been constructed to date.

The Maryland General Assembly passed the Offshore Wind Energy Act of 2013 ("OWEA" or the "Act") that was signed by Governor O'Malley on April 9, 2013. The Act carves out a portion of the Tier 1 renewable resource requirement under Maryland's Renewable Energy Portfolio Standard ("RPS") for "Qualified Offshore Wind Projects", as defined by the Public Utilities Article, Annotated Code of Maryland ("PUA") § 7-701(k), thus supporting the development of one or more offshore wind farms to be located off the Delmarva Peninsula. According to the Maryland Energy Administration Fact Sheet, offshore wind projects would create manufacturing and operations and maintenance ("O&M") jobs, supply clean electric energy, reduce air emissions, and help establish Maryland as a manufacturing and supply chain base.[1] The Act contains price and rate caps to protect Retail Electric Customers.

OWEA and Commission Regulations

Under OWEA, § 7-704.2(f) of the PUA requires the Commission to issue a comprehensive set of Regulations implementing the Act by July 1, 2014. The Commission has retained outside advisors to assist in drafting the Regulations to meet that deadline. The advisors are the law firm of Kaye Scholer, LLP ("Kaye Scholer"), commercial consultants Levitan & Associates, Inc. ("LAI"), technical consultants DNV GL, and local consultant Sullivan Cove Consultants, LLC ("Sullivan Cove"). The Regulations will define the commercial arrangements and transaction mechanism, and will establish the application, evaluation, selection, and approval process for new offshore wind projects, consistent with the Act.[2]

The Act envisions the purchase by electricity suppliers as defined in Title 20 of the Code of Maryland Regulations ("Electricity Supplier") of Offshore Wind Renewable Energy Credits ("ORECs") from one or more offshore wind projects selected by the Maryland Public Service

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[1] The Fact Sheet can be found at http://www.governor.maryland.gov/wind.html.

[2] The Regulations will also establish the OREC Escrow Account mechanism with PJM payment and crediting procedures that are being addressed separately by Kaye Scholer.

Commission ("Commission"). Purchases would be made through a special purpose account at a financial institution ("Escrow Account") established by the Commission specifically designed to track OREC payments and revenues. The ORECs created by the selected project would be tracked though a PJM Generation Attribute Tracking System ("GATS") account. As required by the Act, the Regulations should: (i) define an Offshore Wind Project procurement process with specified activities and milestones, (ii) provide clear instructions for applicants, (iii) establish minimum threshold applicant qualifications, (iv) define quantitative and qualitative criteria for evaluating applications, (v) establish the quantitative and qualitative approaches to evaluate the applications, and (vi) define the priorities, including positive net benefits, for the Commission to select a project(s) .

The Commission's commercial and technical advisors, LAI and DNV GL, have prepared this report to make certain that the Commission's offshore wind procurement, evaluation, and selection process (i) is as fair, transparent, and workable as possible, (ii) leads to robust and competitive bids, and (iii) preserves the ratepayer protections defined in the Act. In order to ensure that the recommended process achieves these goals, we have relied upon best practices and lessons learned from previous procurements for offshore wind and other renewable and conventional resources, including Maryland's Request for Proposal ("RFP") for gas-fired Generation Capacity Resources.[3] We have also relied on our own experiences in developing procurement structures, administering procurements on behalf of government agencies, and assisting bidders, and have been guided by a key OWEA principle: applicants bear all development, construction, and operating risks of the wind project and interconnection facilities, thereby protecting ratepayers. Moreover, the Act itself contains price and rate caps to further protect Maryland Retail Electric Customers.

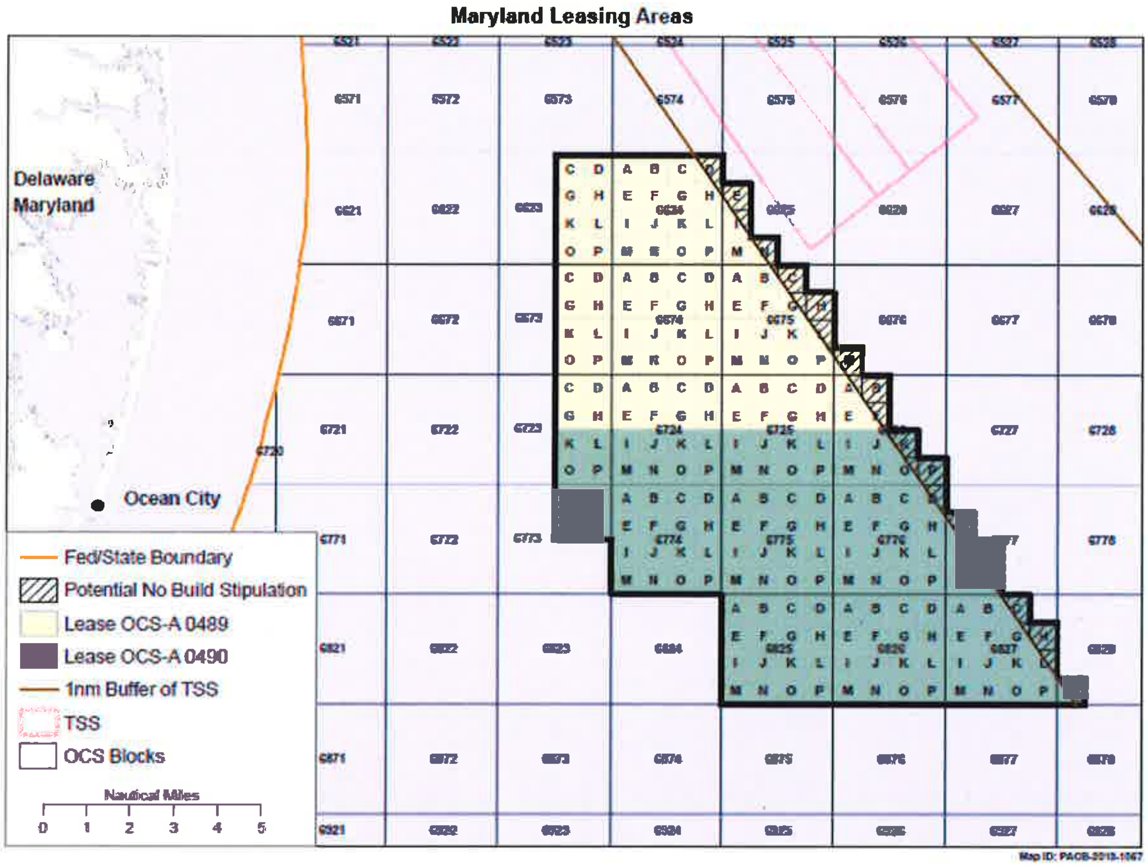
Project Location

PUA § 7-701(k) limits a Qualified Offshore Wind Project to a project "located on the outer continental shelf of the Atlantic Ocean in an area that: (I) The United States Department of the Interior designates for leasing after coordination and consultation with the state in accordance with § 388(a) of the Energy Policy Act of 2005; and (II) is between 10 and 30 miles off the coast of the State..." The U.S. Department of Interior ("DOI") Bureau of Energy Management ("BOEM") is responsible for leasing areas of the outer continental shelf that are under federal jurisdiction for energy resource utilization. The Regulations should establish that Qualified Offshore Wind Projects are restricted to the BOEM lease parcels OCS–A 0489 and OCS–A 0490 for which Maryland has coordinated with DOI. Offshore wind projects located on the Delaware BOEM site are not eligible under the Act. BOEM published a Proposed Notice of Sale

[3] The Amended RFP in Commission Docket No. 9214 was issued on December 8, 2011.

announcing its intention to auction leases for the two Maryland parcels, shown below.[4] The lease auction schedule will be established when BOEM issues a Final Notice of Sale, expected to be during Q2 2014, in which case the lease auction would likely be conducted this summer.

Figure 1. Bureau of Energy Management Lease Areas



Overview of Recommended Process

Based on our power procurement and evaluation experience, best practices and lessons learned from other procurements (described later in this report), discussions with Commission Staff, and one meeting and multiple conference call discussions with interested stakeholders, we recommend that the Commission establish a multi-step process to solicit, evaluate, and select project applications. This multi-step process is consistent with best practices and adopts the threshold and evaluation criteria specified in the Act. Each step is briefly described below and is defined in detail in later sections of this report.

[4] Volume 78, No. 243 of the Federal Register on Wednesday, December 18, 2013, Docket No. BOEM-2013-0002; MMAA104000.

Application Requirements

We recommend that the Regulations clearly and comprehensively define the information required from applicants describing their capabilities and the proposed project. The basic required information should include (i) the applicant's background and contact information, (ii) a description of the proposed project, (iii) a milestone schedule with the Commercial Operation Date ("COD"), (iv) financial information, (v) a cost-benefit analysis, (vi) the annual prices for OREC purchases ("Proposed OREC Price Schedule"), and (v) the proposed annual OREC quantity ("Proposed OREC Amount") to be delivered and purchased.

Step 1: Pre-Application Tasks

Once the Regulations are effective, the Commission should, with the assistance of an Independent Consultant ("IC"), (i) prepare an estimate of transmission upgrade costs that applicants can utilize in their Proposed OREC Price Schedules, (ii) establish communication protocols, including a secure website, (iii) specify discount and inflation rates the Commission will utilize in its evaluations, and (iv) prepare detailed Proposed OREC Price Schedule forms for applicants, consistent with the Regulations. The first task of estimating the cost of transmission upgrades is particularly important because it is unlikely that applicants will have conducted the necessary analysis for their applications.[5] The benefits of providing an estimate of transmission upgrade costs are discussed on pages 19-21 of this report. Once these pre-application tasks are completed, the Commission should distribute this information to potential applicants through the project web site.

In addition, the Commission should identify industry-standard models and determine key modeling parameters (i) for forecasting energy, capacity, ancillary service ("Power Products"), and Tier 1 REC values and (ii) for calculating economic impacts due to changes in employment, taxes, and local spending. Getting a head start on these tasks will minimize the chance of delays when applications are evaluated. The models and parameters should not be distributed to potential applicants, consistent with other procurements.

The Regulations should clearly indicate that the period of time during which applications may be submitted ("Application Period") would commence upon a Commission determination that the first application contains all of the information required by the Regulations, with a valid explanation for why any missing information cannot be provided ("Administratively Complete"). Once the Application Period is open, the Commission should post notice of an open Application

[5] We recommend the Commission issue an RFP for transmission consulting services to develop a reasonable estimate of transmission upgrade costs as quickly as possible. We estimate that an independent study, comparable to a PJM System Impact Study, will take 2-3 months and $120,000-$180,000 based on discussions with a transmission consultant, assuming the consultant has the resources and a base power flow case.

Period in accordance with Commission procedures and PUA § 7-704.1(a)(2)(i). In order to allow time for the Commission to estimate the cost of transmission upgrades and for applicants to develop a well-conceived project and incorporate the transmission upgrade cost estimate into a complete application, we recommend that the Application Period be 180 days, consistent with PUA § 7.704.1(a)(2)(ii) that requires at least 90 days.[6] Establishing a 180 day Application Period would maximize the number of participants and enhance competition. The notice should be posted on the website and broadly communicated to all potential applicants and other stakeholders.

Step 2: Application Completeness Review

The Commission should examine each application to verify it is Administratively Complete against a checklist of application requirements. Unless an applicant provides a valid explanation for why any missing or incomplete information cannot be provided, they should be permitted to amend or supplement their application to supply missing or incomplete information to cure any deficiencies until the application is found to be Administratively Complete or until the end of the Application Period, whichever comes first.

Step 3: Minimum Threshold Criteria Review

The Commission should review Administratively Complete applications to determine if they satisfy the threshold criteria derived from prescriptive requirements in the Act plus a limited number of additional threshold criteria recommended by LAI and DNV GL (together "Minimum Threshold Criteria"). Administratively Complete applications that do not satisfy the Minimum Threshold Criteria should be disqualified, *e.g.,* applications in which the Proposed OREC Price Schedule exceeds the $190/MWh (2012 dollars) price cap specified in the Act. The price cap test should be conducted on a projected basis and should not be revisited after a project is selected, consistent with the Act.

The Act contains provisions requiring the Proposed OREC Price Schedule to not exceed $190 per megawatt-hour in 2012 dollars. As explained in the Step 3 section, we recommend that the Commission conduct this price cap test on a levelized basis over the delivery term. This approach would provide applicants with the greatest amount of pricing flexibility and avoid situations in which an applicant might fail a price cap test in only one of twenty years and be disqualified during the Step 4 project evaluation. Our recommendation would help ensure a robust and competitive process that would ultimately benefit Retail Electric Customers.

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[6] If there is a risk that the Commission cannot retain a transmission consultant to provide a cost estimate of expected transmission upgrades to applicants well before the close of the Application Period, then the Application Period should be longer than 180 days.

Step 4: Quantitative and Qualitative Evaluations

Many evaluation criteria can and should be quantified, *e.g.,* (i) the Proposed OREC Price Schedule, (ii) the value of market revenues for Power Products and for avoided Tier 1 REC costs that will reduce the net payment for Retail Electric Customers, and (iii) the effect of a competitive new renewable resource supply on market Power Product and REC values. These values are the first step for the Commission to confirm that an application's projected rate impact would not exceed \$1.50/month (2012 dollars) for residential customers or 1.5% for nonresidential customers as provided by the Act. The net rate cap tests should be conducted on a projected basis and should not be revisited after a project is selected, consistent with the Act. We recommend that the Commission conduct these calculations on an independent basis using an industry-standard production cost (aka dispatch simulation) model to determine a project's effect on energy prices to insure a fair and consistent evaluation of projects. As with the \$190/MWh price cap, we recommend that the Commission calculate the residential and nonresidential net rate impacts on a levelized basis over the term of the delivery period.

The construction and operation of an offshore wind project to serve Maryland retail customers will have beneficial economic impacts on employment, taxes, and local spending that should also be quantified and expressed in monetary terms using an economic input-output model, provided that an applicant offers reasonable assurances regarding future employment, taxes, and local spending in Maryland. Although the Act requires applicants to provide their own results of power market and economic modeling analyses, we again recommend that the Commission conduct an independent analysis of in-State economic impacts using an industry-standard economic input-output model in order to assure a fair and consistent evaluation and comparison among projects.

Some evaluation criteria are difficult to quantify and express in monetary terms, such as the environmental and consequential health impacts of avoiding power plant air emissions and generally improving environmental quality. The U.S. Environmental Protection Agency ("EPA") has developed guidelines for analyzing environmental regulations and policies and for estimating the value of such health benefits, but these guidelines cannot be easily applied to assess the benefits of individual projects.[7] LAI is not aware of any renewable resource procurements in which the basis for approval included a monetary quantification of environmental and health benefits. Not expressing these benefits in monetary terms avoids potential disagreements regarding the validity of the relevant models and the monetary values assigned to those results. This approach avoids assigning an inaccurate monetary value that could lead to an erroneous procurement outcome. Therefore we recommend that the

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[7] U.S. EPA, *Guidelines for Economic Analyses*, EPA 240-R-10-001, December 2010; http://yosemite.epa.gov/ee/epa/eed.nsf/webpages/Guidelines.html

Commission estimate the quantities of avoided power plant emissions (using the output from the production cost model mentioned earlier) and evaluate the consequential health benefits on a qualitative basis.

There is a third category of project features that cannot be reasonably quantified monetarily, and we also recommend that the Commission evaluate them on a qualitative basis. These features include (i) project weaknesses and risks that would minimize the likelihood a project will actually achieve commercial operation and (ii) project strengths that would contribute to net economic, environmental, or health benefits to Maryland, including the applicant's plan to engage small business, seek minority investors, utilize skilled labor, and compensate employees and subcontractors consistent with state rules.

Step 5: OREC Application Selection

Upon completion of the Step 4 application evaluation process, the Commission should identify the individual projects or combinations of projects (i) whose combined Proposed OREC Amounts do not exceed the maximum permitted OREC RPS requirement, *i.e.,* 2.5% of Maryland electricity sales adjusted for large industrial process and agricultural loads (the "RPS OREC Percentage") starting in 2017 and (ii) which satisfy the residential and nonresidential net rate caps. In the event that no project satisfies the rate caps, the Commission should consider a solution that will allow applicants to adjust their OREC Price Schedule and/or Proposed OREC Amounts to meet the rate caps and thus avoid the need for a new offshore wind process. We define three options to meet the rate caps in the Step 5 section of this report: (i) issuing a Conditional Order, (ii) requesting a Best and Final Offer, or (iii) retaining the IC early in the Application Period to inform applicants if they satisfy the rate caps.

At this point the Commission would have four key evaluation results to select one or more projects that were previously determined to be Administratively Complete and satisfy the price cap and the residential and nonresidential net rate caps:

- The combined power and REC market impacts on ratepayers ("Net Ratepayer Cost").
- In-State economic impacts due to employment, taxes, and local spending.
- Environmental benefits (including, but not limited to, tons of avoided emissions) and the consequential health benefits (considered qualitatively).
- Other factors of project strengths and weaknesses (including a project's feasibility and thus likelihood of achieving the State's renewable energy policy goals), and commitments to engage small business, solicit minority investors, utilize skilled labor, and compensate employees and subcontractors consistent with state wage rules, all as required by PUA.

We recommend the Commission consider these evaluation results independently for each offshore wind project. In considering these results, we recommend that the Commission give the greatest consideration to maximizing the quantity of ORECs to advance its policy goals while minimizing the Net Ratepayer Cost that will directly affect ratepayers.

Once selected and operational, if a project's output exceeds the OREC quantity approved in the Commission's order ("Approved OREC Amount") in any year, it should have the option to either bank the excess as ORECs to be retired in a future year ("Surplus ORECs") or merchandize the excess Power Products and Tier 1 RECs at market prices. In case the total Approved OREC Amount is significantly less than the RPS OREC Percentage and a project site is available, the Commission could make provisions for a second round of applications provided those applications do not cause the RPS OREC Percentage or the residential and nonresidential net rate caps to be exceeded in the aggregate. Once the Commission makes a final selection, it should publicly announce the winning application(s) and issue an order with findings as suggested in this report.

Best Practices and Lessons Learned from Offshore Wind Projects

Best Practices – General Principles

With the advent of utility restructuring and divestiture of generation assets, electric distribution companies ("EDCs"), load-serving entities ("LSEs"), and state commissions have increasingly relied on competitive procurements to obtain wholesale power supplies to assure reliability or to promote the development of renewable resources. In most restructured states, the procurement processes have been developed through legislation, regulation, or state commission proceedings. Stakeholders have had opportunities for public comment on the pros and cons of various aspects of procurement design. Moreover, the successes and failures of recent procurements for both conventional and renewable generation have contributed to an improved understanding of best practices for the design of competitive procurements. These best practices have been incorporated in the draft regulations to implement the portions of Maryland's OWEA that address the application requirements, qualitative and quantitative evaluation methodology, and selection process. Additional consideration was given to the specific challenges faced by offshore wind, and how the lessons learned from experience in Europe, Asia, and the nascent US offshore markets apply in the Maryland context.

The best procurement practices embody basic principles designed to ensure that the process is fair and transparent, produces competitive bids, considers all relevant factors, facilitates consistent comparisons, and is consistent with the letter and spirit of OWEA. A 2008 study conducted for the National Association of Regulatory Utility Commissioners ("NARUC"), Competitive Procurement of Retail Electricity Supplies: Recent Trends in State Policies and Utility Practices, summarized these basic principles as excerpted below, underlined to emphasize the most relevant points for the Maryland offshore wind process:

> The procurement process should be <u>fair and objective</u>. A fair and objective process can avoid intended or unintended biases that may prevent selection of the "best" alternatives. The integrity of such a process encourages the participation of third-party suppliers by providing them with confidence that their offers will be fairly considered on their merits. To achieve this goal, procurements must include appropriate safeguards to prevent undue preferential treatment of any offers, to ensure that procurements are implemented as designed, and to ensure that unforeseen circumstances are addressed in manner that is fair and fundamentally consistent with the competitive intent of the process.
>
> The procurement should be designed to encourage <u>robust competitive offerings</u> and creative proposals from market participants. To encourage a competitive response, market participants need to have: (1) confidence that their offers will be considered fairly and objectively; (2) assurance that their confidential information will be reasonably protected; and (3) access to adequate information about bidder requirements, product

specifications, model contract terms, evaluation procedures, and other factors that would affect the resources they choose to offer.

The procurement should select winning offers based on appropriate evaluation of all relevant price and non-price factors. Selecting the "best" offer(s) requires first identifying appropriate evaluation criteria and then evaluating the offers objectively against them. Designing an effective evaluation process is inherently challenging when such evaluations require comparisons of price and non-price factors. In particular, many of these non-price factors are quite complex to quantify and/or qualitative in nature. By contrast, procuring products that meet standardized specifications…greatly simplifies the evaluation process by allowing for the selection of winning offers based on price terms alone.

The procurement should be conducted in an efficient and timely manner. Procurements should avoid unnecessary administrative costs that may discourage market participants, create transaction costs that produce price premiums in supplier offers, and ultimately impose greater costs on ratepayers.

When using a competitive procurement process, regulators should align their own procedures and actions to support the development of a competitive response. Regulators' own actions can positively – and in some cases, negatively – affect the integrity of a competitive procurement process. Positive signals can arise, for example, by doing what is legally possible to protect the confidentiality of commercially sensitive information submitted through supply offers, by conducting regulatory reviews in a time frame that supports the "best" price terms in offers, and enforcing elements of the procurement design that enhance the overall fairness and objectivity of the process and the integrity of the procurement results.

There are numerous benefits of adhering to these best procurement practices. For example, the 2010 Anholt offshore wind farm tender in Denmark provides a useful reminder of the importance of designing a fair and objective process to facilitate a robust and competitive response. The Anholt tender received only a single application from DONG Energy, Denmark's largest energy company with the Danish government owning the majority stake, in large part because other bidders felt it was a foregone conclusion that DONG Energy would be awarded the 400 MW contract. While this may be an extreme example, our recommendations concerning the evaluation and selection process, along with provisions concerning communications, confidentiality, timing, and other aspects of the proposed Regulation, are consistent with these best practices and lessons learned.

Lessons Learned from Other RFP and Power Procurements

We have summarized best practices for power procurements based on LAI's experience and documents in the public domain. The following RFPs (or legislation, regulations, or commission order that effectively act as an RFP) are particularly appropriate for the Maryland offshore wind process. Detailed descriptions of these procurements are provided as Appendices 2 - 7 to this report.

- Maryland Gas-Fired Generation RFP – The Maryland EDCs issued an Amended RFP for up to 1,500 MW of new gas-fired generation capacity and associated energy located in SWMAAC on December 2, 2011. The RFP had forms clearly specifying the required information, which we consider to be a best practice. The evaluation process was very similar to our recommendation with an independent consultant utilizing minimum threshold criteria, scoring of an initial shortlist based on quantitative and qualitative factors, and modeling to estimate market energy price effects. We note that it is easier to estimate the cost of conventional power plants, particularly combined cycle technology used in the winning bid, compared to offshore wind plants. Bidders were responsible for including the cost of transmission upgrades in their bids; the winning bidder had a reasonably accurate estimate since they had already initiated the PJM interconnection process. The winning bidder was selected based upon the net cost to ratepayers that also took into account key risk factors of natural gas prices, environmental compliance costs, and ratepayer load uncertainties. The Commission issued its Order No. 84815 on April 12, 2013, approving a Contract for Differences ("CfD") with the winning bidder, CPV Maryland, for its 661 MW St. Charles combined cycle project that established fixed revenues net of Power Product sales.

- Rhode Island Offshore Wind RFP – The Rhode Island legislature passed General Law §39-26.1, Long Term Contracting Standard for Renewable Energy, which required EDCs to solicit proposals for new renewable energy resources to enhance the electric reliability and environmental quality of the Town of New Shoreham, *i.e.,* Block Island. Development of a small offshore wind farm was a logical match to supply Block Island with an underwater cable to the mainland for excess and backup power. Narragansett Electric, d/b/a National Grid, issued an RFP on July 31, 2009 and selected Deepwater Wind to develop the 30 MW Block Island Wind Farm. Deepwater Wind was responsible for the costs of the wind farm, interconnection, and underwater cable; National Grid was responsible for transmission upgrades.

  The RFP specified Price Evaluation and Non-Price Evaluation considerations process but did not have a multiple step qualification and evaluation process or a defined scoring system. However, these process characteristics were not necessary since there was only a single bidder that had already secured the site lease and had negotiated a contract.

- New Jersey Offshore Wind Economic Development Act – New Jersey's Offshore Wind Economic Development Act ("OWEDA") was passed in 2010 to provide financial and tax incentives in support of up to 1,100 MW of offshore wind projects. On February 10, 2011, the Board of Public Utilities ("BPU") established OWEDA regulations to implement the legislation that requires all LSEs to purchase ORECs, defined as the environmental attributes of offshore wind energy, *i.e.,* Power Products were excluded. The regulations included a detailed list of the application requirements but only a general description of the evaluation criteria and process. At least one bidder identified this as a serious flaw. The OWEDA regulations included a "Determination of completeness of application" step, during which the Board reviews each application for administrative completeness. The start of the 180-day period for the Board to approve, conditionally approve, or deny an application commences on the date the complete application is filed.

Fisherman's Energy filed a petition with the BPU for a 20 MW demonstration project (separate from its proposed 350 MW utility-scale project in federal waters) in state waters off the coast of Atlantic City in 2008. Fishermen's Energy amended its petition to 25 MW in response to the BPU's regulations. The project originally offered an all-in OREC price starting at $199.17/MWh less credits for power revenues and avoided REC costs, *i.e.,* ratepayers would bear the risks of market power and REC prices netted against the OREC price. The prices were lowered to a starting value of $187/MWh in 2013 with an average escalation rate of 3.3% over the first nineteen years. Those prices were stated on an Energy Year (June 1 - May 31) basis, similar to a calendar year in that the price for a given Energy Year would not "slip" if COD were delayed. Although the regulations have a target evaluation period of 180 days to approve or deny a project, the BPU decided to reject the Fishermen's Energy project after almost three years of hearings and deliberation.

- Massachusetts Green Communities Act – Massachusetts passed An Act Relative to Green Communities (the "Green Communities Act") in 2008, which required the EDCs to solicit proposals for renewable resources at least twice over a five-year period, commencing July 1, 2009. The Act resulted in a total of nine long term contracts among the four EDCs. These contracts were primarily for on-shore wind projects, but included two contracts with Cape Wind. Cape Wind, a proposed 468 MW offshore wind project to be located in federal waters of Nantucket Sound, did not participate in the RFP process but instead directly negotiated with National Grid and with NSTAR. National Grid executed a contract for 50% and NSTAR Electric later executed a contract for 27.5% of the output. Both contracts have 15 year terms with buyer extension options. The National Grid contract required construction to commence by year-end 2013 and full capacity COD by year-end 2015. Under the NSTAR contract, Cape Wind must commence construction by year-end 2015; NSTAR has the right to terminate the contract if that milestone is not achieved.[8] There are provisions for extensions but the National

[8] Development of the Cape Wind project was considerably far along when the NSTAR contract was executed, and thus a milestone requirement was reasonable. No Maryland offshore wind project has been developed sufficiently to

Grid contract price will not escalate after 2015 and COD must occur no later than year-end 2017. As of April 1, 2014, Cape Wind construction has not commenced.

Although the Massachusetts Department of Public Utilities ("DPU") acknowledged that the contract prices were over-market, even when considering the benefit of the market price effects, the DPU approved both contracts based on its determination that the contracts were cost-effective and in the public interest. In determining that the contracts were cost effective and in the public interest, the DPU considered the unquantified benefits of the project, including: (i) contract provisions that may benefit customers if the project over-performs, if the contract is extended, and certain other price adjustments, (ii) contribution to achieving the Commonwealth's RPS goals, (iii) contribution to achieving National Grid's greenhouse gas reduction goals under the State's Global Warming Solutions Act, (iv) enhancement of regional system reliability, (v) moderation of system peak load, and (iv) employment benefits.

The Act was revised in 2012, requiring the EDCs to solicit proposals for new renewable resources at least twice over a four-year period, commencing January 1, 2013. EDCs were required to enter into reasonable, cost-effective 10-20 year contracts for up to 4% of total load. The four EDCs issued a joint request for proposals on April 1, 2013, for up to 1.8% of their combined load. The RFP used a multi-stage evaluation process. (i) Projects first had to meet eligibility, threshold and other minimum requirements. (ii) Eligible projects were evaluated based on price (80% of score) and non-price (20%) criteria and ranked. The price analysis was based on a levelized $/MWh net benefit analysis that considered the bid price relative to forecasted energy and REC prices. The non-price evaluation was a qualitative review of siting, permitting, and project development status, operational viability, development experience and capabilities, financing, and exceptions to the draft PPA. Bidders were permitted to refresh their pricing, and the EDCs submitted six proposed PPAs for onshore wind farm projects, later reduced to three projects. The cost to ratepayers of required but undefined transmission upgrades was a key concern during the DPU hearings. The contracts were approved by the DPU's Order of February 26, 2014, which also directed the EDCs to propose a revised tariff within 10 days.

- Delaware Electric Utility Retail Customer Supply Act – Delaware established the Electric Utility Retail Customer Supply Act 2006 ("EURCSA") that required Delmarva Power & Light (now Delmarva Power, "Delmarva") to issue an RFP for long-term (10-25 year) contracts to support the construction of up to 400 MW of new in-state generation

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warrant establishing a similar milestone requirement, particularly given the significant uncertainties of domestic offshore wind development.

resources by June 1, 2013. Delmarva issued an RFP, approved by the Delaware PSC, on November 1, 2006 for the purchase of Power Products and RECs. Proposals were evaluated by Delmarva and an IC pursuant to the RFP "…to approve one or more of such proposals that result in the greatest long-term system benefits … in the most cost-effective manner."

The proposal evaluation process was comprised of several steps. (i) A pass / fail Non-Responsiveness Test to ensure that all proposals were complete and submitted on time. (ii) A pass / fail Threshold Test to ensure that each bidder met minimum criteria of financial strength, project financeability, site control, permitting, plant design, and commitment to non-negotiable contract terms. (iii) Detailed Price (60% of final score) and Non-Price (40%) evaluations of qualifying proposals. The price components included the bid price, other ratepayer effects (changes in wholesale market prices), transmission and distribution impacts (including losses), imputed debt impacts, price stability, and compliance with the Delaware RPS. Estimated transmission upgrade costs were included in the proposal cost for evaluation purposes; bidders were responsible for PJM's final cost estimate. Non-price components included project characteristics of environmental impact, fuel diversity, and technical innovation and project viability regarding expected COD, technical reliability, site development, bidder experience, and project financeability. The Bluewater project was selected for 300 MWh/hour of energy from 450 MW (nameplate rating) of capacity. The PPA was approved by the Delaware PSC in July 2008, but the project was cancelled in December 2011.

- Connecticut: An Act Concerning Connecticut's Clean Energy Goals – This act, approved on June 5, 2013, directed the Department of Energy and Environmental Protection ("DEEP") to procure specific types of renewable resources under long term contracts. In 2013, DEEP sought proposals for new, eligible renewable resources, for up to 4% of the load of the state's two EDCs under contracts up to 20 years. Eligibility criteria included a requirement that the proposed resource qualify as a Connecticut RPS Class 1 renewable resource, have a commercial operation date no earlier than January 1, 2013, offer a delivery point on the ISO-NE grid, have a minimum nameplate capacity of 20 MW, have demonstrated site control, and be technically viable. Bidders were permitted to offer energy plus RECs, or RECs alone.

  The DEEP's scoring system awarded up to 80 points for price, 14 points for system reliability factors, and 5 points for the likelihood of meeting the target COD. The price evaluation was based on the levelized unit cost ($/MWh 2013 dollars) for energy and RECs, net of market revenues from sale of those products. A unit cost measure facilitated comparison of projects with different capacities. Out of 47 proposed projects, DEEP awarded contracts to a wind farm in Maine and two solar projects in Connecticut that were approved on October 23, 2013. DEEP also solicited proposals for new or existing biomass, landfill methane gas, and small run-of-river hydroelectric projects in

October 2013. Eligibility and evaluation criteria were similar to the previous wind and solar solicitation, with a similar scoring system for price and non-price factors, including reliability, environmental, and local economic development benefits. In December 2013, DEEP directed the EDCs to execute REC-only contracts that are awaiting approval by the Public Utilities Regulatory Authority.

Lessons Learned – Transmission Upgrades

Potential offshore wind applicants likely have experience (either themselves or their consultants) with the design and cost estimation of two key project components: the offshore wind farm and the interconnection to the existing grid. Designing, constructing, and operating these facilities are the direct responsibility of the applicant. However, there is a third important cost component that is difficult to estimate: the transmission upgrades required "downstream" of the interconnection point to assure deliverability and the safe and reliable operation of the bulk power system, *i.e.,* power plants and the high voltage transmission grid. These upgrades can occur anywhere on the bulk power system, not just at the point of interconnection, and are designed to keep the system operating even in the event of contingencies. While the applicant must pay for the cost of any upgrades, the bulk power system operator and local transmission owner are responsible for identifying the upgrades and estimating the costs.

The transmission upgrades and associated costs for a Qualified Offshore Wind Project would be determined through the PJM interconnection process. The process would be initiated when a project developer files an interconnection request for Capacity Resource status, at which point PJM and the local transmission owner, Delmarva, would identify the upgrades and develop the associated cost estimate over roughly a two-year period through a three step process consisting of increasingly detailed studies: Feasibility Study, System Impact Study, and Facilities Study. The definition of the required upgrades and the accuracy of the associated cost estimate improve through each stage of the interconnection process and PJM's estimated upgrade cost would be memorialized when an Interconnection Service Agreement is executed. PJM's interconnection process can take longer if there are changes to the generation project, resource mix, load growth, or transmission topology that materially affect the results, in which case PJM might have to conduct a "re-tool" of the System Impact Study.

Potential applicants are not likely to have completed the PJM interconnection process in time to be able to accurately estimate transmission upgrade costs in their applications. If applicants are required to submit firm Proposed OREC Price Schedules with no opportunity for subsequent true-up to account for more accurate transmission upgrade cost estimates, applicants would likely protect themselves from unexpected high upgrade costs by including a risk premium in the Proposed OREC Price Schedule. This would result in Maryland Retail Electric Customers paying more than the actual upgrade cost if the actual upgrade cost is less than the applicant's estimated cost and threaten the project viability if the actual upgrade cost is higher than the estimated cost, a "lose-lose" proposition.

Alternatively, the Commission should permit applicants who have neither completed the PJM interconnection process nor developed their own estimate to utilize a common set of upgrade cost estimates in their Proposed OREC Price Schedules, with an opportunity for a subsequent true-up. We recommend that the Commission retain a transmission consultant to estimate the transmission upgrade costs for likely-sized projects, *e.g.,* 200 MW and 400 MW, at likely 138 kV and 230 kV interconnection locations on the Delmarva Peninsula.[9] Applicants who elect to utilize the Commission's upgrade cost estimate would submit a two-part OREC Price Schedule: (i) the first component would include the costs of the wind farm and electrical interconnection to the PJM grid and (ii) the second component would cover transmission upgrade costs based on the Commission's estimate. This second component would be trued up based on any change between the Commission's estimated and PJM's upgrade cost in the Interconnection Service Agreement, subject to the price and rate caps in the Act. Our recommended approach avoids the need for applicants to include a risk premium that can harm Retail Electric Customers while observing the Act's price and rate caps.

To provide applicants with additional flexibility, they should have the option to utilize their own upgrade cost estimate developed by a consultant or through the PJM interconnection process. In this case an applicant would submit a firm, one-part Proposed OREC Price Schedule that would not be trued up.[10]

If the Commission retains a transmission consultant, we anticipate that developing an upgrade cost estimate would require about two to three months, provided that the transmission consultant has adequate resources. Thus we recommend that the application acceptance period be longer than the minimum of 90 days per § 7-704.1(2)(ii) of the Act, *i.e.,* 180 days to ensure that the Commission's upgrade cost estimate is provided to applicants well before the close of the Application Period. This added time would allow potential applicants to incorporate the Commission's upgrade cost estimate, submit an application, and provide any missing or incomplete information before the Application Period closes.

If a project with a one-part OREC Price Schedule is selected, that project developer would be responsible for submitting a PJM interconnection request for and obtaining Capacity Resource status. Such project would be responsible for all transmission upgrade costs and there would be

[9] Since the project location must be the BOEM site, there are a limited number of potential interconnection points on the Delmarva Peninsula. There are a perhaps three potential 138 kV substations, which would likely have similar upgrade costs for a 200 MW project. A 400 MW project would likely have to interconnect at one of the two 238 kV point on the Delmarva Peninsula and they would likely have similar upgrade costs as well.

[10] LAI introduced the concept at the January 28th stakeholder meeting. LAI subsequently prepared a Whitepaper on this issue (provided with minor modifications as Appendix 1) and discussed it at other stakeholder meetings. Stakeholder reaction has been favorable.

no upgrade cost adjustments. If a project with a true-up component is selected, that applicant should be required to submit a PJM interconnection request for Capacity Resource status within a reasonable period of time, *e.g.,* six months from selection, if an interconnection request has not already been submitted. Once the interconnection process is completed, the upgrade component of the two-part Proposed OREC Price Schedule would be trued-up if the upgrade cost in the PJM Interconnection Service Agreement differs from the Commission's estimated upgrade cost, subject to the Act's price and rate caps. We do not expect the true-up to result in a significant adjustment to the Proposed OREC Price Schedule.[11]

In order to avoid burdening Retail Electric Customers with disproportionate costs, we recommend that the upgrade cost true-up be limited to the project capacity reasonably required to meet its Proposed OREC Amount. If a selected applicant decides to construct a larger project, then the applicant should have the burden of demonstrating that the upgrade cost true-up would be allocated fairly and equitably between the capacity reasonably required to deliver the Approved OREC Amount and any excess capacity.[12]

Our recommendation to conduct the $190/MWh price cap test on a levelized basis would have the advantage of providing applicants with more flexibility to accommodate actual transmission upgrade costs in excess of the Commission's estimated cost. Similarly, performing the net rate impact tests on a levelized basis would facilitate communication of limits on the true-up. The levelized price and rate cap tests would minimize the risk that a true-up might result in a failure on either type of test. In the event that the full true-up adjustment would cause an application to fail a test, the amount of disallowed true-up would generally be less.

Lessons Learned – Surplus ORECs

Once a Qualified Offshore Wind Project is operational, its output may exceed its Approved OREC Amount in any year. In this case we recommend that the project have the option to direct the administrator of the Escrow Account ("Administrator") to either (i) treat such excess output as Surplus ORECs to be utilized for compliance by Electricity Supplies in a future year or (ii) merchandize such excess output at market power and Tier 1 REC prices. In the first option,

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[11] For example, a 200 MW offshore wind project (excluding transmission upgrades) would cost just over $1.1 billion based on a 2011 NREL cost estimate of $5600/kW. Injecting energy into the Delmarva Peninsula, an energy import region, should require less expensive upgrades than if energy were injected into an energy exporting region. Assuming an upgrade cost estimate of $50 million for the 200 MW project and a maximum true-up of +/-50%, the OREC bid price adjustment would be no more than 2% (= $25 billion / ($1.1 billion + $50 million).

[12] To continue this example, if the selected applicant offered a 200 MW offshore wind project and decided to construct and request interconnection for a 300 MW project and the actual upgrade cost was estimated at $120 million, then only 66.7% (= 200MW / 300MW) of the actual upgrade cost or $80 million would be used to true up the OREC Price Schedule.

Surplus ORECs would be banked in the Administrator's GATS Account for up to three years and the Administrator would retain the associated PJM market revenues. The project would not receive the OREC revenues and the associated PJM market revenues would not be credited to ratepayers until the banked Surplus ORECs are used or retired. In no event, however, should the project be compensated for new plus banked Surplus ORECs exceeding the Approved OREC Amount in any year. In the second option, excess output would be merchandized by the project at market values, the excess output would not qualify as ORECs, and the market revenues for energy, capacity, ancillary services, and Tier 1 RECs would flow into the Escrow Account and then to the project on a current basis. The project should be permitted to merchandize its excess output to PJM or to any other buyer, since such sales and revenues will not affect Maryland ratepayers.

Lessons Learned – COD Delays

The U.S. experience demonstrates the many challenges and uncertainties in developing offshore wind resources. In particular, it is very difficult for a developer to accurately predict the actual COD, particularly at the time the OWEA applications will be due. In order to give applicants some flexibility and yet maintain ratepayer protection, LAI recommends that the Regulations require applicants to specify firm, calendar year OREC prices (ignoring adjustments for transmission upgrade costs) that would cover the term of the proposed OREC Price Schedule plus five additional years to accommodate a COD delay of up to five years.

Table 1 Example of OREC Prices and COD Delay

Delivery Year	(a) COD 2017	(b) COD 2018	(c) COD 2022	(d) COD 2023
2017	$200	n/a	n/a	n/a
2018	$201	$201	n/a	n/a
2019	$202	$202	n/a	n/a
2020	$203	$203	n/a	n/a
2021	$204	$204	n/a	n/a
⋮	⋮	⋮	⋮	⋮
2036	$219	$219	$219	$218
2037	n/a	$220	$220	$219
2038	n/a	n/a	$221	$220
2039	n/a	n/a	$222	$221
2040	n/a	n/a	$223	$222
2041	n/a	n/a	$224	$223
2042	n/a	n/a	n/a	$224

Each OREC price would be for that specified calendar year, regardless of when COD occurs, for up to five years of delay. If a selected project were to be delayed for more than five years, the Commission should have the right, but not the obligation, to extend the delay period beyond five years, in which case the applicant would have to propose OREC prices beyond those already submitted. For example, if an applicant offered a COD of 2017 and the project achieved a 2017 COD, then the OREC prices for the delivery years might be as listed in column (a) above starting at $200/MWh in 2017. If the COD were delayed one year to 2018 or five years to 2022, the OREC prices would be the calendar year OREC prices for those delivery years as shown in columns (b) and (c). The table indicates that the calendar year OREC price for any year would not change if the COD were delayed up to five years. If the COD were delayed six years to 2023 (more than five years) then the OREC prices would be the COD 2022 prices "pushed out" one year, as shown in column (d), notwithstanding Commission action to extend the COD delay period.

LAI believes this approach reasonably balances the interests of developer risk and ratepayers. This approach is generally consistent with the pricing provisions for the Fishermen's Energy and the Cape Wind projects. The Cape Wind / National Grid contract limits such adjustments to three years, but given its experience we believe a five year COD delay is reasonable and provides a financial incentive for selected project developers to avoid longer delays.

Other Best Practices and Lessons Learned Applied to Maryland's OWEA Process

Based on the best practice principles and on the lessons learned from other procurements, we recommend that the Commission's Regulations include the following provisions.

- Clear Policy Aims – It is important that the OWEA process provide clear guidance to bidders regarding the State's aims. For example, the over-riding objective of offshore legislation in France is to support the development of a local offshore wind industry and supply chain, with the government willing to pay a higher price to achieve these benefits. The UK has traditionally focused on maximizing the volume of offshore deployment but is now seeking to drive down cost, while hoping for greater local benefits. Thus it is important to consider the stated goals of the Act and design the process appropriately to maximize the likelihood of projects that match Maryland's specific needs.

- Site Control – In order to enhance the likelihood of a robust and competitive response to the Commission's Regulations implementing the Act and accepting offshore wind applications, we recommend that applicants should not be required to have site control at the time the application is submitted, *i.e.,* applications should not be restricted to winners of the BOEM lease auction.[13] Such a restriction would lead to at most two, and possibly

[13] PJM defines site control in its interconnection procedures as requiring the applicant to have "...an exclusive option to purchase the property..., a property deed, or a range of tax and corporate documents that identify property ownership. Site control must either be in the name of the party submitting the generation interconnection request or documentation must be provided establishing the business relationship between the party developer and the party having site control."

one, offshore wind project bids. Instead, the Commission should require all applicants who are not lease holders to provide documentation regarding their plan to secure a BOEM lease if selected by the Commission. This plan may consist of an option (but not an obligation) to transfer the lease from the lease holder, a joint venture, or some other arrangement with the lease holder to develop a wind farm on that lease. If an applicant who does not have BOEM lease rights is selected, it will be that applicant's responsibility to negotiate a transfer, joint venture, or other arrangement to develop the wind farm on that lease as long as the selected applicant retains a controlling interest in, or at least 50% ownership control of, the project.[14] Applicants who hold BOEM leases would receive higher scores for the site control criterion in the qualitative evaluation.

- Timing and Risk – The timing of the OWEA process was specified in the Act but best practice would provide sufficient time to resolve important outstanding commercial and technical uncertainties prior to applications being submitted. The higher the uncertainty, the more risk will be priced in by developers leading to higher prices passed on to ratepayers. For example, the process in Denmark has evolved to minimize site risk as much as possible, *i.e.,* undertaking substantial survey and environmental work prior to requesting tenders. This allows developers to focus on what they are good at – building wind farms. At this point in time, there are uncertainties and risks associated with developing an offshore wind farm at the BOEM lease sites. The sites are relatively poorly understood with regard to geographical and geotechnical conditions, climatology conditions, marine and avian conditions, etc. Consequently, a considerable amount of design and optimization will be required before the selected developer can prepare a final design. It is therefore important that there is a sufficient amount of time allowed for potential developers to prepare their applications, and that approved applications retain some flexibility to modify project design as new technologies become available.

- Strong Application Vetting – Best practice is to design the process to ensure only qualified candidates are considered without restricting their development ability. Virtually all European tenders pre-screen applicants, and in some cases, *e.g.,* the Netherlands, a substantial deposit from applicants is required to deter speculative applications. Our recommendation that only Administratively Complete applications be accepted for this process, plus implementing a clearly defined Step 3 Minimum Threshold Criteria review and Step 4 qualitative evaluation, should screen out speculative or weak applicants and minimize any risks of future litigation by those applicants.

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[14] It is unclear how long a selected project that had not been awarded a BOEM lease should have to make such an arrangement. We recommend not establishing a deadline, because the requirement to make periodic and substantial deposits into Maryland Offshore Wind Business Development Fund will provide an effective incentive for any selected project to either reach an arrangement with a lease holder or terminate the project.

- Application Requirements – All parties benefit from clear and defined application requirements. The required application information should be clearly specified in the Regulations so that applicants develop the information required by the Commission to the appropriate level of detail, minimizing the need to request missing or additional information and avoiding any additional time and costs to obtain such information. Such required information will permit the Commission to conduct production cost and economic input-output modeling as described later on in this report. Applicants should be made aware of the discount and deflation rates the Commission will use, as well as the RPS OREC Percentage and the Applicable Load that will cap the quantity of ORECs to be purchased in any year. In addition, the Commission should prepare and distribute Proposed OREC Price Schedule forms for applicants to utilize in their applications that automatically calculate levelized OREC Price in 2012 constant dollars per MWh ("Levelized OREC Prices").

- Design and Equipment – In one of the offshore wind solicitations we reviewed, a bidder pointed out that it was unable to substitute later model turbines for the ones specified in their application. Offshore wind technology is developing at a rapid pace, and turbines are becoming larger, thereby bringing down costs through economies of scale. Nonetheless, applications should be based upon technologies that are currently feasible and commercially available. If applicants know they can substitute later turbine models that are commercially proven and available, they might lower their Proposed OREC Price Schedule knowing that their costs will likely decline by the time turbines have to be ordered. The Commission should want to be assured that technical risks would not increase, and thus should require that the developer demonstrate that the selected turbine technology has been certified by an accredited certification body. Bidders also indicated that foundation and support structure designs will likely improve, further lowering costs. While lower costs could be shared with Retail Electric Customers, calculating or verifying the resulting improved project economics is difficult at best and infeasible at worst, akin to an open book cost-of-service arrangement. Thus we do not recommend any cost sharing if turbines, foundations, or structures are substituted. Allowing developers to keep the resulting financial upside is consistent with having developers accept the risk of financial downsides.

- Quantitative and Qualitative Evaluations – Many of the evaluation criteria specified in the Act are difficult to accurately and comprehensively quantify in monetary terms, *e.g.*, health impacts. The Commission should indicate in the Regulations whether these criteria would be considered quantitatively or qualitatively.[15] In at least one offshore

[15] We recommend that avoided power plant air emissions be quantified and the consequential health impacts be considered qualitatively.

wind solicitation, the state regulations did not specify how the evaluations would be conducted, and whether project attributes would be considered quantitatively or qualitatively. Best practice would be for the Regulations to lay out the general evaluation process (without necessarily specifying specific models or input assumptions) so applicants understand what attributes are considered, how they will be measured, and how they will be considered (including on a quantitative or qualitative basis).

- Communications and Confidentiality – In order to assure confidentiality of commercially sensitive information and promote bidder interest, the Commission should allow applicants to (i) identify confidential information that they request be exempt from disclosure and (ii) specify a process to maintain that confidentiality. At a minimum, Proposed OREC Price Schedules and any financial projections should be kept confidential.

- OREC Price Adjustments – The Act does not address the Commission's right to request that applicants adjust their OREC Price Schedule or to request a Best and Final Offer after a complete application is submitted. Such requests should be made to all qualified applications to be consistent with the good practice. Additionally, such requests would be especially useful if none of the projects satisfy all of the requirements, *i.e.,* the price cap, the RPS OREC Percentage, and the residential and nonresidential net rate caps, in which case a small reduction in the Proposed OREC Amount or in the OREC Price Schedule would allow a project to satisfy all of these requirements.

Application Requirements

We have developed this list of application requirements that includes general information followed by the list of requirements in PUA § 7-704.1(c). The Regulations should make clear whether applications will be made public or how applicants can designate certain portions as proprietary and subject to confidentiality restrictions. The Regulations should be clear and complete so that potential applicants submit the full range of required information for proposed projects in an organized manner and with the correct level of detail. This would help ensure that the Commission can easily check each application for completeness, ensure that Minimum Threshold Criteria requirements are met, and subsequently conduct the quantitative and qualitative evaluations.

We note that some of the application requirements described below may not be fully available at the time that an application is submitted. Potential applicants should be advised that if certain information cannot be furnished, the applicant should explain when and how such information would become available.

We recommend that applicants be permitted to provide multiple, mutually exclusive applications with different delivery terms, CODs, Proposed OREC Amounts, and/or Proposed OREC Price Schedules for a particular project configuration, *e.g*, a project with a defined capacity, type and number of turbines, and BOEM lease site. The Commission should determine to what extent common application components could be provided separately, rather than repeated for each application, *i.e.,* should the entire application be submitted for commercial variations of a particular project or could one application contain multiple options for term, COD, Proposed OREC Amount, and Proposed OREC Price Schedule. For example, an applicant could submit a proposed OREC price and a Proposed OREC Amount (with corresponding confidence level) of \$150 per OREC for 700,800 ORECs at P40, \$160 per OREC for 630,720 ORECs at P75, etc.[16]

We also recommend that applicants be permitted to provide multiple, mutually exclusive applications for different project configurations, *e.g*., capacity and turbine type, on the same BOEM lease site. An applicant should provide separate applications for different project configurations, each with all of the required application elements.

Conditional applications may be permitted but the quantitative evaluation should be conservative so that ratepayers are assured the project's OREC quantities and prices do not violate OWEA's OREC price and net rate impact caps. Any future conditions that might lower the OREC price, *e.g.,* a larger project or obtaining tax benefits, would be considered positively in the qualitative evaluation but would not be included in the quantitative evaluation.

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[16] Note that P confidence values correspond to the probability of exceeding an output level in a given year.

Applicant Background and Contact Information

Applicants should provide sufficient information about themselves and the rest of their development team to provide the Commission with reasonable assurance that they have adequate commercial, financial, and technical capabilities to develop, construct, and operate the offshore wind facility and decommission it at the end of its planned operational life. This information should include any information about their organization, key staff, and prior experience.

a) Developer information, including the name and business organization (partnership, corporation, LLC, etc.), all owners, parent company, and other sponsoring firms (including contingent obligations to fund the project if selected).

b) Name and title of the primary contact person and any other person authorized to verify application information (including the Proposed OREC Price Schedule and Proposed OREC Amount) with telephone number(s), email address, and mailing address.

c) Name and primary contact person of the companies providing financing, with most recent audited financial statement (per GAAP or IFRS accounting rules) and issuer and unsecured senior debt ratings from at least one recognized rating agency.

d) Name and title of each member of the applicant's executive team and project development team that will be responsible for the proposed project with telephone numbers, email addresses, mailing addresses, and curriculum vitae demonstrating capability and expertise in wind or large generation project management, development, financing, permitting, engineering, procurement, construction, operations, maintenance, decommissioning, and other significant and relevant functions;

e) Name, address, contact information for any companies with whom the developer has a contract (or similar agreement) to perform any permitting, design, construction, procurement, or O&M functions.

f) Disclosure of any prior business bankruptcies, defaults, disbarments, investigations, indictments, or any other actions against the developer, parent, or other sponsoring firms, or key employees.

g) Work performed by applicant, parent, sponsoring firms, and contractors in developing projects of similar scope, especially any ocean-based energy project, utility-scale wind projects, or large scale generation projects in Maryland or elsewhere.

h) A signed and notarized statement by an officer of the offshore wind project developer stating (i) the officer has the authority to submit this Application to the Commission, (ii) the Application, including the Proposed OREC Price Schedule and Proposed OREC Amount, shall remain binding through the Application Period, (iii) the information and materials contained in the Application are accurate and correct, and (iv) if the Application is selected, the developer will work diligently and engage in a continuous development and construction program, to achieve the COD specified in the application ("Estimated Project COD").

Project Description

Applicants should provide reasonably detailed information about their intended projects sufficient for the Commission to understand each proposed project's basic operating parameters and to estimate power market, rate, economic, environmental, and health impacts. This information should include reasonably complete and detailed descriptions of the foundation, support structure / tower design, and the manufacturer, model, number, and nameplate rating of proposed turbines as detailed below.

The following information should be required from applicants on their offshore wind projects. Any missing item should be clearly identified by applicants with a plan demonstrating how any missing information will be provided if it is not available at the time of application.

a) A general description of the project in order to understand the basic project characteristics, including site plan, project location, number of turbines, capacity (gross and net), area, typical distance to shore, water depths, general seabed description, main competing uses and sensitive areas, with general maps showing turbine layout, landfall and grid interconnection point, and construction layout site.

b) A project development timeline and critical path schedule including milestones for site assessment, engineering, permitting, turbine certification, Certificate of Public Convenience and Necessity, financing, procurement, construction, testing and commissioning, COD, and delivery term. This information will require the applicant to fully consider the development and construction process and help screen out fatally flawed projects.[17]

c) Wind resource and energy yield assessment at planned hub height with supporting data in an industry-standard report with expected gross (at generator terminals) and net (at PJM billing meter) annual energy production with losses and turbine availability (scheduled and forced outages), uncertainty estimates of the net annual energy production at several confidence intervals (P5, P10, P50, P90, and P95), and hourly energy production profiles by month (12x24 matrices) for a typical year per industry standard practice. This information will allow the Commission to conduct its own independent power market analysis.

[17] We anticipate that a Certificate of Public convenience will be required for any above-ground electrical line above 69 kV per PUA § 7-208.

d) Wind turbine technology with turbine manufacturer, model, track record in offshore wind applications, physical dimensions and weight, hub height, rotor diameter, and nameplate capacity, design standard, certification status, service life, and design life information.[18]

e) Foundation and support structure descriptions with explanations why they are appropriate for the site; climatology information including wind, wave, and current data, to ensure that applicants have appropriately planned for expected site conditions.

f) A description of the electrical collection system and connection to the PJM grid, including the location and description of any onshore and offshore substations, inter-array and export power cables, interconnection route, landfall and facilities, including rights of way; interconnection plans, status of PJM interconnection request, schedule for completing the interconnection studies (if applicable); electrical one-line diagram of the facility up to the PJM interconnection point.

g) Site control status or plans to ensure site control for the operating term; interconnection and right-of-way status or plans; status of discussions with BOEM.

h) A general description of Balance of Plant components including met mast, communication system, supervisory control and data acquisition ("SCADA") system.

i) A permitting and approvals plan with a detailed matrix and schedule of all federal, state and municipal environmental and regulatory permits and approvals that will allow the Commission to identify projects that are more or less advanced.

j) A procurement and construction plan with a general overview (with milestones) of all steps from commencement of procurement and construction to testing and commissioning of the project; a contracting strategy and organizational chart; a description of laydown, storage, and assembly areas; applicant's plan to promote the prompt, efficient and safe completion of the project, particularly with regard to the construction, manufacturing, and maintenance of the project per PUA § 7-704.1(d)(1)(ix); plans to comply with the Jones Act; a framework for a construction period Health and Safety ("H&S") plan.

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[18] Certification from an accredited certification body would confirm that the turbine is designed, documented, and manufactured in conformity with design assumptions, specific standards and other technical requirements to ensure the its long-term safety and reliability. Accredited certification bodies for wind turbines certification, according to the International Electrotechnical Commission standard 61400-22, Wind Turbines - Part 22: Conformity Testing and Certification, include Bureau Veritas, DEWI-OCC, DNV GL, TÜV NORD, TÜV Rheinland, and TÜV Süd. Turbine certification should not be required at the time of the application for the purpose of assessing whether the application is Administratively Complete and whether the application complies with the Minimum Threshold Criteria, but the Commission should require certification by COD for the project's output to qualify as ORECs.

k) An O&M Plan with a schedule of principal O&M activities and locations of specific ports with O&M facilities; estimated O&M labor divided between specialized out-of-state and in-State labor.

l) A year-by-year spending projection of expenses and capital expenditures by five- or six-digit North American Industry Classification System ("NAICS") code and divided into the following four categories: (i) in-State labor, (ii) in-State non-labor, (iii) out-of-State labor, and (iv) out-of-State non-labor, to allow the Commission to conduct its own independent economic input-output analysis.

m) Plans to develop an environmental impact assessment and monitoring plan with a description of the types of studies (physical, biological and socio-economic) to be conducted, including plans to comprehensively assess impacts from pre-construction activities through decommissioning. Plans should demonstrate compliance with the National Environmental Policy Act, Endangered Species Act, Migratory Bird Treaty Act, and Marine Mammal Protection Act, BOEM guidelines for surveying of avian species, benthic habitats, fish, marine mammals and sea turtles and spatial data submission, local/state regulations, and the Coastal Zone Management, as applicable.

n) A decommissioning plan that demonstrates the safe and environmentally responsible removal and disposal of the turbine structures, offshore electrical substation and other offshore facilities, particularly those located in State waters and on State lands, along with a comprehensive estimate of decommissioning costs and a plan to ensure adequate funding for decommissioning the project.

Commercial Operations Date

Applicants should propose a target COD, but the actual COD may be delayed for a variety of valid reasons, from delays in acquiring meteorological and climatic data to necessary lead times for major equipment. In commercial arrangements for conventional power plants, it is typical to either have a COD cutoff date or to require liquidated damage payments to increase with any COD delay to avoid unreasonable delays. Given the inherent risks and long lead time to develop an offshore wind project, however, we recommend that the Regulations do not penalize the applicant for COD delays, recognizing the challenges in developing and constructing an offshore wind project, and thus not require a COD cutoff date. Once selected, a project applicant would have sufficient incentive to develop the project expeditiously given the early phase investments for meteorological data collection, geophysical and geological data collection, permitting, etc. We note that a selected project applicant will have payment requirements into the Maryland Offshore Wind Business Development Fund as well as annual BOEM lease payments that together will serve as financial incentives for the selected bidder to achieve the Estimated Project COD diligently and expeditiously.[19]

a) PUA § 7-704.1(g) effectively provides liquidated damages for the first two years as a selected applicant will have to deposit $2 million into the Maryland Offshore Wind Business Development Fund (i) within 60 days after Commission approval, (ii) within one year of the initial deposit, and (iii) within two years of the initial deposit, provided these deposits are non-refundable.

b) BOEM requires the wining lease bidder to make rent payments of $3/acre-year up to COD; the entire lease would require payments of $239,000 per year.

If a selected offshore wind project does not achieve the target COD in its application, we recommend that the Commission permit the COD to be delayed for up to five years and the delivery period to remain intact. In the event the COD is delayed the OREC Price Schedule should have five years of additional OREC prices and the proposed OREC price for any calendar year would be the price at which such ORECs would be purchased. If the COD is delayed for more than five years, the calendar year prices in the OREC Price Schedule would be "pushed out" one year for each year of additional delay beyond five years. In no event, however, should either the price cap or the residential and nonresidential net rate caps be exceeded.

Given the risks and long lead time to develop an offshore wind project, we recommend that the Commission not require additional payment provisions or financial security for a selected applicant to achieve a target COD. However, we recommend that the Commission may consider withdrawing any Order selecting a project and establishing an Approved OREC Amount from a project that, for example, (i) is unable to obtain rights to a BOEM lease site, (ii) declares bankruptcy, or (iii) is unable to demonstrate to the Commission that it has diligently pursued and engaged in a continuous development and construction program to achieve project COD.

Maryland Business Impacts

These application requirements were specified in OWEA §s as indicated.

a) Applicant's plan for engaging small businesses, as defined in §14-501 of the State Finance and Procurement Article per PUA § 7-704.1(d)(1)(vii).

b) Applicant's plan for the use of skilled labor, particularly with regard to the construction and manufacturing components of the project, through outreach, hiring, or referral

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[19] BOEM requires financial assurance in the form of a surety bond to ensure that any monies due from a lease holder are paid; the surety bond would not be retained by BOEM if the lease holder cancelled the project.

systems that are affiliated with registered apprenticeship programs under Title 11, Subtitle 4 of the Labor and Employment Article per PUA § 7-704.1(d)(1)(viii).

c) Applicant's plan to provide for compensation to its employees and subcontractors consistent with wages outlined in the State Finance and Procurement Article, per PUA § 7-704.1(d)(1)(x).

Financial Information

Each Applicant should provide sufficient financial information to demonstrate that there will be sufficient funds to develop and construct the project. Given the complexity and high cost of constructing offshore wind projects, demonstrating sufficient sources of equity and debt funds will be required, particularly for the first large-scale project in North American waters. The Act requires applicants to seek all financial support to offset the project cost for the benefit of ratepayers.

a) A detailed financial analysis of the project, including a pro forma income statement, balance sheet, and cash flow projection covering the development period, construction period, and proposed OREC operating term with detailed revenues and expenses; a description and estimate of any State and Federal grants, rebates, and tax credits; estimated internal rate of return and return on equity, consistent with PUA § 7-704.1(c)(1).

b) The project balance sheet at COD should include all capital expenditures broken down by major cost category, *e.g.,* permitting, legal, and consultant costs, site and meteorological assessment, ship or barge leases, wharfage fees, construction labor, foundations, support structures, wind turbines, capitalized interest, and owner's costs. This balance sheet should be consistent with the spending information requested on page 27 of this report.

c) The proposed capital structure identifying equity investors, sources of debt, any other sources of capital, and written demonstration, *e.g.,* letters of intent or commitment letters, of equity and debt funding commitments, consistent with PUA § 7-704.1(c)(2).

d) Documentation that the applicant has applied for all current eligible State and Federal grants, rebates, tax credits, loan guarantees, or other programs available to offset the cost of the project or provide tax advantages, per PUA § 7-704.1(c)(2).

e) A list of the minority investors interviewed by the applicant and whether those investors have purchased an equity share in the project and an affirmative statement that the applicant will interview minority investors in any future attempt to raise venture capital or attract new investors, per PUA § 7-704.1(d)(4)(ii).

f) An affirmative statement of the applicant's commitment to use best efforts to apply for all eligible state and federal grants, rebates, tax credits, loan guarantees, and other similar benefits as those benefits become available, and pass along to ratepayers, without any subsequent Commission approval, 80% of the value of any state or federal grants, rebates, tax credits, loan guarantees, or other similar benefits received by the project and not included in the application, per PUA § 7-704.1(c)(8).[20]

g) An affirmative statement of the applicant's commitment to deposit $6,000,000 into the Maryland Offshore Wind Business Development Fund per PUA § 7-704.1(g).

h) An affirmative statement by the applicant that ratepayers, purchasers of ORECs, and the State shall be held harmless for any cost overruns associated with the offshore wind project per PUA § 7-704.1(f)(1)(iv)(2).

Project Analyses

PUA § 7-704.1(c)(3) requires each application to provide a cost-benefit analysis. Each applicant will likely utilize its own models and assumptions for the cost-benefit analysis, an approach that would not permit a fair and consistent comparison among the proposed projects. The Regulations should permit applicants to identify qualitative and quantitative impacts on Maryland's ratepayers, environment, health, and economy.

a) A detailed input-output analysis of the in-state impact on income, employment, wages, and taxes.

b) Detailed information on expected employment impacts in Maryland, including supporting evidence, an analysis of in-State business impacts due to in-State construction, operations, maintenance, and equipment purchases, and any binding commitments for such in-State activities.

c) An analysis of anticipated environmental and health impacts during project construction, operations, and decommissioning, including direct emission impacts of carbon dioxide, oxides of nitrogen, sulfur dioxide, mercury, and particulates, as well as other relevant environmental impacts and consequential health benefits.

d) An analysis of (i) long-term effects on wholesale energy and capacity markets and (ii) impacts on residential, commercial, and industrial Retail Electric Customers over the life of the project, including direct OREC costs and indirect costs or benefits of required transmission or distribution system improvements associated with the project.

[20] While the Act specifies that the applicant would pass along 80% of the value to ratepayers without the need for Commission approval, we recommend that the Regulations provide a mechanism for the Commission to check if any 80% valuation was calculated correctly and passed to ratepayers.

e) Relevant information on reliability, fuel diversity, generation competition, transmission congestion, or other power market benefits or for Maryland Electric Retail Customers.

In order to have consistent calculations and assure comparability among the cost-benefit analyses, we recommend that the applicants provide sufficient information for the Commission to independently calculate these impacts and prepare cost-benefit analyses that can be used to fairly and consistently evaluate proposed projects. The Regulations should specify the data required for the Commission to conduct these analyses, consistent with the requirements of PUA § 7-704.1(c)(3).

Proposed OREC Price Schedule

A Proposed OREC Price Schedule may consist of either (i) a two-part OREC price in which the second component would be trued-up based upon any change between the Commission's estimated cost of transmission upgrades and the PJM Interconnection Service Agreement upgrade cost or (ii) a one-part OREC price that is not subject to true-up.[21] An applicant should not be required to have commenced or completed any part of the PJM interconnection process to submit a one-part OREC price. If a project with a one-part OREC price is selected by the Commission, that project effectively takes on any risk associated with the ultimate cost of required transmission upgrades. The first component of the two-part OREC price and the one-part OREC price should be expressed as either a single firm price for the proposed delivery term or a series of firm prices for each year for the proposed delivery term, as illustrated in Table 1. The second component of a two-part OREC price should be expressed as a single price for the entire delivery term, but subject to true-up. Each application with a two-part OREC price should include a methodology for allocating any transmission upgrade costs and demonstrating that the methodology is fair and reasonable in the event the project's actual capacity exceeds the capacity required to provide the Proposed OREC Amount. All prices should be expressed as a firm nominal price for each calendar year of operation; an applicant should not be allowed to utilize a non-firm price such as a price index, *e.g.,* CPI or GDP Deflator, for any bid component. Examples of one-part and two-part Proposed OREC Price Schedules for a twenty year term (requiring twenty-five years of OREC prices) are presented in Table 2 below.

[21] The challenge of estimating transmission upgrade costs and our recommended solution are described on pages 15-17 of this report.

Table 2. Examples of Acceptable Proposed OREC Price Schedules

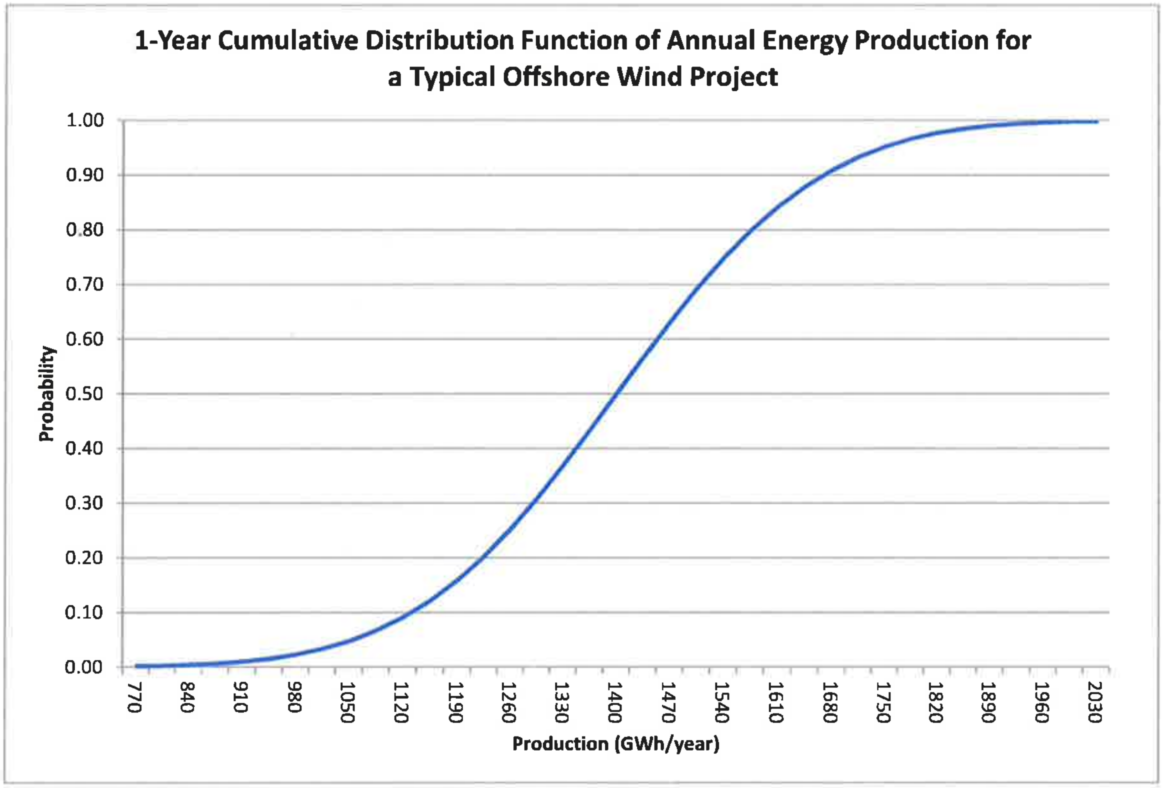
Delivery Year	One-Part Bids: Example A	Example B	Two-Part Bid: Example C Fixed Component	+ True-Up Component	= Total
2017	$185	n/a	$175	$10	$185
2018	$185	$180	$176	$10	$186
2019	$185	$182	$177	$10	$187
2020	$185	$184	$178	$10	$188
⋮	⋮	⋮	⋮	⋮	⋮
2036	$185	$216	$194	$10	$204
2037	$185	$217	$195	$10	$204
2038	$185	$218	$196	$10	$206
2039	$185	$219	$197	$10	$207
2040	$185	$220	$198	$10	$208
2041	$185	$221	$199	$10	$209
2042	n/a	$222	n/a	n/a	n/a

The Proposed OREC Price Schedule must be on a dollar per delivered OREC (MWh) basis by calendar year. An applicant must also specify the Proposed OREC Amount with the maximum number of ORECs the project can sell in each twelve month period. Payments would commence on the later of January 1, 2017 or the first production of ORECs by the project. The OREC price can vary from calendar year to calendar year, but the Proposed OREC Amount must be constant over the entire delivery term. We recommend that the Commission assume equal monthly OREC generation for calculations involving partial years of operation, *e.g.*, a project with an October 1 COD would be expected to generate 25% (= 3 months / 12 months) of its annual OREC amount in the three months of its first calendar year of operations and 75% (= 9 months / 12 months) of its annual OREC amount in the nine months of its last calendar year of operations.

Proposed OREC Amount

The Proposed OREC Amount would become the Approved OREC Amount for any full calendar year if the Commission selects the project. If the Commission were free to establish the Approved OREC Amount without regard to the applicants' Proposed OREC Amount, the applicant would be at risk of not receiving sufficient revenues in any year. By proposing a Proposed OREC Amount associated with an OREC Price Schedule, the applicant mitigates that risk. To allow the Commission to gauge how frequently the Proposed OREC Amount would be produced from year to year, each applicant should indicate the expected generation confidence level associated with the Proposed OREC Amount. Lastly, the Proposed OREC Amount and OREC Price Schedule should be consistent with the revenue stream identified in the applicant's financial analysis pro forma income statement and cash flow projection.

Figure 2. Typical Offshore Wind Energy Cumulative Distribution



For example, Figure 2 illustrates the cumulative energy distribution in which (i) a P90 confidence level, *i.e.,* the project output expected to be met or exceeded in 90% of the years, corresponds to the 0.10 probability at which wind energy production is about 1120 GWh/year and (ii) a P10 confidence level *i.e.,* the project output expected to be met or exceeded in only 10% of the years, corresponds to the 0.90 probability at which wind energy production is about 1680 GWh/year.

Confidential Information

Financial information provided by the applicants and other commercially sensitive or proprietary information should be kept confidential. Pursuant to PUA § 7-704(1) Annotated Code of Maryland, an applicant must (i) give specific attention to the clear identification of those portions of its application that it considers confidential, proprietary commercial information, or trade secrets and (ii) provide justification why such information should be exempt from disclosure by the State under the Public Information Act, Maryland Code Annex, State Government Article, Title 10, Subtitle 6 (the "Public Information Act").

Therefore, we recommend that any information that the applicant desires to be kept confidential, including financial information, must be identified as such and clearly marked in the application as Material for Which Applicant Claims Exemption from Disclosure Under § 10-617(d) of the Public Information Act. Applicants should be advised that, upon request for such confidential information by a third party pursuant to the Public Information Act, the Commission is required to make an independent determination whether such confidential information must be disclosed.

Step 1: Pre-Application Tasks and Application Period

Once the Regulations are implemented, the Commission should conduct certain tasks that are either necessary for applicants to complete their applications or for the Commission to evaluate submitted applications. These tasks include (i) estimating transmission upgrade costs that applicants can utilize in their Proposed OREC Price Schedules, (ii) establishing communication protocols, including a secure website, and (iii) preparing a bid form for applicants to submit Proposed OREC Price Schedules that automatically calculate Levelized OREC Prices so that applicants will know if they exceed the \$190/MWh price cap. Once these pre-application tasks are completed, the Commission should distribute this information to potential applicants through the project web site. The Commission may be supported by an IC or other experts per PUA §§ 7-704.1(d)(2) and 7-704.1(e)(2)(i) to facilitate communication among all parties, improve efficiency during the application review period, and ensure the modeling assumptions and parameters that will be used to evaluate competing applications are determined sufficiently in advance.

Pre-Application Tasks

The Step 1 tasks to be performed are listed below. Completing these tasks and disseminating the results will maximize bidder confidence in the process, encourage complete applications, and ensure fair and consistent evaluations.

Estimate of Transmission Upgrade Costs

The Commission should develop reasonable estimates of the necessary transmission upgrade costs for 200 MW and 400 MW projects at likely 138 kV and 230 kV interconnection locations on the Delmarva Peninsula prior to applications being received, as described in detail on pages 19-21 of this report. This should take no more than 2-3 months, provided the transmission consultant has sufficient resources. The IC and the transmission consultant should be retained as soon as possible after the date the Regulations are implemented.

Establish Communication Protocols

The Commission should establish communication protocols, including a secure and dedicated website, to disseminate information to the public at large and for potential applicants to obtain information on the application and evaluation process. We recommend that potential applicants register to receive notifications, application instructions, and to submit questions. Answers should be posted for viewing by all registered parties, with applicants' identities redacted.

Prepare Proposed OREC Price Schedule Form

To ensure that applicants provide conforming Proposed OREC Price Schedules, the Commission should develop and issue a standard form for applicants to use to submit price and quantity data. We recommend that this form should be an active worksheet that calculates a Levelized OREC

Price in 2012 dollars for the Estimated Project COD and for each of five years of potential COD delay to insure that the PUA price cap of $190/MWh (2012 dollars) is not exceeded. The remainder of the application should be in narrative form, with charts, tables, and appendices, as appropriate.

Stakeholder Meetings

While not required under the Act, we note that other offshore wind and renewable procurements have allowed applicants to meet with commissioners, staff, and/or their advisors prior to submitting an application. For the Maryland OREC application process, communications, including meetings, is advisable since it will allow the Commission and the IC to answer questions, reduce potential application deficiencies, and provide the Commission and the IC an opportunity to identify likely issues and allocate appropriate resources. Depending on the timing, there can be either meetings with all bidders or separate meetings with individual bidders if commercially sensitive information is to be discussed, prior to submission of any application. We understand that such meetings would be on the record.

Commission Notifications

Once these pre-application tasks are completed, the Commission should provide notice that the secure website is available with detailed Proposed OREC Price Schedule bid forms and other information. In addition, the Commission should determine the modeling parameters for (i) forecasting Power Products and REC values that will be utilized to evaluate power market and rate effects and (ii) calculating employment, environmental, and health impacts that will be utilized to determine other benefits for Maryland ratepayers. Completing these modeling tasks early should facilitate the prompt evaluation of proposed projects later on. The models and key inputs will not be determined until after the Regulations are implemented. Consistent with best practices, this modeling information would not be disseminated to potential applicants. However, potential applicants should be apprised (i) of the assumed inflation rate and discount rate(s) that the Commission will use to calculate a Levelized OREC Price that would be used to conduct rate impact calculations, (ii) that more than one OREC Price Schedule (along with corresponding Proposed OREC Amounts and confidence levels) can be submitted for a single project, and (iii) of the RPS OREC Percentage and Applicable Load that will cap the quantity of ORECs that can be purchased in any year. Upon the receipt and acceptance of the first Administratively Complete application, notice of an open Application Period should be posted on the Commission's website and communicated to other potential applicants.

Application Period Commencement and Duration

PUA § 7-704.1(a)(2)(i) permits applicants to submit an application to the Commission for a proposed offshore wind project at any time after the effective date of the Regulations. We recommend that the Commission commence the Application Period once an application is received and determined to be Administratively Complete. This would in line with best practices since it would avoid unnecessarily accelerating the Application Period if an application for a weak, poorly conceived project is submitted immediately after the Regulations are adopted. Once an application is determined to be Administratively Complete, the Commission is required to post notice that it is accepting applications once the Application Period has commenced along with the duration and closure of Application Period.

The Commission should have a defined period of time to conduct the administrative completeness review, *e.g.,* 30 days, and the effective deadline for applications to be received would occur prior to the end of the Application Period to allow time for the completeness review plus a cure period. Providing the Regulations with some flexibility in defining the end of the application period would maximize applicant participation.

PUA § 7-704.1(a)(2)(ii) requires the Application Period to be open for at least 90 days. We recommend that the Application Period be 180 days (or longer) to ensure that all bona fide potential applicants have a chance to submit a well-defined application, the Commission can conduct a completeness review, and an applicant has sufficient time to provide any missing or incomplete information.

At some point during the Application Period, the Commission should also provide notice of the date by which it will approve, conditionally approve, or deny an application, which should be 180 days from the close of the Application Period per PUA § 7-704.1(b). The Commission may extend the evaluation period beyond 180 days by mutual agreement of the parties.

Step 2: Application Completeness Review

The purpose of Step 2 is to determine if each application received by the Commission is Administratively Complete, in accordance with the Regulations issued by the Commission. Upon receipt of each application, the Commission should review it for completeness, including the requirements in PUA § 7-704.1(c). An application must contain all of the information specified in the Regulations, or provide a valid explanation for why any missing information cannot be provided, to be determined Administratively Complete. If certain information is not reasonably available at the time the application is submitted, the application may still be considered Administratively Complete if the applicant indicates how it proposes to obtain such information, and when such information will be furnished. We recommend that the Commission notify each applicant if the application is Administratively Complete or deficient within 30 calendar days of receipt. If the application is deficient, the Commission should identify the missing or incomplete information and provide the applicant with an opportunity to remedy the deficiency provided that a complete application is received before the end of the Application Period.

Step 3: Minimum Threshold Criteria Screening

The Commission will determine if each complete application satisfies Minimum Threshold Criteria. The screening of complete applications against a set of Minimum Threshold Criteria is consistent with best practices observed in most procurements seeking resources to fulfill a defined resource need. The Minimum Threshold Criteria screening step would be accomplished in a relatively short time frame since there is no qualitative evaluation or scoring process required. The limited number of Minimum Threshold Criteria are based upon specific requirements set forth in OWEA, *e.g.,* the proposed project must be capable of being a Qualified Offshore Wind Project as defined in OWEA, it must provide ORECs no sooner than required by the RPS, it must conform to the 20-year term limit, it must comply with the maximum bid price, and it must meet minimum requirements for siting and design feasibility.

Bidders that do not offer an offshore wind project with a complete application that satisfies the Minimum Threshold Criteria should not advance to the Step 4 evaluation process. The Minimum Threshold Criteria suggested in Step 3 are intended to be "pass-fail" criteria, *i.e.,* the application either meets all of the criteria or it will not be evaluated in Step 4 of the OWEA process. Thus, any application that does not meet all of the Minimum Threshold Criteria should be notified that it has been disqualified from further consideration by the Commission.

Reasons to Use Levelized Calculations

PUA §7-704.1(e)(iv) requires that the Commission may not approve a project unless the prices set in the proposed OREC price schedule do not exceed $190 per megawatt-hour in 2012 dollars. This provision (and other similar OWEA provisions) permits the developer to propose its OREC Price Schedule as comprising a single price or a series of nominal prices that varies throughout all years of the delivery term. We recommend that the Commission assess whether a Proposed OREC Price Schedule complies with the statutory caps by converting the submitted OREC prices to account for the time value of money through a levelized financial calculation.[22] We recommend this approach because applicants should have the ability to specify a series of nominal OREC prices that can vary by calendar year, as needed to match varying cash flow needs over the project term of up to twenty years. Furthermore, our recommended approach to conduct the price cap test (as well as the net rate impact tests described in Step 4) on a levelized basis avoids the risk of determining that an applicant has failed a price cap (or net rate impact) test in one of the twenty years and thus be disqualified from further consideration.

Pricing flexibility is a best practice. A requirement that applicants submit a single fixed nominal price for the entire delivery term is inconsistent with established offshore wind pricing practices,

[22] Levelization is explained in an LAI whitepaper (provided as Appendix 9) that was discussed with stakeholders.

as demonstrated by the publically available prices for other projects.[23] The economic rationale is simple: a single fixed (nominal) price that satisfies the $190 price cap (2012 dollars) in the first delivery year would have declining 2012 dollar (real) equivalents in each successive year, minimizing the effective lifetime revenue available to the developer over the term. Such rigidity would interfere with achieving successful development of offshore wind projects. Likewise, requiring applicants to specify a firm price schedule that increases yearly at the announced inflation rate assumption is also unnecessarily restrictive. Accordingly, we recommend giving applicants flexibility in submitting their OREC Price Schedule that would be evaluated on a levelized basis. This recommendation would provide applicants with pricing flexibility to match anticipated revenues with operating and maintenance costs, facilitate competition by providing opportunities for developers to submit innovative applications, enhance prospects for achieving the State's renewable energy policy goals, and avoid imposing unnecessary costs on Retail Electric Customers resulting from rigid pricing rules and a lackluster competitive procurement.

Minimum Threshold Criteria

To conform to the Minimum Threshold Criteria requirements, each OREC application should demonstrate compliance with the following:

a) The ORECs' source is an offshore wind project, including the associated transmission-related interconnection facilities and equipment, that (i) is located on the Outer Continental Shelf of the United States in an area that the U.S. Department of Interior designates for leasing after coordination and consultation with the State in accordance with § 388(A) of the Energy Policy Act of 2005, (ii) is located between 10 and 30 miles off the coast of Maryland, and (iii) interconnects to the PJM grid at a point on the Delmarva Peninsula, per PUA § 7-701(k).

b) The OREC Price Schedule (i) commences no earlier than January 1, 2017, (ii) has a duration no longer than 20 years (plus five years of additional prices to accommodate COD delays of up to five years) consistent with the Maryland RPS carve-out for ORECs in PUA §s 7-703(b)(12) and 7-704.1(f)(1)(ii), includes and (ii) conforms to the allowable forms of pricing in the Regulations.

c) The OREC Price Schedule does not exceed the $190/MWh (2012 dollars) price cap, per PUA §§ 7-704.1(e)(1)(iv) and 7-704.1(f)(1)(i). Applicants should not be able to submit OREC Price Schedules exceeding the price cap if the Commission provides active OREC Price Schedule worksheets per our recommendation.

[23] The Cape Wind price has a 3.5% annual escalator as described in Appendices 4, the Fishermen's Energy prices escalate at an average rate of 3.3% per year for the first nineteen years as described in Appendix 6, and the Block Island Wind Farm price has a 3.5% annual escalator as described in Appendix 7.

d) The Proposed OREC Amount does not exceed the maximum quantity of ORECs permitted by the OREC RPS requirement and the Applicable Load.[24]

To determine if the applicant's nominal dollar OREC Price Schedule conforms to this requirement, the Commission should convert the nominal OREC prices to a Levelized OREC Price in constant 2012 dollars based on Commission-approved assumptions for inflation and discount rates.[25] Guidelines for calculating the Levelized OREC Price and calculating the residential and nonresidential net rate impacts are provided in Appendix 8.

We recommend that the Commission utilize discount and deflation rates consistent with prior evaluations of ratepayer payments and benefits over time. The discount rate for OREC payments should be relatively low, consistent with their certainty and long-term concern over societal welfare. Thus we recommend that the discount rate be set at the Long-Term Composite (maturity of 10 years or greater) Treasury Bond Rate (or equivalent). The U.S. Department of the Treasury publishes this rate daily; as of March 14, 2014 it was 3.30%.[26] Future OREC benefits could be discounted at the same rate or a slightly higher rate to reflect their uncertainty relative to OREC payments.

We also recommend that the near-term (next three to five years) average inflation rate, such as the GDP Deflator (or equivalent), be utilized to deflate future nominal dollar OREC payments to 2012 constant dollars. For example, the U.S. Federal Reserve published its most recent outlook of Core (excluding food and energy) Personal Consumption Expenditure inflation on March 19, 2014; the average for 2014-2016 was 1.75% and 2.0% thereafter.[27] The utilities' weighted average cost of capital would not be appropriate for discounting or deflating in the context of OREC payments and benefits.

If an application offers multiple Proposed OREC Price Schedules and/or project capacity options, the Levelized OREC Price should be computed for each option. If any Levelized

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[24] The Commission should provide the Applicable Load to applicants.

[25] The Levelized OREC Price, if inflated to each year over the OREC purchase term and multiplied by the expected OREC production for each year, would result in a PV equivalent to the payments resulting from the OREC Price Schedule.

[26] http;//www.treasury.gov/resource-center/data-chart-center/interest-rates/pages/default.aspx

[27] http://www.federalreserve.gov/newsevents/press/monetary/20140319b.htm

OREC Price exceeds the $190/MWh (2012 dollars) price cap, that OREC price option should be excluded from further evaluation.[28]

e) The wind turbine electricity generation facility, including the associated transmission-related interconnection facilities, is constructed using components and equipment that are commercially proven and available at the time the application is submitted.[29] Wind turbines should be certified, or be in the process of being certified, by an accredited certification body for offshore operation during the planned project lifespan under specific project site conditions.

f) The application demonstrates site control or a feasible plan for site control. If the BOEM lease auction has concluded and the applicant was awarded a lease, that applicant should provide documentation that it has control over the BOEM lease for its proposed offshore wind project, including all necessary easements or development rights necessary to construct, interconnect, and operate the project. Alternatively, if the BOEM lease auction has concluded and the applicant was *not* awarded a lease, the application should include a plan to transfer the lease from the lease holder, a joint venture, or some other arrangement with the BOEM lease holder to develop a wind farm on that lease.

Clarifying Questions

During this Step 3 (as well as during the Steps 4 and 5) of the application review process, the Commission may issue clarifying questions to the applicant on a confidential basis in order to facilitate the evaluation of the application. Information submitted by an applicant in response to a clarifying question would become part of the application. Once the Application Period has ended, information that is submitted in response to a clarifying question may not change the Proposed OREC Price Schedule or materially change any other aspect of the application. Responses that the applicant requests be kept confidential should be identified and justified by the applicant as described on pages 37-38 of this report.

[28] We recommend that the OREC Price Schedule be checked against the $190/MWh price cap in this Step 2 and be checked against the $1.50/month and 1.5% rate caps in Step 3 because rate calculations require significantly more analysis and calculations.

[29] This would not preclude the developer from modifying the design or equipment at a later date, with the consent of the Commission, if improved technology becomes available as expected.

Step 4: Quantitative and Qualitative Evaluations

At the conclusion of the Application Period, the Commission has 180 days to approve, conditionally approve, or deny an application. The Commission's 180-day application evaluation period may also be extended by "mutual extent of the parties" per PUA § 7-704.1(b). In Step 4, the Commission should evaluate applications in accordance with quantitative and qualitative criteria set out in the Regulations. Those criteria should include and be consistent with PUA § 7-704.1(d)(1)()-(xiii) and other criteria the Commission determines to be appropriate. The Commission is not permitted to approve an application that does not meet the requirements of PUA § 7-704.1(e)(1)(i)-(iv), which include the $190/MWh price cap, the $150/month residential net rate impact cap, and the 1.5% nonresidential net rate impact cap. The Commission may rely on an IC to conduct the quantitative and qualitative evaluations described below per PUA § 7-704.1(e)(2)(i).

Our proposed quantitative evaluation is oriented around the power market and rate effects that can readily be estimated and expressed in monetary terms. PUA § 7-704.1(e)(1)(ii) and (iii) requires that each application meet the residential and nonresidential net rate caps for Maryland residents.[30] While the quantitative evaluation should be applied to individual applications, the Commission should check to ensure that any selected combination of applications also satisfies the rate impact requirements of the Act in the aggregate.

Our proposed qualitative evaluation is oriented around (i) identifying project weaknesses and risks to maximize the likelihood that a project will actually achieve commercial operation and (ii) identifying any project features that contribute to net economic, environmental, or health benefits to Maryland, but cannot readily be expressed in strict monetary terms. This category includes the applicant's plan to (i) engage small business, (ii) solicit minority investors, (iii) utilize skilled labor, and (iv) compensate employees and subcontractors consistent with state wage rules.

As discussed in the Introduction and Overview, environmental and health benefits are difficult to express in monetary terms. While the application instructions must direct applicants to provide "...an analysis of the anticipated environmental, health benefits, and environmental impacts..." per PUA § 7-704.1(c)(iii), we suggest that the Commission independently estimate the quantities of avoided power plant air emissions and consider the health and environmental benefits in qualitative terms, consistent with common practice in other procurements for renewable resources. This would avoid controversial issues associated with the uncertainty and validity of the models that would be used.

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[30] We recommend that the $190/MWh price cap be checked as part of the Step 2 Completeness Review.

Similarly, applicants must provide "…a detailed input-output analysis of the impact…on income, employment, wages, and taxes in the State" per PUA § 7-704.1(c)(3)(i). The applicants are likely to utilize different input-output models as well as different underlying assumptions, precluding a fair and consistent comparison among proposals. Thus, we recommend that the Commission prepare an independent analysis, using an industry-standard input-output model, to compare the economic benefits, *i.e.,* employment, tax, and local spending, of each application on a comparable basis, using common assumptions and data. In addition, an applicant may propose to hire in-State workers, utilize a Maryland port, and make local investments, but without firm commitments these economic benefits may not materialize. To properly interpret the associated economic impacts, we recommend that the Commission consider the firmness or reasonableness of any in-State employment or investment commitments.[31] In summary, we recommend that the Commission weigh the advantages and disadvantages of treating the net economic, environmental, and health benefits to the state quantitatively or qualitatively carefully.

Qualitative Evaluation

Applications that meet the Minimum Threshold Criteria in Step 3 should be evaluated by the Commission to identify those which significantly exceed or fall short of expectations in areas that contribute to the likelihood of successful development and to the net economic, environmental, and health benefits to the State. The qualitative evaluation may result in the elimination from further consideration of some applications that, despite being found to be complete and passing the Minimum Threshold Criteria review, are found to represent a significant risk of not achieving successful commercial operation or to not provide net economic, environmental, and health benefits to the State.

One way the Commission can qualitatively evaluate the completion risk or other qualitative aspect of each application would be to assign a color-code score to each, based on whether the application is Unsatisfactory (black), Poor / Falls Short of Expectations (red), Meets Expectations (yellow), or Good / Exceeds Expectations (green). While potential applicants should be notified that the Commission would use this (or a similar) system for the qualitative evaluation, we recommend that the Commission keep any such qualitative evaluations confidential and not distribute them to applicants. The Commission could create a master grid showing the color code scores for each application under each relevant category and update it over the evaluation period based on responses by applicants to clarifying questions issued by the Commission. Pervasive Unsatisfactory (black) scores would be the basis for excluding an application from further consideration. A predominance of Poor (red) scores would be the basis for reducing the priority of an application among applications with similar quantitative scores.

[31] An obligation to make certain investments may subsequently be part of the conditions of a Commission Order selecting an offshore wind project.

Similarly, a predominance of Good (green) scores would be reason to promote an application among applications with similar quantitative scores. The following questions are representative of the types of considerations the Commission may undertake during its qualitative evaluation of proposed projects, although the list is not intended to be exhaustive.

1. Applicant's Project Team per PUA § 7-704.1(c)

    a. Development – Have key members of applicant's team successfully developed other offshore wind projects or successfully developed other projects of similar size and scope, *e.g.,* large on-shore wind projects?

    b. Environmental Permitting – Do key members of applicant's team have a proven track record of work experience with federal and state agencies for permitting offshore projects in federal waters?

    c. Engineering and Construction – Have key members of applicant's team been involved in the engineering and/or construction of other large offshore wind projects? Have key members been responsible for the engineering and/or construction of major offshore facilities of comparable size and scope, *e.g.,* offshore docks or drilling facilities?

    d. Operations – Have key members of applicant's team been responsible for the operation of other large offshore wind projects or other projects of comparable size and scope, *e.g.,* on-shore wind projects, offshore drilling facilities?

    e. Financing – Is the developer and its owners financial strong and capable of financing the project? Have key members of applicant's team been responsible for the successful financing of other offshore or large on-shore wind projects? Have key members been responsible for the successful financing of other projects of comparable size and scope, *e.g.,* other utility-scale renewable energy facilities? Have key members been able to obtain state and/or federal grants, subsidies, or tax benefits for other renewable energy projects?

2. Project Description per PUA § 7-704.1(c)(1)

    a. Project Design – Is the layout of turbines within the defined site consistent with best practices for optimal output and maintainability? Are the proposed hub heights, turbine technology, and nameplate capacity consistent with the site wind resource and climatology? Is the COD in line with OWEA requirements and is the proposed project timelines reasonable and achievable? Is a detailed site plan including layout drawings supported by physical, geophysical, geotechnical and met-ocean data provided? Are all major project components, *i.e.,* turbines and Balance of Plant, well described?

b. Turbine Technology – Are the turbines proven technology and suitable to the site conditions? What is their commercial availability and certification status? Is their design life compatible with the anticipated service life of the project? What warranties are provided by the manufacturer on power curve and technical availability? What are their characteristics in terms of power quality, grid compliance, remote dispatch capabilities, and provision of ancillary services? Are suitable vessels and crew available for turbine installation?

c. Foundation and Support Structure – Are the foundation and support structures proven technology and suitable for the site conditions? What design standards and criteria were used to guarantee their adequacy with their anticipated service life and environmental conditions? Are suitable vessels and crew available for installation?

d. Converter Station and Interconnection – Is the offshore substation design appropriate for application site, turbine ratings, and number of turbines? Is the collection system design appropriate and does it include enough details on cables, *e.g.,* ratings, protection, and technology maturity, and trenching/burial approaches? Are suitable vessels and crew available for the construction of the collection system? Is the transmission right-of-way identified and permitable? Are the interconnection and delivery points reasonable for site location, capacity, and existing PJM facilities? Are interconnection designs compliant with enforced standards and industry best practice? Has an interconnection request been filed?

e. Net Capacity and Annual Energy Output – Is the claimed net capacity delivered into the PJM grid consistent with turbine technology, conversion losses, and transmission losses? Is the wind resource and energy yield estimate prepared by a competent consultant and presented in accepted industry format? Is the claimed performance consistent with chosen technology and the wind resource? Is the estimated annual output at P50 level consistent with the chosen technology and the resource assessment? Does it provide detail of output by time of day and month of year? Does the application provide the required confidence level on annual estimates, *e.g.*, P5, P10, P90, and P95? Are extreme events entailing turbine shut downs adequately accounted for?

3. Financial Analysis and Financing Method per PUA § 7-704.1(c)(1), (2), and (8)

a. Pro Forma – Does the financial pro forma include all projected revenues and expenses consistent with the information provided in the project description? Are capital costs consistent with the financing plan? Are operating revenues reasonable with respect to future wholesale energy and capacity prices? Are operating expenses estimated on a reasonable basis, considering location and technology, and are they consistent with the input-output analysis? Are equity and debt modeled consistently with the financing plan, and is the equity return adequate? Is the decommissioning plan reflected in the pro forma?

b. Funding – Does the financing plan clearly identify sources of debt and equity? Are the sources, quantities, costs, and terms of these sources of capital defined? Does the plan include provisions for reasonable cost overruns? Are cost risks reasonably allocated between the project and contractors? How firm are commitments and other indications of support from sources of financing?

c. Current Subsidies – Does the financial plan demonstrate that all current eligible State and Federal grants, rebates, tax credits, loan guarantees and other programs are being accessed to minimize the cost of the project? Is there evidence that applications for all of these subsidies have been provided?

d. Future Subsidies – Has the applicant made a commitment to use best efforts to apply for all eligible state and federal grants, rebates, tax credits. loan guarantees, and other programs to minimize the cost of the project? Has the applicant made a commitment to pass along to ratepayers 80% of the value of such future subsidies received?

4. Site Control per PUA § 7-704.1(c)(1)

   a. Lease – Has the applicant been awarded a BOEM lease? If not, has the applicant contacted a BOEM lease holder or proposed a reasonable plan to arrange the transfer of the lease from the lease holder, a joint venture, or some other arrangement with the lease holder to develop a wind farm on that BOEM lease?

   b. Interconnection – Has the applicant made appropriate arrangements for an electrical cable interconnection right-of-way and for any on-shore or offshore facility site that may be necessary?

5. Project Schedule and Operations Plan per PUA § 7-704.1(c)(1)

   a. Schedule – Is the proposed project schedule reasonable and achievable? Does it allow for sufficient lead times for critical elements such as procurement, contracting, permitting, vessel availability and weather windows?

   b. Construction – Is the construction plan reasonable? Are the procurement plan, supply chain description and contracting strategy consistent with the overall construction plan? In the context of a large offshore facility, does it adequately address quality management and risk assessment along with mitigation strategies? Does it include H&S as well as environmental monitoring plans during construction? Are port readiness, vessel and crew availability, and Jones Act requirements fully acknowledged and addressed? Are appropriate storage, lay-down and staging areas identified? Are weather-related constraints during construction adequately considered? Is a detailed testing and commissioning plan provided?

c. O&M – Is the proposed O&M plan reasonable? Is an adequate transition plan between pre- and post-turbine warrantee periods presented? Are maintenance vessel availability and their home port locations consistent with proposed scheduled and unscheduled maintenance plans? Are anticipated response times, as well as staffing plans, spare parts supply and remote dispatch, control, and emergency power supply plans reasonable and in line with industry best practice for offshore facilities? Are adequate quality management, H&S plans and environmental monitoring plans presented? Is there an adaptive management plan proposed to minimize impacts to wildlife?

6. Input-Output Analysis and In-State Economic Benefits per PUA § 7.704.1(c)(3)(i), (ii), (vi), and (vii)

   a. Model Data – Did the applicant provide the inputs to the analysis in sufficient detail for the IC to reproduce the analysis using an industry-standard input-output model? Are data provided consistent with other aspects of the application?

   b. In-State Employment Impacts – Has the applicant provided information such as "duration of employment opportunities, the salary of each position, and other supporting evidence of employment impacts"?

   c. In-State Benefits – Does the applicant provide a binding commitment that any in-State construction, operations, maintenance, or equipment purchase contracts will actually be sourced in-State?

   d. Input-Output Analysis – Are the claimed OWS project impacts on income, employment, wages and taxes reasonable with respect to other analyses of offshore wind projects?

7. Environmental Benefits, Health Benefits, and Environmental Impacts per PUA § 7.704.1(c)(3)(iii)

   a. Benefits Analysis – Does the application reasonably describe the mechanisms by which claimed benefits to the environment and health are provided? Does it establish that any claimed benefits are greater than those of any other Maryland OSW project of comparable capacity?

b. Data to Support Benefits Analysis – Are data provided to support the Commission's independent analysis of any claimed benefits to health and the environment during project construction, operation, and decommissioning?

c. Environmental Impacts – Does the application reasonably describe the direct environmental impacts of construction and operation of the proposed facility, including impacts on power plant air emissions and on birds, sea life, water quality, land use, etc.? Is the impact significantly different for the proposed project than for other proposed offshore wind projects of comparable capacity? Do any unique environmental impacts affect the likelihood of successful permitting and development of the project?

d. Net Impact on Air Emissions – Has the applicant analyzed the net change in emissions of carbon dioxide and other pollutants ascribable to the construction, operation, and decommissioning of the Project? Was this analysis conducted rigorously and with reasonable assumptions? Are claimed health and environmental benefits ascribable to avoided emissions based on reasonable assumptions and validated data?

8. Contribution to Meeting the RPS per PUA § 7.704.1(d)(1)(xiii)

   a. Will the project enhance the State's ability to meet its RPS under PUA § 7-703?

   b. Does the application offer a high degree of confidence that the Proposed OREC Amount will be achieved in all years?

9. Analysis of Ratepayer Impact per PUA § 7.704.1(c)(3)(iv)

   a. Quality of Analysis – Does the applicant's analysis reflect the proposed OREC pricing and the allocation of OREC costs to Retail Electric Customers, as provided for in the Act?

   b. Uniqueness – Does the applicant's analysis identify any mechanism by which the impact of the proposed project would be materially favorable or unfavorable than for other Maryland offshore wind projects of comparable size and proposed OREC pricing? Would future changes (such as those identified in a conditional application) materially lower the net residential or nonresidential rate impact?

10. Analysis of Energy and Capacity Market Impacts per PUA § 7.704.1(c)(3)(v)

   a. Quality of Analysis – Does the applicant's analysis reflect the proposed project output profile and location of delivery point? Does it correctly utilize reasonable estimates of future wholesale energy and capacity prices? How does it address offsetting market effects, *e.g.,* reduced plant dispatch or deferral of other Tier 1 renewable resources, in response to the project's entry? Will the project provide reliability, fuel diversity, generation competition, transmission congestion, or other power market benefits for Maryland Electric Retail Customers?

b. Uniqueness – Does the narrative identify any mechanism by which the impact of the proposed project would be different than for impacts of other potential Maryland offshore wind projects of comparable capacity and delivery point? If so, is the impact favorable or unfavorable?

11. Analysis of Other Impacts

a. Quality of Analysis – In order to identify any project features or issues that might distinguish one project from another, the Commission should check if an application has any distinguishing features that offer economic, environmental, or health benefits to the State not previously addressed.

b. Uniqueness – Does the application identify any mechanism by which the impact of the proposed project would be different than for other potential Maryland offshore wind projects?

12. Decommissioning Plan per PUA § 7.704-1(c)(5)

a. Quality of Analysis – Is the proposed decommissioning plan consistent with current requirements per 30 CFR Part 585 Subpart I? Is the cost reasonably adequate and consistent with the financial pro forma?

b. Completeness of the Analysis – Does the plan specifically address project facilities in State waters or on State lands? Does the plan adequately address constraints such as permitting, availability of vessels and crew, and port readiness for the decommissioning?

13. Transmission Improvements per PUA § 7.704-1(d)(1)(xiii)

a. Quality of Analysis – Will the project require transmission or distribution infrastructure improvements in Maryland? Have they been identified?

b. Costs and Benefits – Will the transmission and distribution system upgrades and improvements associated with the project provide any benefits, *e.g.,* improved reliability or reduced congestion, for Maryland Electric Retail Customers? Is the proposed methodology for allocating upgrade costs (for applications with two-part OREC prices) if the actual project capacity exceeds the capacity required to provide the Proposed OREC Amount fair and reasonable?

14. Small Business Engagement Plan, Use of Skilled Labor, and Compensation per PUA §s 7.704-1(d)(1)(vii)-(x)

a. Does the application include any plan to engage small businesses consistent with Title 14, Subtitle 5 of the State Finance and Procurement Article?

b. Does the application include any plan to use skilled labor through outreach, hiring, or referral systems per Title 11, Subtitle 4 of Labor and Employment Article?

c. Does the application include a plan to promote the prompt, efficient, and safe completion of the project?

d. Does the application provide for compensation consistent with §§17-201 through 17-228 of the State Finance and Procurement Article?

e. How firm are these plans or commitments?

15. Minority Investors per PUA § 7.704.1(d)(4)(ii)

a. Has the applicant conducted serious pre-application interviews in good-faith with a reasonable number of minority investors as demonstrated by a statement to the Commission?

b. Has the applicant committed to, if selected, make serious, good-faith efforts to interview minority investors in any future attempts to raise venture capital or attract new investors?

Quantitative Evaluation

The evaluation criteria that should be quantified and assigned monetary values include (i) the Proposed OREC Price Schedule, (ii) the value of market revenues for Power Products generated by the project that will be credited to Retail Electric Customers, (iii) avoided Tier 1 REC purchases, and (iv) the effect on wholesale Power Product market prices and RECs. A quantitative evaluation using a standard production cost model (aka dispatch simulation model) would permit the Commission to determine the power market credits and any wholesale power market impacts.[32] The resulting Net Ratepayer Cost calculation would include all of the power market impacts for ratepayers that would then be used to check if a project or a combination of projects were to result in a projected rate impact exceeding $1.50/month (2012 dollars) for

[32] Although each applicant is required to provide a Cost-Benefit Analysis that includes "an analysis of any long-term effect of energy and capacity markets as a result of the proposed offshore wind project..." per PUA § 7-704.1(C)(3)(V), we recommend that the Commission conduct its own power markets analysis to ensure fair and consistent evaluations of projects and comparisons among projects. The production cost model results will include the change in output from individual power plants, which should be utilized to estimate the tonnage reduction in air emissions based on each plant's technology, heat rate, and fuel characteristics.

residential customers or 1.5% for nonresidential customers as required by the PUA. These net rate cap tests should be conducted on a projected basis and would not be revisited after a project is selected, consistent with the PUA. In addition, these net rate cap tests should not be based on a Proposed OEC Price Schedule that is contingent upon conditional events in the future that may not occur. Any potential benefits associated with a conditional application should be included in the qualitative evaluation.

As explained earlier, we recommend that the Commission conduct these calculations on a levelized basis in order to provide applicants with pricing flexibility, facilitate a more robust and competitive process, and avoid situations in which a project exceeds a cap in one year and must be eliminated. A levelized approach is even more important for the net rate cap tests, because of the uncertainty in the future Power Products and REC prices. Those values will almost certainly not be linear over time, so a yearly test would raise the chance that a project would be eliminated by exceeding a cap in a single year. A levelized approach effectively averages these values over the delivery term, avoiding this elimination problem.

Rate Impact Tests

The Commission should calculate the Net Ratepayer Cost as the levelized equivalent of the Proposed OREC Price Schedule payments less the levelized equivalent of a stream of annual power market revenue credits, avoided Tier 1 REC purchases, and market price effects (all in 2012 dollars per year).[33] Guidelines for calculating Net Ratepayer Cost are provided in Appendix 8. Net Ratepayer Cost should be a key factor in the Commission's selection process and would be utilized for both the residential and nonresidential net rate impact calculations. The value of (i) PJM market revenues generated by the project, (ii) the avoided costs of Tier 1 RECs, and (iii) the impacts on market Power Product prices and REC prices, should be based on the proposed project's projected (P50) estimate of energy and capacity delivered to the PJM grid on the Delmarva Peninsula, adjusted for losses and outages, for each year of the proposed delivery term.

Both the residential and nonresidential net rate impacts should be calculated on a projected basis during the Step 3 evaluation based on actual 2012 Maryland residential and nonresidential load and rate data. At the time the Commission conducts the net rate impact tests for any two-part Proposed OREC Price Schedule, the Commission should try to provide that applicant with the maximum true-up value that would allow the Proposed OREC Price Schedule to satisfy (i) the $190/MWh price cap and (ii) the residential and nonresidential net rate caps. This would avoid the need to conduct these calculations in the future for two-part Proposed OREC Price Schedules

[33] The Net Ratepayer Cost would be based on the Proposed OREC Price Schedule in the application. If there is a transmission upgrade cost true-up, the Net Ratepayer Cost would have to be recalculated.

and provide the applicants with greater clarity regarding the maximum true-up for Proposed OREC Price Schedules.

As explained earlier, we recommend that these net rate impact calculations utilize a societal discount rate equal to the Long-Term Composite Treasury Bond Rate (or equivalent) to discount OREC payments; the Commission may utilize this discount rate or a slightly higher discount rate to levelize projected future benefits. We also recommend that the Commission utilize a near-term deflation rate equal to the forecasted GDP Deflator (or equivalent) for the years between 2012 and 2017 and a long-term inflation rate for other calculations.

Residential Net Rate Impact Test

Consistent with PUA § 7-704.1(e)(1)(ii), the Commission should calculate the projected residential net rate impact of an application (or a combination of applications) as the Net Ratepayer Cost (2012 dollars/year) divided by the annual MWh of Applicable Load for 2012, multiplied by an average residential load of 12,000 kWh/year, and divided by 12 months/year. Further details of this calculation are provided in Appendix 8. If the residential net rate impact exceeds $1.50 /month for an individual application (or combination of applications), that application (or combination of applications) would fail the residential net rate cap and cannot be approved.

Nonresidential Net Rate Impact Test

Consistent with PUA § 7-704.1(e)(1)(iii), the Commission should calculate the projected nonresidential net rate impact as the Net Ratepayer Cost (2012 dollars/year) divided by the annual MWh of Applicable Load for 2012 , and divided by the 2012 effective all-in average nonresidential rate (2012 dollars/MWh). Further details of this calculation are provided in Appendix 8. If the nonresidential net rate impact exceeds 1.5% for an individual application (or combination of applications), that application (or combination of applications) would fail the nonresidential rate cap and cannot be approved.

Evaluation of Net Environmental, Health, and Economic Impacts

PUA § 7-704.1(d)(1)(vi) requires the Commission to evaluate the extent to which the cost benefit analysis demonstrates net economic, environmental, and health benefits to the state. Criteria such as the value of reduced power plant air emissions, health impacts, and in-state employment, taxes, and local spending may be quantitatively (in monetary terms) or qualitatively evaluated.

- The advantages of treating these criteria *quantitatively* are that (i) applicants will have certainty about how important these project features will be and (ii) the net benefits test would be more objective.[34]

- The advantages of treating these criteria *qualitatively* are the Commission (i) avoids any arguments about the accuracy and validity of the models used to quantify the impacts and express them in monetary terms and (ii) avoids assigning an inaccurate monetary value that could lead to erroneous results.

The environmental and health evaluations submitted by the applicants are likely to utilize different models as well as different underlying assumptions, preventing a consistent evaluation and comparison of proposed projects. Thus we recommend that the Commission conduct its own independent analysis to estimate the tons of avoided air emissions due to each offshore wind project. This should be a straightforward calculation based on the change in the output of power plants located Maryland due to an offshore wind project (from the production cost model used to estimate the change in market energy prices) and each plant's technology, heat rate, and fuel characteristics.[35] As explained below, we also recommend that the Commission consider the environmental and consequential health benefits qualitatively in non-monetary terms.

<u>Environmental and Health Benefits Evaluation</u>

Applicants are required to submit a cost-benefit analysis that includes an estimate of the "...anticipated environmental benefits, health benefits, and environmental impacts..." of their proposed projects per PUA § 7-704.1 (c)(3)(iii) Although the U.S. EPA has developed guidelines for analyzing environmental regulations and policies and assigning them monetary values, these guidelines cannot be easily applied to assess the benefits of individual projects. LAI is not aware of any renewable resource procurements in which the basis for approval included a monetary quantification of environmental and health benefits. Therefore we do not recommend assigning a monetary value to avoided emissions and other environmental or health benefits ascribable to the proposed project.

<u>Economic Benefits Evaluation</u>

Applicants are required to submit a cost-benefits analysis including "...a detailed input-output analysis of the offshore wind project on income, employment, wages, and taxes in the State...", "... employment impacts in the State...", and "...other benefits, such as increased in-State

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[34] A more objective test in the narrow sense does not necessarily imply a more accurate test if there is controversy over the financial values assigned to the health benefits.

[35] While power plants throughout PJM would be affected by an offshore wind project, we interpret the Act to refer just to emission impacts of Maryland-based power plants.

construction, operations, maintenance, and equipment purchase…" per PUA § 7-704.1(c)(3)(i), (ii) and (vii).[36] In the Step 3 qualitative evaluation, the applicant's economic benefits analysis should be evaluated in terms of the reasonableness of assumptions, the rigor of analysis, and likelihood that the purported investments and benefits will materialize. As previously explained, the Commission should utilize an industry-standard input-output model along with reasonable underlying assumptions that would apply to all proposed projects so that quantitative evaluation of project economic benefits provides for fair and consistent evaluations and comparisons. The Commission's input-output modeling and other employment analyses should be expressed in present value ("PV") terms consistent with the Net Ratepayer Cost.

Positive Net Benefits Requirement

According to PUA § 7-704.1(e)(1), the Commission may not approve a proposed project unless it "…demonstrates positive net economic, environmental, and health benefits to the State…" We interpret this to mean that Net Ratepayer Cost (that accounts for the Proposed OREC Price Schedule and effects on wholesale Power Product market prices and Tier 1 RECs for Maryland ratepayers), along with the rate impact calculations, is independent from the net benefits to the State. Thus the net benefits for each application should independently consider (i) economic, environmental, and health benefits and (ii) the qualitative evaluation of the project development team, project plan, completion risk, and various funding and employment commitments. Applications or combinations or applications with negative net benefits to Maryland fail the net benefits requirement and should not be approved.

[36] Input-output analyses quantify the direct, indirect, and induced economic benefits from employment, local spending, and taxes provided by the construction, operation, and decommissioning of a proposed project.

Step 5: OREC Application and OREC Price Schedule Selection

Once all applications have been evaluated against the qualitative and quantitative evaluation criteria in Step 3, the Commission should determine which project (or combination of projects) successfully meets the rate impact tests in the quantitative analysis and the net benefit test in the qualitative analyses in Step 4.[37] If only a single project with multiple Proposed OREC Price Schedules meets the Step 4 tests, then the purpose of this Step 5 will be for the Commission to select the project with the most advantageous Proposed OREC Price Schedule offered by the applicant.[38] If multiple projects meet these Step 4 tests, then the purpose of Step 5 will be to determine how to select the most cost-effective combination of projects and associated Proposed OREC Price Schedules.

Annual generation from an offshore wind facility will vary from year to year, based on the natural variability of the wind resource and the availability of the facility itself. The Step 4 Evaluation of ratepayer costs and net benefits over a 20-year horizon should be based on the expected average, *i.e.,* P50, generation profile for a project (subject to the Proposed OREC Amount annual limit in the application) with the associated Proposed OREC Price Schedule. In this Step 5, the Commission should consider the range of Proposed OREC Price Schedules offered by a project in relation to the expected project generation and to the OREC RPS percentage.

Approved OREC Amount and RPS OREC Percentage

The Commission must balance several competing factors in determining the selected projects and the total Approved OREC Amount. As indicated by PUA § 7-704.2(a)(2), customer electric load is subject to forecasting error. The Act requires the Commission to establish the RPS obligation "...for ORECs on a forward-looking basis that includes a surplus to accommodate reasonable forecasting error in estimating overall electricity sales in the State." We interpret this to mean that the Commission should set the OREC RPS obligation percentage conservatively high, *i.e.,* some margin above the total Approved OREC Amount (in equivalent percent terms). Thus, in the event that actual customer load is less than forecasted load, the total Approved OREC Amount will not exceed the RPS OREC Percentage and the risk of undercollection from

[37] The $190/MWh price cap is a relatively straightforward calculation that should be tested as part of Step 3 Completeness and Minimum Threshold Evaluation.

[38] We assume that the Proposed OREC Price Schedule is defined as an OREC price for each delivery year. Applicants should be permitted to offer a range of Proposed OREC Price Schedules and associated Proposed OREC Amounts that are associated with a specific confidence level, *e.g.,* P5, P10, P50, P90, and P95.

customers is mitigated.[39] For example, if the Commission establishes a 2.5% RPS OREC Percentage and Retail Electric Customer load is expected to be 60 million MWh/yr in 2020, then the Commission should approve a total Approved OREC Amount of somewhat *less* than 1.5 million MWh/yr (= 60 million MWh/yr * 2.5%) to allow for load forecasting error. This would also minimize any chance that there would be insufficient collections from customers to pay for ORECs deposited in the PJM GATS Account.

Approved OREC Amount and Expected OREC Generation

From a policy perspective, the Commission should also avoid setting an Approved OREC Amount that is optimistically high relative to a project's capacity and likely output. In this case, the actual ORECs purchased in an average year would be considerably less than the Approved OREC Amount and the RPS OREC Percentage, undermining the Commission's offshore wind policy objectives.[40] We recommend that each applicant provide the expected generation probability associated with the Proposed OREC Amount offered in the application, *e.g.*, a Proposed OREC Amount of 800,000 MWh/year applicant might correspond to the P40 expected level of generation from a 200 MW project. We recommend that the Commission select a Proposed OREC Amount that corresponds to a confidence level that ensures that number of actual ORECs delivered and purchased come close to the Approved OREC Amount in most years.

Selection of Project and OREC Price Schedule

In Step 5 the Commission would have four key evaluation results to select one or more projects that were previously determined to be Administratively Complete and satisfy the OREC price cap, the RPS OREC Percentage, and the residential and nonresidential net rate caps:

- The Net Ratepayer Cost that includes power and REC market impacts on ratepayers.
- In-State economic impacts due to employment, taxes, and local spending.
- Environmental benefits (including, but not limited to, tons of avoided emissions) and the consequential health benefits (considered qualitatively).

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[39] Undercollections are problematic since the Escrow Account would not have sufficient funds to pay for the ORECs. Undercollections are not contemplated in PUA. On the other hand, overcollections are not problematic, since overcollections can be credited back to customers through the EDCs per PUA.

[40] Presumably, if an applicant offers an OREC Price Schedule with a low Proposed OREC Amount, the OREC price will be set sufficiently high so that the developer has a high probability of recovering sufficient revenues to cover costs.

- Other factors of project strengths and weaknesses (including a project's feasibility and thus likelihood of achieving the State's renewable energy policy goals) and commitments to engage small business, solicit minority investors, utilize skilled labor, and compensate employees and subcontractors consistent with state wage rules, all as required by PUA.

We recommend the Commission consider these results independently for each proposed offshore wind project. Even though Net Ratepayer Cost and in-State economic impacts are both expressed in monetary terms, we view them as different in the sense that they would be derived from separate modeling efforts, are functions of different inputs, and have different risk profiles in terms of actual outcome.

We recommend that the Commission should select the most cost-effective project (or combination of projects) and give the greatest consideration to maximizing the quantity of ORECs to advance its offshore wind policy goals and minimizing the Net Ratepayer Cost that will directly affect ratepayers (the first bullet above). In addition, the Commission may not approve any project that does not "...demonstrate positive net economic, environmental, and health benefits..." per PUA § 7-704.1(e)(1)(i) (which includes the second and third bullets above). Lastly, the Commission should consider the range of other factors (as identified in the fourth bullet above). The Commission's Order selecting a Qualified Offshore Wind Project will allow that project to generate and sell ORECs up to the Approved OREC Amount set in the Order.

Failure of Any Project to Satisfy the Rate Caps

In spite of our recommendations to inform applicants of the RPS OREC Percentage and to develop an active OREC Price Schedule worksheet that would screen out prices above the $190/MWh cap, there remains the possibility that no project will satisfy the rate caps. In this case the Commission should consider a solution that will avoid the need for a new offshore wind process. One option would be for the Commission to issue a Conditional Order that sets an OREC Price Schedule and Proposed OREC Amount low enough to satisfy the rate caps. A second option would be for the Commission to request a Best and Final Offer from the highest ranked applicants with some direction regarding how much of a reduction, in terms of price and quantity, would be required to satisfy the rate caps. A third option would be for the Commission to retain an IC early in the Application Period to permit the IC to conduct the rate impact calculations on submitted applications, in which case each applicant could be informed if their applications satisfy the rate caps and permitted to revise them prior to the close of the Application Period. If necessary, the Application Period could be extended to permit this process to be completed.

Additional Round of OREC Applications

In case the total Approved OREC Amount is significantly less than the RPS OREC Percentage, the Commission should make provisions for a second round of applications provided those applications do not result in a total Approved OREC Amount exceeding the RPS OREC Percentage. For example, if the Commission only selects a single application for lease parcel OCS-A 0489 with an Approved OREC Amount equivalent to 1% of Maryland retail electricity sales in the first round and the RPS OREC Percentage is set at 2.5% of Maryland retail electricity sales, then the submittal of a complete application for another project in lease parcel OCS-A 0490 could trigger a second open application period. In this event, the second period applications should be evaluated as part of portfolios including the application selected in the first round.

As long as (i) the second-round application is complete, meets Minimum Threshold Criteria requirements, satisfies the $190/MWh price cap, and has positive net benefits for Maryland ratepayers and (ii) the combined first and second round applications satisfy the residential and nonresidential net rate caps, the Commission may select a second round project.

Recommended Findings to Be Included in a Commission Order

Once one or more OREC applications are evaluated and selected per the Regulations, the Commission will issue an Order approving the purchase of an Approved OREC Amount from each selected project. We recommend that any such Order include the following specific and essential findings (drafted for the selection of a single project for simplicity). Additional language describing the project application and the evaluation process in detail could be included, but is not necessary to include, in such Order. The recommended findings below do not address establishing an escrow account, designating an escrow agent, tracking ORECs, or other matters outside our scope of work.

- The Commission has adopted Regulations implementing a process that satisfies the provisions of the Maryland Offshore Energy Act of 2013 ("Act") and incorporated into the Public Utilities Article, Annotated Code of Maryland ("PUA") to accept, evaluate, and select offshore wind applications to satisfy a portion of the State's renewable energy portfolio standard.

- The [name] project application was received on [date] and contained a Proposed OREC Price Schedule and a Proposed OREC Amount, as well as commercial, financial, and technical information about the development team, the project, and its expected benefits.

- The [name] project application was found to be Administratively Complete on [date], within the Commission's time frame for accepting project applications.

- The [name] project was evaluated by the Commission, with assistance by [consultant] as independent consultant, utilizing (i) the minimum threshold criteria and (ii) the quantitative and qualitative evaluation criteria specified in the Regulations and recommended by the Commission's advisors.

- Based on the Estimated Project COD[, the expected cost of transmission upgrades,] and the Commission's quantitative and qualitative evaluation, the [name] project:[41]

    - Satisfies the quantitative and qualitative criteria in the Regulations.

    - Does not exceed the maximum quantity of ORECs that can be purchased as set by the RPS OREC Percentage and the Applicable Load.

    - Does not exceed the price cap of $190/MWh (2012 dollars) on a levelized basis over the project term.

[41] The text regarding the cost of transmission upgrades would only apply to projects with a two-part OREC Price Schedule.

- Does not result in a projected net rate impact exceeding $1.50/month (2012 dollars) for residential electric customers with an annual consumption of 12,000 kWh on a levelized basis over the project term.[42]
- Does not result in a projected net rate impact exceeding 1.5% for nonresidential customers on a levelized basis over the project term.
- Demonstrates positive net economic, environmental, and health benefits to the State.

- An officer of the [name] project submitted a notarized statement stating (i) the officer has the authority to submit this Application to the Commission, (ii) this Application, including the Proposed OREC Price Schedule and Proposed OREC Amount, shall remain binding through the Application Period, (iii) the information and materials contained in this Application are accurate and correct, and (iv) if this Application is selected, the developer will work diligently and engage in a continuous development and construction program, to achieve the Estimated Project COD.

- The [name] project will be considered a Qualified Offshore Wind Project as defined in the PUA provided the project is developed, constructed, and operated as proposed in the application. Modifications to the project may be permitted provided that any material modifications, including but not limited to (i) a change in the capacity of the project, (ii) the use of a different turbine model, which must be certified by an accredited certification body, and (iii) a change to the design of the foundation or support structure, are approved by the Commission.[43] If the [name] project wishes to make material modifications, the [applicant] must request Commission approval stating the reason behind such modification and demonstrating that such modifications do not materially alter the project.[44] Neither the OREC Price Schedule nor the Approved OREC Amount shall be modified after this Order becomes effective except by Commission action.

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[42] An Order approving more than one project would state that the combined projects would not exceed the residential and non-residential rate caps or the RPS OREC Percentage.

[43] The Commission will have to determine what constitutes a material change; we recommend consistency with the Commission's existing regulations, including those concerning Certificates of Public Convenience and Necessity.

[44] It is possible that a selected applicant may wish to utilize improved designs or equipment for the actual project construction to take advantage of the latest technological advances, a likely scenario given the long lead time prior to COD. For example, a winning applicant may prefer to use fewer but larger wind turbines without altering the project's capacity, or may select a foundation or tower design more appropriate for the site conditions. Such modifications may improve the expected financial performance of the project, but it would be difficult for the Commission to measure the improvement and require the applicant to share the financial improvement with

- The [name] project's COD may be delayed by up to five years beyond the Estimated Project COD. During the term of the OREC Price Schedule and for such five-year delay, the price at which ORECs shall be purchased in any calendar year shall be the calendar OREC price set forth in the OREC Price Schedule, provided that the (i) price cap of $190/MWh (2012 dollars, (ii) the residential net rate cap of $1.50/month (2012 dollars), and (iii) the nonresidential net rate cap of a 1.5% increase are not exceeded. If a COD delay would cause any of these price or rate caps to be exceeded, then the Commission shall inform the [name] project of such exceedances. In the event of a COD delay, the Commission and the [name] project shall agree to lower the OREC prices during the period beyond the original term to ensure the PUA price and rate caps are satisfied.

- Once operational, output from the [name] project will qualify as ORECs provided that (i) the [name] project is a Qualified Offshore Wind Project and (ii) the installed turbines are certified by an accredited certification body, up to the Approved OREC Amount, and (iii) it has obtained Capacity Resource status. The OREC price purchased in any calendar year during the term of the OREC Price Schedule shall be the OREC price for that calendar year as long as the actual COD occurs within five years of the Estimated Project COD. If the [name] project's COD is delayed beyond five years then the OREC Price Schedule shall be also be delayed such that the OREC price for the sixth year in the OREC Price Schedule shall be the purchase price in the first calendar year of operation.

- The project will be entitled to sell up to the Approved OREC Amount of up to [tbd] ORECs per year over the [number of years] term from the target COD of [starting date] to [ending date]. Consistent with the PUA, the Commission (i) may extend the term for an additional five years, prior to two years from the [ending date], if the anticipated PJM revenues are greater than the project operating costs for the additional five years, in which case the OREC price shall equal one-half the sum of the anticipated PJM revenues and the anticipated project operating cost over that five year additional term, and (ii) may extend the term for a second additional five years, prior to two years from the [ending date of the first additional five year term], if the anticipated PJM revenues are greater than the project operating costs for the additional five years, in which case the OREC price shall equal one-half the sum of the anticipated PJM revenues and the anticipated project operating cost over the second five year additional term.

- If the [name] project's output exceeds the Approved OREC Amount in any year, the project may direct the Administrator to treat such excess output as either (i) Surplus ORECs to be banked in the PJM GATS Account for up to three years, in which case the

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ratepayers. Moreover, if a selected applicant is exposed to financial downsides in the case of cost overruns or lower-than-expected performance, then fairness indicates that the winning applicant should retain financial upsides.

Administrator shall retain the associated power revenues and the project will not receive the associated OREC revenues until the banked Surplus ORECs are retired in a subsequent year, or (ii) output to be merchandized at market power and Tier 1 REC prices, in which case the Administrator will forward any associated market revenues to the [name] project.

- The [name] project (i) has submitted a statement to the Commission that lists the names and addresses of all minority investors that it has interviewed and (ii) has executed a Memorandum of Understanding with the Commission requiring it to make serious, good-faith efforts to solicit and interview a reasonable number of minority investors in any future attempt to raise venture capital or attract new investors. The Governor's Office of Minority Affairs, in consultation with the Office of the Attorney General, and the [name] project have established a clear plan to set reasonable and appropriate minority business enterprise participation goals and procedures for each phase of the [name] project.

- The Commission has verified that representatives of the United States Department of Defense and the maritime industry have had the opportunity, through the federal leasing process, to express concerns regarding project siting.

- The [name] project has committed to using best efforts to apply for all eligible state and federal grants, rebates, tax credits, loan guarantees, or other similar benefits as those benefits become available, and shall pass along to ratepayers 80% of the value of such state and federal benefits received and not included in the [name] application. Any benefits passed along to ratepayers shall not require Commission approval but shall be subject to Commission review at its discretion.

- Ratepayers, purchasers of ORECs, and the State shall be held harmless for any cost overruns associated with the [name] project. Any debt instrument issued in connection with the [name] project shall not establish a debt obligation or liability of the State.

- If the [name] project submitted a one-part Proposed OREC Price Schedule, the [name] shall be responsible for submitting an interconnection request for Capacity Resource status with PJM if an interconnection request has not already been submitted. The [name] project shall be responsible for all transmission upgrade costs associated with the [name] project.

- If the [name] project submitted a two-part Proposed OREC Price Schedule, then [name] shall submit an interconnection request for Capacity Resource status with PJM within six months from the date of this Order if an interconnection request has not already been submitted. Once the PJM interconnection process is completed, [name] shall request the Commission to true-up the upgrade component of the OREC Price Schedule if the upgrade cost from the executed PJM Interconnection Agreement differs from the

Commission's estimated upgrade cost, subject to the PUA's price and rate caps. The Commission shall inform the [name] project of the maximum increase in the upgrade cost that would satisfy the price and rate caps. If the [name] project is larger than required to meet its Approved OREC Amount obligation, then the [name] shall have the burden of demonstrating to the Commission that its request for an allocation of the transmission upgrade costs between the project capacity required to meet its Approved OREC Amount obligation and any additional project capacity is fair and equitable.

- The [name] project shall deposit $2,000,000 into the Maryland Offshore Wind Business Development Fund within 60 days of the date of this Order; deposit an additional $2,000,000 into the Maryland Offshore Wind Business Development Fund within one year after the date of this Order; and deposit an additional $2,000,000 into the Maryland Offshore Wind Business Development Fund within two years after the date of this Order. Failure to make a timely deposit would be a violation of the Order.

- The [name] project shall file annual reports to the Commission on the anniversary of this Order specifying (i) progress made in achieving milestones, (ii) any adjustments to the project development timeline and COD, (iii) any material changes to the project ownership structure, sponsors, financiers, or contractors, and (iv) any material changes to the project, including but not limited to the capacity of the project, the turbine model, and the design of the foundation or support structure.[45]

- If the [name] project (i) is unable to obtain rights to a BOEM lease site, (ii) declares bankruptcy, or (iii) is unable to demonstrate to the Commission that it has diligently pursued and engaged in a continuous development and construction program to achieve project COD, then the Commission may withdraw this Order.

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[45] Any change in the COD would allow the Commission and electricity suppliers to calculate OREC prices in advance on a calendar year basis.

Appendix 1 – Maryland Offshore Wind Energy Act – Transmission Upgrade Whitepaper

The Uncertain Costs of Transmission Upgrades Will Be a Challenge

One of the key issues discussed at the January 28th stakeholder meeting was how to address the cost and uncertainty of transmission upgrades associated with an offshore wind project. Under PJM regulations, any generator interconnecting to the transmission system is responsible for the costs of interconnection and transmission upgrades. The capital costs for the wind farm and interconnection to the existing grid can be estimated with a reasonable degree of certainty by the time applications will be due. By contrast, transmission upgrade costs, *i.e.,* transmission infrastructure improvements that may be required anywhere on the PJM system to ensure reliability is maintained under a wide range of contingency events, are uncertain and require roughly two years for PJM to complete its PJM interconnection process. A project may interconnect as an Energy Resource and avoid upgrade costs, but that may be an inferior alternative.

Once a generator makes an interconnection request, PJM plans and designs the upgrades, and if approved by the generator, the local transmission owner performs or manages the actual work.[46] It is almost certain that any significant wind project off the Delmarva coast will require transmission upgrades, but, it is doubtful that generators will have reliable cost estimates in time for the OWEA process.

Transmission Upgrades Would Improve Reliability on the Delmarva Peninsula

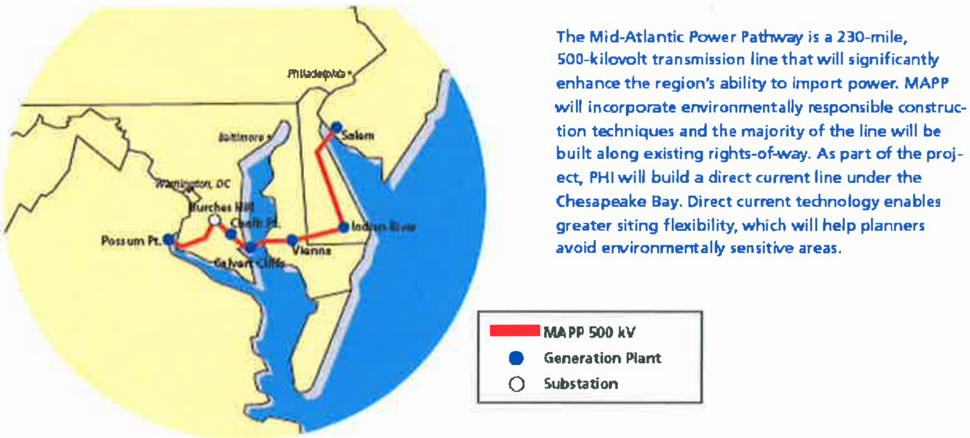
The Delmarva Peninsula has had serious transmission reliability problems in the past. A 2010 PJM study identified grid reliability issues due to bulk power contingencies that would cause voltage and thermal limit violations in the Eastern Mid-Atlantic Area Council (EMAAC) region of New Jersey, Philadelphia, and the Delmarva Peninsula. The 500 kV Mid-Atlantic Power Pathway (MAPP) project was determined to be the best solution, with an in-service date of June 1, 2015 and an estimated cost of $1.45 billion. Since then, reduced demand growth projections, incremental transmission improvements, additional capacity commitments, and increased EE and DR eliminated the near-term need for MAPP. On August 24, 2012, the PJM Board formally cancelled MAPP, but there is a possibility of problems on the Delmarva Peninsula in the future.

Transmission limitations serving the Delmarva Peninsula were evident in PJM's 2009 Base Residual Auction for the 2012 /2013 Delivery Year, in which market capacity prices for the Delmarva Peninsula reached $222.30/MW, considerably higher than nearby zones.

[46] The transmission owners are Delmarva Power for the Delaware and Maryland portions of the Delmarva Peninsula and A&N Electric Cooperative for the Virginia portion.

Transmission investments since 2009 have eliminated this price premium in the most recent PJM capacity auctions.

Map of the Mid-Atlantic Power Pathway



Any transmission upgrades required for an offshore wind project will improve reliability on the Delmarva Peninsula. Note that if upgrade costs are borne by Maryland ratepayers, Delaware and Virginia ratepayers on the Delmarva Peninsula will likely get "free rider" benefits.

Estimating Transmission Upgrade Costs Is Difficult and Time-Consuming

It is difficult and expensive to estimate required transmission upgrades and associated costs for any generation project. Energy injections at a particular interconnection point can cause reliability violations in numerous locations throughout the PJM transmission system when contingencies are tested. There are two ways for a developer to obtain a cost estimate.

<u>Estimating Cost via the PJM Interconnection Process</u>

A generator can submit an interconnection request to PJM with sufficient information about the generation unit's size, location, and operating characteristics. Once the request is accepted, PJM would initiate a three-step process with increasing degrees of cost accuracy: Step 1 – Feasibility Study, Step 2 – System Impact Study, and Step 3 – Facilities Study, the last step before a construction contract can be issued.

Advantages:

1. Highest degree of accuracy.
2. Ability to work with PJM and transmission owner during process to develop lower cost solutions.

Disadvantages:

1. This is a lengthy process: up to 10 months for a Feasibility Study, 1.5 years for a System Impact Study, and 2 years (in total) for a Facilities Study from the time an interconnection application is submitted.
2. PJM would charge the developer roughly $180,000 (or more) to complete the interconnection process for a 200 MW project.[47] A developer may incur further costs for re-tooled studies. The cost for a 400 MW project would be higher.

Estimating Cost Using an Independent Consultant

Alternatively, an independent transmission engineering consultant can be hired to estimate the need for upgrades and their costs.

Advantages:

1. Faster; can be completed in 2-3 months, depending on the degree of accuracy and consultant's backlog.[48]
2. Generator can control deliverables and milestones.

Disadvantages:

1. An independent estimate cannot be as accurate as the PJM process.
2. A study comparable to a System Impact Study can cost $120,000 - $180,000.
3. Doesn't replace the need for the PJM interconnection process.
4. The project developer would still incur PJM's interconnection study costs.

Treatment of Upgrade Costs in an OREC Price Schedule Is a PSC Policy Decision

The OWEA definition of a Qualified Offshore Wind Project includes"…a wind turbine electric generating facility, including the associated transmission-related interconnection facilities and equipment…" This definition does not explicitly include associated transmission upgrades. However, an OREC is equal to "…the generation attributes, including the energy, capacity, ancillary services, and environmental attributes." Capacity attributes cannot be created without transmission upgrades, implying that transmission upgrade costs should be required as a bidder's responsibility and included in its OREC Price Schedule bid.

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[47] Typical PJM charges are $30,000 for a Feasibility Study, plus $50,000 for a System Impact Study, plus $100,000 for a Facilities Study.

[48] The original whitepaper estimated 3-6 months and up to $200,000 for a detailed study. This was changed to 2-3 months and $120,000-$180,000 for an independent study comparable to a System Impact Study based on discussions with a transmission consultant, assuming two project sizes and the consultant has the necessary resources and a base power flow case.

Bidders will require reasonably accurate cost estimates in order to submit a competitive OREC bid. If there is cost uncertainty, bidders will include a risk premium in their bids to protect them in case actual costs are higher than expected. If actual costs materially exceed the estimated costs included in their bid, they could cancel or default on the project. Requiring all bidders to assume a single reasonably accurate estimate of upgrade costs would (i) minimize the chance of a material cost increase and consequent cancellation or default and (ii) enhance comparability among bids.

There is no "best practice" for transmission upgrade costs. State procurements have instead managed the cost uncertainty of transmission upgrades with different strategies:

<u>Procurements in which Bidders Bear Upgrade Cost Risks</u>

1. In Maryland's recent procurement for new gas-fired capacity resources, upgrade costs are the responsibility of the generation owner, i.e. the CPV Maryland CC plant. In this case, CPV Maryland had commenced the interconnection process well before the procurement.
2. The Massachusetts PPAs with National Grid and NStar require Cape Wind to be responsible for all upgrade costs.
3. Under the New Jersey Long-Term Capacity Agreement Pilot Program (LCAPP), bidders were responsible for transmission upgrade costs.

<u>Procurements in which Bidders Do Not Bear Upgrade Cost Risks</u>

1. Transmission upgrade costs for the Block Island Wind Farm are the responsibility of the purchaser, Narragansett Electric (dba National Grid).
2. Transmission upgrade costs for the cancelled Bluewater Delaware project were the responsibility of the purchaser, Delmarva Power & Light.
3. Renewable resources (other than Cape Wind) procured under the Massachusetts Green Communities Act had the option to operate as energy-only resources. Those projects would forgo capacity revenues and were required to meet the minimum deliverability standard, thus avoiding upgrade costs.
4. For the two Connecticut renewable procurements in 2013, bidders avoided upgrade costs under the minimum deliverability standard as energy-only resources.

<u>Procurements in which Bidders Use Estimated Upgrade Costs</u>

1. The Long Island Power Authority has issued multiple RFPs in which bidders are provided with an estimate of upgrade costs for potential interconnection points. Bidders were responsible for including capital costs for transmission upgrades in their bid prices, relying in part on LIPA's estimates. If actual costs came in higher or lower, there was a reconciliation process.

Interconnecting with Energy Resource Status Is an Inferior Alternative

In general, a developer may request either of two forms of PJM interconnection status: Capacity Resource status or Energy Resource status. Projects with Capacity Resource interconnections have sufficient upgrades and thus receive the right to schedule both capacity and energy deliveries at the point of interconnection. Projects with Energy Resource interconnections require no upgrades and receive the right to schedule only energy deliveries at the PJM interconnection point, and are subject to curtailments.

Capacity Resource status is granted based on having sufficient transmission capability to ensure the deliverability of generator output to network load under established reliability planning criteria. Feasibility Study and System Impact Study results identify the transmission system upgrades required to meet these criteria. Once required upgrades are constructed, a completed unit is granted Capacity Interconnection rights, enabling it to participate in PJM capacity markets. Planning studies for generating units seeking Energy Resource status do not include the deliverability analyses. As a result, Energy Resource units are only permitted to participate in the energy market, do not provide resource adequacy as capacity, and cannot receive capacity revenues. The vast majority of PJM generators have Capacity Resource status, which would be necessary for an offshore wind project to have capacity attributes and provide capacity revenues.

Advantages of Energy Resource Status:

1. Inexpensive to construct
2. Estimating the interconnection work is inexpensive and relatively easy

Disadvantages of Energy Resource Status:

1. No capacity revenues to offset ratepayer OREC payments
2. Possible generation curtailments
3. Curtailment risk impedes financeability

Advantages and Disadvantages of Each Transmission Upgrade Options for Maryland

Based on the past procurements described above, the advantages and disadvantages of the three transmission upgrade options for the Maryland offshore wind procurement are as follows:

<u>Bidder Estimates Upgrade Costs and Includes in OREC Price Schedule</u>

Advantages:

1. Bidders, not ratepayers, estimate upgrade costs and take on cost risk.
2. OREC Price unambiguously includes all costs and would not require an adjustment if actual upgrade costs are higher than estimated.

Disadvantages:

1. There are no active requests in PJM's interconnection queue for offshore wind projects, thus no bidders will have a reasonable upgrade cost estimate from PJM.

2. It is expensive and time-consuming for a bidder to hire an independent transmission consultant to estimate upgrade costs.
3. Bidders may require additional time to complete their upgrade cost estimates before an OREC Price Schedule can be submitted.
4. The independent cost estimate may not match PJM's estimated cost.
5. Bidders will ask a risk premium in their OREC Price Schedule to protect them against upgrade cost uncertainty.
6. Ratepayers would pay bidder's premium-adjusted, estimated upgrade cost that is likely to be higher than the actual cost.
7. If PJM's estimate is materially higher than bidder's estimate, the project awardee may cancel or default on project.

Bidder Excludes Upgrade Costs from OREC Price Schedule

Advantages:
1. Ratepayers pay actual upgrade cost, never more.
2. Transmission upgrades provide social benefit of improving reliability on the Delmarva Peninsula.
3. Greater chance of a bidder meeting $190/MWh cap.

Disadvantages:
1. Not contemplated by OWEA and no cost recovery mechanism was provided.
2. Ratepayers exposed to uncertain upgrade costs after project selection.

Bidder Utilizes PSC's Estimated Upgrade Costs in OREC Price Schedule

Advantages:
1. Bidders will not include a risk premium in their OREC Price Schedule to cover upgrade cost uncertainty, thus improving the chance of meeting the $190/MWh price cap and $1.50 and 1.5% rate caps.
2. Actual cost incorporated into OREC Price Schedule so ratepayers pay actual upgrade cost, never more.
3. Utilizing an estimated upgrade cost is not prohibited by OWEA.
4. Since transmission upgrades provide a social benefit of improving reliability on the Delmarva Peninsula, ratepayers can reasonably bear the risk that the actual cost may differ from the estimated cost.
5. The OREC bids will assume identical upgrade costs, facilitating grater transparency and consistency in the bid evaluation process.
6. Consultant can estimate discontinuities where upgrade costs jump up due to inherent "lumpiness" of transmission investments.

7. OREC Price Schedule can be trued up once actual upgrade cost is determined; true up would likely not be significant.[49]

8. If actual costs exceed estimated costs, the project awardee determines whether or not to cancel or continue the project.

Disadvantages:

1. OREC price will require pro rata adjustment mechanism, subject to caps.
2. PSC will bear transmission consultant cost to develop estimate.
3. Transmission upgrade costs are never certain and could exceed PSC's estimate.

Recommendation: Minimize Upgrade Risks by Utilizing an Estimated Upgrade Cost

Each of the alternatives described above has advantages and disadvantages. In LAI's opinion, the most workable solution is to provide OREC bidders with an estimate of the transmission upgrade costs, and then incorporate an adjustment mechanism to the OREC Price Schedule in the regulations. Requiring bidders to utilize an estimated upgrade cost strikes a reasonable allocation of cost risk, is consistent with OWEA, and would facilitate offshore wind bids, avoid delays, and ensure competitive bid prices. Bidders would be largely protected against the risk of upgrade costs that they have no control over up to the statutory caps, and ratepayers would not pay a premium for upgrade cost uncertainty.

The recommended process would be as follows:

1. The PSC would hire an independent transmission consultant to estimate upgrade costs for Capacity Resource status for (i) one lease of approximately 200 MW and two leases with a total capacity of approximately 400 MW relative to a required in-service date and (ii) at multiple locations if necessary, e.g. to 138 kV and 230 kV substations on the Delmarva Peninsula. The PSC would provide these upgrade cost estimates to bidders.

2. Bidders would be instructed to submit a two-part OREC Price Schedule: (i) the first component would include the costs of the wind farm and electrical interconnection and (ii) the second component would cover transmission upgrade costs based on the PSC's estimate. That second component would be adjusted pro-rata by any change between the estimated and actual upgrade costs, i.e. ratepayers would bear the risk that actual upgrade

[49] A 200 MW offshore wind project (excluding transmission upgrades) would cost just over $1.1 billion using a 2011 NREL cost estimate of $5600/kW. Injecting energy into the Delmarva Peninsula, an energy import region, should require much less expensive upgrades than if energy were injected into an energy exporting region. Assuming an upgrade cost estimate of $50 million and a maximum true-up of +/-50%, the OREC bid price adjustment would be no more than 2% (= $25 billion / ($1.1 billion + $50 million)).

costs (determined by completing PJM's interconnection process) could be higher or lower than estimated.

3. The total OREC Price Schedule (incorporating the PSC's upgrade cost estimate) would be utilized for the $190/MWh cap determination and the $1.50 and 1.5% rate caps, the comparison among bidders, and any selection of a winning bid(s).
4. Upon completing the PJM interconnection process, the OREC Price Schedule would be adjusted by the change between the estimated and actual upgrade costs (per examples below) subject to the $190/MWh price cap and the $1.50 and 1.5% rate caps.
5. If the Adjusted OREC Price Schedule satisfied the $190/MWh price cap and the $1.50 and 1.5% rate caps, the bidder would continue to be responsible for completing project development. If the Adjusted OREC Price Schedule would exceed any of the price or rate caps, then the Adjusted OREC Price Schedule would be set up to the cap and the bidder would have the option to either continue or cancel project development to avoid unnecessarily penalizing the bidder.

Examples of Adjusting the OREC Price Based on Actual Upgrade Costs

Assume the PSC hires a transmission consultant who estimates $50 million in transmission upgrades in advance of the PSC accepting OREC proposals. All bidders utilize the PSC's $50 million upgrade estimate in their OREC Price Schedule bids.

In this example the winning bid is:	$175/MWh for wind farm and interconnection
	<u>$ 10/MWh for transmission upgrades</u>
	$185/MWh OREC Price Schedule

<u>Example A: Higher Upgrade Cost</u>

Bidder completes PJM interconnection process; actual upgrade cost is $75 million (50% higher). The Adjusted OREC Price Schedule is:

$175/MWh for wind farm and interconnection
<u>$ 15/MWh for transmission upgrades (50% higher)</u>
$190/MWh Adjusted OREC Price Schedule

The Adjusted OREC Price Schedule meets $190/MWh price cap and $1.50 and 1.5% rate caps; PSC approves the higher Adjusted OREC Price Schedule.

<u>Example B: Lower Upgrade Cost</u>

Bidder completes PJM interconnection process; actual upgrade cost is $25 million (50% lower). The Adjusted OREC Price Schedule is:

$175/MWh for wind farm and interconnection
<u>$ 5/MWh for transmission upgrades (50% lower)</u>
$180/MWh Adjusted OREC Price Schedule

The Adjusted OREC Price Schedule meets $190/MWh price cap and $1.50 and 1.5% rate caps; PSC approves the lower Adjusted OREC Price Schedule.

<u>Example C: Higher Upgrade Cost Exceeds Cap</u>

Bidder completes PJM interconnection process; actual upgrade cost is $100 million (100% higher). The Adjusted OREC Price Schedule is:

$175/MWh for wind farm and interconnection
<u>$ 20/MWh for transmission upgrades (100% higher)</u>
$195/MWh Adjusted OREC Price Schedule

The Adjusted OREC Price Schedule meets the $1.50 and 1.5% rate caps but would exceed the $190/MWh price cap; PSC approves a $190/MWh Adjusted OREC Price Schedule; bidder has option to continue development at $190/MWh or cancel the project without penalty.

Appendix 2 – Connecticut RFP Summary

Connecticut adopted Public Act 13-303, An Act Concerning Connecticut's Clean Energy Goals on June 5, 2013 to further the state's renewable energy goals. Part of the Act directs the Connecticut Department of Energy and Environmental Protection ("DEEP") to undertake procurements for specific types of renewable resources under long term contracts. In 2013, DEEP sought proposals for new, eligible renewable resources under Section 6, for up to 4% of the load (equivalent to approximately 525 MW of wind capacity) of state's two EDCs, United Illuminating and Connecticut Light & Power, for contracts up to 20 years. Eligibility criteria included a requirement that the proposed resource qualify as a CT RPS Class 1 renewable resource, have a commercial operation date no earlier than January 1, 2013, offer a delivery point on the ISO-NE grid, have a minimum nameplate capacity of 20 MW, have demonstrated site control, and be technically viable. Bidders were permitted to offer energy plus RECs, or RECs alone.

The scoring system awarded up to 80 points for price, 15 points for system reliability factors, and 5 points for the likelihood of meeting the target COD. For the price evaluation, the "measure of merit" was the levelized unit cost (in constant 2013 dollars per MWh) for energy and RECs, net of market revenues realized from sale of the products. The use of a unit cost measure allowed for comparison of offers of different MW capacities. Out of 47 proposed projects, DEEP awarded contracts to the 250 MW Number Nine Wind farm in Aroostook County, Maine and the 20 MW Fusion Solar Center in Sprague and Linden, Connecticut. These contracts were approved for cost recovery by PURA on October 23, 2013 (Docket No. 13-09-19)

Pursuant to Section 8, DEEP also solicited proposals for new or existing biomass, landfill methane gas, or small run-of-river hydroelectric projects, for up to 4% of the EDCs' load for contracts up to 10 years. This procurement was initiated in October 2013. Eligibility criteria were similar to Section 6, except that the minimum installed capacity was 2 MW. Bidders were permitted to offer energy plus RECs, or RECs alone. The scoring system was similar to the previous one and awarded points for price and non-price factors, including reliability, environmental, and local economic development benefits. In December 2013, DEEP directed the EDCs to execute a REC-only contract for a 21.5 MW portion of Public Service of New Hampshire's Schiller Unit 5, and two REC-only contracts for a 5.4 MW and a 2.7 MW portion of the Joseph C. McNeil Generating Station in VT. These contracts with existing facilities will provide approximately 200,000 RECs per year, or approximately 1% of the distribution load as of 2014. PURA approved these contracts for cost recovery in an April 2, 2014 decision in Docket No. 14-02-02.

Appendix 3 – Delaware RFP Summary

In March 2006, the Delaware General Assembly passed House Bill No. 61, the Electric Utility Retail Customer Supply Act of 2006 ("EURCSA"), in response to significant increases in PJM market-based prices. One of the provisions required Delmarva Power & Light (Delmarva) to issue an RFP for long-term (10-25 year) contracts to support the construction of up to 400 MW of new generation resources by June 1, 2013 within Delaware to serve its standard offer customers. Delmarva filed a draft RFP and the final version, approved by the PSC, was issued on November 1, 2006 for the purchase of Power Products and RECs. Wholesale energy and capacity price impacts were included in the evaluation.

A number of bids were reviewed by Delmarva and various state agencies; public comment sessions were held as well. On May 22, 2007, by Order No. 7199, the state Agencies accepted Staff's recommendation and directed Delmarva to negotiate a long-term power purchase agreement ("PPA") with Bluewater Wind for an offshore wind facility. The Order provided that the negotiations conclude within a 60-day time frame, but the State Agencies indicated their flexibility in extending this deadline, if necessary, to the extent that there was continuing progress in the PPA negotiations. The State Agencies also directed the Staff to retain a third party to oversee the progress of the negotiations and report back periodically.

During the summer months of 2007, the parties engaged in PPA negotiations and provided a status report to the State Agencies on August 7, 2007. After lengthy negotiations, Delmarva filed a PPA with what it believed to be unacceptable terms and the arbitrator, who had been engaged for the final negotiations sessions, issued his proposed resolutions. After additional discussions, the State Agencies unanimously voted to table the matter in December 2007.

Evaluation Criteria and Process

The proposals were evaluated by Delmarva and an Independent Consultant pursuant to the RFP "...to approve one or more of such proposals that result in the greatest long-term system benefits ... in the most cost-effective manner." The proposal bid prices could include cost escalators that were "known and measurable." The proposal evaluation process was comprised of several steps.

1. A pass / fail Non-Responsiveness Test to ensure that all proposals were complete and submitted on time.

2. A pass / fail Threshold Test to ensure that each bidder met criteria of financial strength, project financeability, site control, permitting, plant design, and commitment to non-negotiable contract terms.

3. A detailed Price and Non-Price Evaluation of qualifying proposals.

   Price components accounted for 60% of the evaluation score and included the bid price, other ratepayer impacts (changes in wholesale market prices), transmission and distribution impacts (including losses), imputed debt impacts, price stability, and compliance with the Delaware RPS. Transmission upgrade costs were estimated by Delmarva and added to the proposal cost for evaluation purposes; bidders were responsible for PJM's final cost estimate.

Non-price components accounted for 40% of the evaluation score and included (i) project characteristics of environmental impact, fuel diversity, and technical innovation and (ii) project viability regarding expected COD, technical reliability, site development, bidder experience, and project financeability.

4. Delmarva and the Independent Consultant provided evaluation reports containing their recommendations to the state agencies for a final decision.

Bluewater

On December 22, 2006, Bluewater Wind LLC (Bluewater) submitted twelve variations of a bid proposal that included both 20- and 25- year terms and (i) a 600 MW offshore wind plant with a 400 MW energy limit or (ii) a sale of two-thirds of the energy from a 600 MW plant. Bluewater was selected by Delmarva for 300 MW of energy from a 450 MW (nameplate rating) plant and the PPA was approved by the PSC in July 2008 after considerable negotiations and pricing modifications. Bluewater won a BOEM lease in June 2009. Under the PPA, Delmarva was responsible for PJM transmission upgrades and associated costs. NRG acquired Bluewater in November 2009 but the project was cancelled in December 2011.

Appendix 4 – Massachusetts Green Communities Act

An Act Relative to Green Communities, encouraging EE, DR, and renewable energy, became law in 2008. Known as the Green Communities Act, it authorized the auction of 100% of RGGI allowances, expanded the state's RPS targets, established a Renewable Energy Trust Fund, increased EE and DR measures, and clarified net metering rules. Section 83 of the Green Communities Act required electric distribution companies ("EDCs") to solicit proposals for 10 to 15-year renewable energy contracts at least twice over the five-year period commencing July 1, 2009. Provided reasonable proposals were received, the EDCs were directed to enter into cost-effective contracts for up to 3% of the total energy demand of distribution customers. Contracts could be for energy, for RECs, or for energy plus RECs. Provided the contracts were approved by the Department of Public Utilities ("DPU"), EDCs were permitted to recover the direct contract costs plus 4% remuneration to compensate the EDC for accepting the financial obligation of the contract. The DPU initiated a rulemaking docket to establish the RFP timetable and process. Regulations promulgated under 220 CMR 17.00 set forth the method for soliciting and evaluating proposals, and for the disposition of the products purchased. Consistent with the GCA, the regulations mandated that long term contracts must be with renewable energy generation sources that:

(a) Have a commercial operation date on or after January 1, 2008

(b) Are qualified as eligible to participate in the RPS program and sell RECs

(c) Be determined by the DPU to provide enhanced electricity reliability within the Commonwealth of Massachusetts, contribute to moderating system peak load requirements, be cost-effective to Massachusetts electric ratepayers over the term of the contract, and create additional employment, where feasible

(d) Be a cost-effective mechanism for procuring renewable energy on a long-term basis.

After purchasing the energy and/or RECs, each EDC could sell the energy to its basic service customers and utilize the RECs for RPS compliance, sell all products into the market, or some other transaction subject to DPU approval. If products are sold, revenues are credited against the direct contract costs, and the difference (either positive or negative) is allocated to all distribution customers.

Each EDC conducted a procurement in accordance with regulations, and submitted recommended contracts to the DPU for approval. These solicitations resulted in a total of nine long term contracts among the four EDCs. These contracts were primarily for on-shore wind contracts, but included two contracts with Cape Wind, a proposed offshore wind project, further discussed below. The contracts for the on-shore wind projects were determined by the DPU to meet the criteria for approval, including cost-effectiveness, based on a comparison to a market price forecast for energy and RECs.

The Green Communities Act was revised in 2012, inserting Section 83A, and regulations were promulgated under 220 CMR 21.00. Key statutory and regulatory changes were:

- The EDCs were required to solicit proposals for new renewable resources at least twice over a four-year period, commencing January 1, 2013.
- The EDCs' remuneration was lowered to 2.75% of the contract cost.
- The EDCs were required to issue joint RFPs, unless an EDC could demonstrate that an RFP issued individually was more cost-effective.
- Renewable energy generation sources must have a commercial operation date on or after January 1, 2013,
- The products procured by the contracts are allocated among the EDCs on a pro rata basis based on load share.
- 10% of the aggregate level of Long-term Contracts is reserved for newly developed, small, emerging or diverse renewable energy distributed generation facilities, to be procured through a separate solicitation
- To the extent that significant transmission costs are included in a bid, the DPU will authorize the contracting parties to seek recovery of such transmission costs through federal transmission rates, consistent with policies and tariffs of the FERC, to the extent the DPU finds that such recovery is in the public interest.

A joint procurement was conducted in 2013, and the EDCs filed petitions with the DPU for approval of six on-shore wind projects in September 2013. Three projects subsequently were cancelled, and the EDCs revised their petition to include the remaining three projects. A DPU decision is pending.

Cape Wind

Two of the contracts approved under CMR 17.00 are contracts between National Grid and Cape Wind, and NSTAR and Cape Wind. Unlike the other long term contracts procured under the Green Communities Act, the Cape Wind contracts were not competitively procured, but resulted from direct negotiations between the parties, as explicitly permitted under the GCA. Massachusetts does not have an OREC carve-out of the RPS, and therefore the Cape Wind contracts were reviewed under the same regulations as conventional renewable contracts.

Under the contracts, Cape Wind will construct a 468 MW wind facility (comprised of 130 3.6 MW units) located in federal waters of Nantucket Sound. Power would be delivered to the existing transmission grid on Cape Cod via two 115 kV 18 mile u/w transmission cables and extend under existing roadways and within a transmission right-of-way to an existing NSTAR substation. National Grid executed a contract for 50% of the output and NSTAR executed a contract for 27.5% of the output. Both contracts are for energy, capacity, RECs, and other environmental attributes, and have 15 year terms with options for the buyers to extend the contract for an additional 10 years. The DPU approved the National Grid contract in 2010 and the NSTAR contract in 2012.

The National Grid and the NSTAR contract have essentially the same terms, except for the percent of output allocated to each buyer. Both contracts start at $187/MWh in 2013 and escalate at a 3.5% annual rate. The National Grid contract required construction to commence by year-end 2013 and full capacity COD by year-end 2015. Under the NSTAR contract, Cape Wind must commence construction by year-end 2015; NSTAR has the right to terminate the contract if that milestone is not achieved. There are provisions for extensions but the National Grid contract price will not escalate after 2015 and COD must occur no later than year-end 2017. As of April 1, 2014, Cape Wind construction has not commenced and it is uncertain whether these milestones will be achieved.

The contracts allow for upward and downward price adjustments based on a variety of contingencies:

- If Cape Wind obtains PTC but not ITC, the price would go up by approximately 10%. If Cape Wind cannot obtain PTC or ITC, the price would increase approximately 13.5%.
- If debt financing costs be reduced due to a DOE loan guarantee, 75% of the savings would be passed along to customers.
- If actual project costs, as verified by an independent audit, fall so that the developer's total rate of return exceeds 10.75%, the contract price will be reduced to give ratepayers 60% of the benefit. If actual project costs are higher than anticipated, the developer absorbs those entire losses.

In addition, if Cape Wind's actual production exceeds its target, 50% percent of the surplus power will be credited without charge to the Buyers. Ratepayers are not at risk if Cape Wind is not constructed; power is only purchased when delivered. Under the terms of the contracts, Cape Wind is responsible for the cost any transmission upgrades.

In its Order approving the National Grid-Cape Wind contract, the DPU estimated that the likely range of net above-market contract cost was between $420 and $695 million.[50] The over-market value was computed as the PV of contract payments, less the market value of the energy,

[50] Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval by the DPU of two long-term contracts to purchase wind power and RECs, pursuant to St. 2008, c. 169, § 83 and 220 C.M.R. § 17.00 et seq. DPU 10-54, November 22, 2010 p. 209.

capacity, and REC products, plus the impacts on power market prices, over the contract term The bill impact on National Grid customers as a result of the over-market contract costs was estimated at 1.7% - 2.2%., not including price suppression.[51] However, in determining that the contract was cost effective and in the public interest, the DPU considered the "unquantified" benefits of the contract, including (i) contract provisions that may benefit customers if the project over-performs, if the contract is extended, and certain other price adjustments, (ii) contribution to achieving the Commonwealth's RPS goals, (iii) contribution to achieving National Grid's greenhouse gas reduction goals under the State's Global Warming Solutions Act, (iv) enhancement of regional system reliability, (v) moderation of system peak load, and (iv) employment benefits.

Similarly, in the Order approving the NSTAR-Cape Wind contract, the DPU reported that the over-market value of the contract ranged from $438 million to $513 million, depending on the outcome of certain terms in the agreement. Similar to the reasoning in the National Grid contract, the DPU concluded that there were

> "significant unquantified benefits associated with the PPA in terms of its: (1) pricing adjustment provisions; (2) option to extend; (3) role in achieving compliance with Massachusetts RPS requirements; (4) role in avoiding future GWSA compliance costs; (5) enhancement of electric system reliability; (6) moderation of system peak load; and (7) employment benefits. When these benefits are compared with the likely range of net (including price suppression) above-market costs … we find that the unquantified benefits exceed even the high end of the likely range of above-market costs. Therefore, we find that the expected benefits of the PPA to NSTAR Electric customers exceed the expected costs to NSTAR Electric customers. Accordingly, the Department finds that the PPA is both a cost-effective mechanism for procuring renewable energy on a long-term basis, and cost-effective to NSTAR Electric ratepayers over the term of the PPA, pursuant to Section 83 and 220 C.M.R. § 17.05(1)."[52]

In February 2014, Cape Wind announced it had secured a $600 million loan from the Danish Export Credit Agency that will facilitate the manufacturing of the blades and nacelles in Denmark. This loan follows a $200 million loan from PensionDenmark and a $100 million equity commitment from Siemens, the manufacturer. Cape Wind also announced that the

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[51] Ibid. p. 284.

[52] Petition of NSTAR Electric Company for approval by the Department of Public Utilities of a long-term contract to purchase wind power and RECs, pursuant to St. 2008, c. 169, § 83 and 220 C.M.R. § 17.00 et seq. DPU 12-30 November 26, 2012, p. 137.

offshore electric collection platform will be constructed in Maine, with staging work to be performed either in New Bedford Massachusetts or North Kingstown Rhode Island.

Appendix 5 – Maryland RFP for Generation Capacity

As directed by the Maryland Public Service Commission, the Maryland electric distribution companies ("EDCs") issued an RFP on September 29, 2011 and an Amended RFP on December 2, 2011 for up to 1,500 MW of new gas-fired generation capacity and associated energy located in Southwest Mid-Atlantic Area Council ("SWMAAC"). The RFP was issued in response to the Customer Choice Act to assure long-term service reliability in light of numerous load, generation, and transmission risks.

EDCs would enter into a Contract for Differences ("CfD") in which capacity and energy would be settled financially for a term of up to 20 years beginning as early as June 1, 2015 and no later than June 1, 2017. A model CfD was included with the RFP, in which the generation owner would assume all development, construction, and operating risks and responsibilities, and must offer the generation products into the PJM wholesale markets. CfD pricing could be structured with either fixed or indexed (to a recognized published index such as CPI or GDP deflator or gas price index) price components.

Projects had to meet a number of threshold criteria:

- Plants were required to qualify as a PJM capacity resource and be electrically located inside the SWMAAC Locational Deliverability Area ("LDA"), which generally covers the Baltimore-Washington metropolitan area.
- The plant's capacity must clear in PJM's Forward Capacity Market in order to be paid under the CfD.
- Plants had to offer energy into the PJM wholesale Day Ahead and Real Time energy markets as well as ancillary services.
- Plants had to achieve a COD as early as June 1, 2015 and no later than June 1, 2017, with terms up to twenty years.

Bidders had to provide detailed commercial and technical information about the owners, contractors, proposed plant, proposed fuel supply, ratepayer costs and benefits, and the CfD pricing by filling out forms with the required information clearly specified on forms attached to the RFP. Bidder communications were strictly administered to assure (i) commercially sensitive information was kept confidential and (ii) the process was fair and transparent.

Bidders had to include all costs for PJM interconnection and upgrades. The winning bidder, CPV Maryland, had already progressed through most of the PJM interconnection process for its 725 MW St. Charles Energy Center and had an upgrade cost estimate that was included in its bid.

Evaluation Process

Proposed generation projects were evaluated in a multi-step process by an independent monitor. An excerpt from the RFP is provided below. The evaluation consisted of (i) an initial screen to ensure the bid meets the minimum threshold criteria, (ii) for all bids that pass this screen an initial shortlist evaluation consisting of a price and non-price score, (iii) for the top bids in the initial shortlist evaluation, a final shortlist evaluation using production cost modeling, and (iv) the selection of the top bids from the final shortlist to sign agreements with one or more EDCs.

Step 1 – Minimum Threshold Criteria

The RFP included minimum threshold criteria regarding the proposed generation plant, bidder capability, site control, location, financial strength, financing plan, and acceptance of the model CfD.

Step 2 – Initial Shortlist Scoring

Proposals meeting the minimum threshold criteria were evaluated and given qualitative evaluations (up to 30% of the final score) and quantitative price scores (up to 70%). The qualitative criteria considered (i) development feasibility and risk, (ii) site control and permitting, and (iii) operational viability and risk impacts. Bidders could earn up to 10% in each of these areas.

The price score was based on the levelized net PV including the (i) requested capacity and fixed O&M payment plus (ii) variable fuel expenses. Proposals with costs 80% or less of the average bid cost would receive the full 70%, proposals with costs 140% or more of the average bid cost would receive 0%, and proposals with intermediate costs would receive linearly interpolated scores. Up to 3,000 MW of the highest scoring bids were eligible for the Initial Shortlist.

Step 3 – Final Shortlist Analysis and Award

Each shortlist bid was modeled using a production cost model to determine the net cost after taking market energy price impacts into account. The net cost to ratepayers also took into account key risk factors such as natural gas prices, environmental compliance costs, and ratepayer load. The bids with the lowest-cost solution for ratepayers when accounting for risk were selected to the Final Shortlist. The Commission had some discretion to direct the EDCs to finalize CfDs with one or more bidders on the Final Shortlist.

Credit & Collateral

The RFP included three types of financial security: (i) shortlisted bidders were required to provide a commitment letter within 30 days of being selected for the Final Shortlist, (ii) Completion Security of $100/kW was required within 10 days of CfD execution, and (iii) Performance Security of $50/kW, declining over the CfD term, was required on the COD.

Appendix 6 – New Jersey Offshore Wind Economic Development Act

On August 19, 2010, Governor Christie signed the Offshore Wind Economic Development Act ("OWEDA"), which provided financial and tax incentives to support a target of 1,100 MW of offshore wind projects. On February 10, 2011, the Board of Public Utilities ("BPU") established OREC regulations to implement the legislation, summarized below.

Only projects interconnected to the New Jersey grid qualify. Unlike Maryland's OWEA, ORECs were defined as only the "environmental attributes" of one MWh, *i.e.*, associated energy and capacity values were excluded from the OREC definition. Project owners bear project development, construction, and operating risks; revenues are only made for ORECs generated. The OWEDA regulations included a "Determination of completeness of application" step, during which the Board reviews each application for administrative completeness. The start of the 180-day period for the Board to approve, conditionally approve, or deny an application commences on the date the complete application is filed.

Under the BPU's OREC rules, Staff must determine an application's completeness after a proposal is submitted. The applicant may be asked to provide missing or deficient information. Once the application is deemed complete, the BPU has 180 days (unless extended) to approve, conditionally approve, or deny it. Applications must include specific information regarding owners, contractors, experience / expertise, financial status, a detailed project description, work or services to be conducted by in-state companies, an O&M plan, a decommissioning plan, and a complete financial analysis with balance sheets, projections of revenues, expenses, and cash flow, and funding sources. The applicant has to document that the project has applied for all eligible financial support and tax incentives, and that any reduction in such tax benefits will not be made up by ratepayers. Applications had to make a $100,000 deposit to reimburse the costs of consultants and other costs.

The project description covers size, design, electrical interconnection, construction plan, schedule with milestones, and a certification (or certification plan) for the wind generators. The project must either be in the PJM interconnection queue or eligible for interconnection. The applicant must also demonstrate the wind technology is "viable, cost competitive, and suitable for…New Jersey's offshore environment…" along with a wind energy assessment, expected energy output, expected reduction in carbon dioxide and other emissions, and plans that address weather risks and emergency shut down procedures. The applicant also has to provide a cost-benefit analysis using an input-output model to project income, employment, and other in-state impacts and estimated ratepayer impacts. Lastly, each application has to specify an OREC pricing schedule on a $/MWh basis.

BOEM Nominations of Interest

On April 20, 2011, BOEM and the State issued The New Jersey Call for Information and Nominations – Commercial Leasing for Wind Power on the Outer Continental Shelf Offshore New Jersey". The BOEM is responsible for leasing areas of the Outer Continental Shelf which are under federal jurisdiction for energy resource utilization. This Call for information and nominations requested public input regarding the development of offshore wind projects in a designated Wind Energy Area located offshore New Jersey. The Call also sought nominations from project developers of areas within the Wind Energy Area that should be put up for auction for project development. The BOEM received eleven such nominations, and the entire WEA was proposed for development by one or more developers. By June 2011, eleven companies had submitted proposals to BOEM for projects off the New Jersey coast.

Fishermen's Energy

Fishermen's Energy filed a petition in March 2008 for BPU approval of a 20 MW demonstration project and a 350 MW utility-scale project off the coast of Atlantic City. The developer received one of the first interim leases from BOEM in 2009: OCS-A-0473, lease block 6931. In response to concern about its high cost and risks to ratepayers if federal grants or tax benefits did not materialize, Fishermen's Energy amended its project to 5 wind turbines with 25 MW of capacity. As part of a Stipulation with the New Jersey Rate Counsel, Fishermen's Energy reduced its OREC price to $187/MWh starting in Energy Year 2013 and the prices escalate at an average of 3.3% for the first nineteen years and then 2.8% thereafter.[53] Those prices were stated on an Energy Year basis, similar to a calendar year in that the price for a given Energy Year would not "slip" if COD were delayed.

At this time the project is fully permitted, detailed wind assessment is ongoing, avian and marine mammal monitoring has been completed, geotechnical and geophysical work completed, and a post-Sandy bathymetry study has been completed. Due to the project's small size, *i.e.,* 25 MW, transmission upgrade costs were expected to be insignificant. In July, 2013, the BPU rejected the Fishermen's Energy proposal, in part due to ratepayer risks if federal grants did not materialize. Although the regulations have a target evaluation period of 180 days to approve or deny a project, the BPU rejected the Fishermen's Energy project on March 20, 2014, after almost three years of hearings and deliberation.

According to representatives from Fishermen's Energy, there were three important lessons learned from this procurement process.

[53] An Energy Year runs from June 1 through May 31.

- The evaluation criteria and process was poorly defined in the BPU's regulations, leaving bidders uncertain regarding the value the BPU would place on various project attributes and giving the BPU significant discretion over the evaluations. The BPU's regulations did not specify how quantitative and qualitative factors would be combined.

- Each bidder had to provide estimated costs and benefits. As a result, it was virtually impossible to compare them on a fair and consistent basis because bidders used different models and different input assumptions. With regard to employment benefits for future offshore wind procurements, Fishermen's Energy suggested that applications should receive credit if they expect to increase in-state employment, an audit be preformed to verify if the employment claims were met after construction, and a penalty be assessed if the employment claim was in fact not met.

- Bidders were prohibited from substituting current turbine models for the ones in their applications. The procurement process should allow some flexibility to utilize improved, more efficient designs, especially if many years elapse between the application and the COD. The need to procure insurance for wind farm operations and to obtain an independent engineer's due diligence acceptance for bank financing ensures that later turbine models will be commercially proven and suitable for use.

Appendix 7 – Rhode Island: Block Island Offshore Wind Project

The Rhode Island legislature passed General Law §39-26.1, Long Term Contracting Standard for Renewable Energy, which required EDCs to solicit proposals for new renewable energy resources to enhance the electric reliability and environmental quality of the Town of New Shoreham, *i.e.,* Block Island. Block Island was not connected to the ISO-NE grid and relied upon relatively expensive oil-fired diesel generators. Narragansett Electric, d/b/a National Grid, issued an RFP on July 31, 2009 with the following details. Deepwater Wind was the successful bidder, but the resulting 20-year PPA for the Block Island Wind Farm was originally rejected by the PUC as too expensive. The Rhode Island legislature amended General Law §39-26.1-7 to facilitate the reevaluation of a slightly renegotiated PPA, which was approved on August 11, 2011. Project development is continuing, and the owner, Deepwater Wind, recently announced an agreement for Alstom to supply five Haliade 150-6 MW offshore wind turbines plus fifteen years of O&M support.

Project Eligibility

Under National Grid's RFP, an eligible facility had to qualify as a renewable generator under Rhode Island General Laws, (ii) had to be new, and (iii) had to be less than 10 MW (later expanded to 30 MW). There was a minimum term of 10 years with option of 15 years; terms longer than 15 years were subject to PUC approval (which was indeed the case for the Block Island Wind Farm). Project capacity had to be eligible as capacity under ISO-NE rules. The bidder was responsible for offering energy and capacity into ISO-NE's wholesale power markets.

Bidders were required to submit an all-in bundled price and prices for the individual components (energy, capacity, and RECs) with the following options: (i) fixed price for the contract term, (ii) price with a fixed rate of change over the contract term, or (iii) a price indexed to a publically available inflation-related index. The developer was responsible for the permitting, development, and costs of interconnections (i) to Block Island and (ii) between Block Island and the National Grid facilities on the mainland. National Grid was responsible for the cost of any system upgrades on its transmission and distribution system.

Proposal Requirements

Proposals had to be complete and submitted on time. An explanation was required for any missing information. Proposals had to contain a detailed schedule covering all permits and approvals, construction, and milestones.

Projects had to demonstrate the ability to develop, permit, finance, and construct the project. Developer had to be "fully engaged" in renewable resource development and establish that it will have primary responsibility for overall management and operation. Developer had to submit a reasonable funding plan. The design and equipment (foundations, towers, generator, and transmission) had to be technically viable. Any projects with a "fatal flaw" could have been rejected.

Bidders had to demonstrate site control via ownership, ownership option, or letter of intent, plus a high likelihood of obtaining the necessary easements from Block Island to the mainland. In this case, Deepwater Wind already had control of the offshore wind site, which was in state waters.

For wind and other projects with capacity factors under 50%, a Development Period Security of $20/kW was required. Once a project achieves Commercial Operation, this Security is to be replaced per National Grid's standard credit requirement that includes unsecured credit for contract counterparties with a credit rating of at least BBB / Baa2.

Evaluation Criteria and Process

The RFP specified Price Evaluation and Non-Price Evaluation considerations process but did not have a multiple step qualification and evaluation process or a defined scoring system. However, these process characteristics were not necessary since there was only a single bidder that had already secured the site lease and had negotiated a contract.

Price Evaluation – The net levelized cost (in $/MWh) of each project was evaluated based on the cost relative to (i) competing renewable projects and (ii) market prices for capacity, energy, and RECs. Projected impacts on wholesale energy and capacity prices were separately considered by the PUC in approving the Block Island Wind Farm PPA.

Non-Price Evaluation – The PUC considered (i) development viability and (ii) operational viability. Development viability included site control, land use, community support or opposition, likelihood of receiving all permits and approvals, technical reliability, financial capability, developer experience, and development schedule. Operational viability included financial strength, O&M plan, quality of generation forecast, direct and indirect state employment, fuel diversity, PPA price stability, and environmental impacts.

Block Island Project Pricing

The Deepwater Block Island Offshore Wind Project will sell bundled Power Products and RECs at a "take if tendered" price of $244/MWh starting in 2013 with a fixed 3.5% escalator over twenty years. There are a number of mechanisms to adjust the price. (i) Every year of COD delay will increase the bundled price by 3.5%. (ii) If the actual capital cost is less than $205.4 million the price will decrease. (iii) If the expected 40% capacity factor is exceeded then one-half of the excess energy will be credited to National Grid and its ratepayers at no cost. (iv) If Deepwater constructs and pays for the cable connection to the mainland, it will be entitled to recover that cost through a price adjustment.

Appendix 8 – Maryland Offshore Wind Energy Act – Financial Calculations

This appendix provides details to support the general concepts for calculation of Levelized OREC Price, Net Ratepayer Cost, Residential Net Ratepayer Impact, and Nonresidential Net Ratepayer Impact for applications and combinations of applications as discussed in the body of this report.

Criteria Defined in OWEA

OREC Price Cap – As a minimum threshold requirement, an application's Proposed OREC Price Schedule may not exceed $190 per OREC, expressed in 2012 dollars per PUA §s 7-704.1(e)(1)(iv) and 7-704.1(f)(1)(i).

Residential Net Rate Impact Cap – As a requirement for approval, "the projected net rate impact for an average residential customer, based on annual consumption of 12,000 kilowatt-hours, combined with the projected net rate impact of other qualified offshore projects, does not exceed $1.50 per month in 2012 dollars, over the duration of the proposed OREC pricing schedule" per PUA § 7-704.1(e)(1)(ii).

Nonresidential Net Rate Impact Cap – As a requirement for approval, "the projected net rate impact for all nonresidential customers considered as a blended average, combined with the projected net rate impact of other qualified offshore wind projects, does not exceed 1.5% of nonresidential customers' total annual electric bills, over the duration of the proposed OREC pricing schedule" per PUA § 7-704.1(e)(1)(iii).

OREC Cost for Rate Cap Calculations – "When calculating the projected net average rate impacts under paragraph (1)(II) and (III) of this subsection, the Commission shall apply the same net OREC cost per megawatt-hour to residential and nonresidential customers" per PUA § 7-704.1(e)(2)(ii).

Evaluation Assumptions

We recommend that the Commission utilize discount and deflation rates consistent with prior evaluations of ratepayer payments and benefits over time. The nominal discount rate for OREC payments should be relatively low, consistent with their certainty and long-term concern over societal welfare. Thus we recommend that the discount rate be set at the Long-Term Composite (maturity of 10 years or greater) Treasury Bond Rate (or equivalent risk-free rate). The U.S. Department of the Treasury publishes this rate daily; as of March 14, 2014 it was 3.30%.[54] Future OREC benefits (market revenue credits, avoided REC costs, and market price impacts)

[54] http://www.treasury.gov/resource-center/data-chart-center/interest-rates/pages/default.aspx

should be discounted at the same nominal rate or at a slightly higher nominal rate to reflect their uncertainty relative to OREC payments. The utilities' weighted average cost of capital would not be appropriate for discounting or deflating in the context of OREC payments and benefits.

We also recommend that the near-term (next three to five years) average expected inflation rate, such as the GDP Deflator (or equivalent), be utilized to deflate future nominal dollar OREC payments to 2012 constant dollars. For example, the U.S. Federal Reserve published its most recent outlook of Core (excluding food and energy) Personal Consumption Expenditure inflation on March 19, 2014; the average for 2014-2016 was 1.75% and 2.0% thereafter.[55] These inflation rates should also be used to estimate future nominal dollar benefits.

The Applicable Load energy quantity (MWh/year) for calendar year 2012, 2013, and any available forecasts of Applicable Load should be established and made available to potential applicants.[56] Applicants need could utilize this information to evaluate (i) the maximum quantity of ORECs that the Commission could approve; and (ii) the expected customer rate impact ascribable to the propose project.

The 2012 average all-in electric rate ($/MWh, including energy supply, capacity, ancillaries, RPS costs, transmission, and distribution costs) for nonresidential customers will need to be established by the Commission and could be made available to applicants.

Levelized OREC Price

The Levelized OREC Price for a proposed OREC Price Schedule is the price, expressed in 2012 dollars per OREC, which, if inflated at the assumed inflation rate and multiplied by the expected OREC production in each calendar year of the proposed delivery term, would result in a series of payments with the same present value as would the string of payments resulting from the annual products of the proposed OREC Price Schedule and proposed annual OREC production for each calendar year. The Levelized OREC Price can be directly compared to the OREC price cap of $190/OREC and can be calculated per the following equation:

$$\mathrm{LOP} = \sum^{cy} \mathrm{POP}_i * \mathrm{EOA}_i \ / \ (1 + \mathrm{NDRP}) \wedge (i - 2012) \ / $$
$$\sum^{cy} \mathrm{EOA}_i \ * (1 + \mathrm{INF}) \wedge (i\text{-}2012) \ / (1 + \mathrm{NDRP}) \wedge (i - 2012)$$

where

[55] http://www.federalreserve.gov/newsevents/press/monetary/20140319b.htm

[56] The U.S. Energy Information Administration reports total retail electric sales in Maryland in 2012 were 61,813,552 MWh, but this includes the agricultural and industrial process loads that are excluded from Applicable Load.

LOP = Levelized OREC Price (2012 \$/OREC)

$\sum^{cy}$ means the summation over calendar years i from COD through the delivery term

POP_i = Proposed OREC Price for calendar year i (nominal \$/OREC)

EOA_i = Expected OREC Amount (P50) for calendar year i

NDRP = Nominal Discount Rate for OREC Payments

INF = Inflation Rate

Net Ratepayer Cost

Net Ratepayer Cost is the levelized equivalent of the proposed OREC Price Schedule annual payments less the levelized equivalent of the projected stream of annual power market credits, avoided Tier 1 REC purchases, and market price effects, expressed in 2012 dollars per year. Net Ratepayer Cost can be calculated per the following equation:

$$NRC = \sum^{cy} POP_i * EOA_i \ / \ (1 + NDRP) \wedge (i - 2012) \ /$$

$$\sum^{cy} MO_i \ / \ 12 * (1 + INF)\wedge(i\text{-}2012) \ / \ (1 + NDRP) \wedge (i - 2012)$$

$$- \sum^{cy} (MRC_i + ARC_i + MPE_i) \ / \ (1 + NDRB) \wedge (i - 2012) \} \ /$$

$$\sum^{cy} MO_i \ / \ 12 * (1 + INF)\wedge(i\text{-}2012) \ / \ (1 + NDRB) \wedge (i - 2012)$$

where

NRC = Net Ratepayer Cost (2012 \$/year)

$\sum^{cy}$ means the summation over calendar years i from COD through the delivery term

POP_i = Proposed OREC Price for calendar year i (nominal \$/OREC)

EOA_i = Expected OREC Amount (P50) for calendar year i

NDRP = Nominal Discount Rate for OREC Payments

MO_i = Proposed months of operation in calendar year i

INF = Inflation Rate

MRC_i = Market Revenue Credits for calendar year i (nominal \$/year)

ARC_i = Avoided REC Cost for calendar year i (nominal \$/year)

MPE_i = Market Price Effect for calendar year i (nominal \$/year)

NDRB = Nominal Discount Rate for OREC Benefits

Net Ratepayer Cost is applied to the Residential Rate Impact test as follows:

RRI = NRC / AALE * 12,000 kWh/yr / 1000 kWh/MWh / 12 mo/yr

where

RRI = Residential Rate Impact (2012 $/mo)

AALE = Annual Applicable Load Energy (MWh/yr)

Net Ratepayer Cost is applied to the Nonresidential Rate Impact test as follows:

NRRI = NRC / AALE / NRAIR

where

NRRI = Nonresidential Rate Impact

NRAIR = Nonresidential All-In Rate (2012 $/MWh)

Adjustments for Transmission Upgrade Cost

Applicants have the option of avoiding at least some of the risk associated with unknown costs for transmission system upgrades by specifying a two-part OREC Price Schedule. Under this option, the applicant would provide (i) a firm set of calendar year OREC prices covering all revenue requirements except for upgrade cost recovery and (ii) a unit price for upgrade cost recovery based on the Commission's estimated upgrade cost that would be representative of the cost would ultimately developed by PJM through the interconnection study process. By specifying an this second OREC price component, the applicant is, in effect, bidding a firm level annual recovery factor ($ per year of revenue per $ of upgrade cost). When the final upgrade cost is determined, the upgrade cost recovery component of the OREC Price Schedule would be adjusted ("trued up") by the ratio of that final upgrade cost to the proxy upgrade cost, notwithstanding potential adjustments for projects larger than required for its Approved OREC Amount.

The adjusted OREC Price Schedule would remain subject to the $190/OREC (2012 dollars) levelized price cap as well as to the residential and nonresidential rate impact caps (either alone or a combination of projects.) In the event that one of these caps would be exceeded by the OREC Price Schedule adjusted for PJM's upgrade cost estimate, the applicant would have the option of (i) accepting a lower OREC price that would match the relevant cap or (ii) withdrawing the project. Final transmission upgrade costs would not be known for at least two years after selection per an OREC Order, so the applicant would likely have committed significant funds to the project by that time.

The adjustment process is relatively straight forward if only a single OSW project application is approved. As part of the application evaluation process, an upper limit can be determined for transmission upgrade costs, based on the upgrade cost recovery rate implied by the applicant's upgrade cost OREC price component and the expected (P50) annual OREC amount specified in the application for the price cap and for each of the rate impact caps.

If the Commission approves two applications, *e.g.,* one for each of the two lease areas, the transmission upgrade true up process could be significantly more complex. Once approved, the two projects would request interconnection studies by PJM, and PJM would likely combine the studies and ultimately develop a combined transmission upgrade cost estimate. PJM would ordinarily allocate the combined upgrade cost based on the requested capacity of the two projects, and each project would be responsible for paying PJM for its designated share of the upgrade cost. In this case, each project's OREC Price Schedule would be adjusted based on the allocated upgrade cost.

If each project were to satisfy the Levelized OREC Price cap test and the combined projects were to pass the net rate impact tests, there would be no problem – each project would receive its adjusted OREC Price Schedule and would be fairly compensated for its share of the final transmission upgrade costs. On the other hand, if any of the tests are failed, implementation of the true-up could be complicated by the withdrawal of one of the projects. Furthermore, the allocation of upgrade costs by PJM could result in one project failing the price cap test, whereas if the upgrade cost for a single project were lower than the allocated portion of a combined upgrade cost then that project might have satisfied the price cap test.[57] Another possible outcome would have both projects passing the price cap test, while the combination failed either or both of the net rate impact cap tests. In that event, the OREC Price Schedules for both projects would have to be capped and the Commission would have to develop a fair and equitable method of determining how the reduction would be allocated between the projects.

In order to preserve the viability of both projects if two are selected, we recommend that both be required to request PJM interconnections for their project alone and for the combination. This would allow a fall-back position if combined upgrade costs were to force one or both projects out. The Commission will need to set guidelines for allocation of OREC Price Schedule reductions based on combined transmission upgrade costs.

[57] This situation could occur due to the "lumpiness" of transmission upgrades, *i.e.* a single project might have a lower upgrade cost than its allocated portion of the upgrade costs for the combined projects.

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Appendix 9 – Maryland Offshore Wind Energy Act – Levelized Constant Dollar Price Concept

This document provides a simplified explanation and examples of calculating a constant dollar levelized price. The same calculation would be applied (with some complicating factors) to determine a Levelized OREC Price from a proposed OREC Price Schedule for the price cap (2012 dollars) as required by the Offshore Wind Energy Act of 2013 (OWEA). To simplify this explanation, these examples assume that the delivered OREC quantities are identical in each calendar year with first delivery on January 1, 2017 and the quantity is assumed to be one OREC in each year over a twenty year delivery term.

Present Value and Discounted Cash Flow

In addition to changes in purchasing power due to inflation, the promise of a dollar to be received in the future is worth less than a dollar today if there is any uncertainty, *i.e.,* risk, in actually receiving the payment as promised (risk) and because there are opportunity costs associated with giving up the dollar today, *e.g.,* earning risk-free interest. The risk-free interest rate, usually measured by U.S. Treasury yields over a relevant term (or equivalent) is generally higher than the expected inflation rate. Future cash flows are discounted to a "present value" reference point using an annual rate consisting of a risk-free component and a risk adder that depends on the nature of the cash flows involved. The nominal discount rate (NDR) for a particular cash flow type would consist of three components:

$$NDR = (1 + \text{inflation}) * (1 + \text{risk-free real interest}) * (1 + \text{risk adder}) - 1$$

Two streams of cash flows are deemed to be financially equivalent if they have the same present value after discounting to a common reference point using the appropriate discount rate(s).

Nominal (Current) Dollars and Real (Constant) Dollars

Nominal or current dollars are the dollars that are exchanged in a transaction at a given point in time. To compare the purchasing power of dollars at different times, the value of a transaction at one point in time can be translated to its equivalent at another point in time using a price deflator index that measures cumulative inflation such as the GDP implicit price deflator (GDP IPD), Core Personal Consumption Expenditure index (Core PCE), or equivalent. A transaction valued at $100 in 2013 can be expressed in "2012 Dollars" by dividing by the GDP IPD for 2013 and multiplying by the GDP IPD for 2012. In a forward- looking analysis, the 2012 dollar value of a 2018 transaction would be determined similarly using a projection of the GDP IPD index to 2018. When a series of annual cash flows expressed in nominal dollars for the years of the series is converted to a constant dollar or real dollar stream, each year's nominal dollar amount is deflated to the reference year by the corresponding cumulative inflation index value. If the reference year is 2012, then the string of cash flows would be described as being in "2012 constant dollars" or just "2012 dollars".

Levelization of Cash Flows and Prices

The term "levelization" in financial analysis refers to the representation of a string of periodic cash flows or prices as the single value, which if it occurred in each period of a specified term, would be financially equivalent on a present value basis over the entire term to the string of actual values in each period. In a situation where the cash flow in each period is the product of a quantity (number of units) for the period and a price (dollars per unit) for the period, either the periodic cash flow (dollars) or the price can be levelized. If quantity varies significantly from period to period, the levelized price would not have much practical value. If the quantity remains identical over all periods in the term, then the levelized price is simply the levelized cash flow divided by the periodic quantity. For small deviations in periodic quantity, the levelized price can be determined as the ratio of the present value of the cash flow (periodic price x periodic quantity) to the present value of the periodic quantities.

Cash flows or prices can be levelized in nominal terms or in constant dollar (real) terms. In the former, a string of varying nominal dollar amounts is converted to a string of level amounts of nominal dollars over the same term. In the latter, that string of varying nominal dollar amounts is converted to a financially equivalent string of amounts which increase each period by the rate of inflation. This string can be defined by a base year *e.g.*, 2012) and a single value in that year's dollars.

A string of nominal dollar cash prices is converted to a constant dollar levelized equivalent price per the formula below:

$$LP = \sum^{cy} P_i * Q_i \;/\; (1 + NDR) \wedge (i - \text{Base Year}) \;/$$

$$\sum^{cy} Q_i \;*\; (1 + INF)\wedge(i - \text{Base Year}) \;/\; (1 + NDR) \wedge (i - \text{Base Year})$$

where

LP = Levelized Price (BaseYr \$/unit)

$\sum^{cy}$ means the summation over calendar years i for the string term

P_i = Price for calendar year i (nominal \$/unit)

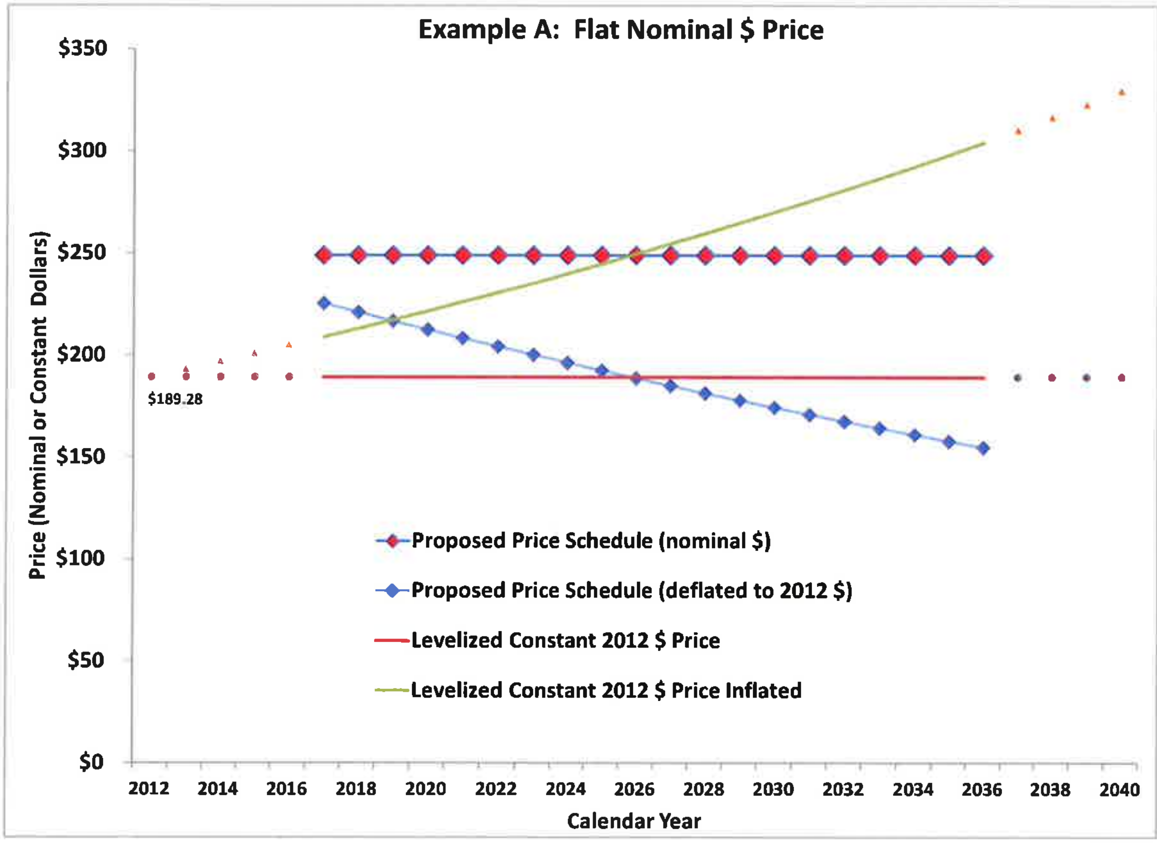
Q_i = Quantity for calendar year i (units)

NDR = Nominal Discount Rate (decimal)

INF = Inflation Rate (decimal)

Examples

In all of the following examples, the Base Year is 2012, inflation from 2012 through 2036 is assumed to be 2% per year, the Nominal Discount Rate is assumed to be 3% per year, the first year of delivery is assumed to be 2017, the term 20 years, and the annual quantity one unit per year. Nominal prices are specified for each of the 20 delivery years as shown in the charts. The levelized 2012 constant dollar price is labeled to the left side of each chart, and plotted over the term, along with representations of the individual nominal prices deflated to 2012 constant dollars and of the levelized constant dollar price inflated to nominal dollars.



In Example A, the proposed price schedule is a level nominal price stream of $249 per unit in each delivery year. This results is a declining series of 2012 constant dollar prices. The levelized price in 2012 constant dollars is $189.28 per unit. If this price is inflated at 2% per year from 2012, it has a lower value than the original nominal dollar price in 2017, but by 2026 the inflated price is above the flat nominal price.

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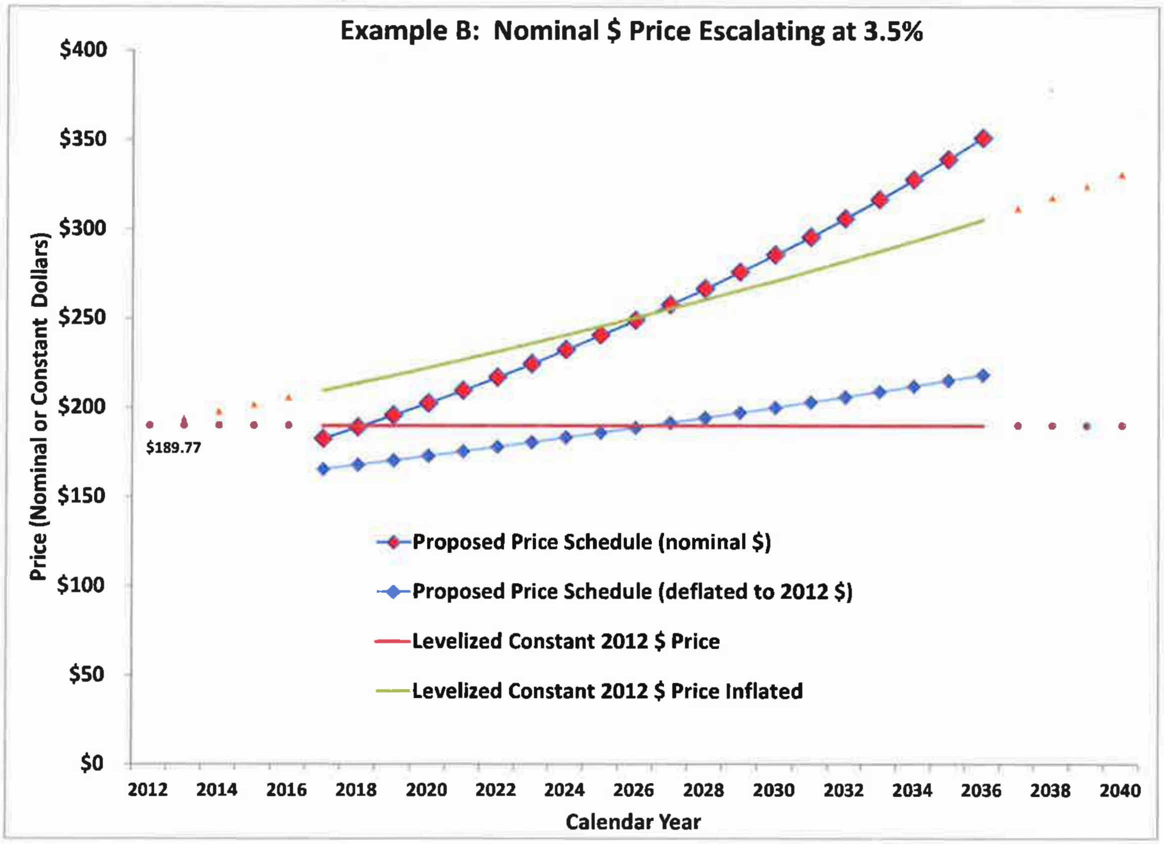
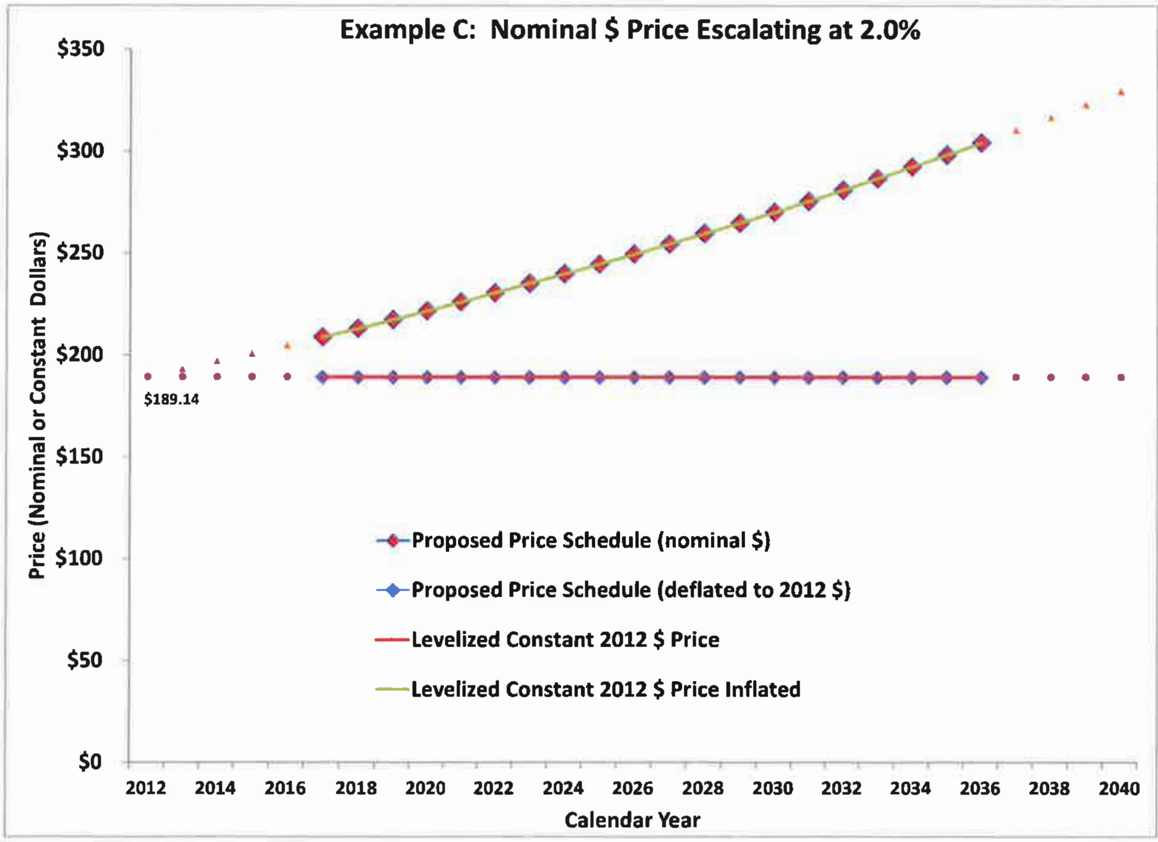


In Example B, the proposed price schedule is nominal price string escalating at 3.5 % per year from a 2017 value of $189 per unit. Since the firm escalation rate is greater than the assumed inflation rate, the string of annual constant 2012 dollar prices increase over the term. The levelized constant 2012 dollar price of $189.77 per unit is above the deflated price line in the early years and above it later on. The inflated string of the levelized constant dollar price is similarly above the original nominal dollar prices for the early years, and crosses below in later years.



In Example C, the proposed price schedule is a nominal price string increasing at 2% per year from a 2017 value of $213 per unit. Each year's price deflates to a value of $189.34 per unit, which is the value of the levelized constant 2012 dollar price. The inflated string of the levelized constant 2012 dollar price matches the original nominal dollar price string.

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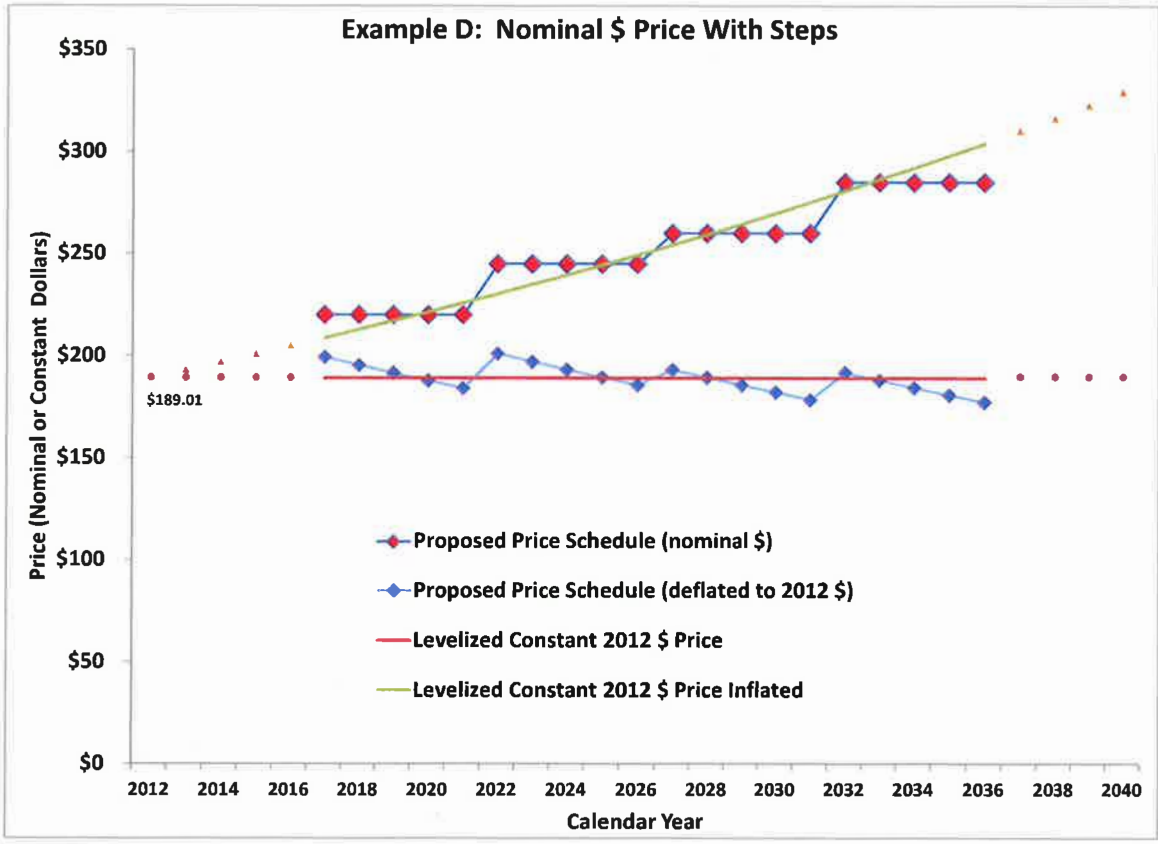

In Example D, the proposed price schedule is a nominal price string consisting of blocks of 5 years with fixed prices in each block. The first block price is $220 per unit, followed by prices of $245, $260, and $285 per unit. The deflated price string in constant 2012 dollars is a set of down-sloping 5-year segments separated by step increases. The levelized constant 2012 dollar price is $189.01 per unit, and the inflated representation of the levelized price is a smooth curve that crosses through the segments of the nominal price string.