**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF DELAWARE**

IN THE MATTER OF INTEGRATED RESOURCE PLANNING FOR THE PROVISION OF STANDARD OFFER SERVICE BY DELMARVA POWER & LIGHT COMPANY UNDER 26 DEL C. § 1007(c) & (d): REVIEW AND APPROVAL OF THE REQUEST FOR PROPOSALS FOR THE CONSTRUCTION OF NEW GENERATION RESOURCES UNDER 26 DEL. C. § 1007(d)
(OPENED JULY 25, 2006)

PSC DOCKET NO. 06-241

# REPORT ON EVALUATION OF BIDS SUBMITTED IN RESPONSE TO DELMARVA POWER & LIGHT COMPANY'S RFP

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***Delaware Public Service Commission***
***Delaware Office of Management and Budget***
***Delaware Energy Office***
***Delaware Controller General***

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***February 21, 2007***

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# I. Introduction

On November 1, 2006, Delmarva Power & Light Company ("Delmarva" or "DP&L") issued a Request for Proposals ("RFP") for the purchase of power under long-term contracts from new generation resources to be built within the State of Delaware for the purpose of supplying standard offer service, as required under the Electric Utility Retail Customer Supply Act of 2006 ("EURCSA" or the "Act"). The RFP was substantially modified from a proposed Request for Proposals filed by Delmarva on August 1, 2006, in response to Order No. 7066 issued October 31, 2006 by the Delaware Public Service Commission ("Commission") and the Delaware Energy Office ("Energy Office"), as modified in certain respects by Order No. 7081 dated November 21, 2006 (the "Orders").

Previously, as directed by the Act,[1] the Commission, the Energy Office (an office of the Department of Natural Resources and Environmental Control), the Office of Management and Budget, and the Controller General ("State Agencies") had retained an independent consultant ("Independent Consultant" or "IC") with expertise in the area of energy procurement to oversee the development of the RFP and to assist the State Agencies in evaluating the bids submitted pursuant to the RFP. Many of the modifications ordered by the Commission and the Energy Office to the RFP were in response to recommendations by the Independent Consultant in a report issued on October 12, 2006 and in response to comments made by participants in the proceeding, including generators who were prospective bidders in the RFP, environmental organizations and members of the public.[2]

The thrust of many of the modifications to the RFP was to allow for more flexibility in the RFP requirements, thereby encouraging a greater number of bidders and proposed projects than would have been expected under the RFP terms and conditions proposed by Delmarva.[3]

Bids in response to the RFP were due on or before December 22, 2006. As is discussed in detail below, three different parties submitted bids by the deadline. The Independent Consultant and Delmarva have been reviewing and evaluating these bids since their submission.

Before discussing the bid evaluations, it is important to observe that this RFP is part of the first Integrated Resource Planning ("IRP") process that Delmarva is required to follow under the Act. In Order No. 7131 (dated February 6, 2007), the State Agencies directed New Energy Opportunities, Inc. (and its subcontractors, La Capra Associates, Inc., Merrimack Energy Group, Inc. and Edward L. Selgrade, Esq.), the Independent

[1] 26 Del C. § 1007(d)(2).

[2] This report followed a draft report dated September 18, 2006 and a redlined markup to Delmarva's proposed RFP dated September 27, 2006; in the report, the Independent Consultant responded to comments made by various participants in the proceeding. The regulatory process, including a public workshop and comments from public participants, is described in Order No. 7066 at 9-14.

[3] Order No. 7066 at 15-16.

Consultant, to review the bids and file an initial evaluation report on or by February 21, 2007. The State Agencies also noted that Delmarva is expected to file its own evaluation report at the same time.

This Report contains the Independent Consultant's evaluation of the bids submitted in response to the RFP. Pursuant to Order No. 7131, the New Energy Opportunities consultant team has also been retained to provide an interim report ("Interim Report") on or by April 4, 2007 to the State Agencies regarding an initial review of Delmarva's IRP, which was submitted on December 1, 2006, "for the purpose of providing a framework within which to consider the results of the RFP evaluation."[4]

The State Agencies will meet on May 8, 2007 to discuss the Interim Report and to provide appropriate direction to DP&L as to whether the Company should initiate negotiations to finalize a contract with one of the bidders responding to the RFP and, if so instructed, should complete negotiations and submit a contract no later than June 15, 2007, for review by the State Agencies for a final decision.

In this overall context, this Report focuses on the evaluation of the bids received in response to the Delmarva RFP. Section II of this Report identifies the bids received and summarizes the bid evaluation process. In Section III, we summarize the bids, address non-conforming aspects of the bids and how they were addressed in the evaluation process, and provide a summary of the bid evaluation results. In Section IV, we provide our assessment of the various project proposals, both from an economic and non-price perspective, and describe the economic evaluation methodology and process. In Section V, we address how contract issues raised by the various bids should or might be addressed in the event the State Agencies decide to direct Delmarva to negotiate a contract with a particular bidder. Our conclusions are set forth in Section VI.

[4] Order at 3-4.

# II. The Bids and the Bid Evaluation Process

## A. The Bids

EURCSA set a December 22, 2006 deadline for the submission of bids in response to the RFP. Three companies submitted a variety of commercial proposals for four different projects that were evaluated.

**Bluewater Wind, LLC ("Bluewater")** submitted bids for power sales from three offshore wind projects, the Atlantic North 600 MW and Atlantic South 600 MW projects and a 546 MW Delaware Bay project. The Delaware Bay project was subsequently withdrawn and is not reviewed in this Report. For both the Atlantic North and Atlantic South projects, Bluewater submitted four commercial proposals, which were differentiated based on contract term ((a) 20 years and (b) 25 years) and contract size ((a) 600 MW with 400 MW energy cap ("600 MW Bid") and (b) 400 MW ("400 MW Bid")).

**Conectiv Energy Supply, Inc ("Conectiv"),** an affiliate of Delmarva Power, proposed the construction of a 177 MW natural gas-fired combined cycle at its Hay Road facility in northern Delaware. Conectiv submitted two proposals -- a "Base" unit-contingent power sale and an "Alternate" unit capacity-based firm energy power sale -- both for 10-year durations.

**NRG Energy, Inc. ("NRG")** proposed to sell energy and unforced capacity credits from 400 MW of a 600 MW coal-fired integrated gasification combined cycle ("IGCC") facility proposed to be built at the Company's Indian River power station in Millsboro, Delaware. In connection with this proposal, NRG offered to shut down its Indian River Units 1 and 2 (collectively, 163 MW) in the event it obtains a power sales agreement with Delmarva Power and the IGCC plant is constructed. NRG submitted three commercial proposals:

- 25-year and 20-year power sales without carbon capture and sequestration;
- 25-year power sales with carbon capture and a sequestration option.

NRG also proposed a 6-year "baseload bridge" power sale proposal from existing coal-fired capacity at Indian River beginning in 2008. Since this proposal was outside the scope of the RFP process, it was not evaluated.[5]

## B. Bid Evaluation Process

The RFP, as approved by the Commission and Energy Office, contained a variety of categories of non-price evaluation factors and several categories of economic evaluation

[5] In the event the State Agencies were to determine that they were interested in proceeding with one of NRG's proposals and were interested in considering the "baseload bridge" option, this proposal could then be evaluated.

factors. The evaluation under the price and price stability categories -- collectively, representing 53 of the 100 potential points in the approved scoring system, was to be conducted by Delmarva's consultant, ICF International ("ICF") using, as a primary tool, its Integrated Planning Model ("IPM").

In our October 12, 2006 report, the IC proposed to conduct a test bid using several different types of proxy generation projects before the actual bids were received, a process approved by the Commission and Energy Office.[6] The purpose was to "gain a perspective on the process and to verify the consistency, efficiency and reasonableness of the modeling methodologies and input assumptions."[7] We went on to state:

> It is important for the integrity of the process that the input assumptions and methodologies be locked down prior to receipt of bids and that assumptions and methodologies do not contain undue bias toward any resource. We recommend that test bidding be conducted unless we agree that it is infeasible to do so within the timeframe and we are otherwise provided with sufficient information and input that we become comfortable with the bid evaluation process, methodologies, and assumptions.[8]

Subsequent to the issuance of the RFP, Delmarva and ICF informed us that there was insufficient time to conduct any form of test bid. As a substitute, they proposed to provide the IC with all of the material input assumptions, explain them, provide outputs for the reference case, and otherwise cooperate with the IC so that we could "become comfortable with the bid evaluation process, methodologies, and assumptions." Given the very limited time to conduct the RFP under EURCSA, we did not disagree regarding the feasibility of a test bid within the allotted timeframe. Instead, we reviewed the material assumptions, agreed on a method to scale the bids (i.e., allocate points), negotiated modifications to the way Delmarva/ICF proposed to implement the price stability analysis approved by the Commission and Energy Office, and prepared to conduct our own spreadsheet analysis of the bids as a means of cross-checking ICF's results. The process and our assessment of Delmarva and ICF's economic evaluation methodology and assumptions are described in more detail in Section IV.B.1 of this Report.

In addition, immediately following the issuance of the Orders and before receipt of the bids, Delmarva and the IC worked together to develop more specificity for scoring within each category and subcategory. This work included development of a combination of more precise metrics where appropriate (such as emissions levels and pricing) as well as identification of factors to be considered for more qualitative factors (such as technology reliability and contract terms).

Also between the time of the issuance of the RFP (November 1) and the receipt of bids (December 21 and 22), Delmarva and its consultant and the IC worked to assist

[6] Order No. 7081 at 71-74.
[7] Report at 54.
[8] Id.

prospective bidders in several different ways. Delmarva created a website with relevant documents and information related to the RFP process, as well as a link to the Commission website and information page where the public could submit questions, comments and concerns. Delmarva expanded this website to include additional public information, while also providing secure sections for potential bidders to submit notices of intent and other documents.

Delmarva hosted a pre-bid conference on November 15, 2006 to present the manner in which the Company intended to evaluate bids and to allow interested parties to ask questions and clarify portions of the RFP. Delmarva's presentation was also provided in the public portion of the website. Potential bidders were required to submit notices of intent to bid ("NOI") by November 22, 2006, along with the location of the planned generating units (which enabled Delmarva to begin its transmission analysis). The final version of the Standard Form Power Purchase Agreement ("Standard Form PPA") was posted on the website for review by the prospective bidders. The Bidder Response Forms specifying the information to be submitted were first posted on November 1, with updates subsequently posted before bids were due.

The three eventual bidders and Invenergy submitted NOIs (Invenergy later withdrew). These potential bidders then submitted more than 100 questions regarding the RFP, which Delmarva, with input from the IC, answered on the website. One bidder, Bluewater, submitted a draft bid by December 8, 2006 in accordance with the RFP so that Delmarva could assess its responsiveness. Delmarva, with the approval of the IC and the Commission Staff, provided feedback regarding compliance with the RFP 400 MW contract size limitation and on areas in which the draft proposal appeared to be non-responsive.[9] The bidders submitted their final proposals to Delmarva by December 22, 2006 (Conectiv, an affiliate of Delmarva, submitted its proposal on December 21, 2006, as required by the RFP).

Following the receipt of bids, Delmarva, ICF and the IC prepared and sent a list of questions for the bidders seeking clarification on a number of matters in their bids to assist in the price evaluation, non-price evaluation, and in determining whether the proposals met the threshold requirements set forth in the RFP. Each party submitted timely responses. On January 5, 2007, Delmarva, the IC and the Commission Staff responded to each of the bidders, stating that their proposals would be moved to the detailed evaluation phase, while indicating areas in which the bids were not in conformance with the requirements of the RFP. As will be addressed elsewhere in this Report, each of the bids was non-conforming with the requirements of the RFP in one respect or another.

During January and into early February, further information was exchanged between the reviewing parties and the bidders by way of written questions and answers and various telephone conversations. These exchanges covered areas where further clarification was needed in order to complete the detailed project scoring. In addition during this time,

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[9] Bluewater subsequently filed an emergency motion requesting that the Commission and Energy Office address this issue, but the Agencies deferred the matter and directed Delmarva to evaluate the proposal.

DP&L, its consultant and the Independent Consultant had frequent discussions concerning the evaluation of each proposal.

Price evaluation and non-price evaluation of the bids were conducted separately. For the non-price categories, the Independent Consultant developed scoring for each project in each category. These category scores were then compared across all bids to ensure that the scoring was consistent. Discussions were held with Delmarva's lead consultant on the non-price evaluation to compare results. As the process progressed, there were some adjustments to the non-price evaluation, but they tended to be relatively minor.

The IC's economic bid evaluation involved: a combination of: a review of Delmarva/ICF's bid evaluation methodology and assumptions; a review and correction of how Delmarva/ICF evaluated the bidders' price formulas and how they applied appropriate quantities to prices; a request for and use of an ICF model run based on certain alternative assumptions; and a separate evaluation of the bids conducted by the IC as a cross-check on ICF's evaluation.

This Report presents the IC's evaluation of the proposals, including a summary of differences between our assessments and Delmarva's and their relative significance. In the Report's concluding section, we outline some questions regarding the RFP in relation to Delmarva's IRP that will be addressed in greater detail in a follow up report due in early April (the "Interim Report" previously referenced) prior to an expected State Agency decision on these proposals.

# III. Important Features of the Bids and Summary of Bid Evaluation Results

This Section provides a more detailed description of the bids received, explains how non-conforming aspects of the proposals were addressed in the bid evaluation, and summarizes the bid evaluation results with reference to the scoring system set forth in the RFP. A detailed discussion of the bid evaluation and economic evaluation methodology and process is set forth in Section IV of this Report.

## *A. Description of Bids*

As previously indicated, three companies submitted a variety of bids in response to the RFP:

1. **Bluewater** proposed offshore wind projects for three different locations. For two locations in the Atlantic Ocean approximately 7 to 13 miles off the Delaware coast, Bluewater proposes wind projects each having a nameplate capacity of 600 MW utilizing 200 3-MW wind turbines. These projects are named Atlantic North and Atlantic South. (For one location in the Delaware Bay, Bluewater proposed a project with a nameplate capacity of 546 MW utilizing 182 3-MW turbines; this proposal was withdrawn on January 22, 2007.)

   For each of the two locations still under consideration (Atlantic North and Atlantic South), Bluewater proposes four contract options: (i) a contract for all the energy and unforced capacity credits ("UCAP") from the entire project -- 600 MW of nameplate capacity -- with a cap on energy sales of 400 MWh in any hour (with either a 25-year term or a 20-year term); and (ii) a contract for two-thirds of the energy and unforced capacity credits from the 600 MW project, i.e., the energy and unforced capacity credits from 400 MW of nameplate capacity (with either a 25-year term or a 20-year term). In option (i), Bluewater proposes to sell any energy output in excess of 400 MWh in any hour to other buyers. In option (ii), Bluewater proposes to sell all energy output and unforced capacity credits associated with the nameplate capacity in excess of 400 MW to other buyers. Under any of these four commercial proposals, Bluewater proposes to sell the maximum amount of renewable energy credits ("RECs") allowed under the terms of the RFP, approximately 10% of the RECs produced by the project, with the remaining RECs to be sold to other buyers. Bluewater proposes fixed pricing for energy, UCAP and RECs, with a fixed escalation rate equal to the same projected inflation rate used by Delmarva in its IRP filing.

2. **Conectiv** proposed a 177 MW combined-cycle project that has dual-fuel capability, with natural gas being the primary fuel. The project will be located at the existing Hay Road Power Complex in New Castle County, Delaware where there are already eight generation units.

Conectiv is offering two alternative commercial proposals. The first alternative (the "Base Offer") is a unit contingent sale under which DP&L receives all the products (energy and capacity) associated with the project, and DP&L will have the rights to dispatch the project. The second alternative (the "Alternate Offer") is an asset backed capacity agreement with firm energy where DP&L will receive the capacity and ancillary service revenue associated with the project, but Conectiv will retain control over the project's dispatch. The source of the energy dispatched by DP&L would be determined by Conectiv. While the proposed price formulas are similar for both commercial proposals, the proposed capacity prices under the Alternate Offer are significantly lower reflecting the value to Conectiv in the optionality around the sourcing of the energy to Delmarva. However, under both proposals, Delmarva would have the right to determine whether it desired to purchase energy at the formula prices based on economics and defined operating constraints.

The pricing associated with Conectiv's commercial proposals has several unusual features for a power contract involving a natural gas-fired combined cycle facility. First, for both its base and alternate offers, Conectiv proposes a one-time adjustment to one-third of its proposed capacity rates and 100% of its base mode energy price (152 MW) during on-peak hours ("Base Energy") based on the ratio of the average 60-month forward NYMEX Henry Hub gas prices ("Forward Gas Price") on the date after all regulatory approvals are obtained for the contract (and, as Conectiv subsequently clarified, all appeal periods have passed) divided by the Forward Gas Price on December 20, 2006. Second, for the Base Energy block, after one year the resulting adjusted price is in turn adjusted annually based on changes in the Gross Domestic Product Implicit Price Deflator and a coal-based index.[10]

In response to questions regarding its rationale for the one-time price adjustment, Conectiv stated that it plans to enter into a long-term hedge (purchase or swap or other financial transaction) involving natural gas for at least a portion of the natural gas that would be used during on-peak hours and the one-time price adjustment is intended to protect Conectiv against significant increases in natural gas forward (future) market prices which would be related to the cost of this hedge (a decline in prices would benefit Delmarva SOS customers). Conectiv has told us that it would not plan to hedge its risk until it is sure that it has a firm purchase contract, when a contract is signed, regulatory approvals are obtained, and the regulatory approvals are no longer appealable. Conectiv states in its proposal that its indexation to inflation and coal is intended to provide the price stability sought in the RFP. Usually, power from natural gas combined cycle units is priced based on the cost of natural gas; therefore, its cost to buyers tends to track wholesale electric power prices since natural gas-fired facilities tend to set market prices, at least during on-peak hours in Eastern PJM.

[10] For the off-peak hours and for a 25 MW block of energy above 152 MW, energy is priced off a daily delivered (city-gate) natural gas index, which is a more conventional pricing method for natural gas projects.

Conectiv also proposed an option on the part of Delmarva to extend the proposed power purchase agreement for an additional five years following the end of the proposed 10-year term.

3. **NRG** proposed the sale of energy and UCAP from 400 MW of contract capacity from a proposed 600 MW integrated gasification/combined cycle plant. This project would be built in Millsboro, Delaware adjacent to the site of several other NRG generation units.

   NRG is offering various alternatives. First, they are offering either a 20-year or 25-year contract. In both versions, the first 280 MW of output would be sold on a "must take" basis. NRG would provide Delmarva with the ability to "virtually turn down" the next 120 MW of output (30% of the total 400 MW), allowing some flexibility in determining the volume of energy received but retaining plant dispatch with NRG. As a separate commercial proposal, NRG is offering to add carbon capture (and if chosen, sequestration) equipment for additional capacity payments. All of NRG's proposals involve the sale of unit contingent power.

   Under its base 20-year and 25-year commercial proposals, NRG's proposed capacity payments would be adjusted annually based on changes in the Consumer Price Index -- Northeast ("CPI-NE"). Energy prices for both Tier 1 (the first 280 MW) and Tier 2 (the next 120 MW) would be adjusted based on changes in the CPI-NE and a coal-based index.

   For the carbon capture and sequestration ("CCS") proposal, there will be an additional capacity charge to reflect the cost of carbon capture. This incremental capacity charge would also be subject to an adjustment based on changes in the CPI-NE index. For the cost of sequestration, NRG proposed an additional capacity charge that would be based on a pass-through of costs incurred for establishing and maintaining sequestration of carbon dioxide. NRG provided a general estimate of those costs.

## *B. Non-Conforming Aspects of the Bids; How They Were Addressed in the Bid Evaluation*

As indicated previously, each of the bids fails to conform to the RFP requirements in certain respects. These requested deviations from the RFP terms and conditions would alter the risk profile for Delmarva and its customers and are important considerations in evaluating and comparing the bids. Therefore, before discussing the specific evaluations, we first identify the material non-conformities and address how non-conforming price-related proposals were addressed in the bid evaluation. In Section V, after providing detailed discussion about the bids, we discuss these issues in greater detail and recommend approaches to be considered for each bid should the State Agencies determine to direct Delmarva to negotiate a power purchase agreement based on that bid.

## 1. Bluewater

Bluewater's proposals contain two significant non-conformities with the RFP requirements:

**a. Contract Size.** The Bluewater commercial proposals to sell energy and UCAP from 600 MW of nameplate capacity with a 400 MW energy cap (600 MW proposals) raise issues of non-conformity with the 400 MW contract size limitation set forth in the RFP.

**b. Security.** In response to questions from Delmarva and the IC, Bluewater stated that it proposes to provide substantially lower levels of security and liquidated damages than required, based on its interpretation of the RFP.[11]

## 2. Conectiv

Conectiv's bid contains five significant non-conformities with the RFP requirements:

**a. Security.** Conectiv proposes to provide financial security or a second lien on the proposed plant but not both; both are non-negotiable contract provisions under the RFP.

**b. Permitting Risk.** Conectiv proposes a return of all of the development period security if it cannot obtain its permits; the RFP provides, at best, a return of 50 percent of the development period security in the event of a failure to obtain permits.

**c. One-Time Pricing Adjustment Provisions.** Conectiv's proposed natural gas-based one-time pricing adjustment does not conform to the RFP specifications, at least for capacity prices, and raises concerns about the energy pricing. Under the RFP, capacity payments are to be fixed prices, with bidders allowed to index portions of the capacity charge related to fixed O&M costs to an inflation index and a one-time adjustment of up to 15% of the capacity charge to a steel index to allow for adjustments to volatile steel prices for up to two years until a construction contract is signed; provided, that the bidder agrees to cap any potential increase.[12] Bidders were given more flexibility on energy price indices to allow their prices to track their costs, but were requested to contact Delmarva if the bidder was uncertain whether a certain index was allowable.[13] At least from our perspective, we did not envision use by bidders of a one-time price adjustment based on natural gas prices and the proposed pricing mechanism raises issues as to its potential impact on Delmarva's customers.

[11] Orally, Bluewater's president stated that Bluewater would provide the amount of security that the State Agencies determine is required pursuant to the RFP.
[12] Final Report at 41-42; RFP Instructions to Bidders Section 2.3.1.
[13] Final Report at 42; RFP Instructions to Bidders 2.3.2.

**d. Greenhouse Gas Regulation Compliance Costs.** The RFP and the Standard Form Power Purchase Agreement provide that the Seller shall be responsible for all present and future environmental compliance costs, but in the event that a change in law occurs which imposes future environmental compliance costs in the form of a Btu or carbon tax, the Seller would be allowed (if the bidder elected this pricing option) to recover only that portion of the Btu or carbon tax that is equivalent to the amount of tax attributable to the average level of emissions subject to the tax in the Eastern PJM market.[14] In its bid, Conectiv excepted to the Standard Form contract seeking full recovery of any Btu or carbon taxes. In response to subsequent questioning, Conectiv stated that it would take responsibility for compliance with the Regional Greenhouse Gas Initiative ("RGGI") but would expect to recover as a pass-through any additional costs associated with more stringent regulation.

**e. Alternate Offer.** The Standard Form PPA (Section 3.9) provides that a seller offering firm power may provide energy from a source other than the unit under contract if the unit is unavailable. As part of its Alternate offer, Conectiv proposes that it have the flexibility to provide energy from another source regardless if the proposed 177 MW unit is unavailable. In return for this flexibility, Conectiv proposed capacity pricing that is substantially lower than it proposed for its Base offer.

## 3. NRG

NRG's bid contains four significant non-conformities with the RFP requirements:

**a. Greenhouse Gas Compliance Costs.** NRG proposed an exception from the Standard Form PPA provisions that require the Seller to absorb any additional environmental compliance costs caused by a change in law. Specifically, NRG proposed that it be allowed to pass through to the Buyer "an agreed portion" of such costs. In follow up discussions and correspondence, NRG clarified its intended meaning of "an agreed portion." NRG responded that to the extent under RGGI or under any other program of carbon dioxide regulation, NRG receives allowances by allocation based on base year emissions for Indian River units 1 or 2 (which NRG is proposing to shut down in connection with the contracting by Delmarva Power for the proposed IGCC plant and the construction and commercial operation of the new plant), NRG would allocate two-thirds of such no-cost allowances (representing two-thirds of the energy and capacity Delmarva would purchase from the IGCC plant) to the Delmarva contract, so that there would be no costs to pass through for an equivalent amount of tons of $CO_2$ emissions from the IGCC plant.

**b. Financing Risk.** The Commission and the Energy Office approved the insertion of a non-negotiable contract provision that would allow Delmarva the right to terminate the contract if at any time during the term of the contract Delmarva's

[14] RFP Key Commercial Terms of Power Purchase Agreement ("Term Sheet") at 14-15; Standard Form PPA Sections 3.6 and 9.2

independent outside auditing firm determines that Delmarva must consolidate Seller on its financial statements under Financial Accounting Standards Board ("FASB") Interpretation No. 46 ("Fin. 46 Consolidation Termination"). While NRG has not proposed to substantially amend the pertinent provision of the Standard Form PPA (Section 12.4), NRG has proposed a "financing out" clause, i.e., if it cannot finance the project, it would have the right to terminate the agreement, and, if the inability to obtain financing is due to the existence of Delmarva's right to terminate due to the Fin. 46 Consolidation Termination clause, NRG would be entitled to the return of all development period or operational period security. In addition, in the event NRG cannot finance the project for any other reason, NRG proposes that it be entitled to terminate the project while paying a termination fee of $20 million ($50 per kW), which is 50 percent of the required development period security of $40 million ($100 per kW).

**c. Charges Associated With Carbon Dioxide Sequestration.** With respect to its carbon capture/sequestration option proposal, NRG's proposed pricing for sequestration is essentially a cost pass-through proposal that is inconsistent with the RFP requirements. NRG provided a cost estimate for sequestration, which it indicated would be included as an additional capacity charge.

**d. Capacity Charge.** NRG's proposes to adjust the full amount of its proposed capacity charges to an inflation-based based index. The RFP allows indexation of capacity charges, but not for the entire amount of the capacity charge.[15]

## 4. Approach in Bid Evaluation

Consistent with what the Commission and Energy Office approvingly termed as the "big funnel" approach, Delmarva and the IC evaluated the bids as proposed.[16] However, the economic evaluation of the bids was adjusted to assure that the full cost of future carbon dioxide regulatory compliance would be properly evaluated in the context of Conectiv's and NRG's proposals to pass through at least a portion of the costs of carbon dioxide regulation costs to Delmarva and its customers. In evaluating the bids as proposed, however, neither Delmarva nor the IC accepted any of the proposed non-conformities from RFP requirements. Whether they should be accepted, rejected, modified or otherwise conditioned is a matter that we address in Part V of this Report.

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[15] See RFP Instructions to Bidders Section 2.3.1.

[16] See Order No. 7066 at 24.

## *C. Summary of Bid Evaluation Criteria and Results*

### 1. Bid Evaluation Framework

The State Agencies, in determining whether to approve any of the proposals submitted pursuant to the RFP, were directed by the Legislature to consider whether a proposal "result[s] in the greatest long-term system benefits," including those specifically set forth in EURCSA, "in the most cost-effective manner."[17] Benefits to be considered include those flowing from proposed projects that use new or innovative technologies, provide environmental benefits, use existing infrastructure, promote fuel diversity, use existing industrial sites, and support or improve reliability.[18] Selection criteria in the RFP were to include price stability, siting feasibility, and contract terms and conditions.[19] The RFP is a component of Delmarva's first IRP. In preparing the IRP, Delmarva is directed to "systematically evaluate all available supply options during a 10-year planning period in order to acquire sufficient, efficient and reliable resources over time to meet its customer needs at a minimal cost."[20]

The RFP, as approved by the Commission and the Energy Office in the Orders, provides for a multi-faceted evaluation of the bids based on three overarching categories or "supercategories." These are:

(a) Economics, of which price and price stability are the major components;

(b) Favorable Characteristics, of which the largest component is environmental, but which also includes fuel diversity and technology innovation; and

(c) Viability, which pertains to the likelihood that the project will be built and operated as proposed, so that the economic, environmental and other benefits identified in the first two categories may be realized.

Within each of these supercategories are a variety of categories and subcategories, each with points allocated to them such that the maximum theoretical number of points a project could receive is 100 points.

The point allocation system is a guide, albeit an important one, to bidders, the bid evaluators and the State Agencies. However, recognizing that "point systems are not infallibly precise," the Commission and Energy Office adopted our recommendation to allow the exercise of judgment within the context of the point system with supercategories as a framework, concluding that "we prefer to have the flexibility to go outside the bare numbers if the State Agencies think that would be appropriate."[21]

The RFP provides for an allocation of points by category. Following issuance of the Orders and the RFP, Delmarva and the IC worked cooperatively to refine this scoring

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[17] 26 Del C. § 1007(d)(3).
[18] 26 Del C. § 1007(d)(1).
[19] 26 Del C. § 1007(d).
[20] 26 Del C. § 1007(c)(1).
[21] Order No. 7066 at 51-52.

approach, including the allocation of points within subcategories of the categories. Below in Table 1 is a summary of the categories and subcategories, with the maximum potential scores within each category and subcategory.

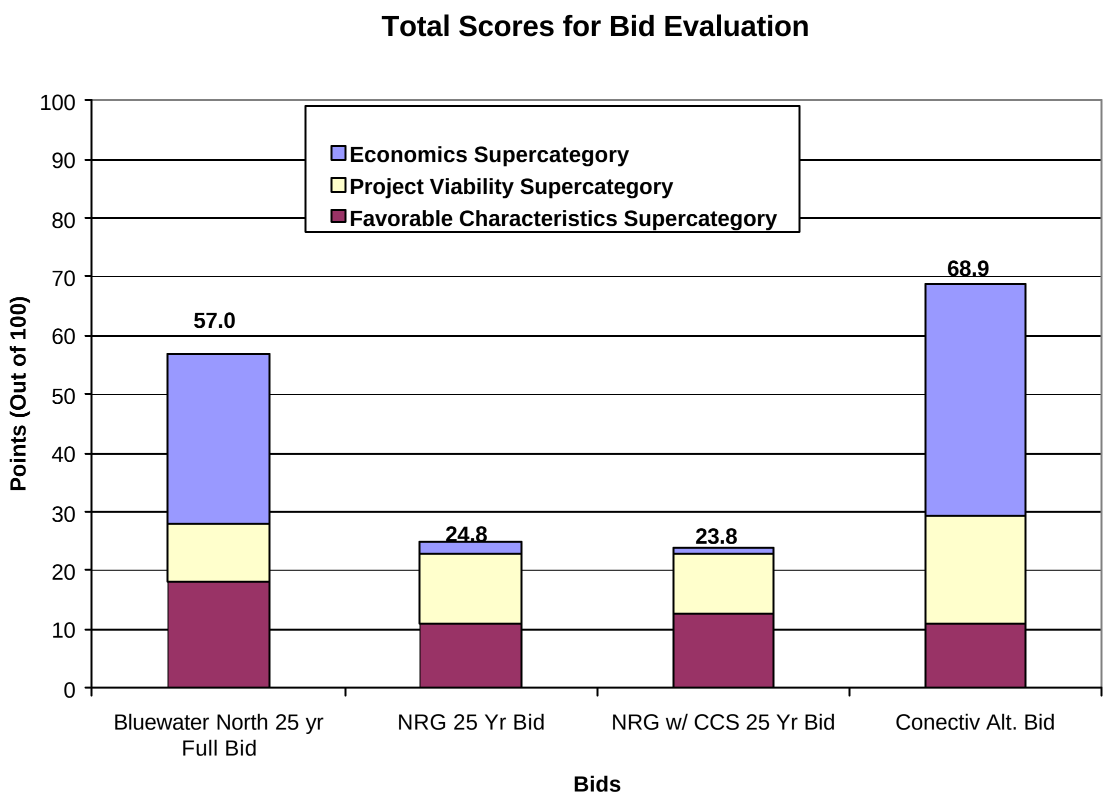
**Table 1: Categories and Related Scores**

| Supercategory Max Scores | Categories and Subcategories | | | Subcategory Max Scores | Category Max Scores |
|---|---|---|---|---|---|
| ***Favorable Project Characteristics (20 points maximum)*** | i. | Environmental Impacts | | | **14** |
| | | *i.1* | *Greenhouse Gases* | 4 | |
| | | *i.2* | *Criteria Pollutants* | 4 | |
| | | *i.3* | *Water, Land, Wildlife, and Waste Disposal* | 6 | |
| | ii. | Fuel Diversity | | | **3** |
| | iii. | Technology Innovation | | | **3** |
| ***Project Viability (20 points maximum)*** | iv. | Operational Date and Certainty | | | **3** |
| | v. | Reliability of Technology | | | **2** |
| | vi. | Site Development | | | **5** |
| | | *vi.1* | *Siting Plan* | 3 | |
| | | *vi.2* | *Brownfield/Industrial Site* | 1 | |
| | | *vi.3* | *Socio-economic Issues* | 1 | |
| | vii. | Bidder Experience | | | **5** |
| | viii. | Financeability | | | **5** |
| ***Economics (60 points maximum)*** | ix. | Price | | | **33** |
| | x. | Price Stability | | | **20** |
| | xi. | Exposure | | | **6** |
| | | *xi.1* | *Contract Size* | 2.5 | |
| | | *xi.2* | *Credit Rating* | 1.5 | |
| | | *xi.3* | *Years of Contract* | 1 | |
| | | *xi.4* | *Operational flexibility and Cap. Factor* | 1 | |
| | xii. | Contract Terms | | | **1** |
| | | | | **Total** | **100** |

## 2. Summary of Bid Evaluation Results

A summary of the scoring results for the best scoring bids from each bidder and NRG's CCS bid is set forth below:

**Figure 1: Total Scores for Bid Projects**




As might be expected, Bluewater was ranked highest on Favorable Characteristics due primarily to the fact that it is a non-emitting renewable resource. Similarly, it also scored highly for contributing to fuel diversity and its use of innovative technology. The other bidders' scores were significantly below Bluewater's, with scores similar to each other.

In terms of Project Viability, Conectiv's bid scored substantially higher than that of Bluewater or NRG. Conectiv's proposed conventional gas-fired combined cycle project would be far easier to develop, finance and build than an offshore wind project or IGCC plant. In addition, Conectiv has more financial strength than the other bidders as well as more experience, at least with respect to the planned projects. Moreover, the Conectiv proposed project is at an existing site, as is NRG's, and should be relatively straightforward to permit.

In the Economic evaluation supercategory, Conectiv had the highest ranking bid, with Bluewater ranked second and NRG ranked third. From a price perspective, the Conectiv bid is expected to produce substantially lower costs for SOS ratepayers than either the

Bluewater or NRG bids, although, as discussed below, the Conectiv bid has a minimal score on price stability. The Conectiv bid, under both ICF's reference case assumptions as well as a case with modified assumptions recommended by the IC, resulted in SOS wholesale costs that are modestly higher than a portfolio supplied completely from the market, because the direct costs associated with the bid were evaluated as being somewhat higher than market prices but most of the energy purchases to meet SOS needs under the Conectiv bid scenario are still purchased through the market.

There are several explanations for the lower price scores for Bluewater and NRG's bids. First, offshore wind projects are very capital intensive, with installed costs substantially higher than most other generating projects, including onshore wind projects. Similarly, IGCC projects are more capital intensive than natural gas projects and conventional coal technologies. In addition, even coal-based IGCC projects (without CCS) produce about double the carbon dioxide emissions than a natural gas combined cycle. Due to the uncertainty around future regulation of carbon dioxide, NRG proposed that Delmarva and its customers would incur most of these costs at then-market rates. Since the evaluation process assumed future regulations would result in material cost increases for carbon dioxide allowances over time, this significantly increased the bid cost of NRG's IGCC. Even though NRG did propose an option that would include carbon capture and sequestration, the IC determined that the total cost of that option would be greater than the NRG option without CCS based on the cost of CCS and the forecasted cost of carbon dioxide allowances.

Given the cost structure of the bids, a key advantage of the Conectiv bid is its much smaller size and the greater operating/dispatch flexibility Delmarva would have in deciding whether to purchase energy under the contract. A smaller project like Conectiv's results in a lower overall SOS costs because more of the SOS supply is assumed to come from low cost market purchases, which may or may not materialize. Conectiv's bid received a higher total score due to its more cost-effective bid, smaller size, Conectiv's parent company's investment grade credit rating, shorter contract term (10 years), and operational flexibility.

However, from a price stability perspective, Conectiv received less than a point. Bluewater's bid, on the other hand, was superior since its pricing structure contains only fixed (albeit escalating) prices.

To put the choices for the State Agencies in perspective, the market rate for wholesale capacity and energy available to SOS customers over the period for which the bids proposed to provide power (2011-2038) is estimated by ICF[22] to be in the range of \$86/MWh levelized in 2005 dollars (taking into consideration inflation at an annual rate of 2.5 percent). The Conectiv bid is evaluated as producing a SOS customer cost of \$87/MWh levelized in 2005 dollars. The Bluewater and NRG bids are projected to cost approximately \$12-\$15/MWh levelized in 2005 dollars more than the market rate. Since \$1.00/MWh is equal to 0.1 cents per kWh, this means that in 2005 dollars, the additional

[22] The costs reported herein are based on model runs conducted by ICF with certain changes in coal and gas price assumptions, with additional post-model adjustments that the IC deemed more likely to be accurate.

cost to ratepayers of going forward with a Bluewater or NRG contract is on the order of 1.2 to 1.5 cents/kWh levelized in 2005 dollars. We address this matter in more detail in our discussion of the economic evaluation of the bids.

In the next Section, we provide a detailed review of the scoring of each of the bidders' proposals and our associated analysis.

# IV. Assessment of Bids

In this Section, we provide our assessment of the bids and associated scoring on a category-by-category basis for each project. First, we discuss the non-price evaluation and scoring by project (in addition to the Favorable Characteristics and Viability categories, we also address the Exposure and Contract Terms, although they are grouped in the Economics supercategory). When a bidder has submitted multiple bids, distinctions on scoring among the bids are highlighted as appropriate. Next, we address the economic evaluation, including our assessment of the bids and the methodology and process used in arriving at our assessment. Finally, we discuss and compare the bids in the context of the "supercategories" of economics, favorable characteristics, and viability. We note that while there are differences between our assessment and scoring of these matters with that of Delmarva in particular categories, the two evaluations are substantially similar overall.

**Table 2: Summary of Non-Price Evaluation**

| Categories and Subcategories | Bluewater North/South | NRG without CCS | NRG with CCS | Conectiv |
|---|---|---|---|---|
| **Favorable Characteristics Supercategory** | **18.2** | **11.1** | **12.7** | **10.8** |
| i. Environmental Impacts | 12.2 | 6.6 | 8.2 | 10.3 |
| ii. Fuel Diversity | 3.0 | 1.5 | 1.5 | 0.5 |
| iii. Technology Innovation | 3.0 | 3.0 | 3.0 | 0.0 |
| **Project Viability Supercategory** | **9.9** | **11.8** | **10.3** | **18.5** |
| iv. Operational Date and Certainty | 1.0 | 0.0 | 0.0 | 2.0 |
| v. Reliability of Technology | 1.5 | 1.0 | 0.5 | 2.0 |
| vi. Site Development | 2.4 | 4.3 | 4.3 | 5.0 |
| vii. Bidder Experience | 3.5 | 3.0 | 2.5 | 5.0 |
| viii. Financeability | 1.5 | 3.5 | 3.0 | 4.5 |
| **Total for Non-Price Evaluation** | **28.1** | **22.9** | **23.0** | **29.3** |
| **Economics (Partial)** | **0.6** | **0.8** | **0.8** | **5.9** |
| xi. Exposure | 0.25 | 0.5 | 0.5 | 5.5 |
| xii. Contract Terms | 0.3 | 0.3 | 0.3 | 0.4 |

## *A. Non-Price Evaluation*

### 1. Bluewater

As noted above, Bluewater has proposals to develop 600 MW of offshore wind at either of two Atlantic Ocean sites that it has named Atlantic North and Atlantic South. In addition, Bluewater has two different contract size proposals for each site. The non-price scoring factors are the same for each of the four site/pricing options.

## Favorable Characteristics Supercategory

As discussed previously, Bluewater's proposals score highly in the Favorable Characteristics supercategory, obtaining 18.2 out of a possible 20 points.

(i) Environmental Impact (12.2 points out of 14 points maximum)

As would be expected for a wind project, the Bluewater proposals score well on environmental impact, receiving 12.2 of the 14 points available. Since the Bluewater projects would have no greenhouse gas or criteria pollutant emissions, Bluewater receives the maximum 4 points available for each of these two subcategories. Of the 6 points available for the water, land, wildlife and waste disposal subcategory, Bluewater receives 4.2 points. This score consists of the full 1.5 points available for water impacts and waste disposal; 0.4 points out of the 1.5 available for land impact; and 0.8 points out of the 1.5 available for wildlife impact.

Bluewater receives full score for water impacts since it would neither consume nor discharge water. Similarly, the Bluewater projects would have no material waste disposal and receive the full 1.5 points available for that criterion.

The land impact score of 0.4 out of 1.5 includes a 1 point deduction since the generating facilities would not be co-located at an existing brownfield or industrial site and a 0.1 deduction for the surface acreage being disturbed. Bluewater sought to obtain some credit for the brownfield/industrial location by identifying its proposed use of a land-based staging area in a brownfield/industrial location. However, the intent of this component is to focus on the generating facility location. The Bluewater proposals are not at a brownfield or industrial site, but rather at currently unoccupied ocean locations; thus, we decided not to award points for this land impact factor. There can be a healthy debate about the acreage being disturbed by a wind project. On the one hand, the actual amount of surface area occupied by the turbines would be small; on the other hand, the turbines would be spread out over approximately 30 square miles. We gave most weight to the surface area occupied as other uses of the surface will clearly remain available after a project is constructed. Nonetheless, the geographic extent of the proposed projects would cause some surface area disturbance, so 0.4 of the 0.5 points available was awarded for this factor.

Bluewater's wildlife score is 0.8 out of a possible 1.5. In scoring this subcategory, we focused on the physical project's impact on wildlife habitat.[23] Bluewater's proposal provides an excellent discussion of the issues to be considered for this subcategory and fairly notes that the wildlife impact is uncertain as studies need to be performed. The project will have potential impact during construction and operation given the project's scope. We decided to score the proposals at 0.8 to reflect potential fishing and fisheries benefits as well as potential negative wildlife impact (avian and marine) that will need to be reviewed in permitting.

[23] The other environmental characteristics, such as no emissions, are addressed in other subcategories.

(ii) Fuel Diversity (3 points out of 3 points maximum)

As renewable energy projects, the Bluewater proposals receive the full 3 points available for this category.

(iii) Technology Innovation (3 points out of 3 points maximum)

As offshore wind projects, the Bluewater proposals also receive the full 3 points for technology innovation.

**Project Viability Supercategory**

In terms of project viability, our greatest concerns are uncertain site development rules with implications for timely project development, and particularly, the overall financeability of the project. Bluewater's score in this supercategory is 9.9 out of a possible 20 points.

(iv) Operational Date (1 point out of 3 points maximum)

Bluewater has projected that half of each project would be on-line in early 2011, with the other half coming on-line in early 2012. Under the scoring standard, this would result in a score of 1.5 for this category subject to a judgment as to the likelihood that the dates identified by the bidder are realistically achievable. Bluewater's timetable is potentially achievable. However, in our opinion, there is also a reasonable potential for delay in many respects based on observations of other wind projects, especially offshore proposals. Issues that have routinely caused delay of eastern wind projects include the need to develop rules for offshore development, evolving rules and markets for project output including energy, capacity, and RECs, and public opposition that delays the permitting process. To reflect the likelihood of some delay for the Bluewater proposals, we deducted 0.5 points and awarded the proposals 1.0 point for this category.

(v) Technology Reliability (1.5 points our of 2 points maximum)

Bluewater receives 1.5 of the 2 points available for this category. The proposed turbine manufacturer has been the world leader in turbine supply since the 1980's including the installation of a number of offshore sites in recent years. However, the history of large-scale offshore wind energy generation is relatively short, and there are no operating projects in North America. While Bluewater correctly reports that there are a number of such projects in Europe, published reports[24] have identified some performance issues at a number of these sites, and we, therefore, decided not to award full credit for technology reliability to these proposals.

[24] For example, "Windpower Monthly," a leading industry trade journal, recently noted the challenge of gearbox failures on larger offshore turbines. November, 2006, at 54.

(vi) Site Development (2.4 points out of 5 points maximum)

Bluewater scores 2.4 on this category, consisting of 1.5 out of 3 points for its siting plan and 0.9 out of 1.0 points for its socio-economic impact. As noted above, Bluewater is not awarded the additional point available in this category for co-locating at an existing brownfield or industrial site.

The factors considered in scoring the siting plan are site control, including needed transmission corridors and site access, the fuel supply and interconnection plan, and the permitting plan. The application of those factors to the Bluewater proposals requires considerable judgment. For example, as the sites Bluewater proposes are in federal waters, the rules for use of those sites are still being developed by the U.S. Department of the Interior's Minerals Management Service. At this time, Bluewater has done as much as it can to pursue the sites, but it cannot claim full site control. Similarly, while Bluewater has utilized substantial available data to estimate the wind resource at its proposed sites, it will need to install specific monitoring at the sites to verify the site specific wind characteristics. With regard to permitting, Bluewater has provided a detailed listing of its plan; however, permitting for offshore wind projects is still evolving and the final rules from the Minerals Management Service, which will be the lead federal permitting agency, are yet to be issued. Taking all of these factors into account produces the overall assessment that Bluewater is as far along as can be expected and has done a thorough job in its site development work. As a number of uncertainties remain, we determined that half credit for the siting plan subcategory is appropriate.

The point available for the socio-economic subcategory is to reflect the proposals' expected impact on the following factors: environmental equity; transportation; aesthetics and noise; historic and archaeological resources; and enhancement of economic and community development. The Bluewater proposals appear to involve limited negative impacts on each of these factors and could produce positive impacts on economic development via employment opportunities. Some argue that wind projects are aesthetically displeasing while others find them attractive. These proposals would be many miles offshore, but a 0.1 point deduction was made to reflect the fact that some will find the projects objectionable.

Some also express concern about the noise from wind projects. Given the distance of the projects from shore and the fact that the turbines will only operate in windy conditions, we did not deduct anything for potential noise impact.

(vii) Bidder Experience (3.5 points out of 5 points maximum)

Bluewater scores 3.5 for this category. The lead developer has experience with one large completed onshore wind project and has assembled a team with substantial offshore wind experience. We feel that consideration of both the lead developer and its team is important in assessing this category. The development team has an excellent safety record and highly experienced staff. Therefore, even though the lead developer has limited experience and has not developed an offshore project, we have awarded 3.5 points in this category.

(viii) Financeability of Project (1.5 points out of 5 points maximum)

Bluewater scores 1.5 in this category reflecting the Independent Consultant's concerns about the financeability of the projects as they have been proposed.

Bluewater plans to use a project financing structure for its proposed capital intensive projects. To achieve maximum score as a project financed project, the bidder must show that it has a well-supported, realistic spreadsheet that can reasonably be expected to attract financing, and has a well-developed plan to obtain third-party financing. In considering the strength of the project financing plan, weight is given to commitments or other evidence of meaningful financial support.

Bluewater has provided detailed spreadsheets and letters of interest from potential financiers. Given the stage of the projects' development, the financial letters understandably are not commitments. In reviewing the project spreadsheets, we identified that a material amount of project revenue is projected to be derived from the sale of both RECs and greenhouse gas ("GHG") credits associated with the same MWh to be produced by the project.

Bluewater was asked to explain the basis for inclusion of both REC and GHG credit revenues in its financial analyses. The response did not alleviate our concerns that a material part of the projects' revenue stream, based on the sale of GHG credits, is speculative.

Bluewater assumes an allocation of GHG allowances (credits) from a GHG (carbon) trading program, either through RGGI or other carbon trading programs. While Delaware's RPS rules might allow Bluewater to keep and sell GHG allowances separate from its RECs, the major issue is whether the project can, in fact, receive GHG allowance allocations at all.

Under RGGI, non-emitting generators cannot receive GHG offsets, but may be allocated allowances at the state's discretion. However, the allocation methodology, for which there are many options, has yet to be determined by each state; and most state participants have indicated that non-emitting generation will not likely be allocated allowances for free, especially those projects that may sell RECs to meet an RPS. Further, even if Delaware chooses to allocate allowances to non-emitting generation, we believe the allocation would be, at best, for a small portion of a non-emitting generator's output. Therefore, we do not believe GHG allowances from RGGI are a reliable revenue source to be included in Bluewater's pro forma.

While there is currently a voluntary market for the sale of GHG offsets, through the Chicago Climate Exchange ("CCX"), CCX rules also specify that a renewable energy project that has sold its RECs for purposes of meeting an RPS are not eligible to receive offsets [25]:

[25] See CCX rules: http://www.chicagoclimatex.com/news/publications/pdf/CCX_Renewable_Offsets.pdf.

- *"Certain renewable energy projects qualify to earn tradable GHG emission offsets on the basis of displacing $CO_2$ emissions from grid supplied power."*
- *"Project proponents need to demonstrate clear ownership rights to the environmental attributes associated with renewable energy production."*
- ***"Eligible renewable energy and associated environmental attributes are those <u>not</u> being used to meet obligations established by state or local mandates (e.g., renewable portfolio standards)."***
- *"To prevent double counting of benefits, any renewable energy credits (RECs) generated by qualifying systems must be surrendered to and retired by CCX in order for CCX Offsets to be issued."*

Based on these rules from an existing carbon trading program and the uncertainties around evolving rules related to RGGI (and even greater uncertainty with respect to any future Federal mandatory greenhouse gas programs), our assessment is that the Bluewater projects will not likely be allocated GHG allowances or receive offsets to sell for additional revenue, at least in the magnitude contemplated by Bluewater, if the RECs are also to be sold for RPS purposes. Therefore, the revenues assumed by Bluewater from the sale of GHG credits are uncertain at best.

In evaluating financeability, we also considered whether other revenues or some cost savings would be likely to make up for the potential revenue shortfall identified in the preceding paragraphs. While there may be some areas for improvement in terms of cost savings, our analysis does not show how the revenue shortfall will be fully made up elsewhere.[26] Further, there is some concern, albeit of a substantially lesser magnitude, over Bluewater's need to sell the project's products (energy, UCAP, and RECs), in excess of the amounts contracted to DP&L at a reasonable price. The magnitude of this subscription/market price risk is greater in the proposal to sell the output from 400 MW of nameplate capacity than in the proposal to sell to DP&L from the full 600 MW up to 400 MWh in any hour. This may be counterbalanced by the diminished marketability of the energy under the 600 MW proposal for term contracts relative to the 400 MW proposal, which would reduce the value of the energy under the 600 MW scenario.[27]

A major portion of the cash flow from wind projects results from the federal production tax credit ("PTC") which was recently extended to apply to projects that begin operation by the end of 2008.[28] In order for the Bluewater projects to be financeable as proposed,

[26] Nor did the pro forma appear to us to be so robust as to be able to easily tolerate the pertinent revenue reduction.

[27] These observations could lead to a slightly lower financeability score for the 400 MW proposal than for the 600 MW proposal since less of the output is committed; for ease of discussion, we elected not to establish another proposal category at this time.

[28] The federal Production Tax Credit provides owners of wind generation projects with a tax credit currently equal to $19/MWh, adjusted by inflation, for a period of 10 years from the commencement of a unit's operation, provided the unit commences operation by December 31, 2008. However, Congress has granted five extensions of the PTC deadline for initial operation over the past eight years.

further extensions of the PTC are critical. While the PTC has been extended a number of times, and a further extension is reasonable for planning purposes, this situation does present a risk for the Bluewater proposals.

In light of all these considerations, the Independent Consultant scores the Bluewater proposals at 1.5 points out of the 5 available for financeability.

**Economics Supercategory**

Bluewater scored few points in the Exposure and Contract Terms categories, as explained below.

(xi) Exposure (25-year bids: 0.25 points; 20-year bids: 0.58 points out of 6 points maximum)

Bluewater scores a total of 0.25 points in this category for its 25-year proposals and 0.58 points for its 20-year proposals. The components for scoring this category are contract size, the bidder's credit rating, the term of the contract, and a combination of expected capacity factor and project dispatchability. Because Bluewater is proposing a sale of products from 400 MW of contract capacity (or more) and does not have an investment grade credit rating, it receives no credit on those components. The only areas in which it does receive partial credit is (a) for non-dispatchable projects with less than 50% capacity factor and (b) for the term of the contract, its 20-year proposals only.

(xii) Contract Terms (0.3 points out of 1 point maximum)

Bluewater scores 0.3 on this category. Bluewater's proposal raises several issues regarding compliance with contract size requirements and the amounts of required contract security and liquidated damages for delay in achieving commercial operation. These issues are addressed in Section V of this Report.

Price and price stability are addressed in Section IV.C of this Report.

## 2. Conectiv

Conectiv is offering two options: (1) a Base Offer that is tied to the output of its proposed facility and (2) an Alternate Offer that is not unit contingent except for the capacity portion of the offer which is tied to the proposed new facility. Both proposals would involve the construction of a new plant. However, in the Alternate Offer, Conectiv will retain control over the dispatch of the project and determine the source of the energy scheduled by DP&L. While we have the environmental characteristics for the Base Offer, the Alternate Offer could involve the dispatch of sourcing of many different types of resources with varied environmental profiles. Since we do not know what those characteristics will be in the Alternate Offer, we have scored the non-price portion of the evaluation the same for both options. The State Agencies should, however, be aware that there may be a difference in environmental characteristics between the two offers.

## Favorable Characteristics Supercategory

While Conectiv scores relatively well in terms of the environmental impact of the proposed project, it receives a low score for fuel diversity and no points for technological innovation, resulting in 10.8 out of a total of 20 points for favorable characteristics.

(i) Environmental Impact (10.3 points out of 14 points maximum)

Conectiv's proposed combined-cycle plant receives a total of 10.3 points out of the 14 maximum for this category. Scores for greenhouse gases (2.1 points) and criteria pollutants (2.9 points) are derived directly from the anticipated emissions rates as provided in Conectiv's proposal. As part of the evaluation process, we were asked to review each project in isolation, irrespective of potential net environmental impacts at a project's site. Given this point of view, the plant is expected to have consumptive use of water for cooling purposes. However, Conectiv indicated in its response regarding water usage that the thermal discharge would be at lower temperatures than the current thermal discharge from the existing plants combined. In other words, the company explains that the cooling towers will remove more heat from the discharge canal than it returns in the blow down stream. For winter and summer operations, the total heat rejected to the river from the canal would be reduced. Since there would be no increase in thermal discharge and no adverse change to the character of the water discharge, we award 1.0 out of a possible 1.5 points for water impacts.

Hazardous waste would consist of potentially flammable substances (gas pipeline condensate, small amount of water treatment chemicals and volatile compounds), but Conectiv notes that the environmental impact of the onsite treatment, storage and disposal facilities will be minimal. This is generally true given that the primary fuel input to the facility is natural gas, resulting in minimal hazardous solid waste. Therefore, we score the project at 1.3 out of 1.5 for this subcategory.

Since the plant will be sited on a cleared upland portion of an existing industrially zoned site, the location lacks potentially sensitive environmental or land use resources (e.g., wetlands, surface waters, endangered species, aesthetics, or cultural resources), according to the company. Therefore, for land impact and wildlife impact, the combined score given was 3.0 out of a possible 3.0.

(ii) Fuel Diversity (0.5 points out of 3 points maximum)

Though the plant has dual fuel capability, the fuel options are still natural gas (primary) and liquid fuel oil (secondary). Since the plant does have flexibility, however, this is somewhat better than a natural gas-only plant or an oil-only plant. Accordingly, we have awarded 0.5 points in this category.

(iii) Technology Innovation (0 points out of 3 points maximum)

Since combined-cycle generation is a conventional technology type, it does not receive any technology innovation points.

**Project Viability Supercategory**

Conectiv scores highly in terms of project viability based on its use of a conventional technology, its financial capabilities and experience, and use of an existing site, resulting in a score of 18.5 out of a total 20 points for this supercategory.

(iv) Operational Date (2 points out of 3 points maximum)

The proposed on-line date for this project is for the middle of 2011, which would receive a maximum of 2.0 points. The proposed timeline provides almost four years for permitting, development, and construction once the bid is accepted. We feel that since Conectiv already has site control and there are similar units on-site, the project should not face significant permitting delays. Since the project team is very experienced in developing combined-cycle units and the technology is well understood, there should not be any major delays. It is true that the development schedule starts with obtaining a contract with Delmarva by May 2007, a date that may not be achieved as this process unfolds. However, we think that even with some additional time for the contracting process, a mid-2011 on-line date is reasonably achievable. Therefore, we score the project 2.0 points for its operational date proposal.

(v) Technology Reliability (2 points out of 2 points maximum)

As mentioned previously, combined-cycle generation is a widespread, time-tested technology with numerous installations in the U.S., so the Conectiv project scores the maximum 2.0 points.

(vi) Site Development (5 points out of 5 points maximum)

Since the project is located at an industrial site with existing generation units owned by Conectiv, the bidder already has site control, a transmission interconnection point, and a fuel supply infrastructure. The plans for permitting entail expansion of existing permits. The fuel supply capacity appears to be able to meet the new plant's average daily consumption, though it is not apparent from the proposal what the priority of gas usage would be relative to other generation units on-site. The company does allude to acquiring high volume storage to support peak plant operations. Given these circumstances, the project scores the full 3.0 points for its siting plan and 1.0 points for being located at an industrial site.

With regard to socio-economic impact, the project is located on a site surrounded by industrial facilities, so the visibility impact should be minimal. The company claims that the site is not an archaeological or historical site. It should not have any noise or air traffic impacts. There is no traffic through residential or roadways with unacceptable levels of service and the project would provide an economic and community enhancement of 400,000 construction job hours. Therefore, the project receives the maximum score of 1.0 for this criterion.

(vii) Bidder Experience (5 points out of 5 points maximum)

The Conectiv team has permitted, installed, and commissioned a total of 1,650 MW of capacity in the last five years using the same technology. The company states that these three combined-cycle projects all came on-line as scheduled. Furthermore, Conectiv will be the main project manager of the entire project, similar to its role in the other projects cited. Availability factors at these other facilities range from 85% to 90%. Given the extent of Conectiv's experience with the technology and project management, we assign the maximum 5.0 points for the category.

(viii) Financeability of Project (4.5 points out of 5 points maximum)

We score the Conectiv project 4.5 on financeability. Review of the financial information provided by Conectiv shows that the project is very likely financeable if its bid is accepted as proposed. Conectiv plans to use balance sheet financing and has an investment grade parent company that supports this plan. Alternatively, Conectiv would have the option to project finance this project. Both approaches are likely to have merit due to a large fixed capacity price component that would allow the project to receive sufficient debt coverage or equity returns, even if the facility is underutilized or gas prices increase.

One potential downside financial risk may be the expected natural gas fuel cost. Since the base energy price component of the proposal is tied to GDP and coal indices, any major price spikes in natural gas would ordinarily dramatically increase generation costs, decreasing cash flow. However, Conectiv plans to hedge gas prices several years ahead to mitigate a substantial portion of that risk. Conectiv will use PEPCO Holdings, Inc. as its parent guarantor, which will allow the project to be project financed or corporate financed. Overall, the financeability of the project appears very good if its bid is accepted as proposed.

## Economics Supercategory

Conectiv scored highly in the Exposure category due to its relatively small contract size, Conectiv's investment grade credit rating, the relatively short contract term (10 years), and the operational flexibility allowed to Delmarva. Conectiv did not score highly on contract terms and conditions, as explained below.

(xi) Exposure (5.5 points out of 6 points maximum)

Conectiv scores a total of 5.5 points in this category. The components for scoring this category, as mentioned previously are contract size, the bidder's credit rating, the term of the contract, and a combination of expected capacity factor and project dispatchability. Because Conectiv is proposing a fully dispatchable, 177 MW project with a 10-year term, it receives the maximum available points for those components. The only area in which it receives partial credit is for credit rating; its parent holding company, PEPCO Holdings, Inc., has a corporate credit rating of BBB, a low to mid-level investment grade rating.

(xii) Contract Terms (1 point maximum)

Conectiv scores 0.4 out of a possible 1.0 points for contract terms. Conectiv's proposal and proposed exceptions raise several threshold and other key risk allocation issues. The company proposes to provide financial security or a second lien but not both; both are non-negotiable contract provisions under the RFP. Conectiv also proposes a return of development period security if it cannot obtain its permits. The company is also proposing Btu and carbon tax as total pass-through charges to DP&L. Finally, Conectiv proposes that any incremental carbon costs above costs related to meeting Delaware's commitment as part of the RGGI be passed through to DP&L.

The price and price stability attributes of Conectiv's proposal are addressed in Section IV.C.

### 3. NRG

Since NRG proposed two configurations for its IGCC facility (with and without Carbon Capture and Sequestration "CCS"), it was necessary to evaluate these two configurations separately, though scoring for many of the categories is the same for each configuration.

**Favorable Characteristics Category**

NRG scores somewhat above Conectiv in the Favorable Characteristics supercategory – 11.1 points for the base bid and 12.7 points for the CCS bid -- with higher points for fuel diversity and technological innovation but lower points for environmental impact.

(i) Environmental Impact (Base bid: 6.6 points; CCS: 8.2 points)

Under environmental impact, there are differences in emissions between the two proposed configurations, because CCS will contribute to reduced energy conversion efficiencies while reducing GHG emissions. Therefore, while a large portion of GHG emissions will be sequestered, criteria emissions will tend to be higher as a result of lower efficiencies. NRG's proposed IGCC plant without CCS receives a total of 3.3 points out of a possible 8.0. Scores for greenhouse gases (0.3 points) and criteria pollutants (3.0 points) are derived directly from the anticipated emissions rates as provided in NRG's proposal. For the configuration with CCS, the emissions total is 5.2, with scores for greenhouse gases at 2.4 and criteria pollutants at 2.8. Overall, from an emissions perspective, the CCS option is better.

The discussion on water usage, solid waste generation and land usage applies to both configurations. As part of the evaluation process, we were asked to review each project in isolation, irrespective of potential net environmental impacts at a project's site, such as the retirement of Indian River Units 1 and 2. Given this point of view, the plant is expected to have consumptive use of water for cooling purposes. We do note that NRG stated in its response concerning water usage that the plant is expected to use less water than other technologies such as pulverized coal or natural gas combined cycle plants. Additionally, NRG has indicated that it intends to use best available technology to reduce thermal discharge into the river. Based on NRG's representations and our investigations, we have awarded a score of 0.5 out of 1.5. Finally, we note that while the raw score of this project reflects only the attributes of the proposed IGCC plant, NRG has stated that it would commit to shut down Indian River Units 1 and 2 at the Millsboro location, using their existing intake and discharge structures. This means that from a practical perspective, the water impact to the location would likely be improved by the acceptance of this proposal, although this effect is not reflected in the scoring consistent with paragraph 173 of Order No. 7066.

Solid waste from this project would be less than for other coal-based technologies. Additionally, much of the waste produced (such as slag and sulfur) may be usable in other industries. Nonetheless, the project will be generating significant amounts of hazardous solid waste that would require proper storage, handling, and disposal. Therefore, we score the project at 0.5 out of 1.5 for this subcategory.

The plant will be sited on a portion of a parcel of land that is zoned for industrial use and is near an existing steam plant, a landfill and other related structures. The physical impact of the proposed plant would be relatively modest, but full credit for co-locating at an industrial site does not seem correct since this is an incremental land use that would expand the industrial footprint. The IC awarded 1.0 points for land impact due to the relatively small footprint in an area that is already zoned industrial.

For the IGCC without CCS, the wildlife impact appears to be minimal given the conditions adjacent to the proposed site, but the plant would potentially impact wildlife through its use of incremental land. The Independent Consultant concludes that the physical plant's modest direct impact should score 1.3 of the 1.5 points available. However, a distinction is appropriate for the potential negative wildlife impact of CCS since the science and potential long-term impact associated with carbon sequestration is generally unknown. For this option, we assign a score of 1.0 out of 1.5 since there is some risk associated with this technology to wildlife by virtue of the concentration of the $CO_2$ which will need to be stored.

(ii) <u>Fuel Diversity</u> (1.5 points out of 3 points maximum)

Although the plant is intended to run full time using the synthetic gas created from the coal gasification process, several opportunities for fuel diversity may exist. First, NRG is investigating the potential to include 5% biomass in its coal mixture. Additionally, NRG is investigating the possibility of having a natural gas pipeline to the facility for backup purposes. The RFP states a preference for renewable and solid fuel resources as well as for projects that can use diverse fuels. The NRG project is not renewable, but does meet the solid fuel objective and may meet the fuel diversity objective. Accordingly, we score the project at 1.5 points for this category.

(iii) Technology Innovation (3 points out of 3 points maximum)

Since this project is an integrated gasification/combined-cycle plant, a technology with substantial potential that is in the process of commercial development, it receives 3.0 out of 3.0 technology innovation points.

**Project Viability Supercategory**

NRG scores somewhat above Bluewater for project viability but substantially behind Conectiv, with 11.8 points for the base bid and 10.3 points for the CCS bid.

(iv) Operational Date (0 points out of 3 points maximum)

The proposed on-line date for this project is for the middle of 2013. As such, the project receives no points. The proposed timeline provides almost four years for permitting, development, and construction. We note that NRG has offered a bridge contract from its existing coal-fired resources that would begin in 2008. We did not credit the early start date that would result from the bridge proposal in our evaluation since the bridge proposal is not responsive to the requirements specified in the RFP. We scored this category 0.0 out of 3.0 points.

(v) Technology Reliability (Base bid: 1.0 point; CCS: 0.5 points out of 2 points maximum)

Integrated gasification/combined-cycle generation is still a relatively new generation technology with only a handful of demonstrated projects worldwide. While there are hundreds of gasification facilities producing syngas worldwide and, similarly, many installed gas combined cycle generation facilities, the uncertainty in technology reliability is in the integration of the two technologies. We note that NRG has assembled a quality team for its project with expertise in both gasification plants and electric generation. One of the key team members is Shell, one of the leading gasification technology providers in the world and one with significant IGCC experience. Accordingly, we scored this category 1.0 out of the maximum 2.0 points for the configuration without CCS.

The inclusion of CCS produces an additional reliability issue with regards to equipment necessary for capture and sequestration. The CCS proposal does involve greater complexity and operational risk given the unproven nature of the technology. Therefore, this configuration receives only 0.5 out of a maximum 2.0 points.

(vi) Site Development (4.3 points out of 5 points maximum)

Since the project is located at an industrial site with existing generation units owned by NRG, the bidder already has site control, a transmission interconnection point, and a fuel supply infrastructure. The plans for permitting entail expansion of existing permits. The fuel supply plan to bring in coal by rail, similar to that of the existing on-site coal-fired generation, appears to be adequate. The land is generally already zoned for heavy industrial use. However, NRG indicates that given the proposed size of the project and the need to develop an additional portion of the existing parcel of land, a local site plan review is likely to be required. Given these circumstances, the project scores 2.5 points for its siting plan and 1.0 point for being located at an industrial site.

With regard to socio-economic impact, the project is located on a site surrounded by industrial facilities, so the visibility impact should be minimal, although noticeable from some directions. The company claims that the site is not an archaeological or historical site, although it notes that some historically significant areas are nearby, which could require mitigation measures in the future. The proposed project should not have any noise or air traffic impacts. There are no sensitive residential areas within 1.5 miles of the site. NRG indicated a plan to mitigate noise issues through the selection of low-noise equipment and the inclusion of shielding and insulation materials. Finally, it is anticipated that the existing roads can handle the additional traffic for construction and operation personnel, and the existence of a railroad spur into the site can be used for delivery of heavy or oversized equipment. NRG noted that they plan to schedule construction traffic to avoid peak rush hour times. Overall, the socio-economic issues are minimal, but some potential for further mitigation efforts does exist. We therefore gave this project a 0.8 out of the maximum score of 1.0 for socio-economic issues.

(vii) Bidder Experience (Base bid: 3.0 points; CCS: 2.5 points out of 5 points maximum)

NRG has assembled a quality team with experience in various components of IGCC development (gasification and electric generation), but the company does not necessarily have the experience of developing one or more IGCC projects as required to receive a score at or near the maximum. However, we felt that a score of 3.0 for the category was appropriate for the team NRG has assembled to carry out the project despite the lack of direct IGCC development experience.

For the CCS configuration, we had to evaluate the experience of the team in that area as well. While carbon capture from gasification and carbon injection into oil wells has some application today, there is insufficient experience with the particular type of site being proposed in this proposal. Therefore, due to the limited experience with CCS, this configuration receives 2.5 points.

(viii) Financeability of Project (Base bid: 3.5 points; CCS: 3.0 points out of 5 points maximum)

NRG has provided letters of interest from multiple banks and has answered many questions related to financeability. However, the company did not provide a pro forma, having taken the commercially understandable position that for the IGCC technology such information is highly confidential. Based on information that NRG was willing to supply and publicly available data, our assessment is that the project as bid is very likely to be financeable. However, there is some risk associated with the potential range of capital costs of an IGCC once engineering estimates are more complete. There is also potential performance risk in the initial years, although some of that has already been taken into account.

From our internal analysis, we find the price as bid can accommodate these risks. An additional concern is whether a resolution satisfactory to potential investors can be reached regarding the variable interest entity contract language. There is also some risk associated with the need to sell the 200 MW that would not be under contract to DP&L. Accordingly, we have scored this project as 3.5 out of the maximum 5.0 for this category for these perceived risks for the IGCC.

Though there may be uncertainties related to the costs of CCS if that option is selected, most of those costs would be passed-through to DPL as part of NRG's proposal terms. Nonetheless, the CCS proposal does involve the added financial risk associated with estimating the cost of carbon capture which is included in the fixed cost portion of the bid. Because of the added risk, we score the financeability of the CCS proposal 3.0.

## Economics Supercategory

Like Bluewater, NRG scored few points in the Exposure and Contract Terms categories, as explained below.

(xi) Exposure (25-year bids: 0.5 points; 20-year bids: 0.83 points out of 6 points maximum)

For the exposure category, NRG scores a total of 0.5 points for its 25-year proposals (both with and without CCS) and 0.83 points for its 20-year proposal. The components for scoring this category, as mentioned previously, are contract size, the bidder's credit rating, the term of the contract, and a combination of expected capacity factor and project dispatchability. Because NRG is proposing a 400 MW contract and does not have an investment grade rating, it receives no points for contract size and credit rating. NRG receives 0.5 points for providing "virtual dispatch" for 30% of the contract capacity and 0.33 points for its 20-year bid.

(xii) Contract Terms (0.3 points out of 1 point maximum)

NRG scores 0.3 out of a possible 1.0 point for contract terms. NRG has proposed that incremental environmental compliance costs due to a change in law concerning $CO_2$ regulation or otherwise will be "passed through" to Delmarva. In addition, NRG has proposed that it have the right to terminate the PPA if it cannot obtain financing. If this is due to the Consolidation Termination clause in the PPA, NRG would get its security deposit back; if it is for any other reason, NRG would pay a breakage fee in an amount equal to 50% of the required development period security deposit. NRG has a variety of other contract markups, which present issues for negotiation but are of a less fundamental nature than those identified above.

The price and price stability attributes of NRG's bid are addressed in Section IV.C.

## *B. Economic Evaluation*

### 1. Economic Evaluation Methodology, Process and Assumptions

This Section of the Report describes the price and price stability evaluation methodology used in the analysis of the bids and the IC's review of the process.

As noted in Section II.B of this Report, Delmarva and its consultant, ICF, agreed in lieu of conducting test bids to provide the IC with all material input assumptions and a summary of the evaluation methodologies prior to receipt of the bids so that the IC could conduct an assessment regarding reasonableness and a lack of bias for or against any resource or bid. This was particularly important where, as in this case, an affiliate of the utility is a bidder and the utility has expressed in advance of the receipt of bids strong opinions regarding the outcome of the process.

The RFP states that all proposals will be assessed in the price evaluation based on a simulation of the impact of the proposal on the costs paid by Delmarva's SOS customers.[29] The following components of SOS cost are to be considered:

- PPA capacity price
- PPA energy price
- Residual SOS cost impact
- T&D project impact
- Transmission losses
- Imputed debt offset
- Costs to comply with the Delaware Renewable Portfolio Standard

[29] Instructions to Bidders, Section 3.2

These same factors (absent imputed debt) are also to be considered in the price stability analysis where the variance in prices to customers associated with a bid in relationship to the option of procuring power from the market

Out of 100 points to be awarded, a maximum of 33 points are to be awarded for the project that results in the lowest average SOS cost (price) with 20 points to the project that produces the most stable average SOS price (price stability).

The RFP did not contain a summary of the assumptions to be utilized in the evaluation, such as fuel forecasts and projected future emissions regulation requirements, or have a definitive description as to the metric for the bid evaluation or how the bids would be scaled (dollars or dollars per MWh converted to points). The role of the IC was to work with Delmarva and its consultant to obtain agreement on reasonable methodologies and to review the input assumptions for reasonableness.

In late October, the IC met with Delmarva and ICF to review the proposed methodology and input assumptions to be used by Delmarva/ICF in the conduct of the bid evaluation. Over the next several weeks there were additional meetings, conference calls and other communications regarding the price stability evaluation, imputed debt, scaling, and other matters.[30] Many issues were resolved, some after substantial discussion.

- It was confirmed that the key metric in the price and price stability evaluation would be the real levelized 2005$ Delmarva SOS cost per MWh over the period (beginning with the earliest start date of the bids and ending with the last end date of the bids).

- A scaling methodology was agreed based on the spread between the high and low bids.[31]

- Delmarva and its consultant, ICF, proposed in the price stability analysis to consider the impact of above-market purchase contracts on customer migration and resulting unit SOS customer costs; after discussions with the IC, this approach was modified to take into consideration the Commission's authority under EURCSA to place above-market costs on a non-bypassable wires charge to protect remaining SOS customers.

Prior to and after the receipt of the bids, there were a number of areas in which the IC disagreed with the assumptions Delmarva/ICF proposed to make or outputs of the ICF model.

- Calculation of imputed debt
- Coal price forecast

[30] As noted in Section II.B of this Report, test bids were not conducted due to time constraints.
[31] As pertinent here, if the difference between the high bid and the low bid is greater than $10/MWh and less than $15/MWh, the bids will be scaled with the low bid receiving 33 points, the high bid receiving 0 points, and intermediate bids to be scaled proportionately.

- Gas transportation cost forecast
- Method for projecting the impact of Conectiv's proposed one-time price adjustment
- Projection of the value of Renewable Energy Credits

With regard to coal price forecast, gas transportation cost forecast, and method for projecting the impact of Conectiv's one time price adjustment, ICF agreed to conduct model runs with those set of assumptions (others were unchanged). Our assessment of price and price stability is based on those model runs (IC case) with other modifications we made separately regarding imputed debt, REC value and a few other minor items. In the next Section of the Report, we discuss the results of the price and price stability cases based on these assumptions. We note that the difference in the assumptions we used and the assumptions Delmarva used did not make a material difference in market price forecasts or bid ranking or bid evaluation points, but did alter the absolute cost of some of the bids to some extent. In the following Section, we discuss the difference in assumptions and approaches.

The IC reviewed ICF's natural gas price forecasts and compared them to forecasts in the public domain, especially those of the Energy Information Administration. We also reviewed ICF's methodology for forecasting carbon dioxide allowance costs, which is based on a probabilistic analysis of the potential enactment and implementation of various potential federal carbon dioxide regulation schemes (as well as that of the Regional Greenhouse Gas Initiative). Our assessment was that the reference case forecasts were generally reasonable for use in the bid evaluation, although not necessarily ones that we would select ourselves.[32] However, in our view, the range of high and low gas prices used for evaluating price stability was narrower than it should be for testing potential volatility of the market.

In terms of the bid evaluation process, we did learn of one instance where there was a change in the reference case assumptions by Delmarva/ICF after the bids were received without our knowledge or approval. However, the changes which involved a reduction in onshore wind energy resource availability in Delaware and a correction to treatment of a generating unit's dispatch cost in the model were relatively minor, substantively appropriate, and would not have a material impact on the analysis.

[32] For example, compare Delmarva/ICF's expected carbon dioxide allowance costs, Delmarva Power IRP Supporting Documentation (Jan. 8, 2007) at 52 with the somewhat higher mid case of Synapse Energy Economics in "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning (June 8, 2006) at 40. http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.Climate-Change-and-Power.pdf We compared ICF's reference case forecast for natural gas with EIA's forecast for natural gas and NYMEX futures prices.

### 2. Code of Conduct

The RFP set forth a number of requirements to assuage concerns about self-dealing between Delmarva and any affiliate of Delmarva that would submit a bid.[33] In addition to compliance with the FERC code of conduct rules, the following measures were directed:

- Any proposal submitted by a Delmarva affiliate would be submitted a day in advance of the due date for other bids and would be submitted at the same time to both Delmarva and the Commission;

- No staff working on an affiliate bid is permitted to participate in the bid evaluation process;

- All members of the bid evaluation team were required to sign a confidentiality agreement to protect bidder information;

- All requirements of the RFP, including security requirements, apply to a Delmarva affiliate submitting a bid.

We are unaware of any improper contacts between Delmarva and Conectiv, Delmarva's affiliate. Shortly before the submission of this Report, we inquired of Delmarva as to whether any person worked on the Delmarva RFP and on Conectiv's bid or whether the companies shared resources: we received a response that there functional separation was adhered to and there was no sharing of resources. Moreover, Conectiv did submit its bid a day before the due date applicable to other bidders. Conectiv did propose certain exceptions to the security requirements, but that is a matter we address in Section V.B of this Report.

## *C. Price and Price Stability Bid Results*

### 1. Price

In the table below is the forecasted ICF reference case market price for SOS customers (residential and small commercial) as modified by our assumptions (for coal prices, gas transportation prices and other matters) and the following bids in $2005 real levelized dollars (2011-2038): Conectiv Alternative Offer, Bluewater Atlantic North 25 year 600 MW (BW 25 Full), Bluewater Atlantic North 25 year 400 MW (BW 25 Partial), NRG base 25 year (NRG 25), and NRG base 20 year (NRG 20).

As shown below, based on the high/low method of allocating points, Conectiv receives 33 points as the low bid and NRG 20 receives 0 points as the high bid. The intermediate

[33] See RFP Instructions to Bidders Section 3.6.

bids are scaled, with BW 600 (BW 25 Full) receiving 8.3 points, BW 400 (BW 25 Partial) receiving 5.6 points and NRG 25 receiving 1.1 points.

**Table 3: IC Case Price Scoring**

| Summary | Market | BW 25 Full | BW 25 Partial | NRG 20 | NRG 25 | Conectiv Alt Bid |
|---|---|---|---|---|---|---|
| **SOS Cost (2005$/MWh)** | $86.20 | $98.21 | $99.42 | $101.84 | $101.37 | $87.48 |
| **Points Scored** | | 8.3 | 5.6 | 0.0 | 1.1 | 33.0 |

All of the bids are above the market price case, although Conectiv's bid, the low bid, is only $1.28/MWh above the market price. The other bids submitted by the bidders were higher priced than these bids. In evaluating and scoring the bids, we and Delmarva/ICF focused on the bids with the most attractive pricing. NRG's CCS alternative was priced higher than NRG 25 and NRG 20 because the cost of capture and sequestration embedded in NRG's bid when using NRG's estimated sequestration rate exceeds ICF's forecast for carbon dioxide allowance costs.[34] This total resulting cost of the CCS alternative was about 8% higher than the non-CCS bid.

Below is a table containing Delmarva's assessment and scoring of the bids. As can be seen, there is relatively little difference in the results as scored by us and as scored by Delmarva in terms of ranking. However, with lower projected T&D system upgrade costs and imputed debt calculations for Bluewater, it received a somewhat more favorable price score than the ICF reference case. It is also important to point out the total SOS costs associated with NRG's bids are lower in the IC cases as a result of lower coal price assumptions.

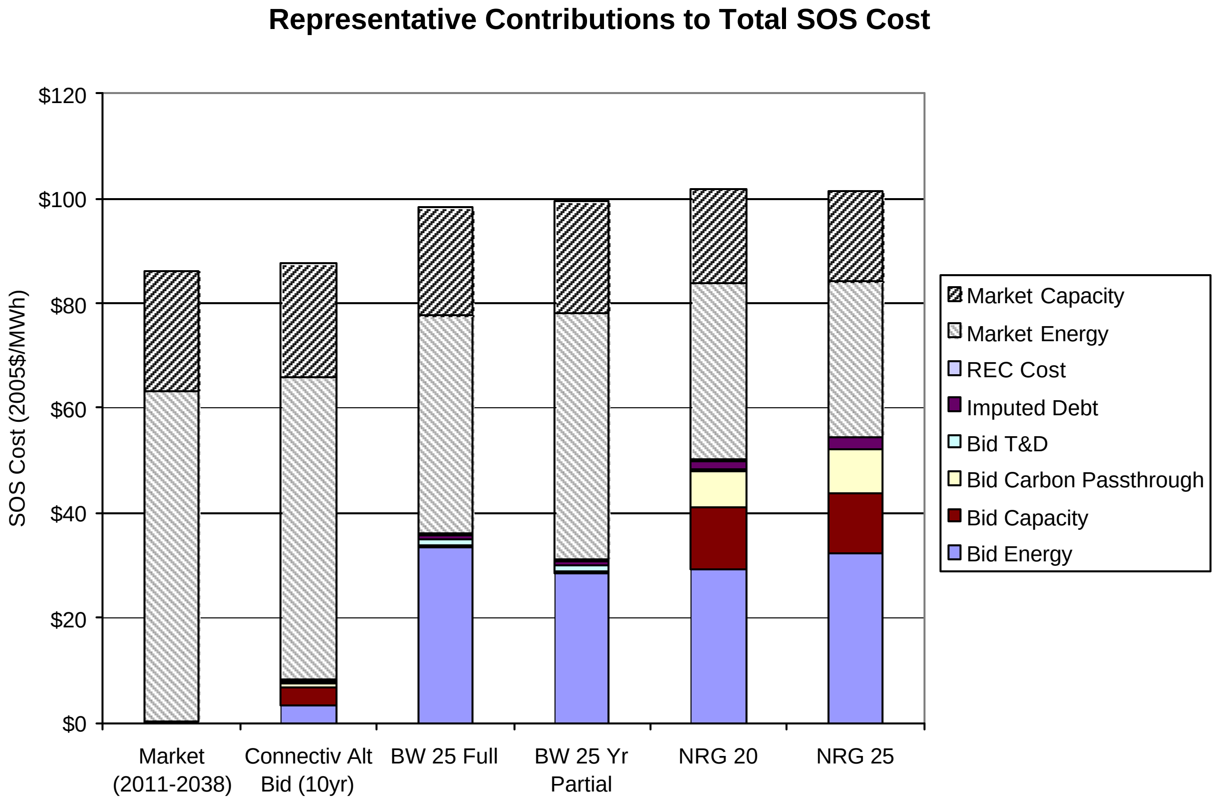
**Table 4: Delmarva/ICF Reference Case Price Scoring**

| Summary | Market | BW 25 Full | BW 25 Partial | NRG 20 | NRG 25 | Conectiv Alt Bid |
|---|---|---|---|---|---|---|
| **SOS Cost (2005$/MWh)** | $85.40 | $99.5 | $99.8 | $107.6 | $106.9 | $86.6 |
| **Points Scored** | | 4.8 | 4.0 | 0.0 | 0.0 | 33.0 |

In order to obtain a sense of the impact of the best of the bidders' proposals on SOS prices over time, below is a graph containing the IC reference case and the bids of Conectiv, Bluewater and NRG as contributions to the average SOS cost ($/MWh).

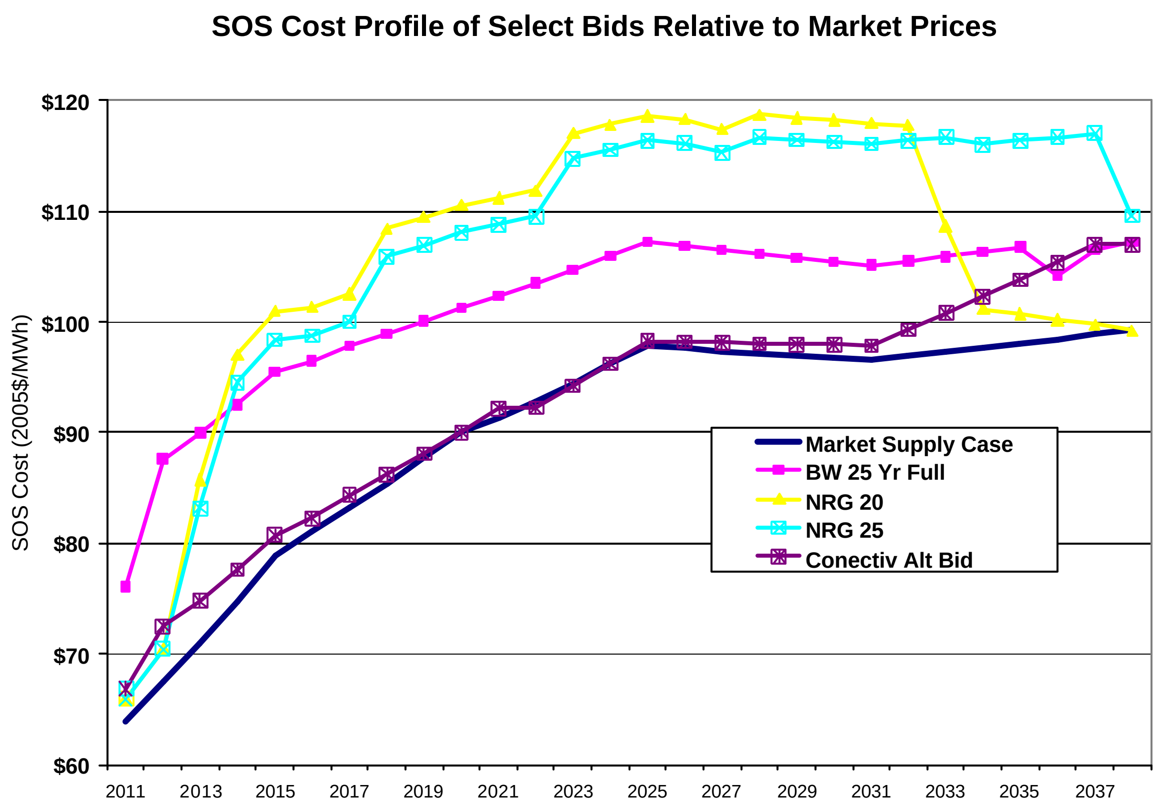
[34] NRG projected $/MWh costs based on its expected equivalent availability factor, which is higher than the target equivalent availability factor that is used in adjusting capacity prices based on a seller's operating performance. Delmarva and the IC used the target equivalent availability factor in our evaluation consistent with RFP Instructions to Bidders Section 2.3.1.

**Figure 2: Relative Contributions to Total SOS Cost -- 2005$/MWh real dollars, levelized for 2011-38**



The following graph shows the trajectory of projected SOS costs based on the bids and against the market supply forecast over the entire period of analysis, 2011-38 (in 2005 dollars).

**Figure 3: SOS Costs By Year -- 2011-38 (2005 $/MWh)**




As can be seen, the impact in the first full years of the project being in service on SOS costs (during the 2012-15 period) is on the order of $67/MWh for Conectiv, $83-$86/MWh for NRG, and $77-$80/MWh for Bluewater in $2005. As seen in the graph above, the SOS cost of the Conectiv bid closely tracks the SOS cost if supplied completely from the market.[35] NRG SOS costs increases to above $115/MWh towards the latter half of the contract life as a result of increasing carbon dioxide costs and faster growth of the CPI index proposed by NRG relative to that of the Gross Domestic Product Implicit Price Deflator, the inflation index used in the analysis. Additionally, the large capacity and energy size of the contract and long term nature also contributed to relatively high overall SOS cost. Lastly, the SOS cost associated with Bluewater's bid increases to over $105/MWh towards the latter half of its contract duration, despite the fixed real price of the bid. This is due to the increasing costs of market purchases to meet the remainder of SOS needs.

[35] We note that the SOS costs in the period of 2031-2038 (after the expiration of Conectiv's contract) does not appear to be aligned with the market supply case. Due to time limitations, we were not able to confirm with ICF the cause of this discrepancy. However, this should not have a material impact on the pricing evaluation.

From a customer perspective, since $.01/kWh is equal to $10/MWh, the additional cost to consumers from the "best of the bids" is 0.1 cents/kWh for Conectiv, 1.2 cents/kWh for Bluewater, and 1.5 cents/kWh for NRG in today's dollars (2007$). For a residential consumer with consumption of 1,000 kWh per month, the incremental monthly cost would be in order of $1 for Conectiv, $12 for Bluewater, and $15 for NRG levelized over the entire period in today's dollars.

## 2. Price Stability

In testing price stability, ICF ran several scenarios and calculated the SOS cost to customers as a result of the scenarios for a market purchase option and the proposed bids. The scenarios tested in addition to the reference case, which is what the price evaluation was based on, are as follows:

- **Low CO2 / Low Gas:** reflects a RGGI carbon regime with lower gas prices.
- **Low Gas:** reflects the reference case carbon regime, but gas prices are lower.
- **High Gas:** reflects the reference case carbon regime, but gas prices are higher.
- **Reduced Capital Costs:** reflects reduced capital cost of generic new market entry
- **No MAPP:** reflects no transmission with MAPP, PJM's neighboring RTO.
- **High CO2:** reflects a faster increase and higher cost of carbon (>$50/ton)
- **IC Case (Lower Coal/Higher Gas Basis)**: reflects the Independent Consultant's view of relative flat growth in coal prices (real prices) and a higher basis differential used for natural gas prices delivered to PJM.

The degree of stability was determined by calculating the standard deviation of the real levelized SOS cost across the above scenarios, including the reference case for each bid. Those bid with a standard deviation higher, thus less stable, than the market-based option received a score of 0. Price stability is scaled with the bid that is most stable scoring 20 points and the market option receiving 0 points, with bids with variances in between these points scaled accordingly.

**Table 5: Price Stability Scoring ($/MWh 2005 dollars levelized)**

| Scenarios | Market Case Supply Costs | BW Atlantic North 25 year full bid | BW Atlantic North 25 year partial bid | NRG 20 Year Base Bid | NRG 25 Year Base Bid | Conectiv Firm Bid |
|---|---|---|---|---|---|---|
| ***Reference Case*** | $85.43 | $99.45 | $99.82 | $106.87 | $107.56 | $86.63 |
| ***Low CO2 / Low Gas*** | $75.11 | $92.76 | $92.12 | $95.04 | $95.98 | $76.79 |
| ***Low Gas*** | $78.39 | $94.89 | $94.57 | $102.57 | $104.15 | $80.36 |
| ***High Gas*** | $90.01 | $103.05 | $103.86 | $109.68 | $109.75 | $91.70 |
| ***Reduced Capital Costs*** | $80.97 | $96.45 | $96.70 | $103.45 | $104.36 | $83.80 |
| ***No MAPP*** | $86.20 | $100.43 | $100.88 | $107.25 | $107.85 | $87.99 |
| ***High CO2*** | $93.35 | $104.01 | $105.14 | $116.37 | $117.94 | $95.16 |
| ***IC Case (Lower Coal/Higher Gas Basis)*** | $86.21 | $100.34 | $100.76 | $102.54 | $102.17 | $87.57 |
| | | | | | | |
| ***Standard Deviation*** | $6.02 | $3.93 | $4.48 | $6.23 | $6.36 | $5.91 |
| | | | | | | |
| **Price Stability Scores** | | **20.0** | **13.4** | **0.0** | **0.0** | **0.7** |

As might be expected, Bluewater's bid, a fixed rate bid with an annual escalation rate equal to Delmarva's assumed annual rate of inflation of 2.5 percent (based on the Gross Domestic Product Implicit Price Deflator), scored best in this category, obtaining all 20 points for being the most stable pricing. Conectiv's bid, also as expected, had little variance from the market, primarily because of its relatively small amount of capacity, energy, and shorter term (10 years). It obtains 0.7 points. NRG's bid received 0 points because its standard deviation among scenarios was greater, thus less stable, than the market case. While this appears to be counterintuitive, the reason is that the NRG bid include a large exposure to changes in carbon dioxide allowance prices on its total PPA cost. NRG's bid is also sensitive to coal price assumptions, since its energy component of its bid is indexed to coal prices.

The total economic scores for each bidders' best bids are as follows:

**Table 6: Total Economic Scores for Bidders' Best Bids**

| | Bluewater North 25 yr Full Bid | NRG 25 Yr Bid | Conectiv Alt. Bid |
|---|---|---|---|
| **Economics Supercategory** | **28.9** | **1.9** | **39.6** |
| ix. Price | 8.3 | 1.1 | 33 |
| x. Price Stability | 20.0 | 0.0 | 0.7 |
| xi. Exposure | 0.25 | 0.5 | 5.5 |
| xii. Contract Terms | 0.3 | 0.3 | 0.4 |

## 3. Differences Between the Analyses of the IC and Delmarva

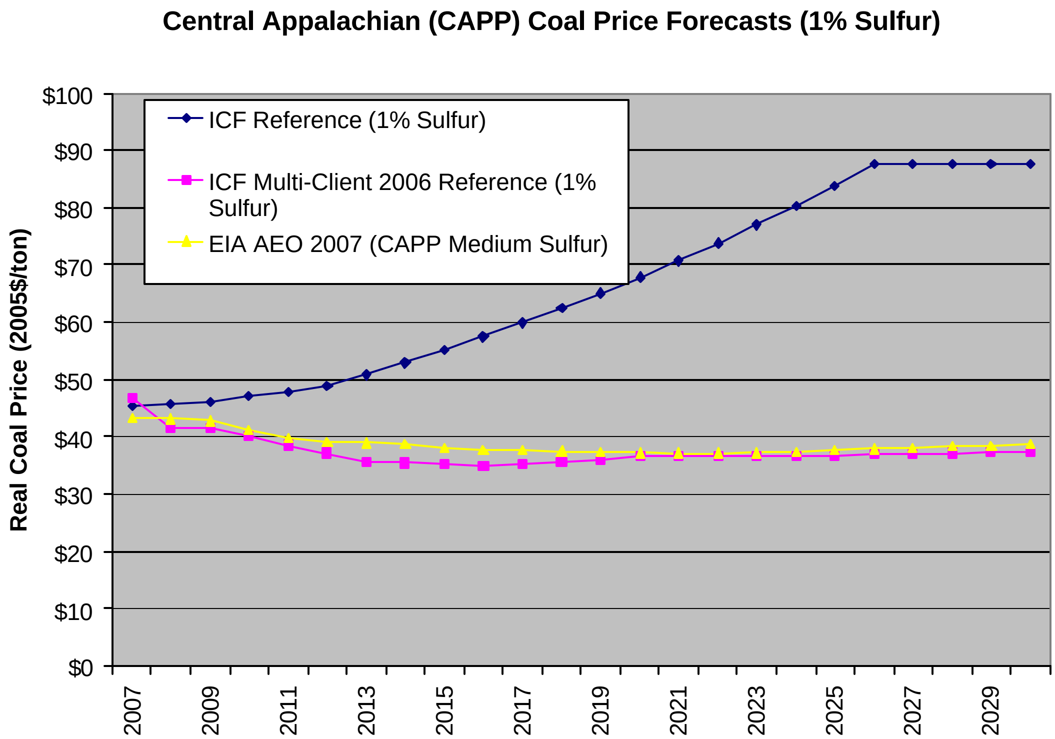
Although our results do not materially differ from Delmarva's, in this Section we provide a brief summary of the differences between our analysis and that of Delmarva's in terms of the economic analysis.

a. Fuel and Fuel Transportation Forecasts

As indicated previously, we reviewed ICF's fuel price forecasts in late October and November. Following Delmarva's filing of its Integrated Resource Plan on December 1 and prior to the submittal of bids later in the month, we obtained an "update" on key modeling assumptions from ICF, including natural gas and coal price forecasts and generation capital cost estimates. While the natural gas forecast was somewhat lower than the previous forecast, the coal price forecast was dramatically higher than previously provided to us.

Two of the bidders proposed to use a coal index, one for all of its energy costs and another bidder for a portion of its energy costs. When we applied the revised ICF coal price forecast for this quality of coal to the bids, we noted that the reference case forecasts real price increases that rise to 4.2% annually (in real 2005$) for each year from 2017 through 2030. By comparison, the coal price forecast that was provided to us in October/late November for this quality of coal generally forecasts modest real price declines after some price increases over the next few years, as does the 2007 EIA forecast. The effect is that ICF's forecasted coal prices are 40% higher by 2016 compared to the ICF analysis previously provided to us and EIA's forecast and 134% higher by 2030, as demonstrated in the graph below.

**Figure 4: Coal Price Forecasts**




We asked Delmarva and ICF for an explanation. We were told that the earlier forecasts provided to us were consistent with that of a multi-client study conducted by ICF. We were told that Delmarva was concerned that the earlier forecast did not appropriately take into consideration the prospect that there would be substantial and ongoing declines in coal mining productivity, with the effect that there would be substantial and ongoing real price increases in the cost of coal, at least from Central Appalachia. The reference case for coal prices was revised, apparently based on the direction of Delmarva to be used for purposes of the RFP and IRP. At our request, Delmarva agreed to run a case based on the earlier coal price forecast. This run also included what we thought were more reasonable gas transportation costs to the Mid-Atlantic market -- $1.00/Mmbtu instead of $0.43/Mmbtu (2005$) -- and modeling the Conectiv one-time price adjustment using current NYMEX futures prices instead of ICF's forecast. This resulted in a higher one-time adjustment than using ICF's forecast. The lower coal price forecast resulted in a lower evaluated price for NRG.

b. Imputed Debt

In Order No. 7081, the Commission and Energy Office directed the bid evaluators to assess the cost of additional equity that might be needed to rebalance Delmarva's capital structure because rating agencies might treat a portion of a power purchase contract as imputed debt. Specifically, the bid evaluators were directed to determine the potential cost of imputed debt based on a 30% risk factor and to conduct sensitivity analyses based on a 0% risk factor and a 50% risk factor. The RFP states that Delmarva and the IC will conduct additional review regarding the appropriateness of the 30% risk factor and present their assessments to the State Agencies.[36]

On the day after the Commission and Energy Office met to make their determination on the 30% risk factor, Standard & Poor's issued revised proposed guidance on imputed debt.[37] S&P proposed several significant changes, including:

- A proposed reduction of the 30% risk factor, generally applicable where PPA capacity costs were recovered through a fuel adjustment clause, to 25%;

- For PPAs where the price is generally stated as a single, all-in energy price, such as is usually the case for wind energy projects, a proxy capacity charge based on the cost of a combustion turbine unit would be utilized (the risk factor would be applied to this amount);

- The net present value of the fixed cost stream of the PPA would be discounted using the utility's average cost of debt rather than the standard 10% used previously.

After discussing the matter with Standard & Poor's, we decided to apply all of the elements of the proposed guidance, including the 25% risk factor to the proposed power purchase agreements of the bidders. Delmarva said it would continue to use the 30% risk factor. Both of these factors resulted in our having somewhat lower imputed debt calculations for NRG and Conectiv (even with our calculation of a somewhat higher capacity charge for Conectiv due to different assumptions regarding the one-time price adjustment).[38] Our calculation of the imputed debt charge for Bluewater was substantially lower than Delmarva's, due primarily to the use of a 50/50 capital structure for a peaker compared to Delmarva's assumptions of 70% equity and 30% debt and due to the reasons previously stated.[39]

To put the magnitude of these numbers in perspective, the real levelized $/MWh for SOS customers for imputed debt associated with each of the bids is a follows:

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[36] RFP Instructions to Bidders Section 2.3.6.

[37] See Standard & Poor's, Request for Comments: Imputing Debt to Power Purchase Obligations, Nov. 1, 2006, attached as Appendix A to this Report. The previous S&P guidance was issued on May 8, 2003 and is attached as Appendix E to our Final Report on the RFP (dated October 12, 2006).

[38] In our view, a substantial portion of NRG's recovery of its capital costs would be through the Tier 1 "must run" energy payment (the first 280 MW) in addition to its capacity charge. While we believe there is a significant risk that a portion of the Tier 1 energy charges might be treated as a proxy capacity charge for imputed debt purposes, we did not include any portion of the Tier 1 energy charge in our imputed debt calculations.

[39] For Bluewater, we believe that the proxy combustion turbine method was appropriate and is the method S&P would use. The alternatives were to use 50% of the entire Bluewater cost, as in the prior S&P guidance, which would have resulted in a much higher imputed cost, or to only use Bluewater's very small capacity payment.

**Table 7: SOS Customer Costs With Imputed Debt Sensitivities (2005 $, Levelized)**

| Imputed Debt Risk Comparison | Bluewater North 25 yr Full Bid | NRG 25 Yr Bid | Conectiv Alt. Bid |
|---|---|---|---|
| **0% Risk Factor** | $97.24 | $99.19 | $87.18 |
| **25% Risk Factor** | $98.21 | $101.37 | $87.48 |
| **50% Risk Factor** | $99.66 | $103.56 | $87.78 |

Therefore, there would not be material differences in the ranking for the price evaluation in the sensitivity cases of 0% risk factor and 50% risk factor.

While for purposes of this analysis all imputed debt costs are being assigned to SOS customers, we note that ordinarily the result of adding equity to capital structure is higher distribution rates which would be incurred by all Delmarva customers.

In the event that a contract is awarded to a bidder as the result of this process, the Commission should give strong consideration to the rate recovery mechanism. Since the risk factor is primarily a function of the risk of non-recovery as perceived by S&P and given the role of legislation in this regard, the Commission through its structuring of the rate recovery mechanism could minimize the risk factor and thus the cost or potential cost associated with imputed debt.

c. Renewable Energy Credit Value

The RFP allows renewable projects to bid up to 175,000 RECs per year based on the requirements of the Delaware Renewable Portfolio Standard and projected Delmarva SOS load (residential/small commercial customers). Initially, ICF's IPM model projected RECs as having no value based on a projected oversupply of wind projects relative to regional RPS demand. Subsequently, based on revised inputs, the model projected RECs as having some value in earlier years but declining over time and the outputs did not appear to behave rationally based on certain model runs. This has significance in terms of valuing Bluewater's bid.

We decided to value Bluewater's proposed sale of RECs based on our assessment of the forward market for RECs – approximately $12 flat.[40] We adjusted the value based on a 50% probability of attaining commercial operation by the end of 2012, which, if Bluewater was successful, would entitle Delmarva to receive a 150% credit under the RPS regulations.[41] Hence, we valued the RECs as having a value of $15 with no escalation (125% of $12), but this would only apply to the RECs purchased by Delmarva, significantly less than 15% of the total energy to be purchased under the 600 MW bid.

[40] This assessment was based on conversations with two active market participants in the region with respect to forward REC purchases and sales with terms of 5-10 years.
[41] Rules and Procedures to Implement the Renewable Portfolio Standard, Section 3.2.8. We are assuming that the Bluewater project would be a "wind energy installation[] sited in Delaware."

Against the REC price benefit, we have estimated an average cost of approximately $0.50/MWh (2005$) across all of the MWh purchased from Bluewater as a result of potential costs Delmarva may incur for operating reserves associated with imbalance deviations for Day-Ahead vs. Real-Time delivery from Bluewater and the cost and risk of managing an intermittent power supply.[42] The resulting net effect of these two adjustments to the analysis is not significant.

## *D. Project Comparisons in the Context of "Supercategories"*

The bidders' highest scoring bids produce the total project scores and the total supercategory scores set forth below.[43]

**Table 8:Total Scores by Project**

| Supercategories | Bluewater North 25 yr Full Bid | Bluewater North 25 yr Partial Bid | NRG 25 Yr Bid | NRG w/ CCS 25 Yr Bid | Conectiv Alt. Bid |
|---|---|---|---|---|---|
| Favorable Characteristics Supercategory | 18.2 | 18.2 | 11.1 | 12.7 | 10.8 |
| Project Viability Supercategory | 9.9 | 9.9 | 11.8 | 10.3 | 18.5 |
| Economics Supercategory | 28.9 | 19.6 | 1.9 | 0.8 | 39.6 |
| **Overall Total Scores** | **57.0** | **47.7** | **24.8** | **23.8** | **68.9** |

Table 8 immediately above highlights the merits and differences among the proposals.

Conectiv's alternate proposal has the highest point score overall, with the highest scores for economics and project viability but the lowest score (albeit only slightly lower than that of NRG) for favorable characteristics. In the economic supercategory, Conectiv's price score was the best among the bids but had minimal points for price stability. The reason is that the Conectiv bid provides for substantially less energy than the other bids (and less UCAP than offered by NRG) and over a much shorter time period (10 years instead of 20-25 years). Moreover, the Conectiv offer gives Delmarva the right to decide whether it should purchase the energy on economic grounds, whereas under the NRG and Bluewater proposals Delmarva does not have that option (with the exception of NRG's Tier 2 energy). In return, the capacity payment Delmarva would pay Conectiv is substantial (in effect, an option payment or premium).

[42] We recognize that the actual costs could vary widely from this estimate.
[43] Comparable bids from Bluewater's Atlantic South project had marginally lower scores than those of Bluewater's Atlantic North.

On the whole, under the reference case assumptions, the Conectiv alternate bid was evaluated as being marginally above market over the evaluation period when mixed in with market purchases over the 27-year period of analysis (2011-38). For much the same reason, there was not much variance with market prices over this period since for much of the period there were no purchases from Conectiv. Conectiv did propose an optional five-year extension of the contract that was not evaluated since it was based on a pricing formula that makes it extremely difficult to evaluate and might not provide significant value (given the time allotted to conduct the evaluation, this was deemed a low priority). If the price stability evaluation was conducted over the 10-year period of the base term of its offer (2011-21), Conectiv might have received a better score.[44] Conectiv also scored well in the Exposure category, which is a measure of how well a bid mitigates the exposure of Delmarva and its ratepayers, for many of the same reasons mentioned above -- limited contract size (177 MW), short contract term (10 years), and dispatch flexibility, and additionally, because of the investment grade credit rating of its parent company, and prospective guarantor.

Conectiv received high scores for project viability, substantially higher than those obtained by Bluewater or NRG. This is not surprising in that Conectiv proposes to build conventional technology at an existing plant site, which Conectiv has done several times previously. The only unusual aspect to this project appears to be the pricing approach and associated fuel hedging strategy that Conectiv would employ.

For much the same reasons, Conectiv's scores in the favorable characteristics supercategory are at the bottom among the bids, albeit slightly lower than those of NRG. There are no points for innovative technology and minimal points for fuel diversity. The environmental impacts for a project are what one would expect from a natural gas-fired combined cycle facility at an existing site. While we have scored the emissions as being those produced by the plant (both from an environmental scoring standpoint and in terms of the economic impact of carbon dioxide allowance costs), we note that under the alternative bid Conectiv can deliver energy from either the proposed unit or any other source consistent with the proposed point of delivery.[45]

Bluewater has the most favorable characteristics of any of the proposals because of its non-emitting environmental profile, its contribution to fuel diversity and its use of innovative technology, the application of advanced wind energy technology in an offshore environment (there are no similar projects in existence in North America). However, it would produce SOS power rates that are substantially higher than that which would be produced by the market either with or without the Conectiv bid, approximately \$12-\$13 in real levelized 2005\$. In the first full year of operation, 2013, this would result in \$20/MWh higher wholesale costs for SOS customers in today's dollars or 2.0 cents/kWh. For a customer using 1,000 kWh per month, this would mean an increase of

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[44] On the other hand, we are not persuaded that the price stability analytical tool employed by ICF appropriately evaluates the potential effect of a one-time price adjustment, as proposed by Conectiv, compared to a price adjustment provision that affects prices over the term of a contract.

[45] Given the pricing structure, we would expect the great percentage of the energy to be delivered during on-peak hours where natural gas-fired generation is produced at the margin so we believe use of the unit's emissions for scoring purposes is reasonable.

approximately $20 per month, which over time would decline (in 2007$) but not break even. At the same time, the Bluewater contract price, albeit relatively high, would be stable in real terms and would increase at a predictable annual rate of 2.5 percent.

If we were confident in the viability of the project at this level of pricing (and assuming the approximate accuracy of the market price forecast), we would pose the issue simply as whether it is worth paying the additional costs outlined above for what would be unquestionably a major societal contribution to addressing global climate change by facilitating the financing and construction of such a large non-emitting renewable energy generation plant.

However, we have significant concerns about the viability of the project itself. As indicated in Section IV.A.1, Bluewater is relying on obtaining substantial revenues from parties other than Delmarva for the separate sale of both Renewable Energy Credits and Greenhouse Gas Credits for the same quantity of MWh produced. This raises the issue of "double counting" of RECs and GHG credits, which we believe is speculative, at best. There is also the risk that the Production Tax Credit, another source of effective revenue, would not be extended, or at least extended in its current form. While Bluewater is proposing to take the commercial risk with regard to sale of RECs and GHGs and the Production Tax Credit, we would not be surprised that if Bluewater obtained a contract the company at some later date it would ask that the contract be amended to increase rates because it could not sell RECs and GHG credits for the same MWh (or perhaps because the production tax credit was extended but at a lower level than under current law).

Moreover, Bluewater has substantial development hurdles. While Bluewater has assembled a strong team (scoring well on bidder experience), the company cannot obtain definitive site control until new federal rules for offshore wind development are released. Other offshore wind projects in development in the Northeast have experienced substantial delays, in large part because of this issue. It is for these reasons that Bluewater had the lowest score for project viability.

The NRG coal-based IGCC proposals had the lowest overall scores and did not have the highest ranking in any supercategory. In the economic category, NRG's price score ranked lowest due to its relatively high fixed costs -- both capacity charges and the Tier 1 "must take" energy rates -- and its proposed pass-through of carbon dioxide allowance costs, which were projected to result in increasingly high customer costs over the proposed contract period. At the same time, the proposed cost of CCS was higher than the forecasted level of carbon dioxide allowance costs that would be reduced by the CCS, rendering this option uneconomic at this time.

We acknowledge that the IGCC technology and the potential for CCS may provide an important contribution to addressing global climate change as part of an overall energy policy. We commend NRG for proposing to develop this technology. However, with respect to NRG's bid, the resulting price to consumers appears higher than alternatives and the high fixed costs, large contract size relative to the load, and sensitivity to carbon dioxide allowance market prices resulted in a proposal that would not likely create price stability and could well contribute to price instability.

NRG's proposal has less favorable environmental characteristics than that of Bluewater or Conectiv but scores well for its use of an innovative technology. The NRG proposals score lower than Conectiv on viability due to the relative newness of IGCC for electrical generation and NRG's relatively less specific experience with such projects, but higher than the Bluewater proposals.

We believe that the foregoing comparative analysis of the projects in the context of the supercategories is a useful way of looking at the projects outside of the specific project scoring. However, it also helps to convey why projects obtained the project scores assigned to them.

# V. Recommendations on Important Contract Matters

In this Section, we address how contract and/or threshold issues raised by various bids should or might be addressed in the event the State Agencies decide to direct Delmarva to negotiate a contract with a particular bidder.

## *A. Bluewater*

Bluewater's proposal raises several issues regarding compliance with contract size requirements and the amounts of required contract security and liquidated damages for delay in achieving commercial operation. The issues stem from a confusion regarding the difference between (a) the maximum capability of wind turbine generating units to produce energy, the wind turbine nameplate ratings, on the one hand, and (b) the unforced capacity value or capacity credits that PJM attributes to wind turbine generating units, on the other hand.

**Contract Size**

Bluewater has submitted bids with two contract sizes: (a) the sale of energy and unforced capacity from 600 MW of nameplate wind turbine generating capacity (200 3 MW wind turbines) with a cap on energy sales of 400 MWh per hour (600 MW bids) and (b) the sale of two-thirds of the energy and unforced capacity from 600 MW of nameplate capacity (400 MW bids). While the 400 MW bids are clearly conforming to the 400 MW contract size limit, the compliance of the 600 MW proposals is at issue. Essentially, Bluewater asserts that the 400 MW limit is a limit on Unforced Capacity and not on nameplate capacity (or installed capacity). Unforced Capacity, or UCAP, for wind projects in their initial years' of operation is set at 20% of their "Net Maximum Capacity" or sum of the nameplate ratings of the wind turbines.[46] So Bluewater's argument is that energy can be from as large amounts of Net Maximum Capacity as possible as long as the UCAP is less than 400 MW and energy in any hour is less than 400 MWh.

The limit on contract size was an issue squarely addressed by the Commission and the Energy Office in their order approving a modified RFP. Delmarva had proposed a 200 MW contract size limit. We proposed a 400 MW limit on contract size. The Commission and Energy Office approved this recommendation.[47] In previous comments, Bluewater had proposed a contract limit of 600 MW nameplate capacity for wind projects, but we specifically recommended against such a limit, stating that "a 400 nameplate capacity limit with respect to UCAP and energy produced from that nameplate

[46] PJM Manual 21, Rules and Procedures for Determination of Generating Capability, Appendix B-1, p. 16, http://www.pjm.com/contributions/pjm-manuals/pdf/m21.pdf
[47] Order No. 7066 at 20-25.

capacity is appropriate for wind and other intermittent renewable energy projects, as well as other projects."[48]

In our view, it is clear that the intended limit was 400 MW of energy and UCAP from 400 MW of nameplate capacity. The pertinent RFP documentation is consistent with this intent and applicable PJM nomenclature, as is described below.

The Term Sheet provides that any proposal must have a "maximum Contract Capacity of 400 MW." (p. 1). "Contract Capacity" is the "maximum MWs of Net Capability rated for the applicable summer or winter rating period (as defined by PJM) that the Seller is offering to make available to Buyer in each month of the Services Term multiplied by Buyer's entitlement." The highest Contract Capacity specified by Seller for any month is referred to herein as the "Guaranteed Capacity." The amounts of required security and liquidated damages for delays in achieving commercial operation are based on the amount of "Guaranteed Capacity." The Standard Form PPA defines "Net Capability" with reference to PJM Manual 21.

Net Capability is defined by PJM as the maximum amount a generator can produce, as opposed to the amount of capacity credit obtained from PJM. "Net Capability" is "the number of megawatts of electric power which can be delivered by an electric generating unit or station of a system after its date of commercial operation without restriction by the owner under the conditions and criteria specified herein and shall be determined as the gross output of the unit or station less power used for auxiliaries and other station use required for electrical generation.[49] For most generating units, the amount of "Net Capability" is determined by testing, and there are both summer and winter ratings. This type of capacity is also referred to as installed capacity.

The type of capacity traded in PJM is "Unforced Capacity," which is different from Net Capability. "Unforced capacity" is defined as "installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating," calculated over a 12-month period.[50] The amount of Net Capability is reduced by the Equivalent Demand Forced Outage Rate (EFOR) for most units. Hence, a 200 MW generator with an EFOR of 5% would have a UCAP, or Capacity Value, of 190 MW.

Wind projects have special rules which are set forth in Appendix B-1 of PJM Manual 21, Rules and Procedures for Determination of Generating Capability. The analogue to "Net Capability" is "Net Maximum Capacity," which is defined as the "sum of the manufacturer's output ratings of the wind turbines at the wind farm, less the Station Load where 'Station Load' refers to the amount of energy that is consumed by the wind farm to operate all auxiliary equipment and control systems for the wind farm." For 600 MW of nameplate capacity -- 200 3 MW wind turbine generators (there is usually little or no Station Load for wind projects) -- the Net Maximum Capacity is 600 MW.

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48 Report at 15.
49 PJM Manual 21, p. 7.
50 PJM Reliability Assurance Agreement, Section 1.72.

The "Capacity Value" for a wind farm is a much lower number. It represents "the amount of generating capacity, expressed in MW, that can reliably contribute during summer peak hours and which can traded as unforced capacity credits in the PJM capacity markets." For the first three years, the Capacity Value or UCAP is 20% of the Net Maximum Capacity, or 120 MW for 600 MW of nameplate capacity. Thereafter, the amount of UCAP is based on the actual MWh output during summer peak hours in annual periods.

Hence, Net Maximum Capacity for wind projects is basically the same as Net Capability for other projects -- the maximum the units can produce at any point in time -- except, for non-wind projects there is a testing requirement. The terms are often used interchangeably. A PJM official in a presentation in September 2005 referred to wind plant capacity credits in the initial years before operating data is available as being "equal[s to] 20% of Net Capability (Nameplate less Station load)."[51]

In summary, the following chart shows how capability or net maximum capacity is used for different types of generating projects and typical levels of unforced capacity credits (or UCAP) for these types of projects, assuming 400 MW projects. For purposes of this chart, a 3% Equivalent Forced Outage Demand Rate (EFOR) is used for a natural gas-fired combined cycle plant and a 7% EFOR is used for a coal plant. For the wind plant, the UCAP rating applicable to immature plants (20% of Net Maximum Capacity) is used.

**Table 9: Capacity Ratings by Generation Type**

| | **Net Capability** | **Net Maximum Capacity** | **UCAP** |
|---|---|---|---|
| | *Gross Output Minus Station Load* | *Sum of Output Ratings of Wind Turbines Minus Station Load* | |
| **Natural gas CC** | 400 MW | | 388 MW |
| **Coal** | 400 MW | | 372 MW |
| **Wind** | | 400 MW | 80 MW |

As shown, there the definitions of net capability and net maximum capacity are virtually identical and refer to maximum capability to produce energy while UCAP is a discounted measure of ability to produce energy during summer peak hours. It is the former that was used to limit contract size and, as shown below, to determine the amount of security

[51] "Integration of Wind Energy in PJM," presentation of Ken Mancini, Sr. Engineer, Capacity Adequacy Planning, PJM Interconnection, at 19 (December 18, 2006), see Appendix B to this Report

required to be provided by bidders (as well as determining the amount of liquidated damages for delay).[52]

However, we recognize that the 600 MW proposals have somewhat better economics than the 400 MW proposals and may be at least marginally easier to finance than the 400 MW proposals.[53] All of the bidders submitted non-conforming bids. The State Agencies should consider whether there is benefit in accepting these bids that may outweigh the additional risks that Delmarva customers would incur due to the additional amount of energy that would be purchased in connection with the non-conforming bids and the associated potential for greater above-market costs should market prices be lower than projected.

**Amount of Security and Liquidated Damages**

In our report, we recommended that due to lower capacity factors of wind projects (generally, less than a 40% capacity factor), lower levels of UCAP (initially, 20% of installed capacity under current PJM rules, and generally lower levels of required security in the industry, that "wind projects pay only 40% of the required security for baseload and other projects (i.e., $40/kW per kW of *nameplate capacity* as compared to $100/kW of development period security), 40% of the associated Delay Damages, and 40% of our proposed cap on operational period security."[54] These recommendations were adopted by the Commission and Energy Office.[55]

Bluewater proposes that the amount of development period security be based on the amount of UCAP, asserting that "Guaranteed Capacity," which is defined as the maximum amount of "Net Capability" that Seller is offering to Buyer, is intended to mean the amount of unforced capacity credits for which a project could qualify for under PJM rules.[56] For the 400 MW proposals, the amount of development period security offered is $3.2 million ($40 * 80,000 kW) instead of $16.0 million ($40 * 400,000 kW). For the 600 MW proposals, the amount of development period security offered is $4.8 million ($40 * 120,000 kW) instead of what could be $24 million ($40 * 600,000 kW).

While the Independent Consultant sought to appropriately reduce the required amount of security by 60% from that applicable to other projects based on their installed (nameplate) capacity, which would be $40 million for 400 MW of Guaranteed Capacity, Bluewater is effectively seeking a 92% reduction to $3.2 million. This amount, effectively, $8.00/kW, is far too low for the magnitude of this project, and is substantially below the non-negotiable amount of $40/kW of nameplate capacity. The same is true of Bluewater's proposal to have the operational period security based on the amount of

[52] For payment purposes, non-intermittent energy projects not providing firm power are to be paid based on the amount of Net Capability of a project multiplied by Buyer's percentage right to the energy and capacity multiplied by an equivalent availability adjustment provision. For wind projects, however, Delmarva is to pay seller the amount of UCAP from Buyer's entitlement to Contract Capacity.
[53] See Table 8
[54] Report at 32.
[55] Report at 44-46, 48-49.
[56] Bluewater Response to Delmarva Questions dated January 4, 2007, at 15-16.

UCAP, approximately $16.00/kW instead of the required $80/kW of nameplate capacity. If the State Agencies wished to direct Delmarva to negotiate a contract with Bluewater, it should be for the amount of (non-negotiable) security approved in the RFP.[57]

We do suggest one accommodation to Bluewater. If the State Agencies were to direct Delmarva to negotiate a contract based on one of Bluewater's 600 MW proposals, the amount of required security and delay damages should be based on 500 MW of nameplate capacity, in light of Bluewater's agreement to limit energy sales to 400 MWh per hour. This appropriately takes into consideration the impact of the energy cap.

Bluewater has suggested a variety of other changes to the standard form contract but we do not find them to be of a nature that reasonable parties should not be able to reach agreement.

## *B. Conectiv*

**Second Lien**

Conectiv excepted to the requirement that it be required to provide a second lien on its proposed gas-fired combined cycle facility. Conectiv asserted that it should be required to provide financial security or a second lien, but not both, arguing that the financial security is sufficient from the standpoint of commercial reasonableness. Conectiv has not provided any reason why providing a second lien would hamper its ability to proceed with the project. We have not been provided with any cogent reason why Conectiv should not be required to provide a second lien on the facility. Delmarva has argued strenuously that a second lien is necessary to protect its interests, especially during the operational period of the contract, regardless of the creditworthiness of the Seller. Conectiv, an affiliate of Delmarva, should not be given special treatment in this regard. As indicated previously, Section 2.6 of the RFP specifically states that the security requirements apply to any Delmarva affiliate.

**"Permitting Out"**

Conectiv did not except from the requirement of posting $100/kW of security of Guaranteed Capacity (approximately $17.7 million) to secure its commitment to have the project achieve the Guaranteed Initial Delivery Date. However, it did except from the requirement that if it failed to achieve required permits for the project by an agreed Permitting Milestone date, it would either have to pay $50/kW in liquidated damages or it could extend the date for six months, but if it failed to meet the extended date, Buyer could terminate the Agreement and Seller would be obligated to pay the full $100/kW of development period security as liquidated damages. In fact, Conectiv proposed a "permitting out" -- that as long as it made commercially reasonable efforts to obtain required permits, it could terminate the PPA if it failed to do so and obtain a total return

[57] This includes the maximum collateral after the initial delivery date as being $80 per kW of nameplate capacity and the daily rate for Delay Damages as $.0933 per kW of nameplate capacity.

of development period security. Moreover, Conectiv also sought a similar "out" if it failed to obtain PJM permission to interconnect the plant in sufficient time.

These risks -- obtaining permits and interconnection rights in a timely fashion -- are those for which sellers take responsibility in power purchase agreements. Moreover, the risks for Conectiv associated with permitting and obtaining interconnection rights for a new natural gas-fired combined cycle unit at an existing site are not in the least extraordinary. Conectiv should be required to assume these risks as provided for under the Standard Form PPA. If Conectiv requires slightly more slack in the schedule, the Guaranteed Initial Delivery Date could be deferred a number of months.

### One-Time Price Adjustment

Conectiv's proposed one-time adjustment to its proposed capacity and energy prices is discussed in detail in Section III.A of this Report. As stated therein, we are concerned regarding the potential impact of these provisions in the event of a price spike in natural gas substantially affecting forward prices before the price adjustment goes into effect.

There are several ways this issue could be remedied. First, the transaction could be conditioned on a maximum upward move in the Forward Gas Price of no more than a specified percentage from the base price, 10%, for example. Another approach is that the transaction could be conditioned on a maximum upward move in the Forward Gas Price of no more than a specified percentage of the price of the Forward Gas Index on the day before a decision is made by the State Agencies to approve the contract. In this manner, Delmarva would have no obligation to purchase and Conectiv would have no obligation to sell if prices moved beyond the specified limits. Another approach, which would be more protective of ratepayers, would be to set the price the day before the State Agencies met to make a decision on the matter and Conectiv would need to incur the risk of rising natural gas prices (it is uncertain whether Conectiv is willing to take this risk).

If the State Agencies decide to approve the Conectiv proposal, they should direct Delmarva to negotiate some form of "circuit breaker" on the transaction to mitigate against unexpected price increase due to Forward Gas Prices moving sharply upward.

### Carbon Dioxide Regulation Costs

As mentioned in Section III.A of this Report, Conectiv proposes (a) to pass through all Btu or carbon taxes and (b) the amount of environmental compliance costs that would be incurred that is greater than what Conectiv would incur under RGGI if a federal greenhouse gas regulatory program is enacted carbon dioxide regulation is enacted. The latter aspect of Conectiv's proposal was not at all clear in their bid and arose in response to questions from Delmarva and the IC. If the State Agencies decide to approve the Conectiv proposal, they could either (a) deny Conectiv's request to pass through certain environmental regulatory costs due to a change in law or (b) direct Delmarva to negotiate provisions regarding future changes in environmental law involving greenhouse gas regulation, regardless of whether they are in the form of taxes or the need to purchase allowances or otherwise, where Conectiv would assume the costs up to a negotiated

$/MWh amount based on what Conectiv has assumed in pricing its bid, with the ability to pass through additional, reasonably incurred costs above the baseline; provided, Conectiv would be responsible for compliance with all costs associated with RGGI for which there would be no pass-through. Another possible structure is to allow a percentage pass-through.

Since Delmarva and Conectiv are affiliated, the Independent Consultant could monitor the negotiations to provide some comfort that the contract provision is being fairly negotiated on behalf of the ratepayers.[58]

**Conformity of Alternate Offer with RFP Requirements**

Conectiv's Alternate Offer is not strictly in compliance with the Standard Form RFP, which only allows bidders to provide energy from other sources where the unit that is subject to the PPA is unavailable (Section 3.9). Conectiv proposes that if have the flexibility to provide energy sources to the same point of delivery from other sources regardless of whether the proposed unit is available or not.

In our view, the benefits to Delmarva ratepayers from this proposal outweigh any detriments. First, Conectiv is offering a substantially lower price for this flexibility and it will be Delmarva's daily choice as to whether to purchase energy for economic reasons. Second, since the sale is for firm energy, there is not the opportunity for "gamesmanship" that concerned us where the bidder is offering unit-contingent power.[59] Hence, we find this aspect of the Alternate Offer to be acceptable.

## *C. NRG*

As noted above, NRG has proposed that all incremental environmental compliance costs due to a change in law concerning $CO_2$ regulation or otherwise will be "passed through" to Delmarva. In addition, NRG has proposed that it have the right to terminate the PPA if it cannot obtain financing, with or without a breakage fee depending on the reason for not being able to obtain financing. In light of the scores received by NRG in the bid evaluation, we do not believe these issues need to be addressed in the context of contract negotiations at this time. The IC will provide greater detail on these contract points should the State Agencies decide that it is useful to their deliberations.[60]

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[58] If Delmarva were to enter into a long-term contract with Conectiv, there would be a general need for greater Commission oversight regarding Delmarva's contract administration than would be the case with a similar contract with a non-affiliated seller.

[59] See RFP Report at 18.

[60] We would like to note, however, that NRG's proposal to index the entire amount of its proposed capacity price to an inflation index is not of significant concern to us. It should not lead to significant price instability and the economic effects have been incorporated in the economic analysis.

# VI. Conclusions

The RFP has succeeded in producing credible proposals related to three projects, each of which warrants serious consideration. The diversity of proposals highlights the trade-offs identified in EURCSA on matters such as environmental benefits, technology innovation, fuel diversity, reliability, feasibility, cost impact on ratepayers, and price stability.

On a total score basis, the Conectiv Alternate Offer for its natural gas-fired project scored highest, followed by the Bluewater Atlantic North offshore wind project (600 MW, 25 year proposal). NRG's various bids for a coal-fired gasification project had the lowest scores.

The Bluewater bid had the most favorable characteristics, especially on environmental grounds, and contributed most to price stability, albeit at a substantial cost. The Conectiv bid had the most favorable economics and is the most "likely to succeed" in terms of project viability. Based on the economic analysis, all the bids, even the Conectiv bid, were above market during the analysis period.

In the next phase of our work, we will explore some of the larger issues involving the relationship between the bids received in the RFP process and the alternatives recommended or just simply considered in the IRP process. Our report, due on April 4, 2007, will address the risks and benefits of going forward, or not going forward with one of the bids in the larger resource planning context and will consider the interactions with alternatives recommended or considered in the IRP. That analysis combined with this Report will provide the State Agencies with important information to help them determine how best to select from the competing factors involved in deciding among the resource options, including the option not to select any of the bids.

# Appendix A: Standard & Poor's Request For Comments: Imputing Debt To Purchased Power Obligations

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

# Request For Comments: Imputing Debt To Purchased Power Obligations

**Publication date:** 01-Nov-2006

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Standard & Poor's Ratings Services is requesting comments from market participants about one specific element of its refined methodology for imputing debt to purchased power obligations involving utility companies.

## Proposal Summary

Standard & Poor's is abandoning its practice of not imputing debt for purchased power agreements (PPA) with terms of three years or less. In addition, where there is a high probability that the utility will have an ongoing obligation to serve load beyond the nominal tenor of short-term contracts, which is almost always the case, Standard & Poor's is contemplating providing evergreen treatment to PPA obligations to reflect the long-term load serving obligations borne by utilities. Unless an electric utility faces a declining population or real prospects of customer migration to other suppliers, both of which are rare, any near-term or intermediate power supply contracts will need to be renewed or replaced with contracted or self-built capacity to continue to meet load obligations.

We acknowledge that the process of providing evergreen treatment to outstanding contracts is imprecise. Uncertainties surround the level of capacity prices that should be assumed and the duration for which contracts should be extended to reflect the load-serving obligation. Therefore, we welcome input on evergreen-related issues as we refine these aspects of the criteria.

## Response Deadline

Please submit your comments on this proposal through Dec. 15, 2006, to criteriacomments@standardandpoors.com

## Imputation Is Important For Credit Analysis

Standard & Poor's has for many years considered PPAs as financial obligations that electric utilities incur when they elect to purchase rather than build their own capacity, and this obligation has affected our view of utilities' creditworthiness. Standard & Poor's has historically applied a "risk factor" of 0% to 100% to the net present value (NPV) of the PPA capacity payments, and capitalized this amount. The risk factor's role is to calibrate the stringencies of debt imputation relative to our evaluation of the certainty of recovery of power purchase costs by virtue of regulatory and legislative protections. The imputation of debt and debt service is important to our credit analysis because the resulting financial adjustments affect several key credit metrics used when we assess credit quality.

The risk factor acts as a proxy for the proportion of risk borne by the utility. At 100%, all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers.

## Reviewing Existing Criteria--And A Few Refinements

From time to time, Standard & Poor's has revisited the methodology employed for making the financial adjustments that incorporate the obligations created by PPAs in its credit evaluations. This article discusses the most recent refinements. It also includes a discussion of additional areas that are under consideration as potential future refinements to our ratings methodology. While we expect very modest, if any, rating changes to result from these modifications, the proposed modifications are being disseminated in this article in the interest of ensuring the ongoing transparency of our rating methodology.

Standard & Poor's published its original PPA criteria in 1991, and provided updates in 1993 and 2003. During this time, the industry has established a very strong track record of demonstrating the viability and effectiveness of the various recovery mechanisms that state regulators have established for costs associated with contracted generation capacity. Recovery mechanisms have largely performed as intended, and related write-offs have proven to be very low. These results justify the continued application of risk factors that serve to temper, often substantially, the amount of debt imputation. Ensuring meaningful comparability in the financial commitments among utilities that are building and those that are purchasing capacity to satisfy load obligations is the rationale for our imputation of debt and debt service for PPAs. PPAs essentially represent substitutes for direct, debt-financed, capital investments. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. The analytical goal of our financial adjustments for PPAs is to reflect the fixed obligation in a way that depicts any credit exposure that is added by the presence of PPAs. That said, a PPA also shifts various risks to the supplier, such as construction risk and most of the operating risk. As a result, the principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates. While it is the utility that must of course make these payments, however, to the extent that regulators and, in certain cases, legislatures, have structured recovery to assign the burden to ratepayers, the utilities' risk diminishes.

## Refinements To The Methodology

With only modest liberalization of the treatment of PPAs, we are perpetuating the current ratings criteria. Current guidelines for utilities whose capacity payments are recovered in base rates provides for the application of a 50% risk factor to the NPV of the capacity payments. This approach will continue. The NPV is calculated using the utility's average cost of debt (excluding securitization debt), rather than the standardized 10% discount rate used previously. For purposes of adjusting cash flow measures, implied interest expense is calculated on the imputed debt amount. This is accomplished by applying the average cost of debt to the relevant year's imputed debt level.

To date, where PPA capacity costs were recovered through a fuel adjustment clause (FAC), as compared with base rate recovery, a risk factor of 30% has been generally used in lieu of the 50% risk factor. We view the recovery of the capacity component of a PPA through a FAC as providing greater certainty and timeliness than recovery through a base rate mechanism. (The base rate mechanism generally has greater potential for under-recovery due to variations in volume sales and fluctuations in fuel prices over time.) Based on the effectiveness of FAC mechanisms, we will adjust modestly the risk factor of 30% down to 25%.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still do not amount to pure FACs. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, a risk factor between the revised 25% FAC risk factor and the 50% risk factor will be employed in calculating adjusted ratios.

In those instances where recovery of PPA-related capacity costs is guaranteed by a legislative mechanism, the level of the risk factor will be determined by the timeliness provided by the legislative true-up mechanism. The strength of the mechanism can result in risk factors as low as 0% because legislatively prescribed recovery mechanisms are viewed as providing utilities with a greater level of protection than that provided by regulatory orders.

There are a number of utilities to which Standard & Poor's does not impute any PPA-related debt. Specifically, Standard & Poor's does not impute debt for supply arrangements if a utility acts merely as a conduit for the delivery of power (e.g., because it has been transformed into a pure transmission and distribution utility by regulators or legislation that has directed the divestiture of all generation assets). For example, in New Jersey, the vertically integrated utility companies were transformed into pure transmission and distribution utilities. The state commission, or an appointed proxy, leads an annual auction in which suppliers bid to serve the state's retail customers, and the utilities are protected from supplier default. In New Jersey, the power supply function of the state's utilities has essentially been reduced to the delivery of power and the collection of revenues from retail customers on behalf of the suppliers. Therefore, while Standard & Poor's has continued to impute debt to New Jersey's utilities for qualifying facility and exempt wholesale generator contracts to which the utilities are parties, we do not do so for other electricity supply contracts where the utilities merely act as conduits between the winners of the regulator's supply auction and the end-user, retail customers.

Finally, Standard & Poor's is abandoning the practice of not imputing debt for contracts with terms of three years or less. In addition to abandoning our historical three-year rule, we are contemplating applying an evergreen mechanism for short-term contracts. Because expiring contracts must be replaced with either debt-financed capacity additions or replacement PPAs for regulated utilities to meet load serving obligations, Standard & Poor's must look beyond the termination of near-term and intermediate-term contracts to approximate the fixed obligations that will succeed the current contracts in evaluating a utility's financial profile.

The process of providing evergreen treatment to outstanding contracts is imprecise. Uncertainties surround the level of capacity prices that should be assumed and the duration for which contracts should be extended to reflect the load-serving obligation. Therefore, we welcome input on evergreen-related issues as we refine these aspects of the criteria over the next 45 days.

## Adjusting Financial Ratios

Standard & Poor's determines the debt equivalence that it will add to a utility's balance sheet as a result of being a party to a PPA by calculating the NPV of the annual capacity payments over the life of the contract because it is the capacity payment that represents the vehicle that funds the recovery of the supplier's investment in the generation asset.

Where the PPA contract price is stated as a single, all-in energy price, Standard & Poor's will use a proxy capacity charge, stated in dollars per kilowatt-year, and multiply that figure by the number of kilowatts under contract. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine. This is a departure from the historical practice of simply halving all-in energy payments and assuming a one-to-one ratio of energy to capacity payments. This new element of the rating methodology will also be applied to generation with extremely low variable costs whose price is stated as an all-in energy price, such as nuclear and wind generation.

The discount rate used in calculating an NPV, imputed debt, and imputed interest expense is the utility's average interest rate on its outstanding debt (excluding securitization related debt). Standard & Poor's multiplies the NPV of the stream of capacity payments by the appropriate risk factor, which will generally be 25% for capacity payments that are recovered through fuel adjustment clauses and 50% for capacity payments that are recovered in base rates. This amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense by multiplying a given year's NPV of PPA-related capacity payments by the risk factor and the company's average interest rate on outstanding debt. The resulting number is added to reported interest expense to calculate adjusted interest coverage ratios.

Key ratios affected include:

- Balance sheet debt is increased by the calculated NPV of the stream of capacity payments, after the application of the risk factor, which is added to the numerator and denominator in calculating an adjusted debt-to-capitalization ratio;
- The implied interest expense derived from applying the average interest rate to the NPV figure is simultaneously treated as a reduction in power purchase expenses and added to interest expense for the calculation of the adjusted funds from operations (FFO) to interest ratio; and
- The FFO to total debt ratio is adjusted by adding the NPV of capacity payments, after the application of the risk factor, to debt in the denominator and an implied depreciation expense is added to FFO.

The depreciation expense adjustment, the last element of the principal financial adjustments cited above, represents a new element within the context of financial adjustments for PPAs (though it has been a long-standing component of the analytical adjustments for leases). Adding an implied depreciation expense to FFO is another element that aligns the analytical treatment of PPAs with the concept of purchased power as a substitute for self-build. The depreciation expense adjustment is a vehicle for capturing the ownership-like attributes of the contracted asset and has the effect of mitigating some of the ratio impact of debt imputation.

The mechanics of these adjustments are illustrated in the table.

| **Adjustments To Ratios** | | | | | | |
|---|---|---|---|---|---|---|
| **(Mil. $)** | **Year 1** | **Year 2** | **Year 3** | **Year 4** | **Year 5** | **Thereafter** |
| Funds from operations | 2,500 | | | | | |
| Interest expense | 650 | | | | | |
| Directly issued debt | 10,000 | | | | | |
| Shareholders’ equity | 9,000 | | | | | |
| Fixed capacity commitments | 500 | 500 | 500 | 500 | 500 | 4,000 |
| **NPV of fixed capacity commitments** | | | | | | |
| Using a 6.5% discount rate | 4,079 | | | | | |
| Applying a 25% risk factor | 1,020 | | | | | |
| **Unadjusted ratios** | | | | | | |
| FFO/interest (x) | 4.9 | | | | | |
| FFO/total debt (%) | 25 | | | | | |
| Debt/capitalization (%) | 53 | | | | | |
| **Ratios adjusted for debt imputation** | | | | | | |
| FFO/interest (x)* | 4.6 | | | | | |
| FFO/total debt (%)¶ | 23 | | | | | |
| Debt/capitalization (%)§ | 55 | | | | | |

*Adds implied interest to the numerator and denominator. Also adds implied depreciation to the numerator. ¶Adds implied depreciation to the numerator and adds implied debt to total debt. §Adds implied debt to both the numerator and the denominator.

Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. The NPV of the PPA will typically decrease as the maturity of the contract approaches, but on a portfolio basis, the overall NPV may remain somewhat static as old contracts roll off and new ones are executed.

## Conclusion

Absent legislative assurance of recovery, or an obligation that is little more than a fiduciary role for a transmission and distribution utility, PPAs constitute a financial risk by adding fixed obligations, though history is clearly on the side of full recovery. There is ample evidence that utility regulators and commissions have intended these costs to be for the account of the ratepayer, which justifies the continued use of risk factors. The modest revisions to our methodology seek to perpetuate our use of financial adjustments that reflect the legislative and regulatory protections that mitigate regulated utilities' exposure to the fixed obligations created by PPAs.

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# Appendix B: PJM Presentation on Wind Generation Capacity Rule

## Integration of Wind Energy in PJM


## *Capacity Credit for Wind Generation*

- **PJM's Wind Capacity Credits**
  - **Based on real operating data when available**
  - **Three year rolling average of hourly outputs:**
    - **For the 4 hours ending 3 to 6 PM...**
    - **On the summer days of June 1 to August 31 Incl.**
  - **Wind "Class Average"**
    - **Used for each year operating data is unavailable**
    - **Equals 20% of Net Capability (Nameplate less Station load)**
    - **Replaced by actual data in rolling average calculation as operating data becomes available**