BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF INTEGRATED RESOURCE PLANNING FOR THE PROVISION OF STANDARD OFFER SUPPLY 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)	)	DOCKET NO. 06-241
and		
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 OF THE INITIAL RESOURCE PLAN SUBMITTED DECEMBER 1, 2006 (OPENED JANUARY 23, 2007).	)	DOCKET NO. 07-20

DELMARVA POWER & LIGHT COMPANY'S RFP BID EVALUATION REPORT

Dated: February 21, 2007

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A PHI Company

Request for Proposals
Bid Evaluation Report

February 21, 2007

EXECUTIVE SUMMARY

This report evaluates the bids from three bidders that Delmarva Power & Light Company ("Delmarva" or the "Company") received in response to its recent request for proposals (the "RFP") for the construction of new electric generation resources in Delaware and makes recommendations to the State agencies involved in the evaluation of these bids.

The RFP was required by the Electric Utility Retail Customer Supply Act of 2006 ("EURSA" or the "Act"). The Act was designed to encourage the construction of new electric generation resources that would provide stable (and low) energy prices; reduce the impact on the environment; realize the benefits of new technologies; be located on feasible sites; and offer Long Term Power Purchase Agreements ("PPAs") terms and conditions that are beneficial to Delmarva's electric customers. The Act envisioned that the power from the new generation resource would supply a portion of the needs of Delmarva's Delaware Standard Offer Service requirements for its residential and small commercial/industrial ("RSCI") customers (the "SOS" load). The power purchases would be consistent with the expected needs of those customers and available generation resources, as set forth in Delmarva's Integrated Resource Plan ("IRP"), filed in December 2006. The Act did not contemplate that Delmarva would be required to enter into a contract to purchase power that its customers did not need.

Delmarva evaluated bids from Bluewater Wind, LLC ("Bluewater," "Bluewater Wind," or "BWW"), Conectiv Energy Services, Inc. ("Conectiv"), and NRG Energy, Inc. ("NRG"). Bluewater proposes building a 600 megawatt facility off the coast of either Rehoboth Beach or Bethany Beach, Delaware. The facility would be an offshore wind park consisting of approximately 200 wind turbines, covering a footprint of 30 nautical square miles. The proposed PPA term is 20 to 25 years. Conectiv proposes building a 180 megawatt facility at its existing power plant complex in New Castle County, Delaware. The facility would utilize traditional combustion turbine technologies. The primary fuel would be natural gas. The proposed PPA term is 10 years. NRG proposes building a 600 megawatt facility at its existing power plant complex in Sussex County, Delaware. The facility would utilize new integrated gasification combined cycle ("IGCC")

Delmarva's evaluation was completed in accordance with the detailed criteria set forth in the RFP that was set forth in the Findings, Opinion and Order of the Delaware Public Service Commission (the "Commission") and the Delaware Energy Office (the "DEO") (collectively the "Public Agencies"), as determined in Order No. 7066 and Amending Findings, Opinion and Order No. 7081. In performing the evaluation, Delmarva worked closely with the Independent Consultant (the "IC") retained by the Commission, the Office of Management and Budget (the "OMB"), the Controller General (the "CG"), and the Delaware Energy Office (collectively, the "State Agencies"). So we have the Public Agencies (just the two) and the State Agencies (all four). Contemporaneously with the filing of this report, the IC will be filing their own independent evaluation report.

Delmarva and the IC evaluated the bids by applying a number of price and non-price factors. Each factor was awarded points based on a 100 point scale previously approved by the Commission and DEO. A maximum of 33, 20, and 7 points was assigned, respectively, for the lowest price, the most stable price, and price exposure and contract terms. A maximum of 40 points was assigned for non-price factors: environmental impact (14); fuel diversity (3); technological innovation (3); operation date and its certainty (3); reliability of technology (2); site development (5); bidder experience, safety and staffing (5); and project financeability (5).

Delmarva and IC are in agreement that the highest ranked bid was Conectiv, followed by Bluewater and then NRG. As detailed below, Conectiv scored highest on price, price exposure, operation date, reliability of technology, site development, bidder experience, and project financeability. Conectiv also scored comparatively well on environmental impact (natural gas is a clean-burning fuel and Conectiv plans on building its facility at an existing power plant complex).

The Public Agencies assigned a combined 53 points to price and price stability (out of 100 points). The weighting of points to these economic factors is to, in Delmarva's view, award points to bidders that achieved the economic objective of the Act: energy price stability in a cost-effective manner. The point allocation recognizes that both cost and stability are very important. Unfortunately, none of the bids reached this objective. Other than Conectiv's bid results, the bids are too costly and produce little price stability. Conecitv's bids were just slightly above forecasted market prices but, in turn, provided no price stability. Conectiv's best price bid has customers paying approximately $100 million above market and reduces market variability by less than 2%. Bluewater's best price bid has customers paying approximately $2.0 billion above market and reduces market variability by only 36%. NRG's best price bid has customers paying approximately $3.9 billion above market and actually increases market variability to customers.

Delmarva recognizes the real importance of environmental factors in the evaluation of bids and in protecting the citizens of Delaware from environmental harm. Accordingly, the RFP gives credit to clean projects in a number of places. There are 14 direct points

available for Environmental Impact. In fact, Bluewater achieved 11.3 of the 14 possible points, more than either Conectiv (9.9 points) or NRG (5.7 points). In addition, there are points available for innovative projects and renewable projects. Thus, Delmarva believes that the environmental benefits and the importance of such benefits to the citizens of Delaware is captured in this evaluation.

Conectiv was ranked the highest in the overall bid evaluation scores for each of the bids with a score of 66.7. Bluewater's and NRG's highest ranked bids scored, respectively, 50.4 and 20.5.

Delmarva urges the State Agencies not to approve any of the bids. In simple terms, even the 180 megawatt facility proposed by Conectiv is too large a block of power from one source, given the limited needs of Delaware's SOS customers. As such, the bid cannot be reconciled with the IRP. Delmarva would likely find itself buying power from Conectiv that SOS customers do not need. Delmarva would then have to turn around and sell that power, likely at a loss. That loss, as required by the Act, would be borne by Delmarva's customers. This problem will be compounded if the conservation and demand side management ("DSM") programs embedded within the IRP have the desired effect, as they should, of reducing energy consumption. (With similar programs, California has kept energy consumption stable, although its economy has grown dramatically.) Moreover, even if Delaware had the electric needs of larger states like New York or New Jersey, long-term, large PPAs, such as the one proposed by Conectiv, provide no upside and significant downside when compared to the existing process whereby Delmarva buys power from a variety of providers under short-term contracts. For example, because the proposed Conectiv PPA price rises and falls with an index, the PPA will not offer much benefit over market prices, but will tie Delaware to a large, long-term contract with associated credit, construction, and other risks.

In sum, therefore, while Conectiv is the highest ranking bidder, neither its bid, nor the other lower-ranked bids achieve the Act's goal of energy price stability in a cost-effective manner, while providing environmental and other benefits to the State of Delaware. Looking at the price alone, Delmarva estimates the NRG bid would cost its customers $4 billion to $5 billion more than buying the power from the wholesale market, and Bluewater's proposals would result in customers paying prices $2 billion over market forecast. Accordingly, the Company recommends that the State Agencies should not approve any of the bids.

It is the Company's recommendation that Delmarva close this investigation of new generation in Delaware and focus its efforts on the original findings of the IRP; implementation of aggressive demand side management to reduce the growth of Delaware's electricity needs, continued reliance on short term 3-year following bids from the increasingly competitive wholesale market for the majority of the SOS energy needs, a focus on a relatively moderate amount of renewable sources of energy to round out the supply portfolio for Delaware, and continued focus on the approval of the new Mid-

Atlantic Power Pathway ("MAPP") transmission line under review by PJM in order to facilitate improved reliability and access to lower cost supply for the Peninsula.

1.1 INTRODUCTION

This report reviews the evaluation results associated with the bids received by Delmarva under its RFP to solicit proposals for the construction of New Generation Resource(s) ("New Generation") within the State of Delaware. The solicitation was required under the Act, which also required Delmarva and the IC retained by the State Agencies to perform a detailed evaluation in accordance with the criteria set forth in the RFP.

The evaluation results contained herein only prioritizes the bids and by no means suggests that Delmarva enter into a PPA to buy electric power (capacity, energy, and ancillary services) to supply a portion of the SOS load. The SOS energy sourcing review will be discussed in this report, but a final recommendation by the Company to execute, or not execute, a PPA will be made once the highest rated proposal is evaluated within the context of the IRP required to be amended by June 29, 2007. The Act does not require Delmarva to select a bid.

The IRP, as originally filed, recommended against the need for PPAs due to the added exposures/risks placed on customers and the availability of conservation, DSM programs, renewable and transmission resources to meet SOS customer requirements. Delmarva concludes, based on the bid results, that none of the proposals achieve the Act's goal associated with the RFP of producing energy price stability in a cost-effective manner, while providing environmental benefits and other advantages to the state.

The IRP, under the Act, was required to investigate all potential opportunities for a more diverse SOS supply at the lowest reasonable cost. The RFP process was a focused assessment as to the benefits of one potential SOS supply sourcing option: newly built generation within the State of Delaware. The RFP bid ranking criteria, per the Act, was to be based on the cost-effectiveness of the project in producing energy price stability, reductions in environmental impact, benefits of adopting new and emerging technology, siting feasibility and terms and conditions concerning the sale of energy output from such facilities. Delmarva, along with the IC, established an evaluation design with the intent to capture these key legislative goals.

1.2 THE PROCESS EMPLOYED

The Act set specific requirements, as part of the initial IRP process, for the issuance of an RFP for the construction of new generation resources within the State of Delaware and the establishment of PPAs to serve Delmarva customers receiving Standard Offer Service.

To implement the requirements of the Act, the Commission issued Order Number 7003 to facilitate public input and involvement in the RFP process. Delmarva and its consultant, ICF International ("ICF"), have coordinated closely with the State Agencies and their IC, and this team has met all statutory deadlines. Together, Delmarva, the State Agencies and their consultants constitute the "Reviewing Parties."

As required by the Act, on August 1, 2006, Delmarva submitted a draft RFP to solicit for the procurement of new PPAs. On August 18, 2006, the Commission staff conducted a public workshop, in which Delmarva actively participated, to discuss this draft RFP. Many parties offered verbal comments at this workshop, and a number of parties later submitted written comments.

The Act authorized the Commission and the DEO to modify the draft RFP to recognize the value of certain features. These Public Agencies have coordinated closely with the State Agencies and the IC throughout the RFP process to align the evaluation criteria with the Act's objectives.

Following the public comment period, the IC provided a draft report and markup of the RFP on September 28, 2006 and, after receiving comments, delivered its final report on the draft RFP on October 12, 2006. The Public Agencies then met for a full day on October 17, 2006, to provide for public discussion and receive public testimony on the proposed RFP design and evaluation process. Prior to the hearing on October 17, Staff developed a list of more than a dozen issues describing the various parties' positions related to the proposed revisions to Delmarva's draft RFP. During these proceedings, Delmarva raised strong concerns to a number of RFP structuring issues that the IC proposed, arguing that these changes would greatly increase the risk to Delmarva's customers. However, Staff indicated that their aim was to "cast a broad net" to encourage as many bid responses to the RFP as possible and that the particulars of each bid could be reviewed during the evaluation phase of the RFP.

During the public hearing, the Public Agencies accepted 15 of the Agencies' and IC's recommendations, deferred a decision on two issues (later accepted with revisions) and accepted one of Delmarva's recommendations. The Public Agencies ruling reflected adopting a "Big Funnel" approach. See Docket No. 06-241, Hearing Transcripts (October 17, 2006).

At the October 17, 2006 hearing before the Public Agencies, Mr. Tom Shaw, Chief Operating Officer of PHI and Chief Executive Officer of Delmarva, provided comments to the IC report on Delmarva's proposed RFP. In his comments, Mr. Shaw clearly articulated in point-by-point fashion the Company's rationale for disagreeing with the IC's recommendations to modify the RFP.

Delmarva's position, as articulated to the Commission, is as follows:

> ". . . there are three core issues that tie together. [T]hose core issues relate to the bid block or the megawatt size that is going to be procured. It relates to credit and security requirements that are needed to protect the customers here in Delaware. [I]t relates to whether the contract is going to be for firm energy, or it's going to be tied to a specific plant.

Hearing Transcript at 247.

Commission Staff ("Staff") took a different point of view. Staff stated that the Company's proposed RFP would restrict the number of bidders.

> "Staff, obviously takes a different position. It is like a funnel. We are interested in having a large response to this RFP. We are fishing with a broader net . . . And Staff believes that its prospective in trying to broaden the net, if you will, and to allow as many potential bidders to participate in this process, and then through the evaluation process what is the most appropriate bid is the way to go rather than narrowing the focus in the beginning and having the prospect that no one will be able to bid."

Hearing Transcript at 250.

Staff's position to "broaden the net" to encourage bids should now be balanced with a careful evaluation of the bids received. The Company is particularly concerned that the three core issues identified and described before the Public Agencies by Messrs. Shaw and Wilson are properly evaluated.

Delmarva, while strongly opposed to many of the changes proposed by the IC, released the final RFP and Term Sheet on November 1, 2006. The evaluation of the responses to the RFP were to be based upon a 100 point scale, assigning 60 potential points to price, price stability and other price-related factors, and 40 potential points to a wide range of non-price factors (e.g., environmental impacts, site development, etc.). This scoring allocation was agreed to by the Public Agencies. The documents issued on November 1, 2006 included the main RFP document and a Term Sheet specifying the non-negotiable terms of the proposed PPA contract that a successful bidder, if selected by the Company and State Agencies, would be required to sign.

To facilitate the RFP process, 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. To maintain openness, efficiency and security, 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 they 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 ("NOIs") to bid by November 22, 2006, along with the location of the plants (which enabled Delmarva to begin its transmission analysis). Once bidders filed an NOI, they received the full PPA for their review. The Bidder Response Forms, specifying precisely the information to be submitted with their proposals to evaluate the bids, were first posted on November 1, 2006, with updates posted on November 16, and the final version posted on November 27, 2006.

Four companies – Bluewater, Conectiv, Invenergy, Inc. ("Invenergy") and NRG - submitted NOIs; however, Invenergy later withdrew. These three potential bidders then submitted more than 100 questions regarding the RFP and Term Sheet, which Delmarva, the Public Agencies and their consultants diligently answered on the website. In accordance with the RFP, one bidder (Bluewater) submitted its draft bid by December 8, 2006, so that Delmarva could assess its responsiveness. The Reviewing Parties then provided detailed feedback to this bidder on areas in which the draft proposal appeared to be non-responsive. As mandated by the Act, bidders submitted their final proposals to Delmarva by December 22, 2006 (December 21, 2006 for Conectiv).

Delmarva received five bids from three parties for the new generation resource. Bluewater, submitted three bids for offshore wind parks. Both the "North Atlantic" and "South Atlantic" proposed facilities are 600 MW offshore wind parks. A third proposal for a 546 MW facility at Bluewater's proposed "Bay" site was submitted, but later withdrawn. Conectiv, a subsidiary of Pepco Holdings, Inc., and affiliate of Delmarva, submitted a bid for a 180 MW dual fuel, combined cycle power facility at its Hay Road facility. Conectiv's bid included a "base" option, as well as an "alternative" option, which would provide firm energy. NRG submitted a bid for a 600 MW baseload IGCC facility to be built at NRG's existing Indian River power station, of which between 280 MW and 400 MW would be available to Delmarva.

The evaluation of bids encompassed three types of assessments: threshold, responsiveness and detailed evaluations. The threshold criteria were clearly specified in the RFP and the "responsiveness" review enabled the Reviewing Parties to ensure that they had sufficient information with which to evaluate the bids. The Reviewing Parties conducted an initial screen of the proposals and provided detailed questions to each Bidder on December 29, 2006. Questions focused on items that were ambiguous or incomplete, as well as areas that did not meet the threshold requirements. All the Bidders responded to these questions within three business days, as required.

Upon receipt of responses to the questions, the bids were passed to experts in each area for more thorough evaluation. Delmarva also issued notes to each of the Bidders on January 5, 2007, as required in the RFP, indicating that all of the Bidders were passed to the Detailed Evaluation stage, though the Reviewing Parties had concerns about lack of

RFP conformance by each of the Bidders. In specific, bids that did not meet the threshold requirements outlined in, and/or had bid structures not in accordance with, the RFP were deemed "non-conforming." In that regard, the Commission ruled in Docket No. 06-241 on December 19, 2006 that Bluewater Wind's proposal to provide up to 400 MW per hour from a project larger than 400 MW did not conform to the intent of the RFP, but that the Reviewing Parties should nevertheless evaluate the proposals of Bluewater Wind. The Reviewing Parties decided to evaluate all of the bids received given the direction provided by the Public Agencies on Bluewater's non-conformance, and all were deemed non-conforming. The Reviewing Parties provided supplemental questions to each Bidder to clarify issues that arose in the course of the detailed evaluation, and Bidders responded in a timely manner to these inquiries.

The Reviewing parties coordinated on the approach to scoring for each of the price and non-price factors to ensure that the evaluation of bids would reflect the values and goals of the Act and would lead to the appropriate ranking of bids. This factor-by-factor evaluation approach allowed the Reviewing Parties to ensure that each criterion was evaluated by experts in the relevant field. For the non-price factors in particular, Delmarva and the Public Agencies, with their respective consultants, conducted wholly independent evaluations, developing their own scores based on their assessment of the merits of each proposal. With regard to the price and price stability factors, the Agencies and the IC reviewed ICF's input assumptions and relied upon ICF's well-regarded energy market modeling capability to ensure consistency of assumptions, scenarios and bid evaluation.

Within each of the appropriate non-price factors, the potential points were sub-divided further so that evaluators could use a common scale to apply to each bid. The Reviewing Parties, while they did not always agree, believe that this scoring approach provided the most objective evaluation possible within the 100 point scoring system for each bid submitted. Each of the non-price factors had team structures for the evaluation in which experts performed independent analysis, then discussed their assessments to finalize each score.

Several of the non-price factors were outlined concretely in advance, and necessitated little discussion during evaluation. For example, "greenhouse gas emissions" and "criteria pollutants" were evaluated based on mathematical formulas developed through the shared efforts of the Reviewing Parties. Other straightforward factors included fuel diversity and technological innovation, where the evaluation criteria clearly designated a point value for each set of circumstances. The only judgment required in these cases was whether the Reviewing Parties agreed with the information provided in the proposals (e.g., whether they agreed that the proposed on-line date was achievable).

Some of the factors were more judgmental. Water, land, and wildlife impacts, for example, required substantial discussion among the experts. For these factors, Delmarva and ICF employed a National Environmental Protection Act expert, an air emissions expert, and an environmental expert. These experts completed independent evaluations,

and then coordinated to finalize the scoring. The ability to arrange financing was another judgmental factor, based on the impression of experts on the ability of the Bidders to obtain sufficient financing to build the project and sufficient cash flow to sustain the project over the term of the PPA.

Once they had evaluated and scored a majority of the non-price factors, the Reviewing Parties met to discuss preliminary results and current standings. The purpose of this meeting was not to persuade each other of their respective positions, but rather to ensure that the experts had considered the full range of important issues throughout their evaluations. Following discussions on a number of important topics, the Reviewing Parties finalized their independent scoring for each of the non-price factors.

With regard to price and price stability analysis (53 total points, not including the assessment of "Exposure" and "Contract Terms"), ICF shared the modeling assumptions and scenarios with the IC in advance of running the models. There was considerable discussion about these assumptions, such as the cost of compliance with future CO2 regulations and the future price of coal. These types of assumptions affected the evaluation since the review of bids included the impact that the proposed project would have on the market as a whole for Delmarva's SOS customers. ICF also conducted a detailed assessment of the cost, if any, associated with the upgrades required to the grid to accommodate the additional capacity that would be injected at the proposed point of interconnection.

The Reviewing Parties have consistently met the requirements established by the Commission in Order 7003, and by the State in the Act. They have complied with all deadlines and requests for information and endeavored to be as responsive and open as possible throughout the RFP process. The process has been objective and the opinions of all the Reviewing Parties, as well as the general public have been integrated whenever possible.

1.3 THE PROPOSED GENERATION FACILITIES

As stated above, Delmarva received bids from three energy suppliers; Bluewater, Conectiv, and NRG. All bids except for the Conectiv alternative bid (described below) were unit contingent offers whereby the energy is based on the operating output of the new generation facility. The following is an overview of each bidder's generation facilities.

Conectiv:

Conectiv proposes to develop a 180 megawatt electricity generating facility located at its existing Hay Road Power Complex in New Castle County, Delaware. Conectiv anticipates the generation to be in-service no later than 2011.

The generation facility is to utilize combined cycle technology in a 1 x 1 configuration which includes a single combustion turbine plus a single steam turbine generator. The primary fuel is to be natural gas.

The PPA term is 10 years with an option to extend the contract for up to five additional years and includes price indexing limiting the bid's potential for achieving the Act's stability objective. Conectiv offered an alternative firm energy bid whereby the energy is not required to be sourced from the new generation.

Bluewater:

Bluewater proposes to develop a 600 megawatt electricity generating facility approximately ten nautical miles (11.5 highway miles) off the coast of Rehoboth Beach, Delaware (Bluewater North) or approximately six nautical miles (6.9 highway miles) east of Bethany Beach, Delaware (Bluewater South). Bluewater anticipates the generation to be in-service no later than 2011-2012.

The generation facility would be an offshore Wind Park consisting of 200 3.0 MW wind turbines for a total of 600 MW of capacity. Each Wind Park's footprint is estimated to cover approximately 30 nautical square miles.

The PPA terms are 20 and 25 years.

NRG:

NRG proposes to develop a 600 megawatt baseload electricity generating facility located at its existing Indian River power station in Sussex County, Delaware. NRG anticipates the generation to be in-service no later than 2013 with at least 280 but up to 400 of the 600 megawatts to be contracted to Delmarva.

The generation facility is to utilize an Integrated Gasification Combined Cycle ("IGCC") technology with the potential for carbon capture and sequestration opportunities. The primary fuel is to be coal. A major additional option involves the capture & sequestration opportunities.

The PPA term is 20 or 25 years and includes price indexing limiting the bid's potential for achieving the Act's stability objective.

1.4 DELMARVA'S SOS LOAD AND THE FUTURE NEED FOR NEW GENERATION IN DELAWARE

In determining the supply need for the Delaware SOS load, it is helpful to understand the size of this load in relation to Delmarva's overall supply obligation.

The Load Duration Curve for 2005 (Figure 1.4.1) shows Delmarva's load requirements for each of the 8760 hours in a year. As the chart illustrates, there are wide variations in Delmarva's load obligations for the different customer "groups" it serves.

For example, the State of Delaware 2005 peak hour load (2,702 MW – on the left axis of the chart) is about 65% of Delmarva's total service territory peak load (4,174 MW) for that hour.

More importantly, in that same peak hour example, the Delmarva retail obligation for SOS customers (1,027 MW) is only 25% of Delmarva's total service territory load.

A further consideration is that, given the Act's requirement that at least 30% of the Delmarva resource mix to service SOS customers must be purchases made through auctions in the regional wholesale market, the remaining 70% Delaware SOS need at the peak hour (719 MW) drops to about 17% of Delmarva's total service territory peak load.

Thus, while the Delaware SOS load is significant, it represents only a fraction of Delmarva's overall supply obligations.

Further, and of more significance than just the peak hour need, for over one-half of all the hours in 2005 (54%), Delmarva's Delaware SOS load was below 400 MW, the maximum bid size established by the Public Agencies.

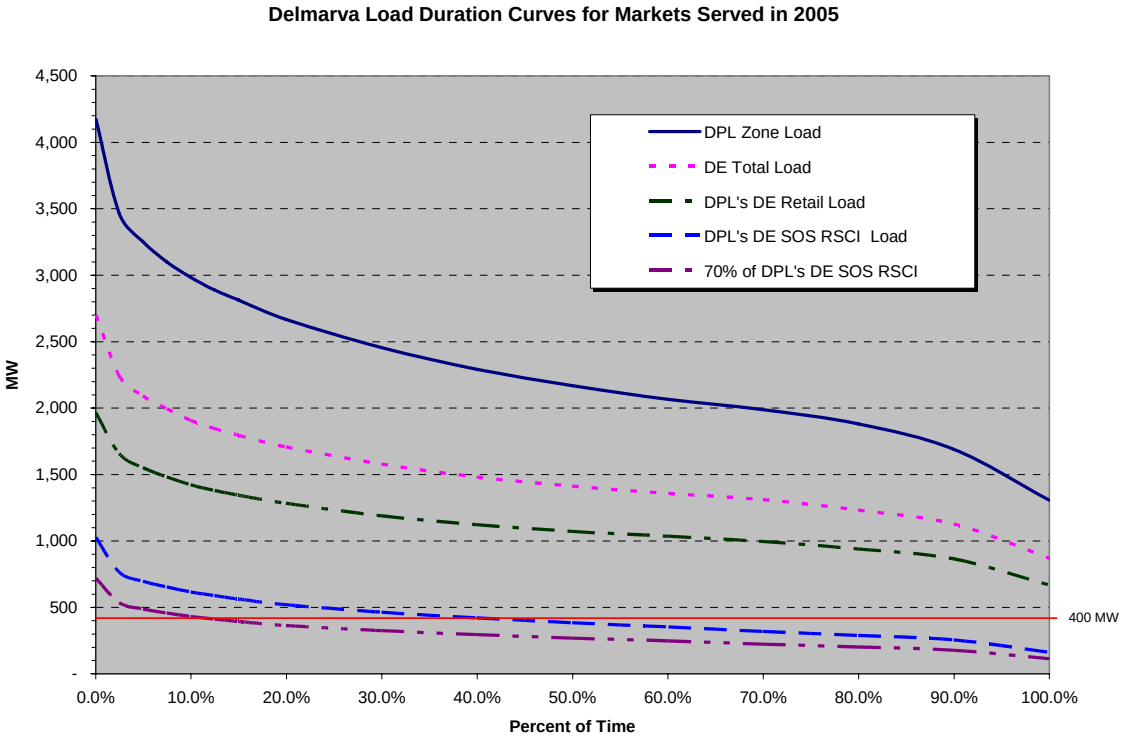
After accounting for the requirement that at least 30% of the load be purchased in the regional wholesale market – the remaining 70% Delaware SOS load, the load available to be served by a PPA per the Act, is below 400 MW 86% of the hours in the year, averaging only 289 MW.

The significance of the information conveyed in this Load Duration Curve, as Delmarva discussed in its IRP submission and discusses below, is that Delmarva's needs for electric power to meet its Delaware SOS obligations are quite moderate for most hours of the year particularly in relation to the size of the bids received in response to the RFP. The MW size of the bids represents a huge supply resource concentration risk relative to the size of the SOS RSCI load. There is great risk that the SOS load levels projected during the time period that a PPA would be in place under this RFP would not be of a size sufficient to absorb all the purchase requirements under a PPA associated with a 400 MW offering.

This moderate need has two implications for Delmarva's power supply strategy. First, Delmarva is fully capable of meeting the Delaware SOS load requirement through its usual procurement practices. These practices, discussed further below, include an annual bidding process to obtain full requirements electric service in 50 MW blocks.

On the other hand the prospect of having to sell power, once procured but not required to serve SOS load involves substantial risk and uncertainty. As we argue in more detail below, should Delmarva, due to contractual requirements, have to procure more power in any hour than it needs in that hour, it would have to sell the excess into the wholesale market. There are two problems with this prospect. First, Delmarva does not have a power "trading" capability and there would be ongoing costs incurred by Delaware SOS customers to perform this activity (such costs are not included in this evaluation). Further, during the many hours in a year when Delmarva might be contractually required to buy more power than its Delaware SOS customers' need, this obligation puts Delmarva's customers in a position of speculators of energy prices. It is likely that, in those hours for which Delmarva has excess supply, the wholesale market price for that power will be below Delmarva's contract purchase price. Thus, in making Delmarva "whole" on its power purchases and sales, Delmarva's Delaware SOS customers will be required to make additional payments above the contract purchase price.

Figure 1.4.1



(RSCI stands for residential and small commercial/industrial)

Delmarva's IRP systematically evaluated renewable and traditional generation supply resources, transmission alternatives, conservation and Demand Side Management ("DSM") programs on an integrated and consistent basis using a level playing field. Among the conclusions of the IRP were the following:

- DSM and conservation offer cost effective opportunities to reduce peak load in Delaware up to almost 200MWand improve energy efficiency;

- The construction of new transmission lines will have a significant impact on Delmarva's SOS and non-SOS customers. In particular, the completion of the Mid Atlantic Power Pathway (MAPP) will result in considerable reduction of congestion on the Delmarva Peninsula and allow for low cost generation resources to the south and west to be more easily imported into Delmarva; and

- PPAs have the very real potential to obligate customers to buy fixed amounts of energy and capacity at above market prices thereby greatly increasing the likelihood that, over the duration of the PPA, customers will be subjected to non-bypassable wires charges to recover stranded costs.

The IRP concludes that there is no need for any new fossil fueled generation or off-shore wind resources be constructed in Delaware let alone contracts in the 200 – 600 MW range. These resources are not cost-effective when compared to conservation, DSM, on-shore wind, and transmission as specifically recommended by the IRP. If the level playing field under which the IRP analysis was prepared was "tipped" to require that a large new generating resource be imposed upon the filed IRP, it would detract from the cost-effectiveness of the conservation, DSM, transmission and renewable resources currently recommended by the IRP. In other words, imposing a large generating resource on the IRP will have a chilling effect on conservation, DSM, new transmission projects, and small renewable resource development.

2. BID EVALAUTION

2.1 INTRODUCTION-SUMMARY OF FINDINGS

The evaluation process included both quantitative (Price) and qualitative (Non-Price) factors. Points were awarded the bids based on a 100 point scale. The point system allocated points to Price and the Non-Price factors based on a Public Agencies' approved methodology. The bid receiving the most points is considered the highest ranked proposal. However, being selected the highest proposal merely indicates that the proposal received the highest points relative to its competitors. It is not a recommendation that the proposal be accepted by Delmarva.

Both the price and non-price factors associated with all proposals were evaluated by Delmarva with assistance from ICF. The IC also conducted an evaluation that consisted of performing an independent evaluation of certain aspects of the proposals and reviewing Delmarva's evaluation of other aspects of the proposals. The RFP development, evaluation criteria development, and evaluation processes were designed to ensure a fair, unbiased review of all proposals.

Delmarva concludes, based on the bid results, that none of the proposals achieve the Act's goal associated with the RFP of producing energy price stability in a cost-effective manner while providing environmental benefits as well as other advantages to the state. The overall bid scoring can be found in Table 2.1.1.

Table 2.1.1
OVERALL BID EVALUATION SCORES

	Maximum Points	BWW -N 25 Yr	BWW - N 25 Partial	BWW - S 25 Yr	BWW - S 20 Year	NRG 25 Year	NRG 20 Year	Conectiv Base	Conectiv Alternative
Non-Price	40.0	24.7	24.7	24.7	24.7	20.0	20.0	27.0	27.0
Exposure	6.0	0.3	0.3	0.3	0.6	0.0	0.3	5.3	5.3
Contract	1.0	0.6	0.6	0.6	0.6	0.2	0.2	0.7	0.7
Price	33.0	4.8	4.0	1.8	0.0	0.0	0.0	28.8	33.0
Price Stability	20.0	20.0	14.2	NA	NA	0.0	0.0	NA	0.7
TOTAL	**100.0**	**50.4**	**43.8**	**NA**	**NA**	**20.2**	**20.5**	**NA**	**66.7**

All proposals were evaluated on price and operational performance factors in the price evaluation through simulation of the impact of the proposal on the costs paid by Delmarva's SOS customers.

The proposals were evaluated for their effect on total Delmarva SOS costs, both through changes in the market prices and the provision of energy and capacity. Further, the evaluation considered the expected cost and variation in the expected costs. As outlined in the RFP, Delmarva provided 33 points for the lowest expected price and provided 20 points for the project(s) that provided the most stable prices.

The modeling considered the following components of SOS cost:

- 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

The price evaluation resulted in the bids, other than Conectiv's firm bid, having significant impacts on SOS customer cost. In addition, none of the bids provided a substantive impact in stabilizing these costs for the SOS customers. Table 2.1.2 below reflects some of the findings from the bid's price evaluations with respect to the direct economic impact on SOS customers.

Table 2.1.2
Selected Features and Economic Impacts of the Bids

	Reference Case	BWW -N 25 Yr	BWW - N 25 Partial	BWW - S 25 Yr	BWW - S 20 Year	NRG 20 Yr Term	NRG 25 Yr Term	Conectiv Base	Conectiv Alternative
Levelized costs (in 2005 dollars)	$85.43	$99.45	$99.82	$100.80	$101.90	$106.87	$107.56	$88.54	$86.63
Additional cost in excess of forecasted market (notional) paid by all SOS customers over the PPA life		$2.0 bil.	$2.1 bil.	$2.2 bil.	$2.2 bil.	$3.9 bil.	$5.2 bil.	$0.2 bil.	$0.1 bil.
Average annual % above forecasted market		9.3%	10.0%	10.4%	10.4%	18.4%	24.7%	1.1%	0.2%
Price stability impact - % of market price variability remaining with SOS customers		64.0%	74.4%	NA	NA	104.8%	105.7%	NA	98.8%
Price and price stability - point allocation (53 Max.)		**24.8**	**18.2**	**NA**	**NA**	**0.0**	**0.0**	**NA**	**33.7**

The price evaluation modeled the cost to supply SOS customers with all of their energy and capacity needs over the time horizon spanning the start date of the earliest bid to the latest date of any bid (2011 through 2038). The bid evaluation results reflect the wholesale cost to supply SOS customers where the energy and capacity are being sourced from the new generation and relying on the wholesale market when, at times, the bid's new generation is under or over supplying the SOS energy need. The bid results were then compared to a Reference Case that reflected the cost to supply SOS customers relying 100% on the wholesale market (excluding any bid).

- The levelized cost (in 2005 dollars) for the Reference Case was $85.43 MWh. All bid results were higher than the Reference Case.

- The additional cost (notional) to be borne by SOS customers due to the bid's generation being a significant energy source ranges from $0.1 billion for the Conectiv alternative bid to $5.2 billion for the NRG 25 year term bid.

A bid's cost impact on SOS customers must be balanced with the bid's affect on stabilizing SOS customer costs.

- Conectiv's alternative bid did not result in any meaningful reduction in future price variability (98% of the variability remains with SOS customers).

- NRG's bid increased the variability to customers while the Bluewater bids only reduced variability by between 25% and 36%.

Delmarva and the IC also used non-price factors to evaluate the development and operational benefits and risks of each proposed project. The points available for each of the non-price factors are shown below.

Environmental Impact	14
Fuel Diversity	3
Technology Innovation	3
Operation Date and its Certainty	3
Reliability of Technology	2
Site Development	5
Bidder Experience, Safety and Staffing	5
Project Financeability	5
Total Non-Price Points	**40**

Delmarva's non-price scoring did not result in scores being different for an individual bidders' multiple bids (i.e., NRG's 20 year bid scored the same as its 25 year bid in the non-price review); therefore, the non-price results are present by bidder irrespective of the specific bid by such bidder. Table 2.1.3 below shows the results of the non-price bid evaluations.

Table 2.1.3
Overall Non-Price Scores

Non-Price Factor	**Maximum Points**	**Conectiv**	**Bluewater**	**NRG**
Environmental Impact	14.0	9.9	11.3	5.7
Fuel Diversity	3.0	0.0	3.0	2.0
Technology Innovation	3.0	0.0	3.0	3.0
Operation Date and its Certainty	3.0	1.3	0.5	0.0
Reliability of Technology	2.0	2.0	1.5	1.0
Site Development	5.0	4.8	2.4	3.8
Bidder Experience	5.0	5.0	1.0	2.0
Project Financeability	5.0	4.0	2.0	2.5
Total	**40.0**	**27.0**	**24.7**	**20.0**

2.2 PRICE EVALUATION DETAIL

All proposals have been evaluated on price and operational performance factors in the Price Evaluation through simulation of the impact of the proposal on the costs paid by Delmarva's SOS customers.

Delmarva has considered the following components of SOS cost on a levelized basis over the time horizon spanning the start date of the earliest bid to the latest closing date of any bid (2011 through 2038):

- PPA Capacity Price
- PPA Energy Price
- Residual SOS Cost Impact based on wholesale market impact including costs to comply with environmental standards such as Delaware's Renewable Portfolio Standard and the Regional Greenhouse Gas Initiative
- T&D Project Impact
- Transmission Losses
- Imputed Debt Offset

A total of 33 points has been assigned to the bid with the lowest expected price based on these factors.

In addition, Delmarva considered the impact of the individual bids on the stability of market prices. To the extent that a bid was able to reduce the expected standard deviation in prices, they were awarded points. The bid resulting in the greatest expected stability received a full 20 points.

Other points assessed included up to six points for the level of exposure that would result for Delmarva and its SOS customers based on the proposed contract size and other factors, and up to one point was assigned based on the bidders mark-up of PPA terms.

Based on the analysis, the Conectiv bid received the most points with 39.7, Bluewater was second with 25.7, while NRG received 0.5 points. A summary of points awarded is provided in the table below. Note, given the limited time to perform the analysis, for each bidder, only those alternatives with the highest scores on price were considered in the stability analysis.

Table 2.2.1
Summary of Price Analysis Scores

Bidder	Variant	Price Impact	Price Stability	Exposure	Contract Terms	Total
Bluewater Atlantic North	25 year term full output	4.8	20.0	0.25	0.6	25.7
	25 year term partial output	4.0	14.2	0.25		19.1
	20 year term full output	1.8	NA	0.58		NA
	20 year term partial output	1.6	NA	0.58		NA
Bluewater Atlantic South	25 year term full output	1.8	NA	0.25		NA
	25 year term partial output	1.3	NA	0.25		NA
	20 year term full output	0	NA	0.58		NA
	20 year term partial output	0	NA	0.58		NA
NRG	25 Year Term	0	0	0	0.2	0.2
	20 Year Term	0	0	0.33		0.5
	25 Year Term with Carbon Capture	0	NA	0.00		NA
Conectiv	Base	28.8	NA	5.25	0.7	NA
	Alternate	33.0	0.7			39.7

Price Impact Analysis

Capacity, Energy, Environmental and Renewable Energy Credit Costs

Under the price impact analysis, Delmarva evaluated the impact on the cost of serving the Delmarva Delaware Residential SOS load of the individual bids submitted in response to the RFP. In order to evaluate the effect of the contract on the full RSCI load, an electric production cost simulation model, the Integrated Planning Model (IPM®) was used to project forward market prices over the time horizon considered. In this model, the electrical energy and capacity needs of customers are met in a least cost manner subject to operational, transmission, and other constraints.

In this regard, the model requires in all years that the reserve margin requirements of Delmarva customers be met, thereby ensuring that power supply will be reliable, consistent with PJM rules including the recently approved Reliability Pricing Model rules which establish that reserve requirements be established for sub-regions within PJM. This reserve requirement is approximately 15-17 percent above summer peak demand levels of each sub-region such that total capacity needs equal 115 to 117 percent of forecast peak demand including load growth (on an unforced basis).

The model assumes that this reserve requirement can be met either by the addition of new local generation units, or firm power imports up to the limits of the transmission grid to reliably accommodate firm imports. This too is consistent with PJM rules. The actual choice of imports or new units is made in a manner which minimizes production costs. Thus, it is possible that no local generation additions will be forecast because incremental needs are met through firm capacity imports. It should be noted that the model's forecast of capacity prices is fully integrated with the determination of the method of meeting local needs and capacity prices rise to the level needed to attract imports.

This analysis also assumes that the ability to import firm power into the Delmarva area will increase in the event that the MAPP and other transmission projects are built, further facilitating imports of capacity for reserve margin requirements.

A summary of the Reference Case Assumptions is provided in Table 2.2.2 below.

Table 2.2.2: Summary of Key Reference Case Assumptions

Parameter	Treatment – Reference Case				
	DPL			DPL – Delaware	
Market Structure	Deregulated; Perfect Competition				
Total System Capacity (MW) 2007	4,827			3,366	
2007 Net Internal Demand (MW)[1]	4,020			1,919 (47.6% SOS)	
2007 Weather-Normalized Net Energy for Load (GWh)	17,586			7,733 (42.5% SOS)	
Annual Peak Growth					
2008-2010 (%)	2.2 (2.2 energy)			2.2 (2.2 energy)	
2011-2015 (%)	2.1			2.1	
2016-2020 (%)	1.6			1.6	
2021+ (%)	1.6			1.6	
Planning or "Market Required" Reserve Margin (%)	15.0				
Transmission Import Capacity (MW)*					
2007-2013					
Energy	2,913			2,913	
Firm Capacity	1,560			1,560	
2014+					
Energy	5,779			3,951	
Firm Capacity	1,560			1,560	
Cost for New Units	CC/Cogen	CT	Coal (PC)	Coal IGCC	Nuclear
Capital Costs [2,3] (2005$/kW) - Summer and Altitude Adjusted	859	517	2,555	2,938	3,943
Fixed O&M[3,4] (2005$/kW/yr)	13.2/26.6	6.7	38.6	55.3	105.5
Financing Costs for New Units	CC/Cogen	CT	Coal (PC)	Coal IGCC	Nuclear
Levelized Real Capital Charge Rate (%)	12.9	14.1	11.2	11.2	11.2

New Power Plant Builds	CC/Cogen	CT	Coal (PC)	Coal IGCC	Nuclear
Variable O&M[5] (2005$/MWh)	3.8	4.3	1.9	1.9	1.2
Availability (%)	93	93	89	89	90
Forced Outage Rate (%)	1.3	2.4	6.3	6.3	3.5
Minimum Turndown (%)	50	0	50	50	0
Levelized[6] (2007-2038) Average Delivered Gas Price (2005$/MMBtu)	7.40				
Levelized[6] (2007-2038) Average Delivered Oil Price (2005$/MMBtu)	Delivered 1% Resid 6.87				
Annual Coal Mine Productivity Improvement[7]	Reference Case Appalachia: -4.3% Interior: -1.9% West: 0.2% PRB: -1.5				
Coal Transportation Annual Real Price Increase (%/year)	1.0				
Expected Levelized[6] (2007-2038) National Air Emissions Control Allowance Prices (2005$)	NOx ($/ton) $1,675	SO2 ($/ton) $1,347	Hg ($/lb) $30,414	CO2 ($/ton) $12.1	

[1]Source: DPL and PJM
[2]Includes overnight construction costs and soft costs such as development costs, spares, interest during construction, contingency fees, electrical connection costs, gas connection costs, change orders, other site modifications, and financing related costs. Adjusted for summer weather and altitude conditions; reflects un-degraded capacity. Capital cost adjustments are derived from the "Means Construction Cost Index" which includes site labor, site material, and installation costs.
[3]Shown for units available in 2015 except nuclear units which are not available until 2020.
[4] Fixed O&M for CC and CT includes only labor, LTSA Fee and G&A. For coal, major maintenance costs are included in fixed O&M due to its baseload mode of operation. The two numbers shown for CCs represent O&M figures for cycling and turndown mode operations, respectively. VOM figures are higher for CCs in cycling mode.
[5]Assumes a 75 percent capacity factor for CC units, 15 percent for CT units, 89 percent for coal units and 87 percent for nuclear units.
[6]Assumes a 6.3 percent real discount rate.
[7]Reference case assumes the negative trend in productivity from 2000-2005 will continue (Source: Mine Safety and Health Administration, Part 50 data).
* Transmission import capability increases in 2014 when the MAPP transmission line begins operation.

Bid Modeling Analysis

The proposed projects were modeled individually within the model simulation exercise. To the extent that the contracts proposed to Delmarva were considered dispatchable by Delmarva, the contract prices were simulated directly in the modeling analysis. Supply additions proposed in the bids in excess of the contracted quantity were simulated directly in order to capture their impact on the power market. Renewable supply additions were simulated using an hourly dispatch profile provided by the bidder.

In the analysis, the purchases under the contract were evaluated based on the bid's proposed capacity, energy, and renewable energy credit pricing where available. The total energy and Unforced Capacity ("UCAP") purchased under each contract was assessed under this price. To the extent that Delmarva was required by the contract terms to purchase supply in excess of the hourly loads, the excess was considered to be sold into the market at the market clearing price with no additional transaction costs. Likewise, the market price was used to determine the costs for any additional purchases that Delmarva needed to make in order to serve the projected SOS load.

In this manner, the total impact on supply costs for capacity, energy, and renewable energy credit prices for SOS load served under the proposed contract and that for the residual load served by market purchases were determined.

Carbon Pass-Through Costs

Both bidders proposing fossil generating units (NRG and Conectiv) have opted to pass through costs of compliance of potential or not fully defined carbon programs. The forward modeling analysis assumes that Regional Green House Gas Initiative ("RGGI") program and an expected national CO_2 cap and trade program will be in effect going forward. Costs of compliance with these programs as modeled have been included as part of the total costs to be paid by SOS customers of Delmarva.

In the case of NRG, allocations assumed to be available under the national CO_2 program to the Indian River ("IR") 1 and 2 units which are anticipated to be retired should the NRG proposed facility be built, have been credited to NRG. The CO_2 allocation scheme for the national cap and trade program being assumed within the Reference Case and CO_2 sensitivities is described below.

- Fossil units would receive a CO_2 allocation based on their share of 2010 fossil generation. Units coming online after 2010 would receive no allocation. Given NRG's response to the allocation questions, the IGCC would be assumed to inherit the allocations of IR units 1 and 2 (which, consistent with the bid, would be assumed to retire when the IGCC comes online). Two thirds (2/3) of that allocation would be applied to offset some of the pass-through under the PPA.

- The national CO_2 program is proposed to be implemented beginning in 2013 to reflect the time it would likely take once legislation is passed and signed in 2008 or 2009 for the United States Environmental Protection Agency ("US EPA" or "EPA") to develop the model rule and the states to file their state implementation plans (SIPs). This timeline allows little time for court challenges, which could delay the start date further.

  The year 2010 was assumed for the baseline year to be consistent with that 2013 start date. States would look toward the most recent emissions data to allocate their assigned budgets (from EPA) as they developed their SIPs and, given the lag in finalizing emissions data and the timing of the SIP development, 2010 (or a range of years including 2010) would be a likely year for the states to use. Generation companies to which the allocations would likely be assigned would discourage states from using baseline years much earlier in time (2000, 2005, etc.) because it would then exclude new generating units that had come online later in time, thereby imposing a greater compliance burden on those companies.

- 75 percent of the total cap would be assumed to be allocated to affected generators in 2013 (the start of the program) with the remaining 25% being auctioned. As discussed, the 25% is consistent with the amount set aside under the RGGI model rule for auction (obviously some states have gone further than that). The program would transition over 25 years to a full auction, in which no allowances are allocated to affected sources. The 25 years is consistent with the

latest proposal by Feinstein/Carper. The modeling assumed a linear transition at 3 percent per year (resulting in 54 percent being allocated in 2020 and 24 percent being allocated in 2030).

- The allocation would be based on emissions output from IPM. Since the analysis implements a probability-weighted CO_2 price stream based on a number of proposed programs in place of an emissions cap from a specific program, annual CO_2 emissions from affected units are an output of IPM rather than an input. For the purpose of determining an allocation, therefore, these emissions would be equivalent to the cap for each year. Using that cap as a starting point, the allocation for a particular unit would be calculated as follows:

  Allocation (tons) = Emissions from all affected sources in year (tons) * Unit share of 2010 MWh (%) * % to allocation (v. auction)

  For example, Allocation = system emissions of 2.7 billion tons * 0.1% * 54% (in 2020) = 1.5 million tons CO2

  For NRG, the 2/3 ratio would then be applied to that allocation to arrive at the pass-through offset for the IGCC.

No allocations have been applied to the Conectiv facility.

Once allocations are credited, the remaining costs of compliance with incremental programs not already accounted for in the bid are then determined and allocated to the costs that customers would bear under the bid. In the case of the Conectiv Alternate bid, the overall impact on rates may be slightly understated in the analysis since clarification of the Conectiv position on pass-through was not received until shortly before this report was complete. However, estimates of the additional impact on the levelized customer rates is between 9 and 15 cents per MWh, which does not impact the overall rank order or score of the bid.

Ancillary Service Cost Impact

Ancillary services are the services necessary to support the transmission of power from seller to purchaser while maintaining the reliable operation of the transmission system. Many power markets offer six main ancillary services:

1. Regulation and Frequency Support: Regulation is a service that corrects for short-term changes in electricity use that might affect the stability of the power system.

2. Energy Imbalance: Energy Imbalances occur in all hours in which a point-to-point transmission customer serving PJM load undersupplied their load responsibility. In such instances, units capable of providing reserves will respond with additional capacity.

3. Operating Reserves, which comprises Spinning, Non-spinning, and Supplemental Reserves: Spinning reserves are synchronized reserve supplies electricity if the grid has an unexpected need for more power on short notice.

4. Voltage Support: Voltage support services are reactive power support in a synchronized market necessary to keep the system operating under normal and approved conditions.

5. Black Start: Black Start supplies electricity for system restoration in the unlikely event that the entire grid would lose power. A black start unit is defined as a generating unit that is able to start without an outside electrical supply or the demonstrated ability of a base load unit to remain operating, at reduced levels, when automatically disconnected from the grid.

6. Scheduling, System Control and Dispatch: Scheduling, system control and dispatch are provided by PJM as the Regional Transmission Organization and Independent system Operator. The costs for these services reflect PJM's administrative costs associated with conducting system and market operations. Costs for these ancillary services are allocated to market members according to usage by PJM.

Delmarva has assessed the impact of the generation bids on ancillary services in the Delmarva zone. Spinning reserves and regulation are the dominant ancillary services provided under a market construct in PJM and hence they are the focus of this analysis. That is, PJM's spinning reserve and regulation services are market-based while the others are not. Participants offer capacity into these markets, and PJM determines a market clearing price for each service based on the offer price of each bid.

- Spinning Reserves: PJM's operating reserve market comprises four separate synchronized reserve regions – PJM Mid-Atlantic Region, PJM Western Region, PJM Northern Illinois Region, and PJM Southern Region. Since all the bid projects are located in the Delmarva zone, the relevant market for this study is the PJM Mid-Atlantic Region. The spinning reserve requirement in the PJM Mid-Atlantic Region is equivalent to the single largest contingency in the region. This is approximately 1,150 MW.

- Regulation: PJM operates a single regulation market that spans the entire Regional Transmission Organization ("RTO"). The regulation requirement is 1.1 percent of the peak load (on-peak) or valley load (off-peak).

Each bid can affect the cost of service in these markets if it results in a variation in either the capacity requirement or the market price of the service. For example, if the addition of a bid project increases the spinning reserve requirement above 1,150 MW, this will increase the cost of providing spinning reserve. Similarly if the market clearing price

changes after installation of the project, this will also result in a variation of the cost of the service.

As part of the analysis of the bids for the various projects, Delmarva determined the impact of the generation addition on:

- Incremental cost to Delmarva consumers for the provision of the ancillary service attributable to the bids;

- Revenues to Delmarva for providing the ancillary service for bids providing this option.

Bid Impact on Ancillary Service Costs attributable to Delmarva Consumers

The maximum bid capacity of any bid is 600 MW, which is less than the spinning reserve requirement in the Mid-Atlantic market area. Therefore Delmarva does not anticipate that any of the projects will result in a change in the spinning reserve requirement. Delmarva also does not expect any of the projects to affect the regulation requirement since that is a percentage of demand, not generation capacity. As such, the need for ancillary services is not anticipated to change from a case absent the bids.

Although the requirements are not expected to change, the proposed projects may have an impact the market clearing price. For example, a new combined cycle unit with a lower heat rate relative to incumbent combined cycles could potentially displace some of these incumbent generation units and provide ancillary services at a lower cost. This will result in a lower market clearing price for the service. However, the Conectiv proposed project will not offer any significant advantages in heat rate over other already existing combined cycles or cogenerators. Further as NRG is anticipated to operate at Baseload (i.e. at or close to 24 x 7 operational levels subject to availability) levels, it will not be in a position to offer spinning reserves and Bluewater, as an intermittent resource is not able to offer spinning reserves. Given the size of the PJM Mid-Atlantic Region relative to the ancillary service requirement and the nature of the three projects, Delmarva anticipates that the impact of the bid projects on market clearing prices will be negligible.

In the case of regulation, costs are determined in a balancing market such that if the individual bid projects were to have deviations greater than the average unit, one would expect a greater need for regulation services. One might expect the Bluewater facility in particular have less certainty in their expected output than a traditional combined cycle such as the Conectiv proposed bid. However, Delmarva does not expect any negative impact on cost to Delmarva due to the intermittent nature of the wind resource. This is because PJM does not assess any imbalance penalties to intermittent resources. Rather, an intermittent resource is directly charged for regulation service based on the market price for the service and the hourly regulation capacity required to compensate for

deviation of the resource from its forecast output. Therefore Bluewater, rather than the Delmarva customers, will be directly responsible for any additional imbalance cost.

In conclusion, Delmarva anticipates that there will not be any incremental requirements for spinning or regulation ancillary products due to the addition of the proposed projects to the market. Further, Delmarva believes that any change in cost will be minimal given the nature of the projects and the scope of the spinning reserve market.

Ancillary Service Revenues or Credits Associated with Bids

Likewise, with the exception of the Conectiv Bid, Delmarva does not anticipate that any of the bids will offer any significant credit to the Ancillary purchase requirements of Delmarva. In the case of Bluewater, no ancillary products will be available from the facility and in the case of NRG, given Baseload type of operation, spinning reserves will be available on a minimal basis only when the unit is operating at lower than full capacity Further, the proposed facility does not offer 10 minute ramp up capability and hence would not be expected to provide spinning reserves to Delmarva under the bid. The facility would be able to offer frequency or regulation control, though not anticipated to be significant.

In the case of the Conectiv proposal, the facility has no Automatic Generation Control ("AGC") capability and hence is not able to offer regulation support. However, it is able to participate in the spinning reserve markets. The facility is characterized as having a 10MW/minute ramp rate after initial start and base load operation and has offered to make Ancillary Products available to DPL. The Conectiv Alternate bid states that it will make available to Delmarva all of the revenues associated with Ancillary Services from the proposed facility. As a proxy to the forward ancillary revenue credit which may accrue to Delmarva, 2005 year hourly data for spinning reserve market clearing prices versus the existing Hay Road facility historical dispatch has been used to determine hours that the new unit will be able to participate in the ancillary service markets. Revenues are then allocated based on the new facility capacity characteristics and historical pricing. As the dispatch of the potential project and existing project are not expected to differ significantly, this reflects a reasonable proxy. This results in approximately a $1.0 million dollar annual credit to Delmarva, which has limited impact of only 16 cents/MWh) on the overall rates and does not affect the rank order or point scoring of the bids. Given the limited impact, a reduction in the necessary purchase of ancillary products was not considered in the Conectiv Base bid.

Transmission Project Impact

The Delmarva RFP bid evaluation process included an assessment of the impact of each bid on the Delmarva transmission system. For each proposed generation plant, Delmarva determined potential upgrades required to facilitate the transfer of power from the generator to the Delmarva load under normal (n-0) and contingency (n-1) conditions. Delmarva compared the list of potential upgrades to that in the Reference Case (i.e. status

quo) and determine incremental upgrades required as a result of the generation addition. To determine the total incremental upgrade cost for each bid, generic costs assumptions provided by Delmarva's transmission engineering group were utilized. The Delmarva cost assumptions were based on actual project costs experienced in the recent past.

Note that this evaluation is meant to provide a comparative analysis for Delmarva's bid evaluation process and is not intended to determine the actual system upgrades or upgrade cost required for any of the proposed generation additions.

The analysis performed utilized the OneLiner model available from Advanced Systems for Power Engineering, Inc. ("ASPEN") to determine circuit breaker overloads and replacement requirements as well as GE Energy's Positive Sequence Load Flow Software (PSLF) model to determine line overloads. ASPEN OneLiner is a PC based short circuit and relay coordination program for relay engineers. It is used to develop a detailed model of the power system and all of its components (lines, transformers, generators, mutual coupling, etc.). Its built in short circuit program will simulate all classical fault types (bus faults, line end faults, line out and intermediate faults), as well as simultaneous faults. The one-line system diagram graphically displays post-fault solutions.

The ASPEN Breaker Rating Module is used to check circuit breaker ratings against the short circuit currents they need to interrupt. The program logic adheres to ANSI/IEEE standards for both total-current rated and symmetrical current rated breakers. The program uses the network model developed in OneLiner to simulate faults with appropriate branch outages to find the maximum short circuit current that flows through each breaker. The connections to each breaker are explicitly modeled in OneLiner. The Breaker Rating Module then computes the ANSI X/R ratio and adjusts the short circuit currents accordingly. It then compares these currents to the rated capabilities of the breakers and reports its findings.

Transmission Savings or Losses

A modeling methodology was also used to assess the impact on transmission losses of the individual bids. PSLF was used to assess the impact of each of the bids on losses in the Delmarva zone. PSLF uses a detailed snapshot representation of the power system to determine the generation required to serve load within the system. PSLF also calculates the associated line losses and aggregates these values into zonal losses. It provides zonal losses as a standard output. For this analysis a 2016 Summer Peak Load representation of the PJM system was used.

In the Reference Case, Delmarva zonal losses represented 1.9 percent of the Delmarva load. In each of the cases examined, losses within the Delmarva zone increased compared to the Reference Case losses. On average, losses increased to 2.0 percent of the Delmarva load, representing a 0.1 percent increase over the Reference Case losses. The maximum increase over the Reference Case losses was 0.25 percent.

These losses reflect a single summer peak hour. Actual losses vary by time of day and system load. However, the change relative to load is expected to be close to the estimates shown. It is therefore reasonable to apply the incremental losses to all hours of the year to determine the impact of losses on total cost on annual basis. Given the relatively small increase in losses, however, Delmarva considered the impact of the bids on Delmarva losses to be negligible.

The impact of the bids on Delmarva losses shows that it is negligible. The bid with the largest impact increased losses by a quarter of a percent relative to Delmarva load. The average increase was a tenth of a percent.

Imputed Debt Offset

Debt rating agencies generally view long-term PPAs as debt-like in nature. Typically, a rating agency will factor a percentage of the net present value ("NPV") of a PPA's capacity payments as debt in their quantitative assessment of a utility's credit quality. In order to account for this, Delmarva considered the costs needed to account for the incremental equity required to return Delmarva's capital structure to the ratios that would be in place had no PPA been in place.

Delmarva assessed the incremental equity amount to be equal to 30% of the NPV of the bid's capacity payment. The Standard & Poor's ("S&P") rating agency has stated that in the case of renewable projects where most of the capital recovery is in the energy component of the bid, S&P would use a proxy unit (combustion turbine) for assessing a PPA's capacity component. Therefore, the Bluewater imputed debt offset was based on an equivalent MW sized combustion turbine. Using this assumption, the overall results indicate that the imputed debt adds less than $1.00/MWh (2005$) on a levelized basis for the bid with the smallest size, and up to $2.80/MWh for highest cost bid.

Results

Based on the foregoing approach, the results of the price impact analysis were as follows (see Table 2.2.3):

Table 2.2.3: SOS Levelized Price Impact Results (2005$MWh)

Bid Alternative	Total Customer Impact	Energy, Capacity, and REC Supply Costs	Incremental Transmission Upgrade Costs	Incremental Ancillary Service Costs	Incremental Transmission Congestion Costs	Imputed Debt Costs	Carbon Pass Through Costs
	(2005$/MWh)						
Reference Case	85.43	85.43	-	-	-	-	-
Conectiv Alternative Bid	86.63	86.33	0.01	(0.16)	-	0.38	0.07
Conectiv Base Bid	88.54	87.64	0.01	-	-	0.49	0.40
BW Atlantic North 25 year full bid	99.45	96.27	0.83	-	-	2.35	-
BW Atlantic North 25 year partial bid	99.82	97.42	0.83	-	-	1.57	-
BW Atlantic South 25 year full bid	100.80	97.61	0.83	-	-	2.35	-
BW Atlantic North 20 year full bid	100.82	97.71	0.79	-	-	2.31	-
BW Atlantic North 20 year partial bid	100.91	98.57	0.79	-	-	1.54	-
BW Atlantic South 25 year partial bid	101.06	98.66	0.83	-	-	1.57	-
BW Atlantic South 20 year full bid	101.90	98.79	0.79	-	-	2.31	-
BW Atlantic South 20 year partial bid	102.16	99.82	0.79	-	-	1.54	-
NRG 20 Year Base Bid	106.87	97.19	0.19	-	-	2.33	7.16
NRG 25 Year Base Bid	107.56	96.18	0.20	-	-	2.79	8.40
NRG 25 Year Carbon Bid	115.14	109.72	0.20	-	-	2.79	2.44

- Across all bids, the Conectiv Alternative Bid results in the lowest price for SOS customers.

- The Conectiv bid is nearly $13/MWh (real 2005$) below the next closest bidder on a levelized cost basis. This difference holds even when removing the ancillary services credit applied on the Conectiv Alternative Bid.

- The Bluewater Atlantic North bid alternatives follow Conectiv in the price impact to SOS customers. The Atlantic North bids range from $99.5 – $100.9/MWh (real 2005$).

- The Bluewater Atlantic South bid alternatives follow the Atlantic North bids closely ranging from $100.8 – $102.5/MWh (real 2005$).

- Just prior to the report filing, an error of exclusion on certain transmission upgrade costs was uncovered in the Bluewater financial model which could potentially affect the Bluewater bid price through increasing the transmission costs allocated to customers. In the analysis of the Bluewater bids Delmarva assumes the best case for incremental transmission upgrade costs (i.e. the least customer cost impact); should additional costs be included, the impact would an increase of roughly $0.5/MWh (real 2005$)

on the customer rate. Although this would result in a slight decrease in the points allocated to Bluewater, the relative impact across bids is negligible.

- The NRG bids begin at prices near $107/MWh and range to $115/MWh.

Price scores are assigned based on the relative difference between the lowest bid and the highest bid or a maximum of $15/MWh above the highest bid. The Conectiv Alternate Bid ranked lowest amongst any of the bidders and was awarded the full 33 points as lowest bidder. Any bid within $15/MWh of the Conectiv bid (up to $101.63/MWh) were awarded points on a linear scale. Thus, six of the Bluewater bid alternatives also received points. The remaining Bluewater and NRG bids were not awarded points as they resulted in prices well above the lowest bid.

Table 2.2.4: Point Scores and Levelized Costs by Bid

Bid Alternative	Total Customer Impact (2005 $/MWh)	Point Scores
Conectiv Alternative Bid	86.63	33.0
Conectiv Base Bid	88.54	28.8
BW Atlantic North 25 year full bid	99.45	4.8
BW Atlantic North 25 year partial bid	99.82	4.0
BW Atlantic South 25 year full bid	100.80	1.8
BW Atlantic North 20 year full bid	100.84	1.7
BW Atlantic North 20 year partial bid	100.91	1.6
BW Atlantic South 25 year partial bid	101.06	1.3
BW Atlantic South 20 year full bid	101.90	-
BW Atlantic South 20 year partial bid	102.16	-
NRG 20 Year Base Bid	106.87	-
NRG 25 Year Base Bid	107.56	-
NRG 25 Year Carbon Bid	117.07	-

PRICE STABILITY ANALYSIS

In the context of this analysis, price stability refers to low variation in SOS prices. The Act specifically identifies price stability as a criterion for evaluating the alternative supply options of Delmarva This section describes the factors that give rise to instability in prices, and discusses Delmarva's analysis of how the bids received would affect the stability of power prices to SOS customers.

Market-based SOS price volatility is driven primarily by wholesale price volatility which, in turn, reflects variation in wholesale supply and demand conditions. While winners of the SOS and similar auctions provide fixed prices for one to three years, their pricing

decisions are heavily affected by spot market conditions. For example, if all suppliers strongly expected spot prices to be very high they would not offer to sell power for less than the expected price since they could simply sell into the spot market.

Two factors which historically have played a large role, and which are expected to continue to play a large role in driving this uncertainty are natural gas prices (which are highly correlated with oil prices on an annual basis), and the balance between capacity supply and power demand at the summer peak. This uncertainty affects spot market prices for power, which in turn affects SOS bids since ultimately power delivered to customers must be paid for at spot market prices

Natural gas prices are key drivers of Delmarva zonal Locational Marginal Price ("LMP") spot electrical energy market prices because in many hours, natural gas-fired power plants are the marginal, or price- setting units. In the future, unless large amounts of baseload coal or nuclear capacity are added, the extent to which natural gas is on the margin is expected to increase over time due to load growth that will utilize existing gas units to a greater extent than today.

The balance between capacity supply and demand at the summer peak is also an important driver of power prices since a deficit of capacity leads to high capacity prices. This driver of prices is expected to be increasingly important in light of the recent Reliability Pricing Model (RPM) reforms of the PJM capacity market, which will cause the local capacity balance (rather than the PJM-wide balance) to drive capacity prices. PJM East, where Delaware is located, is generally the area of greatest PJM capacity deficit in near-term projections. Thus, the RPM approach will decrease the price suppression associated with excess capacity in other parts of PJM, and increase the volatility of prices there. These reforms were recently approved by the Federal Energy Regulatory Commission (FERC).

Other factors can clearly affect wholesale power prices such as environmental regulations, especially stringent CO_2 regulations.

SOS price variability can be divided into two components. The first reflects year-to-year variation around average multi-year prices and is the result of shorter term events (e.g., hurricanes may affect gas prices, and hence, power prices in some years more than others). The second reflects long term price uncertainty (e.g., average gas and power prices over the next twenty years), based on the fundamentals of gas supply and demand. As discussed below, Delmarva's analysis focused on the latter more than the former. Delmarva has taken this approach for three reasons: 1) The SOS price is a rolling three year average of market prices which tends to dampen volatility relative to a SOS price based only on one year's price; 2) Short-term perturbations and events are difficult to anticipate, and 3) the contracts being considered would be long-term commitments by both the bidder and Delmarva. To capture this long-term volatility, Delmarva has captured the market and quantitative complexities of analyzing all aspects of price volatility using a 25-year, detailed, integrated fundamentals-based analysis.

Delmarva's analysis of SOS price stability covers the Reference Case individual bid alternatives. That is, Delmarva evaluated what the stability of prices would be with and without the contracts that potentially would be signed with the bidders. Specifically, Delmarva analyzed the stability of SOS prices after including the effects of the Conectiv, NRG and Bluewater bids, and compared their impacts to the stability of the market as determined in the Reference Case.

The market Reference Case corresponds to a continuation of the current situation in which SOS load is purchased from the market via a declining block auction. The SOS auction winners provide power on a fixed price basis, but the SOS customers are under no obligation to purchase SOS service. The SOS prices under the bids are also affected by market uncertainty and variation in two ways. The first is that the bids contain terms which vary with market related parameters such as general inflation, coal and natural gas prices. The second is that the bids do not supply the entire SOS load, and the residual amounts are provided from the market. Hence, changes in market prices still affect SOS prices when bids are in place.

Long Term Contracts, Retail Competition and SOS Price Stability

It is important to understand the effect of long-term contracts on SOS price stability in order to understand Delmarva's analysis of the bids received. One might expect that to the extent bid prices are fixed and known, and are supplying a large share of the SOS requirements for a long period, the variation in SOS prices under the bid, in response to changing market and economic conditions, would be lower than the market Reference Case, i.e., SOS prices would be relatively stable compared to the market. However, this is not necessarily the case, since customers are not obligated to continue to purchase SOS supply. In specific, if the bid prices are higher than market prices, retail prices could rise overall compared to the market, and some customers may leave Delmarva and cause the remaining customers to be responsible for the remaining fixed costs. Put another way, SOS prices are more stable only with franchised or utility contracted customer arrangements which no longer exist in Delaware.

In fact, one would expect a significant share of SOS customers to leave SOS service if the long-term fixed price obligation causes SOS prices to exceed market prices for even relatively short periods of time. Moreover, since the market price varies, the longer and larger the contract, and the more fixed the price, the greater the likelihood that in some future period the price would be above market. Due to yearly price variation and market cycles, this is true even in cases in which the contract price was on average over the years expected to be equal to market prices. This concern would be especially chronic if Delmarva pays for stability by accepting large contracts with higher than average prices, given that Delmarva's SOS currently has an average load of approximately 400 MW and only 300 MW is potentially available to be serviced by the PPA given a 30 percent market purchase requirement..

In this case, the loss of SOS customers could substantially affect the average SOS price for remaining customers, since there would be fewer customers left to shoulder the burden of the above market contract, as well as the Delmarva's other fixed costs to provide service. One can easily imagine a circumstance in which there is a rapid "death spiral" for SOS load, in which the migration to third party retail providers raises retail prices, causing more switching, which further raises prices, etc.

The Act does contain a mechanism to potentially place above market costs on non-by-passable wires charges. However, the mechanism is not automatic (e.g., it is not like a fuel and purchased power adjustment clause), and it requires a finding by the Commission that such actions are in the public interest. It is not clear how quickly the Commission would act on such requests, whether there would be some threshold out-of-market level which would trigger Commission action, or how such action would be implemented. Thus, Delmarva cannot rely on this provision to protect it against customer migration and price instability due to large, long-term contracts.

In Delmarva's analysis, the treatment of this issue was an outcome of a compromise with the IC which wanted tight limits on allowed migration. Specifically, Delmarva agreed to limit migration to 25 percent of the total SOS load, and once this threshold is reached, Delmarva assumed that the wires charges needed to prevent migration is established with a one year lag for the entire potential small commercial and residential SOS load. This does not eliminate the underlying potential for instability, and places boundaries on the extent to which it affects prices. In the analysis below, the prices shown include this charge.

Approach to SOS Price Stability Analysis

Delmarva carried out the analysis of the impacts of the bids on SOS price stability using a four step process. The first step was to create market scenarios that allow us to analyze the effects of different future conditions on the cost of SOS service to Delmarva customers for each bid. The eight scenarios that Delmarva analyzed included:

- **Reference Case**

- **High Natural Gas Prices** – Levelized gas prices were increased by $0.96/MMBtu in 2005 dollars.

- **Low Gas Natural Gas Prices** –Levelized gas prices were decreased by $1.36/MMBtu also in 2005 dollars.

- **High CO_2 Emission Allowance Prices** – CO_2 allowance prices rise faster than in the Reference Case. By 2028, CO_2 prices reach $50/ton versus $27/ton in the Reference Case in 2003 dollars.

- **Low CO_2 Emission Allowance Prices** – CO_2 allowance prices never exceed $2.50/ton in 2003 dollars.

- **Reduced New Power Plant Capital Costs** – Capital costs for coal, natural gas and nuclear plants were decreased by 35, 25, and 15 percent, respectively.

- **No MAPP Case** – No increases occur in transmission capability into PJM East.

- **IC Case with Higher Coal Mining Productivity and Higher Gas Price Basis Differential** – Gas basis differential increased by $0.57/MMBtu for PJM East in 2005 $, and coal mining labor productivity in the Appalachia and Interior regions changes from negative 4.3 and negative 1.9 percent growth per year respectively (based on recent history) to positive 0.5 percent annual average growth per year each more consistent with a 20 year average historical value.

The advantage of these scenarios is that they specifically address some key uncertainties affecting SOS prices.

- First, the analysis covered four natural gas price scenarios: three natural gas price scenarios for Henry Hub (Henry Hub is located in Louisiana and is the principal marker delivery location in the US for natural gas) prices (Base, Low and High), and one scenario affecting natural gas basis differentials.

- Second, they address the effects of alternative capital costs which can alter the market price effect of needing new capacity to meet summer peak.

- Third, Delmarva varied coal prices, which affect market prices as well as the Conectiv and NRG bid prices.

- Fourth, Delmarva assessed climate issues by varying CO_2 emission regulations scenarios (base CO_2 emission allowance prices in the high and low CO_2 emission allowance prices). CO_2 regulations can have significant effects on power prices to the extent they are high. A gas-fired combined cycle's costs increase approximately $6/MWh in the event that CO_2 allowance costs are $15/ton, and a coal plants costs increase $15/MWh. In comparison, average wholesale prices between 2003 and 2006 in the DPL zone were $40.1/MWh to 67.1/MWh. Prices in PJM's Delmarva North aggregate, a subset of the Delmarva pricing nodes which is more reflective of Delmarva's Delaware customers, over the same time period were $39.7/MWh to $66.9/MWh.

In the second step, Delmarva calculated the average cost for SOS customers over the period of the analysis, including residual purchases from the market, for each bid. In this

regard, the residual market purchases are largest for smaller volume contracts and vice versa. Also, the type of purchases from the market can vary. A baseload contract means that additional non-contract market purchases can disproportionately be on-peak high cost power. 24 x 7 or baseload power has the lowest average cost generally, and Delmarva would still have to purchase the portion of the residual load that includes 5 x 16, or even more peaky load. An intermittent wind source that varies supply by time of day and season will cause the market purchases to have a varying purchase profile. Thus, the SOS variability under each bid can be thought of as a weighted average of the bid and its price variability and the market sub-segment and its variability.

In the third step, Delmarva calculated the variance in prices for each bid including the market Reference Case. In other words, the price analysis gives weight to what is known as the "first moment" of the price probability distribution, which is the expected SOS price in the Reference Case, and also gives weight to the "second moment" of the probability distribution of prices, which is the variance of prices. The Reference Case price (i.e., first moment), as discussed in a separate section, receives a maximum of 33 points, while the price stability (i.e., variance, i.e., the second moment) receives a maximum of 20 points as discussed below.

Delmarva used the standard deviation of levelized prices as its measure of variance, which causes the variation to be expressed as $/MWh. In estimating the standard deviation Delmarva gave all market scenarios the same weight or likelihood. The interpretation of a standard deviation of, for example, $5/MWh in this analysis would be that there is a ninety five percent chance that the long-term average of prices from 2011 to 2038 would be plus or minus $10/MWh (2 x standard deviation) around the average price across the cases. This interpretation assumes the 2011 to 2038 average prices will be normally distributed. Regardless of the exact distribution, higher standard deviations means higher price variations, and vice versa.

In the fourth step, Delmarva allocates points to the bids for their price stability effects. The bids with the greatest decrease in variance relative to the market bid received the maximum points, and the other bids received points based on the extent to which they decreased variance relative to market, compared to the best bid. For example, if the market Reference Case has a standard deviation of $x/MWh, and Bids 1, 2, and 3 have standard deviations of 0.7x, 0.8x and 0.9x respectively, then:

- Bid 1 would receive 20 points,

- Bid 2 would receive 13.3 points (this is two-thirds of 20.0, or 0.2/0.3 times 20.0; with the two-thirds reflecting the fact that Bid 2 decreases the standard deviation of prices at a rate two-thirds of the decrease of the best bid), and

- Bid 3 would receive 6.7 points (one third of 20.0, or 0.1/0.3 times 20.0).

If bids have variances of x (the market variance) or greater, they receive no points. If no bid decreases variance, then no bid receives points. This decision not to award points to bids that do not decrease the variance relative to the market Reference Case was based on the assessment that to have value for SOS customers, long-term contracts with fixed prices should have less variation than the market alone, especially in light of the decision to limit analysis of the impact of the bids on customer migration should they in fact exceed market pricing.

Results

Based on the foregoing approach, the results of the price stability analysis were as follows (see also Table 2.2.5):

- The market Reference Case had a standard deviation of $6/MWh.

- The Bluewater North's 25-year full bid had the greatest SOS price stability and the lowest standard deviation of approximately $3.8/MWh. Thus, the Bluewater North 25-year bid showed a decrease in standard deviation of $2.2/MWh relative to the market Reference, and this bid received the maximum score of 20 points.

- The advantage of the Bluewater bid is related to its pricing terms, which are relatively fixed compared to the other bids, and the large volume of electricity supplied.

- Bluewater North's 25-year partial bid had the second largest reduction in standard deviation at about $1.5/MWh and received 14.2 points. The reduction is less than the full Bluewater bid due to lower volumes.

- Conectiv lowered the market's standard deviation by a relatively small amount and received a score of 0.7 points. The Conectiv Alternative Bid had the lowest volumes over the 25-year period, and hence, contributed less to stability relative to the market price.

- The NRG 20-year bids and 25-year base bids increased standard deviation compared to the Reference Case slightly by roughly $0.3/MWh each. Thus, they received no points. The exposure of the coal based bid to CO2 uncertainty is largely responsible for this increase. Note, even when relaxing the impact of the CO2 exposure by eliminating the worst sensitivity case from the standard deviation calculation, NRG does not provide any benefit to price stability.

These results are shown in Table 2.2.5 below.

Table 2.2.5
Standard Deviation and Points for Price Stability

Bid	Standard Deviation (2005$/MWh)	Rank of Bids Qualified for Points	Point Score
Market (Reference Case)	$5.98	NA	NA
Bluewater Atlantic North 25 Years	$3.83	1	20.0
Bluewater Atlantic North 25 Years Partial	$4.45	2	14.2
Conectiv Firm	$5.91	3	0.7
NRG 20-Year	$6.27	NA	0
NRG 25-Year Base	$6.32	NA	0

The table below shows the difference between the market's standard deviation and each bid, and the price difference associated with that level of instability. It shows that the cost of price stability is high, as the best bidder on this factor (Bluewater) has significant Reference Case price premiums over the market Reference Case. The decrease in standard deviation of $1.5 to $2.2/MWh dollar costs $13/MWh in terms of higher Reference Case prices (see Table 2.2.6).

Table 2.2.6
Differences in Price Stability Compared to Market, and Price Levels

Option	Price Volatility Reduction – Standard Deviation (2005$/MWh)	Base Case Price Premium Over Market (2005$/MWh)
Market	$0.0	$0.0
Bluewater North 25 Years	$2.2	$13.0
Bluewater North 25 Years Partial	$1.5	$13.0
Conectiv Firm	$0.0	$1.0
NRG 20-Year	NA	$22.0
NRG 25-Year Base	NA	$22.0

[1] Price stability decreased relative to the market option.

Additional Caveats

For this analysis, Delmarva assumed that the technologies would perform as claimed by the bidders, and did not address potential operational problems as a source of variation in SOS prices, in spite of the large disparity in operational risk between the bids. More variation in operations and/or a bidders contract performance would lead to greater uncertainty in the amount of power that would need to be purchased from the market, and hence, greater uncertainty in the stability of prices. For example, operational uncertainty arises from NRG's proposed IGCC technology, which is not in use anywhere at this

scale, and is hardly in use in the U.S. at any scale. Also, Bluewater uses off-shore wind technologies not in use in the US, and its availability could be less than claimed in the proposal. In contrast, the Conectiv Alternative Bid uses the most standard new generation technology available. Thus, the analysis of price stability would result in lower scores and higher variability and could result in a different ranking whereby Conectiv receives a higher score if there were a means to capture the non-market risk associated with a long-term PPA.

Exposure Based on Contract Size and Other Factors

Large contract sizes, especially with respect to baseload projects with little or limited ramping flexibility or dispatchability, create higher levels of exposure to Delmarva and its customers than are optimal. The same is true for bidders that do not have investment grade ratings or do not have a parent company that has an investment grade rating. Contract terms of longer durations (e.g., 25 years) create more exposure than contract terms of shorter durations (e.g., 10 years).

The six points potentially available for this category were divided between the four elements as follows: a) contract size – 2.5 points; b) credit rating – 1.5 points; c) contract length – 1 point; and d) operational flexibility – 1 point. Table 2.2.7 below indicates the objective process used to assign the numbers of potential points were assigned, and Table 2.2.8 indicates the scores received by each bid.

Table 2.2.7 – Scoring Methodology for the Exposure Category

Exposure Scoring System							
Contract Size and Facility Installed Capacity		**Credit Rating**		**Contract Length**		**Operational Flexibility / Capacity Factor**	
MW	**Points**	**Rating**	**Points**	**Years**	**Points**	**Capacity Factor**	**Points**
400 or Max. size	0	Below BBB-	0	25	0	Baseload / Must run	0
360	0.5	BBB-	0.75	20	0.33	Ramping capability: <30%	0
320	1	BBB	1	15	0.67	Below 50% Capacity Factor / Non-dispatchable	0.25
280	1.5	BBB+	1.25	10	1	Ramping capability: 30-49%	0.5
240	2	A- to AAA	1.5			Ramping capability: 50%+	0.75
200 or less	2.5					Full dispatchability	1

On this Factor, Conectiv received 5.25 points, Bluewater received 0.25 – 0.58 points, and NRG received 0 – 0.33 points, as shown below.

Table 2.2.8 – Scoring on the Exposure Category

Bid	Contract Size MW	Contract Size Points	Credit Rating Rating	Credit Rating Points	Contract Length Years	Contract Length Points	Operational Flexibility / Capacity Factor Capacity Factor	Operational Flexibility / Capacity Factor Points	Total Points Awarded
Bluewater [1]									
25 year	400	0.00	Below BBB-	0.00	25	0.00	Below 50%, non-dispatchable	0.25	**0.25**
20 year	400	0.00	Below BBB-	0.00	20	0.33	Below 50%, non-dispatchable	0.25	**0.58**
Conectiv									
	180	2.50	BBB-	0.75	10	1.00	Full dispatchability	1.00	**5.25**
NRG Energy									
25 year	400	0.00	Below BBB-	0.00	25	0.00	Baseload	0.00	**0.00**
20 year	400	0.00	Below BBB-	0.00	20	0.33	Baseload	0.00	**0.33**

Note: Scores apply to all alternatives provided by the individual bidders unless noted.

1. Exposure is independent of whether the Atlantic North or Atlantic South location is used, hence scores apply to either.

Contract Terms

The RFP bid package contained the form PPA prepared by Delmarva to be used if one of the bids was selected through the bid evaluation process. Each of the bidders provided either a mark-up of the form PPA or a list of requested revisions (in the case of Conectiv). Each bid was allocated a fraction of one (1) point based on the contract terms that would need to be negotiated with respect to each project based on the proposed revisions. Deductions were made to the scores of each bidder based on proposed modifications that would have an adverse effect on Delmarva or its SOS customers. Deductions were also made to the scores of each bidder based on proposed modifications to provisions in the PPA previously identified as non-modifiable in the RFP. Deductions were not made for clarifying edits and other changes made to conform the form PPA to suit the technology of the proposed facility.

Although deductions were made with respect to at least one of the bidders for proposed revisions in most sections of the form PPA, noteworthy areas of deduction included Credit and Collateral requirements (Conectiv and NRG), Events of Default and Remedies (each bidder) and Obligations and Deliveries (NRG and Bluewater). Conectiv's relatively high score is attributable in part to the fact that it provided a short list of requested modifications to the form PPA rather than a comprehensive mark-up. Conversely, NRG made a number of substantive modifications to material terms of the PPA that are not beneficial to Delmarva and its SOS customers.

On this basis, the scores for each bidder are as follows:

Table 2.2.9

Bluewater	0.6 points
Conectiv	0.7 points
NRG	0.2 points

2.3 NON-PRICE EVALUATION DETAIL

Non-Price Factor Bid Evaluation

Introduction

This section provides Delmarva's scoring and analysis of the proposals with regard to the non-price factors. Non-price factors are those other than price that are important to determine the desirability of purchasing power from that bidder, and whether that bidder is likely to be successful in bringing its project to fruition. As specified in the RFP, there were eight such factors, as approved by the Commission, with maximum numbers of points available as shown below. These were further divided into two "super categories" of 20 points each ("Project Characteristics" and "Project Viability"), for a total of 40 possible points. In addition, as explained below, several factors (e.g., environmental impact) were divided into sub-factors to more objectively and fully capture their effects.

Project Characteristics		**Possible Points**
A.	Environmental Impact	14
B	Fuel Diversity	3
C.	Technology Innovation	3
Project Viability		
D.	Operation Date and its Certainty	3
E.	Reliability of Technology	2
F.	Site Development	5
G.	Bidder Experience, Safety and Staffing	5
H.	Project Financeability	5

In total, Delmarva has ranked the bidders as follows with regard to all the non-price points. The balance of this section provides a detailed explanation for the scores on each of the factors above, which in sum add up to these amounts:

Conectiv	27.0 points
Bluewater Wind – North	24.7 points
Bluewater Wind – South	24.7 points
NRG	20.0 points

In other words, Delmarva's scoring of the bids ranged from about one-half to two-thirds of the possible points in the non-price category. The Reviewing Parties agreed that bids would be scored in tenths of a point. Because it was scored using a formula, one of the factors (environmental impacts) allowed for finer detail, but the others were not scored with such granularity.

A. Environmental Impact (14 possible points)

This factor was further divided into three sub-categories: greenhouse gases (GHGs); criteria pollutants, and other impacts (water, land, wildlife and waste), with the potential for 4.0 points, 4.0 points and 6.0 points in each of these sub-categories, respectively. By agreement among Delmarva, the Public Agencies and their consultants (the Reviewing Parties), Delmarva scored the first two of these using a mathematical formula in which zero emissions received the maximum number of points (4.0), and the emissions that would come from a coal plant just meeting current regulations in Delaware would receive no points. The Reviewing Parties agreed to assign up to 4.0 points linearly between anticipated emissions of zero and the maximum allowed coal plant emissions. Delmarva checked to ensure that the emissions claimed by the Bidders were likely to be the actual emissions – the Company found no discrepancies in this regard. In addition, if there was a primary and a secondary fuel, Delmarva used the ratio of each fuel to determine the expected emissions.

1. Greenhouse Gases (4 points maximum)

Bluewater Wind – Since there are no expected CO2 emissions, this bid received 4.0 points on this sub-factor.

Conectiv – The anticipated emissions of CO2 were divided between those expected for the use of the primary fuel (natural gas) and the secondary fuel (fuel oil). Conectiv is expected to use gas 100% of the time that it is providing power to Delmarva. Using the agreed-upon emissions scale, Conectiv received approximately half the potential points.

NRG – The anticipated emissions of CO2 were divided between those expected for the use of the primary fuel (coal) and the secondary fuel. NRG is expected to use coal 100% of the time that it is providing power to Delmarva.

Again, using the agreed-upon emissions scale, NRG received 7.5% of the potential points.

Table 2.3.1 – Non-Price Points on GHG Emissions

Bluewater Wind North	4.0 points
Bluewater Wind South	4.0 points
Conectiv Energy	2.0 points
NRG Energy, Inc.	0.3 points

2. Criteria Pollutants (4 points maximum)

As with greenhouse gases, the calculation of points awarded for criteria pollutants was formulaic. Since there were four such pollutants (SOx, NOx, Mercury or Hg, and Particulate Matter or PM), the Reviewing Parties agreed to assign 1.0 possible point to each pollutant. Using the anticipated emissions, Delmarva derived the scores for each pollutant and bidder as follows:

Table 2.3.2 a) to d) – Non-Price Points on Criteria Pollutants

SOx:

Bidder	Points
Bluewater Wind North	1.0
Bluewater Wind South	1.0
Conectiv	0.98
NRG	0.81

NOx:

Bidder	Points
Bluewater Wind North	1.0
Bluewater Wind South	1.0
Conectiv	0.92
NRG	0.77

Mercury (Hg):

Bidder	Points
Bluewater Wind North	1.0
Bluewater Wind South	1.0
Conectiv	1.0
NRG	0.78

PM:

Bidder	Points
Bluewater Wind North	1.0
Bluewater Wind South	1.0
Conectiv	0
NRG	0.18

Thus, if one adds up across the emissions sub-factors (both CO2 and criteria pollutants), the scores for each bidder out of a possible 8 points are:

Table 2.3.3 – Non-Price Points on Emissions of GHGs and Criteria Pollutants

Bluewater Wind North	8.0 points
Bluewater Wind South	8.0 points
Conectiv Energy	4.9 points
NRG Energy, Inc.	2.8 points

3. Water, Land, Wildlife and Waste Impacts (6 points maximum)

The maximum potential for each of the four sub-factors in this category was 1.5 points. In the RFP, bidders were asked to describe: (a) their plans for developing their environmental impact reports and permit applications relating to these factors, and (b) the intended impacts of the development of their projects. Delmarva then made qualitative assessments of the bids.

a) Water Impacts (1.5 points)

Based upon the provisions of the RFP, Delmarva scored the water impacts of the proposals based on a qualitative assessment of consumptive use (0.5 points), thermal discharge (0.5 points) and character of the water discharge (0.5 points).

1) Consumptive Use (0.5 possible points)

Bluewater Wind's proposals will not use either process water or cooling water and, consequently, they received the maximum point allocation available. In comparison, significant deductions were made to Conectiv's and NRG's scores because of their need for process and cooling water. Since NRG's proposal would use considerably more water on a daily basis, its deduction was greater. Conectiv's score was then increased as a result of its plans to use cooling water from its adjacent power plant. Likewise, NRG's score was increased on the basis of its obtaining cooling water from adjacent units as well as its plan to recycle municipal wastewater to meet process water needs. Delmarva thus assigned scores as follows:

Table 2.3.4 – Non-Price Points on Water Consumption

Bluewater Wind – North	0.5
Bluewater Wind – South	0.5
Conectiv Energy	0.3
NRG Energy, Inc.	0.2

2) Thermal Discharge

The Bluewater Wind proposals would not result in a thermal discharge and maximum points were allocated to them. Correspondingly, the two proposals that would have thermal discharges, Conectiv's and NRG's received substantial deductions for this factor. On a qualitative basis, the former received an increase in its score based on a projected reduced discharge temperature at it existing outfall. Although the Conectiv and NRG proposals received substantial deductions in comparison to Bluewater Wind's, both indicate that they will meet permitting standards and both firms have considerable experience in meeting these standards. Also, NRG's project is more than twice the size of Conectiv's and will thus have a more pronounced thermal impact.

Table 2.3.5 – Non-Price Points on Thermal Discharge

Bluewater Wind – North	0.5
Bluewater Wind – South	0.5
Conectiv Energy	0.2
NRG Energy, Inc.	0.1

3) Character of the Water Discharge

Bluewater Wind's water discharge would be limited to domestic sewage which would be treated at a municipal sewage treatment facility and the process used by Bluewater Wind would not produce any significant volume of process wastewater streams. In addition, the process used by BWW would not pose a significant risk of contaminating stormwater runoff. Based on this minimal discharge, its proposals received the maximum points. By comparison to Bluewater Wind, Conectiv's score was reduced based on its much larger quantity of water to be discharged. However, the content of this discharge is primarily non-contact cooling water and not process wastewater or stormwater runoff so a smaller deduction was made to this factor as compared to Conectiv's deductions under the thermal and consumptive factors.

The process used by Conectiv does not involve any bulk storage of solid fuels or combustion by-products; thus, does not pose any significant risk of contamination to stormwater runoff. In addition, the process used by Conectiv does not produce a significant level of combustion ash, slag or scrubber by-products that would require periodic cleaning and result in process wastewater streams that require further treatment.

NRG received the largest deductions because it would have greater potential to adversely impact stormwater run-off and would result in a broader range of process wastewater streams that require further treatment, storage and handling. By comparison to Conectiv, the process used by NRG would result in a greater risk of contaminated stormwater runoff and landfill leachate from materials managed on the site such as coal, boiler slag and coal combustion ash. In addition, the NRG combustion and gasification processes would require periodic cleaning of the boiler and gasifier equipment which would result

in process wastewater streams that contain a broad array of hazardous constituents such as metals and petroleum hydrocarbons that require further treatment and may pose a risk of release to surface water during storage and handling.

Table 2.3.6 - Non-Price Points on Water Discharge

Bluewater Wind – North	0.5
Bluewater Wind – South	0.5
Conectiv Energy	0.3
NRG Energy, Inc.	0.2

b) Land Impact (1.5 points)

Delmarva scored land impacts on a qualitative assessment basis with 0.5 points being allocated to acreage disturbed, including the magnitude of the disturbance, and 1.0 point being awarded if a project proposed to co-locate at an existing brownfield or industrial site. In applying the acreage disturbed factor, Delmarva decided that it would not be equitable to limit this factor to the disturbed terrestrial environment but that it should also be applied to the magnitude of the affected marine sites. Also, because the one point that is available here for a brownfield or an industrial site location mirrors the point that is available under the Site Development category, Delmarva reflected the same considerations and scores in both categories. The Company assigned scores as follows:

1) Acreage Disturbed (0.5 potential points)

Conectiv's proposal would disturb the smallest amount of acreage, directly or indirectly. The total acreage of the proposed site is listed as six acres. The proposed plant would be sited on an already cleared, upland portion of Conectiv's existing, industrial site. The latter is surrounded by heavy industrial and manufacturing uses as well as major transportation corridors. All infrastructure needs can be accommodated on site. Consequently, Conectiv received the maximum score for having the smallest direct and indirect acreage impacts.

NRG's proposal is planned for a seventy-acre site. It is larger than Conectiv's site and unlike Conectiv's, it is not cleared land. The vast majority is described as a typical eastern pine and hardwood forest. It also currently buffers the existing Indian River steam plant from adjacent agricultural uses. This buffer would be lost. Consequently, in comparison to Conectiv's proposal, NRG's score was reduced based on these larger direct and indirect acreage disturbances. However, the reduction was limited or mitigated because a portion of the proposed site has previously been disturbed through use as a fly ash disposal pit and the proposal is designed to fit within the existing footprint of an NRG-owned complex.

Bluewater Wind's proposed sites affect large expansions of the marine environment. For example, the estimates for both the Atlantic North and South sites are just over 30

nautical square miles. These large tracts have the potential to disturb a variety of marine uses. Delmarva awarded no points when viewed in comparison to the much more limited spatial impacts of the other two bidders.

Table 2.3.7 – Non-Price Points on Acreage Disturbed

Bluewater Wind – North	0.0
Bluewater Wind – South	0.0
Conectiv Energy	0.5
NRG Energy, Inc.	0.3

2) Brownfield/Industrial Site

Conectiv's proposed site is part of an existing power generation site, one which clearly meets the criteria of an industrial site.

NRG, on the other hand, states in its submission that its proposed site is neither a brownfield site nor an industrial site. Under the Sussex County Land Use Plan, the proposed site is currently located in an overlay zone identified as an environmentally sensitive developing area and will require rezoning. However, the Company allocated a portion of the one point to NRG since it represents a logical and conforming extension of the adjacent industrial use, the Indian River power station.

Bluewater Wind's proposed lease of the Potts Property was not allocated any portion of this point because its use would not meet the public policy intent of this criteria, i.e., to use as an important operational component of the project either a remediated property or existing industrial property. Delmarva rejected Bluewater Wind's claim that they should be considered a brownfield site because they will use some industrial facilities onshore as a staging ground for servicing their wind turbines. The key for obtaining brownfield status is the power generation site; all power plants have materials and services that they obtain from elsewhere that Delmarva did not believe should be considered in this evaluation.

Table 2.3.8 – Non-Price Points on Brownfield-Industrial Site

Bluewater Wind – North	0.0
Bluewater Wind – South	0.0
Conectiv Energy	1.0
NRG Energy, Inc.	0.3

c) Wildlife Impact (1.5 points)

Delmarva assessed wildlife impact on a habitat-based, qualitative basis. Among the factors Delmarva considered were the likelihood for habitat loss/gain; the likelihood of wildlife mortality; the economic value of the habitat being affected; and other impacts on

biodiversity. Delmarva allocated the available 1.5 points between the four factors as indicated below.

1) Likelihood For Habitat Loss/Gain (0.4 possible points)

Conectiv's continued use of a cleared industrial site is not expected to result in any substantive loss of habitat. Its proposal received the maximum points. NRG's proposal will require the clearing of some forest land, i.e., the vast majority of its seventy-acre site. Deductions were attributed to this habitat loss but limited because the affected habitat is not described as either unique or of state or federal significance. Bluewater Wind's proposals will encompass large tracts of Ocean waters, as discussed above under land impacts. Although the resulting impacts to habitat would require further study as part of associated permitting activities, the likelihood of adverse impacts to habitat is several magnitudes greater for Bluewater Wind's proposals, than either NRG's or Conectiv's. Also, the combination of potential habitats affected is much more varied under the Bluewater Wind's proposals, ranging from open water, to ocean floor, beach, perhaps wetlands, and terrestrial.

Table 2.3.9 – Non-Price Points on Habitat Impact

Bluewater Wind – North	0.0
Bluewater Wind – South	0.0
Conectiv Energy	0.4
NRG Energy, Inc.	0.2

2) Likelihood of Wildlife Mortality (0.4 possible points)

Although Delmarva recognized that entrainment/impingement may cause some wildlife mortality at the Conectiv site, no wildlife mortality concerns were noted for that site. This position again stems from the proposal's very limited site impacts. (Indeed, both the Conectiv and NRG proposals state that no new water intake structures would be required, which may indicate that any additional entrainment/impingement resulting from the operation of the new units would be insignificant.) NRG's need to clear forest land would result in a greater likelihood of wildlife mortality and its score was slightly reduced. Delmarva believes that the greatest likelihood of wildlife mortality occurs at both of Bluewater Wind's proposed sites.

Delmarva also recognized that in any future project development stages, considerable data and analyses would have to be completed by both Bluewater Wind and the affected permitting agencies for the purpose of quantifying and clarifying these impacts. Because of the current uncertainty with respect to this factor, Delmarva limited Bluewater Wind's deduction based on the results of its initial and related consultations with the permitting agencies, as summarized by Bluewater Wind, and the wildlife impact studies referenced in its proposal.

Table 2.3.10 – Non-Price Points on Wildlife Mortality

Bluewater Wind – North	0.1
Bluewater Wind – South	0.1
Conectiv Energy	0.4
NRG Energy, Inc.	0.3

3) Economic Value of Affected Habitat- 0.4 points

Delmarva did not consider Conectiv's site to contain habitat of any measurable economic value. The site was previously cleared and is part of an industrial site. Consequently maximum points were awarded to it. By comparison, the use of the NRG site would require the clearing of the vast majority of a seventy acre site with the clearing affecting a typical eastern pine and hardwood forest. Economic value was attributed to this affected forest and a deduction made to the NRG score. In comparison, however, Bluewater Wind's sites are much more likely to have a greater economic value as habitat. This value stems primarily from the affected habitat's contribution to commercial and recreational fishing.

Table 2.3.11 – Non-Price Points on Economics of Habitat

Bluewater Wind – North	0.0
Bluewater Wind – South	0.0
Conectiv Energy	0.4
NRG Energy, Inc.	0.3

4) Other Impacts on Biodiversity (0.3 possible points)

Delmarva decided to allocate 0.3 points as the maximum for this factor. The Company also decided for our purposes to define an "impact on biodiversity" as a significant impact to an identified species or habitat such that the biodiversity of the affected ecosystem was specifically threatened. Neither the Conectiv nor NRG proposal is considered to have the potential or likelihood to trigger any such impacts, so Delmarva assigned them the maximum score. Because Bluewater Wind's proposals have unresolved questions with respect to adverse impacts on biodiversity and in terms of important species such as red knot and some marine mammals and migratory birds, so a deduction was made on the basis of likelihood.

Table 2.3.12 – Non-Price Points on Other Biodiversity Impacts

Bluewater Wind – North	0.2
Bluewater Wind – South	0.2
Conectiv Energy	0.3
NRG Energy, Inc.	0.3

d) Waste Disposal Impacts (1.5 possible points)

Delmarva scored waste disposal on a qualitative assessment basis as follows:

Bluewater Wind's facilities would generate no solid or hazardous wastes of any consequence. Its wastes would generally be confined to petroleum, oil, and lubricants and result from maintenance operations. Consequently, Bluewater Wind received the maximum score.

Conectiv would produce larger and more varied amounts of wastes than Bluewater Wind and its score was reduced. The reductions were not major given the limited amount of its projected wastes. The latter would consist of some potentially flammable substances such as gas pipeline condensate, small amounts of water treatment chemicals, and volatile compounds. No combustion ash would be produced. Conectiv expects to qualify for either small quantity generator status or conditionally exempt generator status.

The NRG proposal would generate the largest amounts of wastes and contain the most diverse constituents. The largest indicated waste stream is slag. Large amounts of gasification fly ash and sulfur would also be generated. NRG states that it is currently requesting permitting for the expansion of its Indian River Ash Landfill for the purpose of extending the useful life by seven to ten years and in order to accommodate 100% of the additional gasifier slag and fly ash. Accordingly and by comparison, NRG received the largest deductions. The evaluators, however, also recognized NRG's stated position that there is an opportunity to sell or recycle several of the by-products of the gasification process. Consequently, NRG's overall score was credited for this recycling opportunity.

Table 2.3.13 – Non-Price Points on Waste Disposal

Bluewater Wind – North	1.5
Bluewater Wind – South	1.5
Conectiv Energy	1.1
NRG Energy, Inc.	0.7

B. Fuel Diversity (3 possible points)

This factor was straightforward to score. To provide credit to the Bidders for offering diversity to Delmarva's fuel mix, as required in the Act, the Reviewing Parties agreed in advance to assign points to this factor as follows:

Gas and oil	0.0 points
Coal (PC, IGCC)	1.0 point
Projects with fuel flexibility (e.g. CFBs, some IGCC)	2.0 points
Renewables, including biomass	3.0 points

On this basis, Delmarva assigned these scores for each of the bidders on Fuel Diversity:

Table 2.3.14 – Non-Price Points on Fuel Diversity

Bluewater Wind North	3.0 points
Bluewater Wind South	3.0 points
Conectiv Energy	0.0 points
NRG Energy, Inc.	2.0 points

C. Technology Innovation (3 possible points)

This factor was also straightforward to score. To provide credit to the Bidders for providing technological innovation, as required in the Act, the Reviewing Parties agreed in advance to assign points to this factor as follows:

Pulverized coal and CFBs	0.0 points
Combined cycle and CTs	0.0 points
On-site generation, cogeneration	0.0 points
Renewables other than off-shore wind	0.0-3.0 points (with the score dependent on the specific type of renewable source)
IGCC and off-shore wind	3.0 points

On this basis, Delmarva assigned these scores for each bidder on Technology Innovation:

Table 2.3.15 – Non-Price Points on Technology Innovation

Bluewater Wind North	3.0 points
Bluewater Wind South	3.0 points
Conectiv Energy	0.0 points
NRG Energy, Inc.	3.0 points

D. Operation Date and its Certainty (3 possible points)

This was a relatively straightforward factor, as the Reviewing Parties agreed in advance that points would be assigned depending on the on-line date of the facility, with June 1, 2013 being the latest possible date (so as to be available for the summer peaking season in that year). The "wrinkle" in this case is that it was important for Delmarva to exercise it judgment as to the likelihood that the Bidders would be able to bring their projects on line on or about the date indicated. The Reviewing Parties agreed to the following:

By June 1, 2013	0.0 points
By June 1, 2012	1.0 point
By June 1, 2011	2.0 points
By June 1, 2010	3.0 points

In that context, Delmarva scored the proposals based on the following:

Bluewater Wind – While the permitting plan for these projects is extremely detailed and clearly based on extensive "homework", we anticipate that both the North and South projects would be likely to experience some delay for several reasons: 1) aesthetic issues that will raise concerns from affected homeowners; and 2) the fact that MMS regulations over rights to offshore areas have not yet been finalized. More information on this topic is provided in Section F below under "Site Development". In this light, Delmarva believes that if one of these projects is accepted, it is more just as likely to come on line between 2012 and 2013 (i.e., a six-month delay) as it is to come on line by the 2012 date in the Bidder's proposal.

Conectiv – Conectiv assumed in their proposal that it would be under contract with Delmarva for the Hay Road facility by March 2007 in order to come on stream by June 1, 2011. Given the regulatory process, and the integration required with Delmarva's IRP, it is unlikely that a contract would be signed (if one is signed) until this summer. The Company recognizes that Conectiv is highly experienced at project development, particularly at the Hay Road site, and that they may be able to accelerate the development schedule in their proposal. Nevertheless, Delmarva thinks that Conectiv's date is optimistic, and that it is more realistic to anticipate a delay in the projected commercial operation date of 6-9 months.

NRG – We expect that NRG will be hard-pressed to realize a June 1, 2013 date for commercial operation, given the need to both obtain required permits and to ensure the commercial operation of an IGCC plant, which is a fledgling technology in the US context. Delmarva expects a delay past June 1, 2013 if NRG is selected, but since the Company cannot assign less than zero points, Delmarva accepts that date for scoring purposes.

On this basis, the scores for each bidder are as follows:

Table 2.3.16 – Non-Price Points on On-Line Date

Bluewater Wind North	0.5 points
Bluewater Wind South	0.5 points
Conectiv Energy	1.3 points
NRG Energy, Inc.	0.0 points

E. Reliability of Technology (2 possible points)

The Reviewing Parties agreed that the key factors here are the track record of the proposed technology, over time, and guarantees from a reputable manufacturer, and further agreed on the following guidelines to assess projects on a case-by-case basis:

No more than 1 similar operating project; with no manufacturer guarantees	0.0 points
Performance guarantees from manufacturers on Projects with fewer than 3 other projects	1.0 point
Three or more similar operating projects that have performed at target availability for at least 3 years	2.0 points

In this context, we evaluated the proposals as follows:

Bluewater Wind – North and South:

Background: Bluewater proposes to build 200 3.0 MW wind turbines for a total of 600 MW of capacity at both offshore sites. The turbines will be connected to the mainland by underwater/underground AC cables, and will be manufactured by Vestas.

Maturity of the technology: Vestas has installed a total of 202 V90 wind turbine units, of which 176 are in offshore installations. Vestas has a total of 290 offshore turbine installations. By 2008 Vestas estimates a total of 356 V90 turbine installations worldwide. V90 turbines first installation was in 2004-05 in the UK. Few of the applications have been in the US, but European experience is considered satisfactory.

The performance history of the V90 is proprietary to the owners of the projects, and Bluewater Wind could not provide this information. We made a deduction based on this factor. Vestas started manufacturing in 1979, and is the world's largest wind turbine manufacturer, with 30,782 wind turbines installed across the world, and a total installed MW capacity of 20,817 MW.

Guarantees Offered: This is a strong feature of this proposal. Vestas would provide a standard guarantee of 95% availability. Also Vestas will provide a power output guarantee of 95% of rated electrical output for a given wind speed. Warranties last at least 2 years. Ballast Nedam (BN) is a Dutch company founded in 1969 that would carry out the off-shore installation. BN collaborated with Vestas to install the first offshore wind turbine for the Netherlands, and it is currently involved in another project with Vestas building the first wind farm in the North Sea. It is one of the top five construction firms in the Netherlands.

Conectiv Energy:

Background: Conectiv Energy proposes a 180 MW gas fired combined cycle using state of the art technology. Distillate will be a back up secondary fuel. The combustion turbine will be a Siemens Westinghouse V84.2 with dual fuel capability, and the configuration will be a 1x1x1 with SCR for NOx control. Standard wet cooling will be used as the condensing mechanism. The estimated equivalent forced outage rate is 2.5% and equivalent availability factor is 90%.

Maturity of the technology: There are many hundreds of installations, and this technology is mature. Over 200 GW of combined cycle capacity has been put in-place over the 2000-2006 timeframe, and a large portion of this has been with GE-7FA or Siemens Westinghouse W501F. The Siemens Westinghouse V84.2 is not as pervasive in usage as either the 7FA or 501F; however, Siemens is one of the top two turbine manufacturers. Conectiv cites 14 years experience operating and maintaining the V84.2 in combined cycle mode. To date, we know of tw0 Conectiv Plants with V84 technology: – Bethlehem (CIV) (V84.3) and Wilmington (V84.2). Overall Delmarva estimates there are approximately 39 turbines using V84 technology out of 1050 turbines that came online over the 1998-2003 period. Twelve of these 39 V84 turbines are V84.2; the V84.2 was introduced in 1984.

Guarantees Offered: Conectiv indicates that it will provide performance guarantees for: i) availability, ii) energy and iii) capacity. All new equipment will be contracted to include performance guarantees and warranties for sustained performance. Final details will be made available as Contracts are awarded. While no specifics on the guarantees are mentioned, it is not expected to be problematic to offer such guarantees.

There were no deductions from Conectiv's based on the reliability of the technology.

NRG Energy, Inc.

Background**:** NRG proposes a 600 MW IGCC using Shell gasification technology. The project will employ dual gasifier trains and also distillate fuel oil (a back up secondary fuel to ensure greater reliability.) Both gasifiers are needed for the synfuel process to achieve 100% capability. NRG is looking into natural gas as the eventual back up fuel. The IGCC will be carbon capture ready as well. The combustion turbine will be a GE-7FB or equivalent. Configuration will be a 2x2x1 with SCR for NOx control. Standard wet cooling will be used as the condensing mechanism taking makeup water from the river. NRG has also employed a "sparing" philosophy such that critical components only comprise 50% of needed capability. This reduces the likelihood of a complete shutdown. Critical pumps will have spares for preventing outages. The target equivalent availability factor is expected to rise over the first 4 years of operation, moving from 60%, to 65%, to 75% and finally reaching 80% in the fourth year and thereafter.

Maturity of the technology: There are concerns here, for which we made a significant deduction. While gasification has been around for years, integration with combined cycle

technology has been a struggle for the last 20 years. There are four competing gasification technologies at present: GE, Shell, ConocoPhillips and MHI. While all are of the entrained type, Shell and MHI use a membrane (water walls) as opposed to a refractory wall approach as does GE and ConocoPhillips. NRG believes this as leading to gains in efficiency, lower O&M and higher availability. NRG believes this will outweigh its slight disadvantage in higher capital cost.

NRG indicates that two plants currently use this technology: the Buggenum (Netherlands) since 1998 and Puertollano (Spain). These plants have operated over 10 years, and we summarize their track record below.

Buggenum-

- 253MW; Commercial online date 1994
- In 1997 overall availability reached 85%
- Gasifier availability approximately 90% over 97'-04' period
- Overall availability from 50-90%, averaging around 70%.

Puertollano- 330MW; commercial on line date 1997

Puertollano Plant Availability

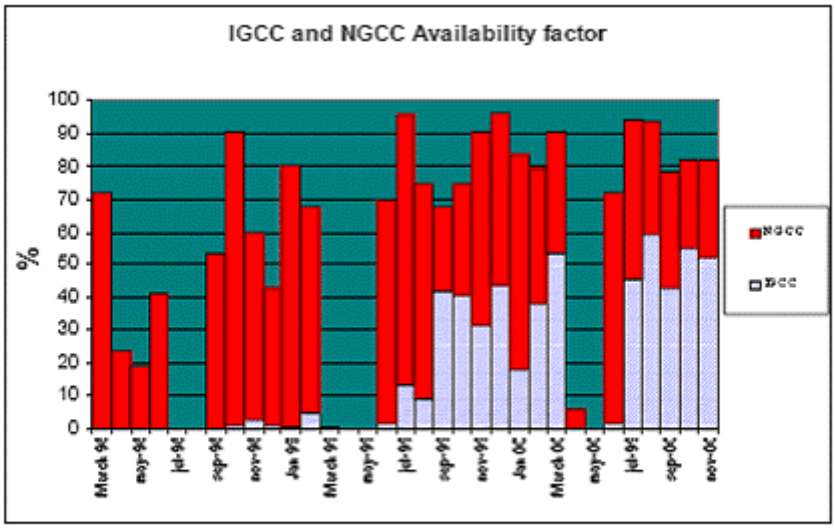


Figure 39. IGCC and NGCC availability factor.

The wide fluctuations in the availability factors of these plants support the uncertainty surrounding NRG's claim that its facility will be able to achieve a smooth progression in terms of its availability. This is not unusual for technologies in their early stage of commercial development, however, it does present a risk to Delmarva that the plant will not perform at the anticipated level.

Shell Quals: over 100 gasifiers developed since 1956. Currently the SCGP is being used in over 10 projects in China. Currently there are 26 such plants in operation.

Black &Veatch (B&V) Qualifications: B&V has built one gasification plant (Farmland Coke plant), and has been involved in design and performed feasibility studies. While B&V is highly experienced in power plant construction, its actual IGCC construction experience is not noteworthy, primarily because few IGCC plants have been built.

Guarantees Offered: NRG indicates that performance guarantees will be negotiated with the EPC contractor, and thus no specifics on the guarantees are mentioned. Delmarva made a deduction due to the lack of maturity of the technology. As noted above, the EPC contractor (B&V) does not have strong IGCC construction experience.

Based on the above information, Delmarva ranked the bids as follows with regard to reliability of technology:

Table 2.3.17 – Non-Price Points on Reliability of Technology

Bluewater Wind North	1.5 points
Bluewater Wind South	1.5 points
Conectiv Energy	2.0 points
NRG Energy, Inc.	1.0 points

F. Site Development (5 possible points)

This factor consisted of three sub-categories: siting plan (3 points), brownfield/ industrial site (1 point), and socioeconomic issues (1 point). Delmarva further sub-divided the siting plan as described below.

1. Siting Plan **(3 possible points)**

The Company awarded up to three points based on our review of the following components: (1) site control over required land including transmission and access – one point; (2) a well-developed fuel supply and interconnection plan – one point; and (3) a well-defined permitting plan – one point.

a) Site Control and Transmission

Delmarva divided the one point available equally between:

- Access to site and site control; and
- Quality of the interconnection plan presented

Site control assesses availability of and likelihood of access to rights-of-way, while quality of the interconnection plan assesses the completeness and comprehensiveness of the plan.

Site Control. NRG and Conectiv are both awarded maximum points for site control. Both projects will be located close to or within existing substations, so we do not anticipate any negative impact from rights-of-way issues. Bluewater Wind, on the other hand, is awarded half the points., because the interconnection of the wind farms will require marine cables to shore, and at least a few miles of underground or overhead cables to access the Delmarva interconnection substations. Bluewater Wind will therefore need to acquire new rights-of-way in addition to the existing Delmarva rights-of-way that it plans to use.

Interconnection. All three bidders provide detailed and comprehensive descriptions of the requirements for interconnection of their generators. NRG and Bluewater Wind further demonstrate that they have filed feasibility study requests with PJM. Although Conectiv does not indicate that it has filed a feasibility study request, it is not penalized since this was not explicitly required in the RFP. All three are awarded the maximum points in this category.

Table 2.3.18 – Non-Price Points for Site Control and Transmission

	Potential Score	NRG	Conectiv	BWW – Atlantic North	BWW – Atlantic South
Site Control	0.5	0.5	0.5	0.25	0.25
Goodness of Plan	0.5	0.5	0.5	0.5	0.5
Total	1.0	1.0	1.0	0.75	0.75
Adjusted Total	**1.0**	**1.0**	**1.0**	**0.8**	**0.8**

b) Fuel Supply

Bluewater Wind. The variability or intermittency of the wind prevents this project from being able to provide a reliable supply of "fuel". In any given day, month or year, the amount anticipated from using an average of historical wind values is almost certain not to be equal to the amount of wind (and power) that the project will receive. Delmarva must therefore make up the difference between what Bluewater Wind provides and what is anticipated. This uncertainty leads us to award Bluewater Wind half the points (0.5 points) available under this category.

Conectiv. Out of a total of 1.0 points that can be awarded to Conectiv for fuel supply for its bid to Delmarva, Delmarva has 0.8 points, for the following reasons:

- The project, an expansion at the existing Hay Road generating facility, would be supplied over an existing lateral, fed by three interstate pipelines

on which Conectiv has pipeline capacity. These pipelines are Transco, Texas Eastern, and Columbia. Liquid back-up fuel would be supplied through the existing edge Moor Barge facility. The project has access to fuel oil markets in New York and Philadelphia.

- Conectiv proposes to serve the facility with a combination of existing pipeline capacity on the three pipelines and new capacity. Conectiv says it will negotiate new transportation agreements. It currently has in place creditworthiness filings, and North American Energy Standards Board (NAESB) standard contracts on the pipelines as well as with a variety of gas producers, marketers, and gas utilities.

- Conectiv describes its gas supply arrangements as an extension of its current arrangements where by it buys from a variety of parties in Appalachia and the Gulf Coast. Conectiv intends to construct a portfolio of supply, transport, and storage, consistent with the energy pricing in the PPA. Pricing will be in reference to published public indices, such as Henry Hub and Tetco M3.

- Conectiv asserts it has a strong fuel procurement and management program consistent with its ownership of 2,000 MW of dual fired combined cycle generation. It proposes to manage all fuel procurement for this project with current staff.

In sum, Conectiv presents that this project is simply an extension of its existing portfolio of projects which can be easily managed under its current operating systems, and with existing facilities at the site, including fuel storage tanks, pipeline laterals, barge off-loading facilities and the like. We are reasonably confident that Conectiv can assemble a solid fuel supply capability for the proposed project at Hay Road.

NRG. Based on a review of their proposal, NRG is awarded the full 1 point available for its fuel plan for its proposed Indian River IGCC facility. The award of the maximum value available for the fuel plan is based on the following factors:

- The proposed project would be located at an existing power plant site owned by NRG with existing rail delivery, unloading, and storage facilities. NRG's proposal indicates that they will also install new tracks including a loop serving a rotary car dumper.
- NRG has solicited rates for delivering coal by rail to the Indian River site and identified Norfolk Southern Railroad (NS) as the most competitive. NS will negotiate a final contract with NRG if their proposal is selected.
- The proposed IGCC facility will have flexibility to burn a wide range of coals from domestic and international sources. The coal supply can be supplemented by petroleum coke and up to 5 percent biomass feedstock.

- Given that NRG's Fuels Group procures approximately 36 million tons of coal per year, it appears to have the necessary experience to obtain competitive prices for coal purchase and delivery.
- NRG's proposal also demonstrates the necessary experience and capability to secure ultra low sulfur #2 diesel fuel as a secondary feedstock.

c) Permitting Plan

Delmarva divided the one point available for this criterion equally between: a) the quality of the permitting plan presented, and b) the likelihood of the plan's results being achieved within the indicated timeframes. Within that framework, based on our review of the proposals, Delmarva's assessment was:

The permitting plan for each of the four proposed projects was thorough, complete and well defined. Each of the projects received a full score for the sub-factor relating to the quality of its permitting plan.

With regard to the sub-factor for the likelihood of being achieved, Conectiv was awarded the maximum score because it has successfully demonstrated the ability to execute its permitting plan and had indeed done so with projects totaling more than 1650 MW of capacity within the past five years. The existing permitted power generation site at Hay Road also makes it highly likely that Conectiv would receive all required approvals for the proposed addition.

Both NRG and Bluewater Wind were awarded somewhat lower scores on this sub-factor (0.3 out of 0.5). NRG was awarded this score because of the uncertainty around execution of its permitting plan for an IGCC in the Mid-Atlantic. At this point, there are only two commercial-size operating ICGG facilities in the United States. The two U.S. projects were supported initially under the U.S. Department of Energy's Clean Coal Technology demonstration program, but are now operating commercially without DOE support. While permits plans for additional IGCC facilities have recently been announced in the Mid-West, none of these plans have been fully executed.

Bluewater Wind was awarded this score because of the relatively high uncertainty of executing a permitting plan for a large off-shore wind park in the Mid-Atlantic. The plethora of permits, the lack of existing regulations from the MMS, and the uncertainties surrounding the aesthetics of the projects combine to lower their likelihood of success.

The sum of Delmarva's scores for the Site Development category was as follows:

Table 2.3.19 – Non-Price Scores for Fuel Supply and Permitting Plan

	Potential Score	NRG	Conectiv	BWW – Atlantic North	BWW – Atlantic South
Fuel Supply	1.0	1.0	0.8	0.5	0.5
Permitting Plan	1.0	0.8	1.0	0.8	0.8

2. Brownfield/Industrial

Delmarva's assessment and scores on this sub-factor is the same here as the evaluation of brownfield/industrial site in Section A. 3. b) 2) above – Environmental Impacts.

3. Socio-Economic Impacts

Delmava assessed the projects based on: a) the level of visual and noise impacts the facility may have on the community b) the level of community support behind the project and the ability of the project to addresses community concerns, c) the potential for environmental equity issues. Delmarva subtracted from the 1.0 point available for deficiencies in these areas. Within that framework, Delmarva's assessment was:

For each of the four proposed projects, it appears unlikely that environmental justice issues will be raised. None of the projects are located in or near residential areas with demographics that warrant environmental justice concerns. No points were deducted from any of the projects.

Conectiv was awarded the maximum score because it should have negligible visual and noise impacts and it appears unlikely to raise significant community concerns. It is likely that, the project will be perceived as a minimal expansion of an existing gas-fired facility which has experienced little organized community opposition since the commencement of its commercial operation.

NRG was awarded the second highest score because it is expected to have relatively low visual and noise impacts but may likely raise some level of community concerns due to the expansion of the existing site's physical footprint and the history of organized community opposition to coal-fired generation in the Mid-Atlantic.

Bluewater Wind was awarded the lowest score because of the relatively high visual and noise impact of an off-shore wind park, and the history of organized community opposition to wind turbines along the Eastern seaboard of the U.S.

Table 2.3.20 – Non-Price Scores for Socio-Economic Impact

	Potential Score	NRG	Conectiv	BWW – Atlantic North	BWW – Atlantic South
Socio-Economic	1.0	0.8	1.0	0.5	0.5

G. Bidder Experience, Safety and Staffing (5 possible points)

The Reviewing Parties agreed to use the following guidelines to assess bidder experience, safety and staffing:

No primary successful development experience with similar projects or Successful development experience but with a questionable safety record and relatively inexperienced staff proposed	0.0 points
Primary successful development responsibility with 1-2 similar projects, with strong safety record and experienced staff proposed	3.0 points
Primary successful development responsibility for three or more similar projects, with an excellent safety record and highly experienced staff proposed	5.0 points

Bluewater Wind - North and South

Delmarva made major deductions from Bluewater Wind due to the fact that they have never developed an offshore wind project. We acknowledge that the sub-contractors that Bluewater has on its team (e.g., Vestas, AWS) are strong, and in many cases represent state-of-the-art experience in the wind industry. However, we assigned most of the weight for this factor based on the primary developer, Bluewater Wind, which is the firm responsible for pulling all of the pieces of the development of the project together. Given the concerns raised under "Site Development" above and "Financeability" below, it is clear that Bluewater Wind does not have experience in the successful completion of the type of project proposed. Further, this project is much larger than any previously undertaken by Bluewater Wind. The guidelines above would enable us to score Bluewater Wind a "zero" due to this lack of experience; however, Delmarva raised the score to "1.0" based on the strength of its sub-contractors and its comprehensive grasp of the regulatory process.

Conectiv Energy

There was no basis for any deductions from Conectiv Energy. Conectiv has developed approximately 2,000 MW of gas-fired projects, many using combined cycle technology of the type proposed here. They have regularly demonstrated the ability to effectively finance, construct and staff such projects.

NRG Energy

NRG is a highly experienced developer, with thousands of megawatts to its credit. While it has successfully developed many coal projects, it has never developed an IGCC project before. Delmarva could not award 3.0 points, since according to the guidelines, 1-2 prior successful projects of the type proposed were required to do so. Delmarva thus assigned NRG 2.0 points overall.

There were no deductions to any of the bidders based on safety record or the proposed staffing. On this basis, the Company assigned these scores to the Bidders on this factor:

Table 2.3.21 – Non-Price Points on Bidder Experience

Bluewater Wind North	1.0 points
Bluewater Wind South	1.0 points
Conectiv Energy	5.0 points
NRG Energy, Inc.	2.0 points

H. Project Financeability (5 possible points)

Bluewater Wind – Bluewater Wind's ability to finance and maintain the financial viability of the project over 25 years is in doubt:

- Bluewater Wind's proforma provides for revenues from both renewable energy credits (RECs) and carbon emissions allowances. Delmarva does not believe that it is likely that Bluewater will be able to claim both.

- The UCAP value that Bluewater Wind has assigned to its sites (e.g., 197 MW for the North Site) is too high, as explained in the Price Evaluation section. Assigning a lower UCAP will reduce revenues to the project.

- Revenues depend in part on factors beyond Bluewater's control (i.e., the wind).

- The company has not previously developed and financed a project of this magnitude or type (offshore wind).

- The returns projected for the project are "thin", particularly for a technology that will be considered innovative.

- The company is not credit-worthy, and will use project finance.

Conectiv – Conectiv is in an overall positive situation with regard to financeability, though it has certain doubts as to its future as well:

- The company is creditworthy and will be using corporate finance.

- Conectiv has successfully financed a number of combined cycle projects before and has relationships with financial institutions that will provide the capital required.

- The proposed project is small compared to the size of the company's overall portfolio, assets and potential financial exposure.

- On the other hand, Conectiv has tied its energy payment to a coal price index that could cause a mismatch between its energy revenues and its costs for natural gas, though Conectiv has proposed a one-time adjustment to deal with this potential mismatch.

- Conectiv is just one notch from being non-creditworthy, and the company's situation could decline over the 10-year term of the PPA.

NRG – NRG's proposal has significant questions with regard to its financeability

- NRG has offered a price for power that would vary with an index of coal prices. NRG acknowledges that costs for rail transportation, which constitute a major share of the delivered price, could rise and cause a squeeze between the price of coal that NRG purchases and the price of power that it sells to Delmarva.

- An IGCC project will raise questions regarding the actual cost and operational reliability in practice, given the lack of maturity of these types of projects.

- NRG is not credit-worthy

Thus, overall, Delmarva rates the proposals as follows with regard to financeability:

Table 2.3.22 – Non-Price Points on Financeability

Bluewater Wind North	2.0 points
Bluewater Wind South	2.0 points
Conectiv Energy	4.0 points
NRG Energy, Inc.	2.5 points

Overall Non-Price Scores

Combining all of the factors above, Delmarva reaches the following aggregated scores. The "Total" at the bottom is not the sum of the numbers in the column because some of the factors are additions of several items beneath them (e.g., the water impact score is the combination of consumptive use, thermal discharge and discharge character):

Table 2.3.23 – Overall Non-Price Scores

Factor	Potential Points	BWW	NRG	Conectiv
Greenhouse Gases	4.0	4.0	0.3	2.1
Criteria Pollutants	4.0	4.0	2.5	2.9
Water Impacts	1.5	1.5	0.5	0.8
Consumptive Use	0.5	0.5	0.2	0.3
Thermal Discharge	0.5	0.5	0.1	0.2
Discharge Character	0.5	0.5	0.2	0.3
Land Impacts	1.5	0.0	0.6	1.5
Acreage Disturbed	0.5	0.0	0.3	0.5
Brownfield	1.0	0.0	0.3	1.0
Wildlife Impacts	1.5	0.3	1.1	1.5
Waste Disposal	1.5	1.5	0.7	1.1
Fuel Diversity	3.0	3.0	2.0	0.0
Technology Innovation	3.0	3.0	3.0	0.0
Operational date/certainty	3.0	0.5	0.0	1.3
Reliability of Technology	2.0	1.5	1.0	2.0
Site Development	5.0	2.4	3.8	4.8
Siting Plan	3.0	2.1	2.8	2.8
Interconnection	1.0	0.8	1.0	1.0
Fuel Supply	1.0	0.5	1.0	0.8
Permitting Plan	1.0	0.8	0.8	1.0
Brownfield	1.0	0.0	0.3	1.0
Socio-Economic	1.0	0.3	0.7	1.0
Bidder Experience	5.0	1.0	2.0	5.0
Financeability	5.0	2.0	2.5	4.0
Total	40.0	24.7	20.0	27.0

Super-Categories

At the beginning of this section, Delmarva indicated that the non-price score could be divided into two super-categories – Project Characteristics and Project Viability. The first three non-price factors (Environmental Impacts, Technology Innovation and Fuel Diversity), when added up, provide the score for Characteristics, while the sum of the remaining non-price factors equals the score on Viability. Thus, the super-category totals are:

Table 2.3.24 – Super-Category Scores

	Potential Score	Bluewater North	Bluewater South	Conectiv	NRG Energy
Project Characteristics	20.0	17.3	17.3	9.9	10.7
Project Viability	20.0	7.4	7.4	17.1	9.3
TOTAL	40.0	24.7	24.7	27.0	20.0

This breakdown highlights the differences between the bids. On Characteristics, Conectiv was the lowest of the bids. It was not as clean in terms of emissions as Bluewater Wind, but it was cleaner than NRG, and it was determined to have the lowest potential wildlife impacts. Working against Conectiv on Characteristics was its scores (zero) on Technology Innovation and Fuel Diversity. In essence, Conectiv was the highest ranking bid largely because of its high score on Viability, where it stands well above the other bids with regard to Site Development, Bidder Experience and Financeability (each of which has five potential points). Conectiv's earlier on-line date is also a factor in its favor.

NRG Energy scored moderately on Project Characteristics overall due to its relatively low scores on air emissions, water impacts, and waste disposal, offset by good scores on Technology Innovation and Fuel Diversity. On Viability, NRG scored lower than Conectiv on the factors of Site Development, Bidder Experience and Financeability mentioned above. While NRG scored higher than Bluewater on Viability, that advantage did not make up for its deficit on Characteristics, so NRG finished in last place among the bids received on non-price factors.

Finally, Bluewater Wind scored perfectly on air emissions, and on overall Characteristics, its score was only lower than the maximum possible with regard to Land Impacts and Wildlife Impacts. On Viability, Bluewater was the lowest ranking of the bids, however, as it received relatively low scores on all the sub-factors in this group except for Reliability.

Delmarva also believes that it is important to look beyond the scoring process, and consider the prospect of Delmarva potentially signing a contract to actually purchase power from one of the bidders on a long-term basis. For example, in terms of the bids received, Delmarva has real concerns about being asked to sign very large contracts (compared to the size of the Company) with non-creditworthy bidders using technologies that have scant if any track record in this country, and in the case of one bidder, would be located offshore in an area where hurricanes are not unknown. There are, for example, no offshore wind projects (in Europe or elsewhere) larger than approximately 150 MW, and all are located in seas as opposed to oceans, and none have a track record of more

than a few years. Apart from the scoring process, Delmarva requests that the Commission consider the practical implications and risks for customers implied by such a contract. Delmarva concludes that there is no strong evidence to suggest that the resulting Super-Category scores should change the evaluation results and Delmarva's findings.

3. RISKS ASSOCIATED WITH LONG TERM POWER CONTRACTS

The Act specifies that:

"As part of the initial IRP process, *to immediately stabilize the long-term outlook for Standard Offer Supply in the DP&L service territory*, DP&L shall file on or before August 1, 2006 a proposal to obtain long-term contracts." (emphasis added).

The language from the Act quoted above implicitly assumes that a long-term contract will somehow provide "stability" to SOS in Delmarva's service territory. This section examines this assumption in some detail and provides evidence that a long-term contract would not necessarily create more stability for SOS customers than the current procurement procedures that were implemented for SOS customers in the Spring of 2006.

Background and General Discussion

One of the criteria being used to evaluate the bids concerns price stability. While it may seemingly appear that a long-term contract would provide greater price stability for procuring SOS electricity supply, this is generally not the case due to the speculative nature of most long-term contracts and the highly variable nature of the electricity product itself. Webster's II New Riverside University Dictionary (1984) defines the verb 'to speculate' as:

> *To engage in the buying or selling of a commodity with an element of risk on the chance of profit.*

Webster's also defines the verb 'to hedge' as:

> *To minimize or protect against the loss of by counterbalancing one transaction, as a bet, against another.*

Long term contracts for capacity and energy are speculative. Long term contracts are not hedges since, by definition, they do not have a counterbalancing transaction to protect the "bet". It is wrong to characterize a long-term power contract as a hedge in this situation. Thus from Delmarva's point of view a long term contract represents a speculative bet that the contract prices will be more favorable than market prices for SOS customers over the life of the contract. The downside risks associated with such a long term contract would be very difficult to hedge. The history of long-term contracts supports this view and clearly shows that such bets have huge downside risks for customers that are difficult to

mitigate. As described later within this report, the industry is replete with examples of long-term contracts that have been detrimental to customers . PHI itself has had very unpleasant experiences with long term power contracts that have become out of market and involved declarations of bankruptcy by the counterparty.

The Act as well as the State Agencies approved RFP structure and evaluation process could, if a PPA is executed, transfers risks to the SOS customer which are not currently being absorbed by the SOS customers. Instability related to a long term contract can manifest itself in many ways. A discussion of some of the more important potential sources of risk and volatility in long-term contracts is provided below. For each risk described there is also a discussion of how that risk is mitigated under the current SOS procurement practice for Residential and Small Commercial and Industrial (RSCI) customers.

- Contract Term Risk

    - **Long Term Contracts**
      The Act directed Delmarva to issue an RFP for new generation facilities with a contract term of no more than 25 years. In response to the RFP issued November 1, 2006, Delmarva received bids from three energy suppliers with the following proposed contract terms:

        - Conectiv: 10 year term with an option to renew contract for an additional 5 years; a firm energy bid and a unit contingent energy bid;
        - NRG: bids having a 25 year term or 20 year term
        - Bluewater: bids having a 25 year term or 20 year term

A PPA based upon a long term contract commitment creates very substantial risks for SOS customers and these risks increase with the length of the contract. This happens because, at the time the contract is executed, it is impossible to know which of all of the possible outcomes over the long life of the contract will actually occur. A PPA would lock customers to a single source energy supply solution for which the SOS customers bare the risk of not benefiting from future cost reduction opportunities.

Electricity prices tend to follow trends that can cause significant deviations over the long term. The table below provides PJM annual average LMP price for Peak Period and All-hours 1999-2006 for the Delmarva zone. During this period prices have moved both up and down but mostly up in recent years. It is not difficult to infer the large degree to which this market price could deviate from the energy price in a PPA over the course of 10 to 25 years, regardless of any indexing that may be a part of the contract. The longer the term of the contract, the more likely that market prices will fall below a long-term contract price. There is no guarantee that a long-term PPA will provide benefits to SOS customers but it will definitely impose risks.

Table 3.1

Historical Wholesale Power Prices (2005$/MWh)

Year	On-Peak Firm (5 x 16)	All-Hours Firm (24 x 7)
1999	47	35
2000	49	37
2001	59	45
2002	46	34
2003	56	43
2004	59	49
2005	83	68
2006 YTD[1]	66	55
Average	58	46

[1] Through September 2006. Delmarva Load Zone.

While the desired policy objectives behind long term contracts may be well intended, the results have often been disastrous for customers. Prime examples are the notorious so-called PURPA contracts undertaken in response to the Federal Public Utility Regulatory Policy Act of 1978. PURPA required utilities to enter into contracts with new resources, and a great many of these contracts were signed in the 1980s and early 1990s. By the time the industry restructured in the late 1990's, many of those contracts had to be sold at a time when they had become significantly out-of-market. For example, New England Electric System was forced to provide over $1.1 billion in support payments to USGen in order to transfer its PURPA contracts in the context of divestiture under the Massachusetts restructuring legislation.

Recently, in MD Case No 9063 , Commission Staff Witness Eric Icart provided the following testimony on Maryland's experience with long-term contracts:

> "Maryland too has experienced PURPA contracts that imposed considerable costs to ratepayers in the State." and "…long term contracts may produce undesirable results as exemplified by PURPA contracts."

Icart p27, lines 12-13. and p31 lines 1-2.

Other notable industry long term contract disasters include:

- **Niagara Mohawk** - In the 1990s, after suffering under out-of-market PPAs and a loss of load resulting from high system energy costs, Niagara Mohawk narrowly avoided bankruptcy as it attempted to buy out and/or restructure many of its PPAs with Independent Power Producers ("IPPs").[1] After years of litigation, Niagara Mohawk reached a Master Restructuring Agreement to

[1] The out-of-market PPAs had been executed under New York's "six-cent law," which required utilities to pay a floor price of $0.06/kWh for qualifying facilities less than 80 MW. Although the law was repealed in 1992, it did not retroactively apply to existing PPAs.

terminate PPAs totaling 1,092 MW and to buy-down the terms of another 535 MW of IPP capacity. The aggregate cost to Niagara Mohawk was a payment of $3.9 billion in cash and an issuance of 20.5 million shares of common stock to the IPPs.

- **NStar -** Massachusetts also encouraged its utilities to sign contracts with IPPs and QFs in the late 1980s and early 1990s to promote competition for new generating resources. These policies led to numerous out-of-market PPAs by the late 1990s. NStar negotiated a buyout of 685 MW of out-of-market PPAs for which the present value of the stream of buy-down payments for the PPAs was $1.4 billion dollars.

- **New England Electric Systems ("NEES") -** In 1998, NEES agreed to sell its non-nuclear generating assets to USGen. This transaction included 1100MW of New England Power's out-of-market purchase power agreements.[2] NEES agreed to provide support payments in the amount of $1.17 billion for the above market cost of these contracts through 2008.[3]

- **California Department of Water Resources ("CDWR") -** In response to the perceived power supply shortages experienced in California and the corresponding skyrocketing energy prices, in 2001, the CDWR negotiated long term power agreements with merchant generators to meet the energy needs of California consumers at a cost of $42 billion.[4] The majority of the contracts are take or pay contracts in which the CDWR guaranteed payment for the contractual quantities whether or not the energy was needed to meet demand. While the CDWR renegotiated many of these contracts due to evidence of market manipulation, reducing the cost of the agreements by $11 billion, estimates are that California will still be required to pay nearly $10 billion in above market power supply costs related to these long term agreements, some of which extend to 2021.[5]

To summarize, the point here is that all long term contracts, whether inspired by PURPA or other legislation, create great financial risk to electric retail customers and once a contract is signed these risks will be present for up to 25 years.

- **Current SOS process**

[2] Subsidiary of NEES.

[3] New England Electric System, 1998 10-K-405.

[4] "DWR Keeps Power Flowing During Unprecedented Energy Crisis," California Energy Resources Scheduling.

[5] "The California Electric Crisis," Sweeney, James L, April 9, 2002, p. 305.

As approved by the Delaware Commission, the current SOS procurement process for RSCI customers obtains full requirements contracts in blocks of 50 MW of peak load contribution through a competitive bidding process. The maximum term of any one contract is limited to three years[6]. The process has been designed so that supply contracts for approximately 1/3 of the RSCI SOS requirements or 'tranche'expire each year. Prior to the time when one set of contracts are set to expire, the competitive bidding process recurs to obtain new contracts to replace those contracts that will be retiring. The premise of this "dollar cost averaging" approach is, among other things, to help insulate RSCI SOS customers from price volatility and other risks. In PHI's New Jersey and District of Columbia service territories, where very similar SOS procurement processes were in place prior to 2006, SOS customers were exposed to an increase in price for only 1/3 of the supply in the Spring of 2006 and ,as a result, total energy price increases for these SOS residential customers were between 12% and 13% .

- Commodity Price Risk

  - **Long-Term Contracts**
    Generation resources that rely upon non-renewable fuel input to create power face commodity price risk for the fuel they purchase. Generators can typically hedge this risk by executing contracts with fuel and transportation suppliers that "lock-in" a fixed price for a specified period of time. However, the period for which the fuel and transportation prices are fixed is typically several years or less and nowhere close to the 10 to 25 year term envisioned in the Act.

    In order to protect themselves from future commodity price changes, generation project developers typically tie the energy portion of a long-term power purchase agreement to a relevant fuel or other index. For example, Pepco's existing long term purchase agreement with Panda is tied to several commodity and transportation indices and most of Atlantic City Electric Company's long term non-utility generation (NUG) contracts tie to an index or simply allow variable cost pass-through. Over time, as the contract indices change, so will the variable costs of these contracts. Depending on the specifics of each contract, prices can change monthly, quarterly or annually.

    All of the bids received by Delmarva in response to the RFP of November 1, 2006 include some form of fuel index or price escalator. Bluewater's proposal does not tie to a fuel index; however, their bid price for energy derived from their wind facilities is tied to a fixed escalation rate consistent with the IRP.

    The NRG bid is tied to the Central Appalachian Producer Price Index and the CPI. The Conectiv bid is also tied to a coal index. Consequently, over the life

[6] It should be noted that this discussion applies to RSCI SOS load. The SOS load requirements for the MGS, LGS, and GSP rate classes are bid 100% annually.

of each of these proposed contracts, energy prices related to plant output will, at a minimum, follow the changes in the relevant fuel, and/or price index or escalator. The changes to costs that result as a change in these indices or escalators will need to be either directly passed on to SOS customers or Delmarva would accrue the cost in a deferral account to be recovered from all distribution or SOS customers through a non-bypassable charge. Price stability, an objective of the Act, is not achievable due to the construct of the bids tying prices to ever changing indexes.

- **Current SOS Procurement**
  Under the current procurement practice for Delaware SOS customers, approximately 1/3 of the RSCI SOS load, or 'tranche', is procured through a competitive bidding process each year. Successful bids provide for full requirements energy for SOS customers and are not tied to any fuel index, price index, or escalator, and, in general, no additional costs can be passed through to SOS customers[7]. This results in stable RSCI SOS prices for each tranche. The successful bidders are free to provide this energy from a variety of sources and the bids are not tied directly to any given fuel or commodity index. Consequently over the three year period for each successful bid in each tranche there is no commodity risk imposed upon SOS RSCI customers. SOS procurement costs will change annually as one tranche of 3 year contracts expires and a new procurement of 1/3 of the SOS customer load is procured.

- Generation Outage ("unit-contingent") Risk

  - **Long Term Contracts**
    Many long-term power contracts are agreements to provide capacity and energy from a specific generating station to the distribution utility. These agreements are termed "unit –contingent" because they only relate to capacity and energy from the generating units specified in the agreement. SOS customers, on the other hand, require "firm" energy and capacity; i.e., at any given moment in time that they require capacity and energy, they expect it to be provided by the distribution utility regardless of generating source. Consequently if Delmarva were to enter into a unit contingent long-term power supply contract and there was an outage at the generating unit, the generating output exceeded the SOS load, or the generating output was not sufficient of an amount to meet the SOS load, Delmarva would need to purchase or sell capacity and energy for SOS customers. Under a unit contingent contract, the SOS customers of Delmarva would be assuming the risk where in most, if not all, hours the generating output from the unit does

[7] There are three instances where costs may be passed through to SOS customers, in general,: 1.) any new FERC approved PJM charges not otherwise specified in the SOS Full Requirements Service Agreement (FSA); 2.) charges resulting from changes to the Renewable Energy Portfolio Standards Act, and; , 3.) for commercial customers only, an increase in base load above 5MW. See the FSA for specific details on each of these exceptions.

not meet the SOS load to be served. This risk has the potential to have a significant effect on the price of SOS service.

This unit availability risk can take at least two forms. The first form is a scheduled outage of the generating plant. These outages are usually scheduled in advance for required maintenance on critical plant components. In NRG's bid, the unit availability is identified as 86% implying that the unit is expected to be down for maintenance or other reasons 14% of each year. Expressed in days, the unit is expected to not be available approximately 51 days each year (.14 x 365). On those 51 days energy for SOS customers would need to be procured somewhere else.

The second form of unit availability risk is an unplanned outage. Unplanned outages typically occur unexpectedly due to an equipment failure that renders the plant inoperable until appropriate repairs are made. A significant risk for SOS customers associated with unplanned outages is that the outage can occur during peak periods when replacement costs are very high.

In either case, whether the timing of the outage is known in advance or not, replacement power requirements for SOS customers will still need to be procured. Depending on circumstances, such as the weather, the length of the outage and demand conditions, the replacement power may be very expensive and this can lead to price instability. If the replacement power costs more than the power procured under the contract, Delmarva would likely accrue the cost in a deferral account to be recovered from all distribution or SOS customers through an adjustment to customer rates. Consequently, even with a long-term contract in place, the SOS customer rates will need to be adjusted for replacement power costs leading to annual changes in SOS rates. The dollar amount of the adjustment will depend upon the performance of the generating plant, the cost of the replacement power, and whether the costs are allocated to all distribution customers or only SOS customers. Price stability, an objective of the Act, is not achievable due to the dependency on market prices during periods when either the generating unit produces to much supply or to little supply to meet the needs of the SOS customers.

- **Current SOS Procurement**
  Competitive bids to provide SOS customer electricity needs under the current process include "firm" energy and capacity requirements. So when a supplier bid is accepted, the supplier is obligated to provide the energy and capacity *whenever* the SOS customers need the energy. The energy and capacity are not contingent on the operation of any specific generation unit. Consequently, the generation outage risk is borne by the supplier and not the customer. In other words, under the current SOS procurement practice there is no price volatility due to generation outage risk.

A key point underlying the current SOS procurement process is that SOS providers have the appropriate skill and diverse portfolio of generation and other resources to manage this risk. In fact, as a result of state and federal level policy initiatives to restructure the electric utility sector, Delmarva has divested its generation resources, transferred its power marketing capabilities to an arms-length, unregulated affiliate, and no longer has the skill sets or resources to manage a long-term inflexible purchase commitment in a competitive wholesale market environment with contestable retail markets. Depending on the particular contract, the amount of excess sales to be managed, the extent of customer migration, and the amount of SOS load to be served over and above what is supplied by a long term contract, the Company may need to acquire additional resources (either internal or external) to manage both excess energy and replacement energy risks throughout the term of the PPA**.**

If additional resources are required to manage the PPA and the smaller and less attractive portion of the SOS load over and above what is provided by the PPA, the cost of these resources would be passed on directly to Delmarva. In addition, given that Delmarva is a regulated company and to the extent that trading and derivative products and other speculative instruments are needed to manage the SOS load supply costs, the Commission would need to establish rules and criteria to ensure that the costs of such reasonably undertaken activities are recoverable in SOS rates.

- Volume and Migration Risk

  - **Long Term Contracts**
    The PPA proposed in Delaware present two significant risks to SOS customers related to load (volume) risk. The first relates to hourly minimum purchase requirements and the second relates to customer migration risk.

    The proposed PPAs generally require the distribution company to purchase at least a minimum quantity of energy during each hour the generating resource is in operation (for example, the NRG proposal would require Delmarva to purchase a minimum of 280 MW every hour the plant is operating). If this minimum quantity exceeds the SOS customer load in any given hour, the distribution company would need to sell the "contract excess purchase" into the spot market. Because SOS customer loads tend to be below the minimum contract requirements when prices are low, e.g., during the off peak early morning hours, it is likely that any sale of this excess power into this low price market would result in a loss to Delmarva. Again, Delmarva would accrue this loss in a deferred account that would be recovered on through an upward adjustment to customer rates.

    Delaware has also fully opened its retail market to competition, granting all of Delmarva's customers the ability to switch from SOS to alternative power

suppliers if the Company's power supply costs are non-competitive. Compounding the risk attendant with full retail access is the demonstrated liquidity of the PJM wholesale market, which ensures that alternative suppliers can readily structure flexible and market-responsive power supply portfolios to compete with Delmarva's SOS. Full market contestability makes it critically important for Delmarva to align its supply resources to its load obligations. Hence, supply flexibility and market responsiveness are vitally important power supply objectives. The large PPA proposals will limit Delmarva's supply flexibility and market responsiveness.

Nineteen competitive suppliers are currently registered in the State to compete against the SOS rate to sell power to retail customers. Following the conclusion of Delmarva's POLR obligation in May 2006, SOS service rates are in the process of moving up to reflect competitive market prices and customers have been choosing suppliers other than taking SOS service through Delmarva.

The table below describes the customer migration from Delmarva to Alternate suppliers over the period December 31, 2005 through December 31, 2006. As can be seen, a very large proportion of non-residential customers have already migrated away from SOS service and over 2,500 residential customers have selected an alternate supplier.

Table 3.2
Customer Migration

	31-Dec-05		31-Dec-06
Residential			
# of DPL Distribution Customers	259,877		259,021
# of Customers served by Alt Supplier	0		2,523
Capacity obligation served by DPL (MW)	872.9		874.9
Capacity obligation served by Alt. Suppplier (MW)	0		9.6
Non-residential			
# of DPL Distribution Customers	31,957		32,078
# of Customers served by Alt Supplier	8		4,804
Capacity obligation served by DPL (MW)	968.1		320.8
Capacity obligation served by Alt. Suppplier (MW)	79.6		672.6

Source: Delaware Electric Supply Choice Enrollment Information

Given the migration that has occurred in 2006 as a result of moving to parity between SOS and market rates, one can infer a significant increase in migration above this level in the event market prices were to fall below the SOS rate. The IC report concedes:

> *"There is a risk that a stable-priced contract with a generator could become substantially over-market during the 2012-2037 contract period …If that were to occur in a sufficiently substantial magnitude, customers might leave SOS for the competitive market leaving fewer customers to bear higher unit over-market costs."*[8]

The above statement illustrates the beginnings of a vicious cycle, with each customer departure creating stranded costs that are then passed on to remaining customers, further widening the gulf between the SOS price and market prices. If market prices continue to fall or at least remain below the SOS price, the inevitable result is that too few customers will be left to pay for the fixed portion of the SOS cost, which in turn could result in Delmarva's default under its supply contract. Price stability, an objective of the Act, is not achievable due to the adjusting of the SOS rates from migration and/or dependency on market prices during periods when either the generating unit produces to much supply or to little supply to meet the needs of the SOS customers.

- **Current SOS Procurement**
  Successful bids resulting from the competitive procurement process are required to provide "load following" services and there are no minimum energy or capacity purchase quantity requirements. Essentially each successful 50 MW peak load contribution bid is for a "Slice of System" contract or *percentage* of the SOS customer load. This load following feature means that the supplier provides a constant percentage of peak load as opposed to an absolute amount under a long-term contract. This spreads the volume risk across the successful bidders. Consequently, RSCI SOS customers are completely protected from any "contract excess purchases" and migration to other suppliers. In other words, RSCI SOS customers only pay for energy they need and the suppliers assume the volume and migration risk.

- Environmental Compliance Cost Pass Through Risk

  - **Long-Term Contract**
    Over the life of a 10 to 25 year PPA, it is highly likely that environmental regulations affecting power plant operations will change. A possible example of this would be a carbon tax on power plant emissions. Because these regulations are not in place at the time a contract may be executed, the cost of compliance with these regulations is not included in the price. Instead most power project developers, including the bidders in this RFP, protect themselves from these potential cost increases by including a "pass-through"

[8] "Final Report Regarding Delmarva Power & Light Company's Proposed RFP," October 12, 2006, p. 10.

provision in the power purchase contract. The pass through provision allows for additional costs due to future environmental legislation to be passed on, dollar for dollar, to the power purchasers, i.e., SOS customers.

Because new environmental compliance costs can be passed on to SOS customers dollar for dollar, the resource owner is under little incentive to efficiently optimize compliance. Delmarva would accrue the additional costs for environmental compliance in a deferral account that would be recovered on an annual basis from either SOS or all distribution customers. Again, this would lead to price volatility. Price stability, an objective of the Act, is not achievable due to the adjusting of the SOS rates caused by contact pass through costs associated with new environmental regulations.

- **Current SOS Procurement**
  Under the current process the suppliers assume all risk for environmental compliance costs over the 3-year life of their bids and additional costs cannot be passed onto SOS customers during the duration of the contract. (check with Cindy Nowell)

- Construction Risk

  - **Long-Term Contract**
    Consistent with the Act, the bids received by Delmarva were for the construction of new generating facilities in the State of Delaware. The construction of new generating facilities creates some additional risk and potential price stability issues. The construction of new generation resources can be a multi-year process, taking up to seven or more years for new coal based plants. Consequently, during the period from when a contract is executed to the start of plant operation, many factors affecting construction costs can change including the cost of required building materials, labor, and other critical components. In addition to changing the cost of the project, these and other factors may affect the timing of when the resource becomes commercially available.

    There have been many instances where existing plants or generating projects in later stages of construction were turned over to lending groups as a result of defaults on project loans. Through mid-2005, the default on debts by the following generating firms, or their affiliates, put at least 9,500 MW of capacity into the hands of bank lending groups:

- **El Paso** defaulted on project loans related to Milford Power (544 MW), located in Connecticut, as a result of project delays due to a fatal construction accident and a lengthy legal dispute. The plant was transferred to a lender

group led by Belgian-based KBC Bank in December 2003 before the plant came on-line.[9]

- **Boston Generating**, a former Exelon subsidiary turned control over to a syndicate of bankers led by BNP Paribas after it defaulted on a $1.25 billion credit facility in August 2003. In September 2004, Boston Generating transferred to its lenders 3400 MW of capacity, including the Mystic and Fore River plants.[10]
- **Reliant Energy's** Liberty Electric (530 MW) located in Pennsylvania was foreclosed upon by a lending group led by JP Morgan in August 2004 after it defaulted on its $242 million project financing. NEG had a 14-year contract to purchase the plant's output, but the contract was terminated in NEG's bankruptcy proceeding, leaving Liberty to sell into the merchant market.[11]
- **TECO Energy** transferred ownership of Gila River (2145 MW) in Arizona and Union (2200 MW) in Arkansas to Entegra, whose 35 members had lent money to the projects after TECO defaulted on $2.2 billion of loans. The transfer occurred in May 2005.[12,13]
- **AES Corp** transferred Granite Ridge (720 MW) in New Hampshire to a creditor group led by ABN Amro in November 2004. Granite Ridge experienced startup problems in 2003 and was involved in a tax dispute. AES decided to transfer the plant to creditors after it was unsuccessful in selling the plant.[14,15]

Price stability, an objective of the Act, is not achievable due to the potential adjustment to SOS rates upon a default on, or delay of, the in-service date of the new generation.

[9] Global Power Report, "Troubled Milford 544-MW Plant in Conn. Ready for Operation After Three-Year Delay," January 29, 2004.

[10] Power Markets Week, "Recycling Merchant Megawatts: Banks Hire Their Brethren to Find Buyers for 10,000 MW," August 23, 2004.

[11] Megawatt Daily, "Lenders Foreclose Reliant's Liberty Plant," August 30, 2004.

[12] Global Power Report, "Banks hold 14,065 MW of Merchant Assets as a Result of Defaults by Four Companies," February 19, 2004.

[13] Megawatt Daily, "Entegra Power Searching for More Assets," June 6, 2005.

[14] Global Power Report, "Unable to Sell Plant, AES Corp. Begins transfer of 720-MW N.H. Plant to Creditors," June 3, 2004.

[15] AES Corp. 2004 10-K.

- **Current SOS Procurement**
  Because the current SOS procurement process requires competitive bidding and is not "unit-contingent", there is no construction risk.

- Credit Risk

  - **Long Term Contract**
    Recent industry experience has shown the vital need for protection from counterparty credit risk. Consequently, it is imperative that SOS customers be protected from the potential that a counterparty may not perform under the contract terms or even file for bankruptcy. For SOS customers this is a critical risk because the replacement cost of capacity and energy due to counterparty non-performance can be hundreds of millions of dollars more than they might otherwise have paid under the contract. The Company's recent and on-going experience with the Mirant bankruptcy in its Maryland and District of Columbia service areas exposed customers to a potential losses of over $500 million not counting an additional $70 million for other disputes, pre-petition claims and legal fees.

    Long-term contracts can also place tremendous pressure on the credit of Delmarva. Delmarva is a relatively modest size electric and gas distribution company with a total equity of less than $650 million. The proposals received for new generation however envisage relatively large financial commitments on the part of Delmarva for up to 25 years. The table below shows the total non-discounted capacity payments that Delmarva would be responsible for over the life of the contract for each of the proposals. These payments range from a low of just over $75 million to a high of just over $4.0 billion for the NRG 25 year with Carbon capture option. These amounts, which would be paid to the generator over the life of the project, are fixed and not dependent upon plant output.

Table 3.3 – Estimated Capacity Payments

	Estimated Total Capacity Payments	% of DPL net worth (less than $650 Million)
Conectiv	(000's)	
Base (10year)	over $425 million	approx. 65%
Alternate (10Year)	over $325 million	approx. 50%
NRG		
25 year contract	over $2.4 billion	approx. 370%
25 year with Carbon	over $4.0 billion	approx. 615%
20 Year	over $2.0 billion	approx. 300%
Bluewater Wind		
S Atlantic (25 Year)	over $75 million	approx. 10%
N Atlantic (25 year)	over $75 million	approx. 10%

To put this burden in perspective, as noted above, Delmarva's balance sheet reports a current total equity of under $650 million. Delmarva's financial condition therefore offers scant capacity for absorbing incremental debt or debt-like instruments. The financial market recognizes this limitation; Delmarva's current senior unsecured credit ratings are BBB-/Baa2 (S&P/Moody's). The financial community understands that the Company has modest capability for absorbing fixed cost obligations of the magnitude inherent in the proposals for new generation without triggering credit quality concerns. Delmarva's credit degradation risk is exacerbated to the extent the RFP allows for under or poorly securitized counterparty credit to backstop PPA performance obligations.

Experience has also shown that there is an unacceptably high likelihood of default by a non-investment-grade entity over a 25-year period. Two of the three bidders, NRG and Bluewater Wind are currently non-investment grade entities. According to Moody's, the cumulative risk of bond default during a twenty-year period by a Ba- rated entity (highest non-investment-grade rating) is approximately 30%. By point of comparison, there is only a 13% risk of default over 20 years for a Baa- rated entity (lowest investment-grade rating).

If the investment term is limited to ten years, the Baa and Ba probabilities of default are 8% and 19%, respectively. While this risk is more palatable than the 20-year term, it highlights the substantial increase in the chance of default when contracting with a non-investment-grade entity, regardless of contract term.

In Delmarva's case, a PPA counterparty default would result in Delmarva having to re-contract for power on potentially less favorable terms. In

addition, Delmarva's liquidity would become constrained, with the possibility of facing a downgrade to non-investment grade.

It is also important to keep in mind that this PPA is not intended to provide the bidders with an outlet for their power. PJM already provides this outlet, and stands ready to purchase every MWh that the unit produces at the full market value of that power. Rather, the PPA is primarily a vehicle for the bidder to use the financial strength of Delmarva to provide the project with credit support so that financial leverage can be used to enhance the project sponsor's return. In this way, the PPA relationship is parasitic, as it also limits Delmarva's financial flexibility in the process.

Common ways to mitigate risk around credit are to require that the contract counterparty be of investment grade, limit the term of the contract, obtain the right to collateralize the monetary value of the PPA, obtain resources from multiple suppliers and to require adequate security to cover replacement costs. The determination of what constitutes adequate security has proven very contentious. In addition, the Public Agencies limited the level of collateralization that Delmarva could impose on the bidder resulting in more of the default exposure being borne by the SOS customers. Price stability, an objective of the Act, is not achievable due to the potential adjustment to SOS rates upon a default.

- **Current SOS Procurement**
  Each successful bidder is required to meet stringent performance assurance requirements over the duration of their contract obligations. The term of the contracts do not exceed three years. Specifically, during the term of the contract, Delmarva makes a daily review of the nominal marked to market exposures for each counterparty. The exposure calculation is based on a formulaic and transparent methodology. If the exposure exceeds the bidder's unsecured credit amount plus the value of any amounts delivered but unpaid by $500k or more, Delmarva will make a non-disputable call on the bidder to post additional security. The form of this additional security must be either cash or a Letter of Credit. After an initial performance assurance call, subsequent and incremental requests for additional security are made at $100k increments.

- **New Technology Risk**

  - Long-Term Contract
    The bids submitted in response to Delmarva's RFP by NRG and Bluewater represent new technologies that increase the risk of counterparty default. For example, NRG has specifically proposed the construction of an Integrated Gasification Combined Cycle ("IGCC") unit. If accepted and built, this project would be the first non-utility IGCC (check with CEA what this

means). The IGCC proposed by NRG also represents a doubling in MW size of any IGCC constructed with the specific technology included in the NRG bid. Previously constructed IGCCs have had an inconsistent track record with regard to efficiency and availability. For example, the lackluster availability demonstrated during the first several years of the operation of the Wabash River Coal Gasification Repowering Project is a major cause for concern to all potential IGCC stakeholders.[16] The following table illustrates the operating problems during this plant's Demonstration Period.

Table 3.4

Operation of the Wabash River IGCC Plant During Demonstration Period[17]		
Year	Availability Factor	Operating problems
1996	22%	• Frequent failure of the ceramic filter elements in the particulate removal system • Ash deposits in the post gasifier pipe spool and HTHRU
1997	44%	
1998	60%	• Ten coal interruptions and other periods of downtime were caused by air separation unit (ASU) • Plant suffered downtime while processing different coal feedstocks
1999	40%	• Failure of a blade in the compressor section of the combustion turbine required complete rotor rebuild that idled Project for 100 days • Syngas leak in the piping system of particulate removal system • Failure of a ceramic test filter in the particulate removal system

Bluewater has proposed off-shore wind power facilities which have yet to be fully accepted as mainstream generation sources. FERC notes: "Even with the advances in wind development, wind generation is a relatively new entrant to markets that were not designed specifically for intermittent energy sources or for energy sited remotely from load centers. As such, wind generation faces several challenges to achieve widespread acceptance, including siting and permitting issues, financing issues and transmission policies that are currently designed for generating units that are more centrally located and that are able to be dispatched."[18]

[16] Wabash River Coal Gasification Repowering Project, Final Technical Report for U.S. Department of Energy, by Wabash River, Ltd., August 2000, p. 4-2.

[17] Wabash River Coal Gasification Repowering Project, Final Technical Report for U.S. Department of Energy, by Wabash River, Ltd., August 2000, p. 4-2.

[18] "Assessing the State of Wind Energy in Wholesale Electric Markets," Federal Energy Regulatory Commission. Docket No. AD04-13-000, Staff Briefing Paper, November 2004, p. 16.

Higher levels of technological risk impose a higher risk of contract counterparty default than more mainstream technologies, and therefore should require higher levels of security. Because the energy and capacity from these new technologies is proposed to be provided on a "unit-contingent" basis instead of a "firm" basis which would insure delivery regardless of unit operating status, Delmarva's SOS customers will take on the development and operating risk of these higher risk technologies. Price stability, an objective of the Act, is not achievable due to the potential adjustment to SOS rates upon a default or performance constraint.

- **Current SOS Process**

  All energy and capacity obtained from the competitive bidding process is provided on a "firm" basis. This means that the SOS Customers will be provide energy capacity and other ancillary services independent of and regardless of the operating status of any particular generating unit. Bidders in the SOS auction are free to obtain their resource obligations from new technologies but the development and operating risk of these new technologies is on the supplier and not the SOS customer.

- Supply Diversity Risk

  - **Long-Term Contract**
    The size of SOS residential customer load to be procured in Delaware is relatively small. In fact, the average load of the Delaware RSCI class is only about 400Mw for every hour of the year. The three bids received in response to the RFP range in magnitude from a minimum of 180 Mw for Conectiv to a maximum of 600 Mw for Bluewater. Even at the low range of the bids that have been received, these projects represent an extremely large portion of SOS energy requirements. Committing to one of these RFP's essentially places most of the SOS customer load requirements "in one basket". This lack of diversification greatly increases the dollar level of SOS customer exposure to the risks described above.

  - **Current SOS Procurement**
    Each year, procurement of one 'tranche' of approximately 1/3 of the SOS customer load requirements will take place through a competitive bidding process. The standard bid size is 50 Mw of full requirements energy. Multiple bidders participate in the process. The result is an SOS customer resource portfolio diversified across suppliers and time.

Summary of the Risks Associated with Long-term Power Contracts

- Long-term contracts for procuring SOS customer requirements do not necessarily provide greater price stability for SOS customers than the current procurement practice.

- Long term contracts are not a guarantee that SOS customers will pay less for their energy requirements for the next twenty five years.

- Long term contracts, as exemplified by a large significant financial commitment over a 25 year period are not an appropriate policy solution to short term issues.

- SOS customers would become exposed to significant risks upon execution of a long-term contract to procure SOS energy requirements. These risks may be very expensive, difficult and not even possible to mitigate.

- The current SOS process allocates risk away from SOS customers to parties who are better able to manage these risks.

- The current SOS procurement represents a flexible and viable process that mitigates most of the risks and exposures that a long-term contract would otherwise present to SOS customers.

Glossary of Terms

As used in this report, the following terms have the meanings set forth below:

"Ancillary Services" means, when used with respect to a generating facility, all products deemed to be "Ancillary Services" by PJM and FERC, including but not limited to reactive power, regulation (including load following), spinning reserves, non-spinning reserves, and replacement reserves associated with a generating facility.

"Biodiversity" refers to the variety of organisms found in a specific region.

"Brownfield" means an abandoned property previously used for industrial or other commercial purposes that has potential for redevelopment.

"Capacity" means, as of any time, the maximum capability of a Project or its units, or an electric system, to generate electric energy.

"Delmarva Zone" means that aggregate of busses as listed on the PJM website and aggregated by Delmarva.

"Forced Outage" refers to unplanned reductions or suspensions of the electrical output from a generating facility or unavailability of the products of a generating facility in whole or in part from a generating facility in response to a mechanical, electrical, or

hydraulic control system trip or operator-initiated trip in response to an alarm or equipment malfunction and any other unavailability of a generating facility for operation, in whole or in part, for maintenance or repair that is not scheduled.

"Fuel" means gas, coal and any other fuel used in connection with the operation of a generating facility, including fuel used to generate energy and for consumption by the auxiliary equipment used in the operation of the generating facility.

"Integrated Gasification Combined Cycle" means a process where a fuel (usually coal) is partially burned in an oxygen-deficient environment to convert it to a "syngas". The syngas is filtered to remove particulates and scrubbed of pollutants such as sulfur, then it is burned in a gas turbine to make power. The hot gas output of the gas turbine is fed to a heat recovery steam generator (HRSG); the steam from the HSRG runs a turbine which makes more power. [confirm definition]

"kWh" means one kilowatt of electric power over a period of one hour.

"KW" means kilowatt(s).

"Moody's" means Moody's Investor Services, Inc.

"MW" means megawatts.

"MWh" means megawatt hour.

List of Acronyms

AGC – Automatic Generator Control
CFB – Circulating Fluidized Bed
CHG – Greenhouse gasses
CT – Combustion Turbine
DOE – Department of Energy
EPC – Engineer, Procure and Construct
EURCSA – Electric Utility Retail Customer Supply Act of 2006
FERC – Federal Energy Regulatory Commission
GW - Gigawatt
IC – Independent Consultant
IGCC – Integrated Gasification Combined Cycle
IPP – Independent Power Producer
IRP – Integrated Resource Plan
LMP – Locational Marginal Price
MAPP – Mid-Atlantic Power Pathway
MMBtu – Million British Thermal Units
MMS – Minerals Management Service
MW - Megawatt
MWh – Megawatt hour
NOI – Notice of Intent
NPV – Net Present Value
NUG – Non-utility Generator
PC - Pulverized Coal
PJM – Pennsylvania – Jersey - Maryland (Interconnection)
PM – Particulate Matter
POLR – Provider of Last Resort
PPA – Power Purchase Agreement
PSLF – Positive Sequence Load Flow (A GE software model)
PURPA – Public Utility Regulatory Policy Act of 1978
REC – Renewable Energy Credit
RFP – Request for Proposal
RGGI – Regional Greenhouse Gas Initiative
RPM – Reliability Pricing Model
RSCI – Residential and Small Commercial & Industrial
RTO – Regional Transmission Organization
SCR – Selective Catalytic Reduction
SIP – State Implementation Plan
SOS – Standard Offer Service
UCAP – Unforced Capacity