BEFORE THE
RHODE ISLAND PUBLIC UTILITIES COMMISSION

In Re: Review of Amended Power Purchase Agreement Between Narragansett Electric Company d/b/a National Grid and Deepwater Wind Block Island, LLC, Pursuant to R.I. Gen. Laws 39-26.1-7	)))))	**Docket No. 4185**

DIRECT TESTIMONY OF

SETH G. PARKER

ON BEHALF OF THE

RHODE ISLAND ECONOMIC DEVELOPMENT CORPORATION

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JULY 20, 2010

STATE OF RHODE ISLAND

PUBLIC UTILITY COMMISSION

LEVITAN & ASSOCIATES, INC.
100 Summer Street, Suite 3200
Boston, Massachusetts 02110
Tel 617-531-2818
Fax 617-531-2826

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I. Introduction

Q: Please state your name, occupation, and business address.

A: My name is Seth G. Parker. I am a Vice-President and a Principal of Levitan & Associates, Inc. ("LAI"), a management consulting firm specializing in the power and fuels markets. I joined LAI in 1998. LAI is located at 100 Summer Street, Suite 3200, Boston, MA, 02110.

Q: Please describe LAI's business.

A: Since its founding in 1989, LAI has conducted numerous power and fuels assignments throughout the U.S. and Canada, including in the regional New England power market administered by the Independent System Operator - New England ("ISO-NE"). These assignments have encompassed diverse matters pertaining to electricity and fuel price forecasts, competitive power market design, project economics, generating asset valuation, bulk power security, power and fuel procurements, contract structures, gas supply / storage / transmission, and risk management. LAI's clients include utilities, power and gas suppliers, ISOs and Regional Transmission Organizations ("RTOs"), end-users, state regulatory commissions, and financial institutions.

Q: Please summarize your professional background and experience.

A: I am an economic and financial manager with an international background in power and fuel project development, evaluation, financing, and transactions. My responsibilities have included modeling and analyses of utility and non-utility projects, as well as market design, regulatory policy, contract structuring, power economics, and asset valuation assignments.

Prior to joining LAI, I worked as a consultant and officer of Stone & Webster Management Consultants, Inc., where I was responsible for due diligence evaluations that financial institutions relied upon to provide over $6 billion to proposed power, fuel, and infrastructure projects in the U.S. and abroad. This work included technical and commercial issues, and was conducted for commercial banks, investment banks, and multilateral lending agencies. I also worked in the Treasurer's Office at Pacific Gas & Electric, and have been involved in project development and financing activities at ThermoElectron Energy Systems and J. Makowski Associates, Inc.

My educational background includes an Sc.B. in Applied Mathematics / Economics from Brown University, and an M.B.A. in Finance / Operation Research from the Wharton Graduate School at the University of Pennsylvania. I have taught undergraduate-level finance as an adjunct faculty lecturer, and have taken additional course work in Basic Gas Turbine Technology and International Political Economics. My resume is provided as Attachment 1 to this testimony.

Q: Have you previously presented testimony or served as an expert witness?

A: Yes. I have (i) provided expert reports and testified before the Virginia State Corporation Commission, the Vermont Board of Public Service, and the Connecticut Department of Public Utility Control, (iii) provided expert reports and testified in U.S.

District Courts, and (iv) provided expert reports and testimony at Federal Energy Regulatory Commission ("FERC") Technical Conferences. A list of my expert reports and testimony is provided in my resume.

Q: Mr. Parker, on whose behalf are you testifying in this proceeding?

A: My testimony is presented on behalf of Rhode Island ("RI") Economic Development Corporation (the "Corporation") as required by the recently passed RI legislation concerning an offshore wind project (Bill Number S 2819 Substitute A as amended / H 8083 Substitute A as amended) RI General Law § 39-26.1-7 (the "Statute").

Q: What is the purpose of your testimony in this proceeding?

A: Under the Statute, the Corporation is required to "…provide testimony regarding the terms and conditions of the power purchase agreement to assist the commission in its review…" My testimony address two specific issues referenced in section 39-26.1-7(c) of the legislation: (i) whether the terms and conditions of the proposed Amended Power Purchase Agreement between the Narragansett Electric Company d/b/a/ National Grid ("Narragansett Electric") and Deepwater Wind Block Island, LLC ("Deepwater") filed December 9, 2009 (the "Amended PPA") are commercially reasonable for a project of similar size, technology and location and meeting the goals set forth in the legislation and (ii) whether the Amended PPA terms and conditions contain provisions for a decrease in pricing if savings can be achieved in Deepwater's actual cost to construct the Block Island Wind Farm ("BIWF").

Q: Has the Corporation asked you to evaluate related power market issues?

A: Yes, I was also asked to (i) evaluate risk factors and how they could affect the Amended PPA prices, (ii) estimate price suppression benefits, and (iii) evaluate other power market impacts associated with BIWF and from future offshore wind projects.

Q: Did you compare the Amended PPA prices to ISO-NE market prices?

A: No, I was not asked to make that comparison or to estimate the change in Narragansett Electric's rates if the Amended PPA was approved and executed. Those questions were addressed in the PUC's Docket No. 4111.

Q: Do you or LAI have any financial interest in the parties in this docket or in the outcome of this matter?

A: Neither LAI nor I have any direct financial interest in the Corporation, Deepwater, National Grid, or any related companies, or in the outcome of this matter.

Q: Please describe the materials, documents, or other resources you have reviewed or relied upon in forming the opinions you have reached and about which you will testify in this proceeding.

A: In addition to the Amended PPA, I have reviewed and relied on the following materials, documents and resources:

1. Report and Order of the RI Public Utilities Commission ("PUC") in Docket No. 4111 in re: Review of Proposed Town of New Shoreham Project pursuant to RI General Laws § 39-26.1-7 ("Order").

2. PPA between Cape Wind Associates, LLC ("Cape Wind") and National Grid, executed May 10, 2010 ("Cape Wind PPA")
3. PPA between Bluewater Wind Delaware LLC ("Bluewater") and Delmarva Power & Light Company ("Delmarva"), executed June 23, 2008 ("Bluewater PPA").
4. ISO-NE "2010-2019 Forecast Report of Capacity, Energy, Loads, and Transmission" ("CELT") of May 18, 2010.
5. "Electric Resource Planning Study" for the Block Island Power Company ("BIPCO") prepared for the Joint IRP Working Group by HDR Engineering dated February 1, 2008 ("BIPCO Planning Study").
6. "Eastern Wind Integration and Transmission Study" of January 2010 ("EWIT Study") prepared for the US DOE National Renewable Energy Lab by EnerNex Corporation.
7. "Analysis of the Impact of Southern New England Offshore Wind and Block Island Wind on New England Energy Prices" prepared by Charles River Associates ("CRA") dated March 2010 ("CRA Analysis").
8. Draft "The Impact of Block Island Wind Farm on Electricity Costs" dated June 2010 prepared by CRA ("Additional CRA Analysis").
9. Direct Testimony of Richard LaCapra on behalf of The Town of New Shoreham, July 15, 2010, RI PUC Docket No. 4185.
10. "Block Island Power Company Electric Resource Planning Study", February 1, 2008, prepared by HDR Engineering, Inc., Docket 3655.

Q: How did you organize your testimony?

A: In preparing my testimony, I organized it to address the requirements of the Statute. The first part of my testimony addresses the Amended PPA prices in comparison to other offshore wind projects, as well as project risks and whether those risks affect the Amended PPA prices. The second part of my testimony addresses a number of related power market issues associated with BIWF. In a separate advisory opinion that is being submitted in this docket, I address various economic development benefits and summarize both the power market impacts and the economic development benefits.

II. The Offshore Wind Industry and New England Power Market

Q: Please provide an overview of the offshore wind industry.

A: The offshore wind industry is centered in Europe where there are approximately 39 offshore wind projects in operation, representing just over 2,000 megawatts ("MW") of installed capacity, with approximately 3,000 MW more under construction, as of year-end 2009. China recently finished its first offshore wind project near Shanghai, rated at 102 MW, the first offshore wind project in Asia. BIWF may become the first offshore wind project in North America, where there are several offshore projects in various planning stages.

According to the European Wind Energy Association, there were eight offshore wind projects installed in Europe last year with an average size of 65 MW. One project had a water depth of 30 meters ("m"); most projects were installed in water depths of 5 m - 13m. Most projects were within 12 kilometers ("km") from shore, and one was as far away as approximately 43 km. European wind farms currently under construction are being installed in deeper waters (average water depth of 27.2 m) and further from shore (average distance of 28.3 km). About 65% of the offshore wind plant foundations are monopile designs, 23% are gravity foundations, and the remaining 12% are jacket (similar to BIWF's foundation design) and tripod designs. Offshore wind turbine sizes ranged from 2.3 MW to 5 MW (average of 2.9 MW) last year. The largest offshore wind turbine suppliers are Siemens (71% of the market) and Vestas (19%); Multibrid, Win Wind, and Sinovel Wind Group also supply offshore wind turbines.

The capital cost of offshore wind projects are typically about double onshore wind plant capital costs on a unitized ($/MW) basis. Capital costs are very sensitive to water depth, as foundation structures are very expensive and can account for a large percentage of the total capital cost. The development of floating structures, now in the pilot stages, could be a major advance and could permit offshore wind projects to be installed further from shore and in deeper waters without cost penalties. Capital costs for offshore wind projects are expected to decline in the future due to technology improvements and economies of scale in both wind turbine manufacturing and wind turbine sizes.

Q: Please describe the New England power market.

A: ISO-NE administers the competitive power market in New England, which consists of three basic power products: energy, capacity, and ancillary services. The energy market actually consists of two markets, a Day-Ahead market and a Real-Time market. The Day-Ahead market is a forward market in which hourly Locational Marginal Prices ("LMPs") are calculated for each hour of the next operating day based on the highest cost resource required in that hour. In general, resources with low marginal operating costs, *e.g.* wind projects, are committed in all hours, while resources with high operating costs, *e.g.* diesel generators, may only be committed a few hours per year during periods of high demand. Resource commitments in the Day-Ahead market are financially binding, and all energy resources receive identical LMPs, adjusted for locational differences for those hours in which they operate.

The Real-Time market is a balancing market for energy based on the actual system conditions. ISO-NE procures reserves and other ancillary services from specific resources to assure system reliability as part of the Real-Time dispatch process. This process satisfies New England's energy requirement and reserve requirements using an optimization algorithm to minimize the energy, congestion, and transmission loss costs, given real-time system conditions and constraints.

ISO-NE also administers a Forward Capacity Market to competitively procure capacity resources three years in advance at the lowest possible cost through an annual descending clock auction process. Capacity commitment periods last one year for existing resources, and from one-to-five years for new resources. The first Forward Capacity Auction occurred in February, 2008 for the delivery year, June 1, 2010 to May 31, 2011; the most recent Forward Capacity Auction occurred in October, 2009 for the delivery year, June 1, 2012 to May 31, 2013. All capacity resources that clear in these auctions receive identical prices for capacity, taking into account their availability and location in the ISO-NE system. Capacity resources that clear Forward Capacity Auction have capacity obligation to offer energy in the Day-Ahead and Real-Time energy markets. Resources that do not clear the Forward Capacity Auction have no capacity obligations but may provide energy as non-capacity resources.

Q: Does Narragansett Electric participate in the ISO-NE power market?

A: Yes, Narragansett Electric, National Grid's RI distribution company, is a regulated electric utility that delivers electricity produced by generation companies throughout ISO-NE and surrounding markets. Under the Rhode Island Utility Restructuring Act of 1996 and related legislation, competition in the RI wholesale power supply markets was extended to retail customers, permitting them to purchase energy from alternative suppliers. Narragansett Electric provides Standard Offer Service to customers throughout virtually all of RI, except for Block Island and a small area in the northwestern portion, as shown in the figure below.[1]

National Grid, on behalf of Narragansett Electric, regularly issues competitive Requests for Proposals ("RFPs") for wholesale power supplies from ISO-NE and surrounding markets that it resells to meet its Standard Offer Service retail requirements. RFPs are issued every six months for its residential and other small customers with prices fixed for that period of time. RFPs are issued every three months for its large customers and those prices vary monthly reflecting market prices. National Grid's most recent Standard Offer Service RFP was issued on April 8, 2010.

[1] Narragansett Electric used to provide Last Resort Service to customers who at one time received generation service from unregulated power suppliers and subsequently returned to Narragansett Electric, but Last Resort Service is no longer offered.

Figure 1. Narragansett Electric's Service Territory

1 **Q: Please describe the renewable energy market in New England.**

2 **A:** RI, as well as 23 other states and the District of Columbia, have implemented Renewable Portfolio Standards ("RPS") that require electricity providers to obtain a minimum percentage of their power supplies from renewable energy resources by a certain date.[2] In RI, for example, the requirement began at 3% of total retail electricity sales in 2007 and will reach 16% by the end of 2019. To comply with the RPS, electricity providers may either purchase renewable energy or may acquire renewable energy credits ("RECs"). One REC is the environmental attributes associated with one MWh of energy,

[2] The only state in New England that does not have an RPS requirement, Vermont, has a voluntary program to provide renewable energy.

which is separable and distinct from the energy itself. REC values provide an additional revenue stream to financially support renewable energy projects, which tend to be more expensive than conventional resources.

III. BIWF and the Amended PPA

Q: Please provide an overview of the BIWF project.

A: BIWF is conceived as a 28.8 MW offshore wind project to be located approximately 3 miles southeast of Block Island.[3] As currently contemplated, BIWF will have eight wind turbines on lattice jacket structures specifically designed for its 25 m to 30 m depth and the local marine environment. The wind turbines will be electrically connected via an underwater cable that will terminate at a new collector substation on Block Island.

BIWF is expected to operate at a 40% capacity factor, *i.e.* energy production measured at the collector substation is expected to be 100, 915.2 megawatt-hours ("MWh") per year, the Annual Production Target contained in Exhibit Y of the Amended PPA.[4] Electric energy generated by BIWF will flow from the collector through the existing BIPCO electrical system to a new substation that will be connected to the Narragansett Electric system on the mainland through a new underwater transmission cable ("Transmission Cable"). I understand that Deepwater is responsible for the design and construction of the Transmission Cable, and that Narragansett Electric has the right to purchase, own, and operate that Transmission Cable. For the purpose of my testimony, I have assumed that

[3] The total nameplate capacity may be up to 30 MW.
[4] The Annual Production Target is equal to 28.8 MW x 8760 hours/year x 40% capacity factor.

Narragansett Electric exercises that right. Therefore, I did not include any costs associated with the Transmission Cable or with possible upgrades to the BIPCO electrical system as part of either the BIWF project or the Amended PPA.

Q: Will all of BIWF's energy be delivered into the Narragansett Electric system?

A: No, once the Transmission Cable is energized, BIPCO intends to put its diesel generators in standby mode. Thus BIWF energy will first be used to meet BIPCO's load, and then any surplus energy will be delivered to the mainland. In my testimony I explain how we estimated BIPCO's load over the term of the Amended PPA. We estimate that 87% of BIWF's energy production will initially be delivered to Narragansett Electric, declining to 79% over time as BIPCO's load increases.

Q: Please provide an overview of the Amended PPA.

A: The Amended PPA, negotiated between Deepwater and Narragansett Electric, one of the regulated operating companies owned by National Grid, provides for Narragansett Electric to purchase all of BIWF's power products: energy, capacity, and RECs (collectively, the "Products"). The original version of the Amended PPA was filed with the PUC on December 10, 2009, in Docket No. 4111, requesting PUC approval. That original version and the current Amended PPA have a fixed price of $244/MWh in 2013, with a fixed 3.5% price escalator over 20 years, for all of the power products.

Q: Describe the primary commercial terms in the Amended PPA.

A: Deepwater will furnish bundled energy, capacity, and REC Products on a unit-contingent, "take if tendered" basis.[5] The bundled price for the Products in 2013 is \$244/MWh, assuming that the project is commercialized by December 31, 2012.[6] Each year thereafter, over the 20-year Amended PPA term, the bundled price will increase by 3.5%. The Products will be delivered to Narragansett Electric at a new substation on Block Island.

Q: What do you mean by unit contingent, take-if-tendered?

A: Unit contingent means that the Products must be generated by BIWF and not furnished from a portfolio of resources or from the market. Take-if-tendered means that, except under certain limited circumstances, Narragansett Electric is obligated to accept and pay for all Products that the BIWF delivers. Because the Amended PPA is for 100% of BIWF's output, this means Narragansett Electric must accept and pay for all of BIWF's energy, capacity, and RECs.

Q: Are there any price adjustments in the Amended PPA?

A: Yes. There are three mechanisms for a price adjustment. The first mechanism resets the initial 2013 price if the actual total capitalized cost of BIWF ("Total Facility Cost") is less than \$205,403,512. If this occurs, the initial 2013 Amended PPA price will be reduced in accordance with a schedule in the Amended PPA, and then the 3.5% annual escalation will apply to the new starting price. The price adjustment in the Amended PPA

[5] The capacity component is settled financially. Narragansett Electric is credited for all capacity revenue earned by BIWF in the ISO-NE Forward Capacity Market.

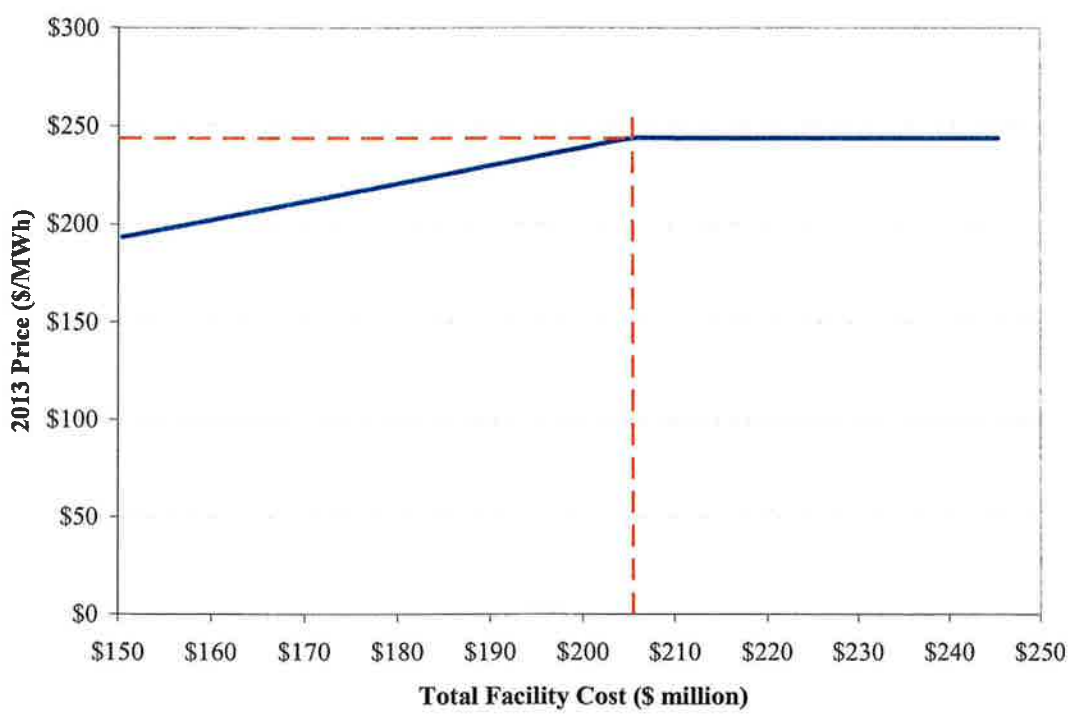
[6] If BIWF is commercialized earlier, the 2012 price would be the 2013 price de-escalated by 3.5% to \$234.70/MWh.

schedule is essentially a discount of about $4.60/MWh for each $5 million of Total Facility Cost savings. This price adjustment is illustrated in Figure 2. Amended PPA 2013 Price Adjustment for Total Facility Cost.

Q: If the Total Facility Cost is greater than $205,403,512 will the Amended PPA price increase?

A: No. Deepwater bears the risk of any overruns of the Total Facility Cost and Narragansett Electric ratepayers are insulated from that risk.

Figure 2. Amended PPA 2013 Price Adjustment for Total Facility Cost



Q: What is included in the Total Facility Cost and how will it be verified?

A: Total Facility Cost includes (i) all development costs, including design, engineering, permitting, and interconnection studies, (ii) all Engineering, Procurement, and Construction costs, including the cost to re-perform any defective work or for warranty work, (iii) all taxes and other fees, (iv) insurance; (v) costs to interconnect to the Delivery Point; (vi) financing and all legal fees, and (vii) any other capitalized costs. Within 90 days after Commercial Operation, Deepwater will certify the Total Facility Cost, and an independent third party ("Verification Agent") will confirm or dispute Deepwater's certification.

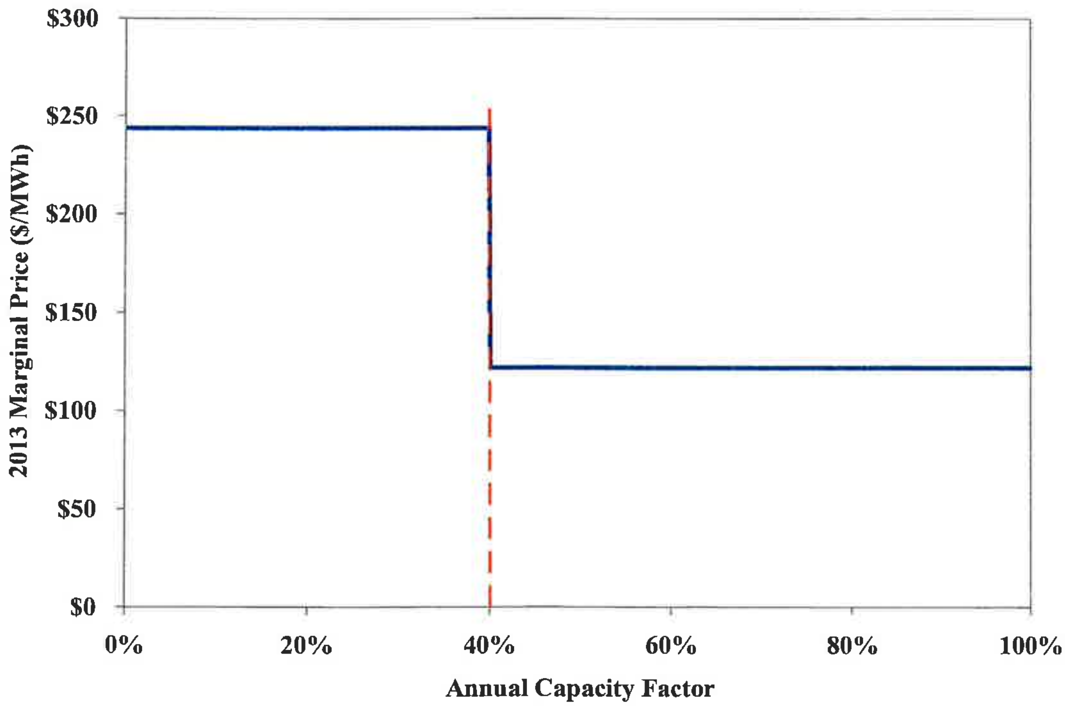
Q: After the BIWF begins commercial operation, does the Amended PPA allow for any price adjustments if actual operating costs are different from what Deepwater originally expected?

A: No. Once the Verification Agent certifies the price, the only change to the Amended PPA price (other than the adjustments discussed below) is the annual 3.5% escalator. Deepwater assumes the full risk of operating costs. If BIWF operating costs are higher than expected, Deepwater will earn a lower financial return. If BIWF operating costs are less than expected, Deepwater will earn a higher financial return.

Q: What is the second price adjustment mechanism in the Amended PPA?

A: The Amended PPA establishes an Annual Production Target based on a project capacity of 28.8 MW and a capacity factor of 40%. If the capacity factor exceeds 40% and actual energy production exceeds the Annual Production Target in any year, one-half of the surplus will be credited to Narragansett Electric at no charge in the following year.[7] In effect, the value of each MWh of bundled Products from BIWF above the Annual Production Target will be shared equally between Narragansett Electric and Deepwater as illustrated in Figure 3.

Figure 3. Amended 2013 PPA Price Adjustment for Capacity Factor



Q: Is there any price adjustment or other penalty under the Amended PPA if BIWF's annual energy production falls short of the 40% capacity factor target?

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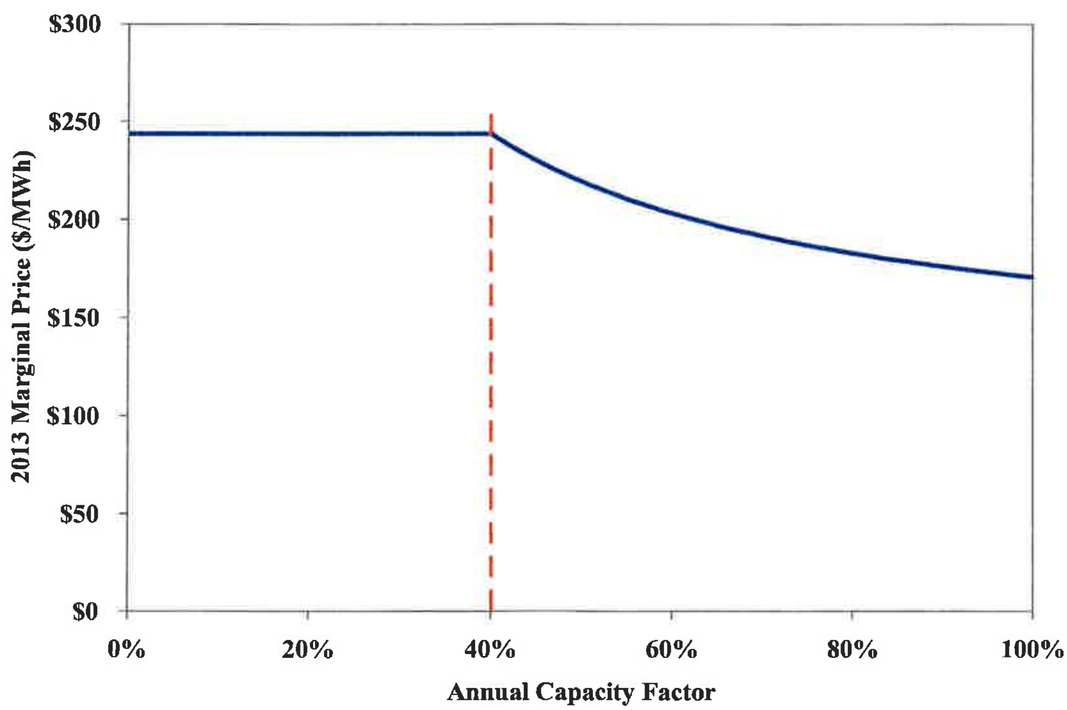
[7] BIWF production shortfalls (relative to the Annual Production Target) would be carried forward on a cumulative basis from contract year to contract year. In any contract year in which the actual production exceeds the Annual Production Target, the production surplus is first netted against any cumulative production shortfall before any remaining production surplus is credited to buyer.

A: No. In the case of a shortfall, Narragansett Electric is only obligated to pay for the quantity of Products delivered at the Amended PPA price, as illustrated in Figure 4. From Deepwater's perspective, however, if the actual capacity factor is lower than expected, Deepwater will have fewer revenues to cover its operating costs and capital recovery costs. This risk is borne entirely by Deepwater.

Figure 4. Amended 2013 PPA Price Adjustment for Capacity Factor



Q: What is the third price adjustment mechanism in the Amended PPA?

A: The third price adjustment mechanism pertains to export of the Products from Block Island to the mainland. In accordance with the Amended PPA, the delivery point for the Project is the collector substation on Block Island. In order to export the energy from

Block Island to the mainland and the rest of Narragansett Electric's service territory, the Transmission Cable will be constructed by an affiliate of Deepwater Transmission LLC, an affiliate of Deepwater. Narragansett Electric has the option of purchasing the Transmission Cable from Deepwater Transmission LLC, or at its sole discretion, constructing the Transmission Cable.[8] In the event that Narragansett Electric does not elect to own the Transmission Cable and Deepwater retains responsibility, Deepwater will be entitled to adjust the Amended PPA price to recover the cable costs.

Q: What is the Amended PPA price adjustment to account for the Transmission Cable costs?

A: Under the Amended PPA, this adjustment will be negotiated between Narragansett Electric and Deepwater. According to Deepwater, the total cost of the Transmission Cable is estimated to be $42 to $44 million. I assume that Narragansett Electric will purchase the Transmission Cable for the purpose of my testimony, and do not address the potential impact on the Amended PPA price.

Q: How does the Amended PPA account for the federal Production Tax Credit ("PTC") and Investment Tax Credit ("ITC")?

A: The Amended PPA protects Deepwater if Congress does not extend the in-service date to qualify for the PTC or ITC until at least December 31, 2015.[9] If this deadline is not extended, Deepwater has the right to terminate the PPA without further obligation by

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[8] If Buyer purchases the cable from Deepwater Transmission or constructs the cable itself, the statute allows Buyer to recover the costs from ratepayers. R.I.G.L. § 39-26.1-7(f).
[9] By law, a developer can not benefit from both types of tax credits.

either party. Deepwater has confirmed that the Amended PPA prices assume that BIWF will qualify for ITC.

Q: Are there other termination provisions in the Amended PPA?

A: Yes. For example, if regulatory approval and/or permits are not obtained within one year of filing, the Amended PPA terminates without further obligation by either party. Furthermore, if commercial operation is not achieved by the Commercial Operation Date of December 31, 2012 (subject to a one-time extension for up to five years), either party may terminate the Amended PPA. For orderly termination under these provisions, neither party is responsible to the other for any costs incurred to that point. Thus, Deepwater has a defined time window when it can exit the Amended PPA on an "off-ramp" in the event it determines that the BIWF project is not viable.

Q: Does this mean that either party can walk away from the transaction at any time without harm?

A: No. The PPA has default provisions that specify certain payments and penalties in the event of default by either party. For example, if Narragansett Electric were to default after financial closing, it would owe Deepwater a termination payment based on the positive difference between the Amended PPA price and the prices Deepwater receives by reselling the Products in the market for the rest of the Amended PPA term.

IV. <u>Comparison of Offshore Wind PPAs</u>

Q: How did you structure your power markets analysis?

A: LAI reviewed the Amended PPA and focused on pricing and other commercial provisions, including price adjustments under certain defined conditions. We (i) compared the commercial terms in the Amended PPA against PPAs for similar products from offshore wind projects, (ii) identified risk factors associated with offshore wind projects and how those risks are allocated between buyers and sellers.

Q: What other PPAs did you examine?

A: I looked at two other PPAs involving offshore wind projects that are have been filed with state regulatory agencies and are in the public domain: (i) the Cape Wind PPA and (ii) the Bluewater PPA. Both projects are considerably larger than BIWF.

Q: Please describe Cape Wind and the Cape Wind PPA.

A: Cape Wind is a 468 MW offshore wind project to be located in federal waters off of Massachusetts in Nantucket Sound. There are many similarities between these two PPAs, most likely because the buyer in both cases is National Grid or one of its affiliates. Cape Wind's expected in-service date is 2013. Under the Cape Wind PPA, Cape Wind will furnish 50% of the energy, capacity, and RECs on a unit-contingent, take-if-tendered basis from the Cape Wind project. These products will be delivered to National Grid at the Barnstable substation on Cape Cod, Massachusetts.

Q: Compare the basic pricing provisions between the Amended PPA and the Cape Wind PPA.

A: The bundled 2013 price for the Cape Wind products is $207/MWh, whereas the bundled 2013 price for Deepwater is $244/MWh. In both PPAs, the bundled price escalates by 3.5% annually. The Cape Wind PPA has a term of 15 years, whereas the Amended PPA term is 20 years.

Q: Are there any price adjustments in the Cape Wind PPA?

A: Yes, there are two price adjustment mechanisms. First, the price assumes that the project will qualify for ITC. However, if the project qualifies for PTC but not ITC, the bundled 2013 PPA price is increased to $228/MWh. If Cape Wind does not qualify for either tax credit, the bundled price increases to $235/MWh. This price adjustment does not apply, however, if Cape Wind is placed in service more than two and one-half years after financial closing.

The second price adjustment in the Cape Wind PPA is for energy production above a target quantity, similar to the price adjustment mechanism described above for Deepwater. Cape Wind's target capacity factor is 37.1% versus 40% for BIWF. Half of the Cape Wind energy produced in excess of the target capacity factor on an annual basis is credited to National Grid, effectively providing a 50% discount for the energy produced over the target quantity, identical to the Amended PPA.

Q: Is there any adjustment to the Cape Wind PPA price if the actual capital cost is higher or lower than expected?

A: No. Unlike Deepwater, Cape Wind is entirely at risk with no capital cost benefits shared with ratepayers. Cape Wind would earn a higher financial return if the total capital cost is lower than expected, and would earn a lower financial return if the total capital cost is higher than expected. National Grid and its ratepayers are insulated from any variance in total capital costs.

Q: Are there any other noteworthy differences in the allocation of risk between buyer and seller in the Cape Wind PPA compared to the Amended PPA?

A: Cape Wind is responsible for all costs to deliver the Products to, and interconnect with, the delivery point on the mainland, and National Grid is responsible for all costs from the delivery point onward. One noteworthy difference compared to BIWF is that Cape Wind, and not National Grid, is responsible for any costs to upgrade the Pool Transmission Facilities that may be required by ISO-NE to assure reliable system operation and delivery of Cape Wind's energy through the its electrical system.[10] I assume that an estimate for these costs are embedded in the bundled Cape Wind PPA price, since there is no adjustment provision in the Cape Wind PPA for higher-than-expected system upgrade costs. Apart from the timing and milestones, the other provisions for PPA termination and default are basically similar between the two PPAs.

Q: Please describe Bluewater and the Bluewater PPA.

A: The Bluewater project is conceived to be a 200 MW - 600 MW offshore wind project located in federal waters off of Rehoboth Beach, Delaware. The in-service date is

[10] Pool Transmission Facilities include transmission lines and associated equipment rated at or above 69 kV that are required for the reliable and safe operation of the ISO-NE system. New projects may require Pool Transmission Facilities as determined through interconnection studies.

planned to be on or before December 1, 2014. In accord with the Bluewater PPA, Bluewater will furnish energy, capacity and RECs to Delmarva on a unit contingent, take-if-tendered basis for a 25-year term.[11] Products will be delivered to Delmarva at the Indian River substation, Delaware. Delmarva will purchase 200 MW of Bluewater Products, regardless of Bluewater's actual capacity.

Q: Compare the basic pricing provisions between the Amended PPA and the Bluewater PPA.

A: Unlike the Amended PPA, the Bluewater PPA does not have a bundled price, but defines prices for each Product component. Expressed in terms of a 2007 base year, the price for Bluewater capacity is \$70.23/kW-year, the price for energy is \$98.93/MWh, and the price for RECs (as transacted under this PPA) is \$15.23/REC. All Bluewater PPA prices are subject to a firm annual escalator of 2.5%.

Q: Are there any price adjustment mechanisms in the Bluewater PPA?

A: There is no price adjustment mechanism *per se*, but Bluewater is subject to damages if its energy production falls below a minimum guarantee.[12] The Bluewater PPA specifies a minimum performance requirement, which is 52% of the target generation based on a capacity factor of 32%. Bluewater is subject to a penalty of \$25/MWh for any shortfalls, but damages are capped at \$1.5 million per year and \$10 million in aggregate over the contract term. If the production shortfall exceeds this cap, it is considered an event of default and Delmarva can terminate the Bluewater PPA.

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[11] Similar to the Amended PPA and the Cape Wind PPA, capacity is settled financially.

[12] There are also provisions in the PPA for buyer and seller to apportion energy price impacts if additional capacity is added in the region by seller.

Q: What do you mean by "the RECs (as transacted under this PPA)"?

A: By Delaware statute, each MWh generated by Bluewater will create 3.5 RECs that can be used by Delmarva to comply with the Delaware RPS requirements for each MWh generated by Bluewater. For clarity, I term these "Delaware RECs" because these fractional RECs can not be used on a one-for-one equivalent basis to comply with any other state's RPS requirements. Each of these Delaware RECs is equivalent to 28.8% (1/3.5) of a standard compliance REC. Under the Bluewater PPA, Delmarva would pay $15.23/Delaware REC to accompany each MWh of energy. Looking at it a different way, if Delmarva purchases 100 MWh of energy, it also takes title to 100 Delaware RECs but these are equivalent to only 28.8 standard compliance RECs. That means that Bluewater retains 71.4 standard compliance RECs which it can then sell elsewhere to enhance project revenues.

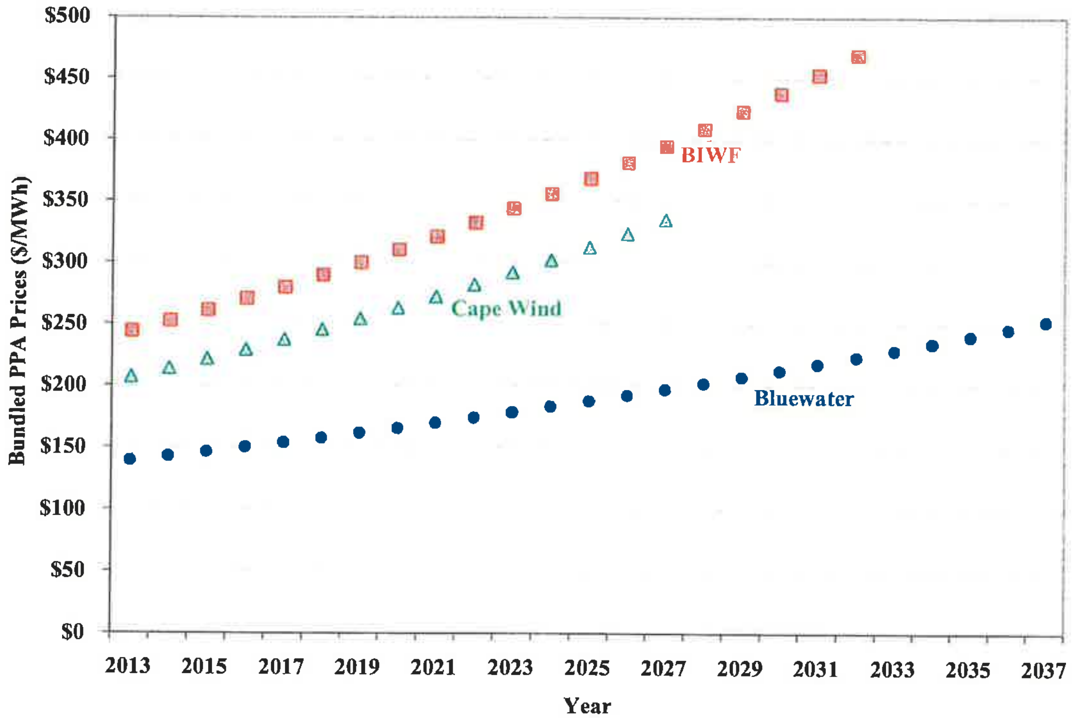
Q: Can you express the Bluewater PPA pricing as a bundled price?

A: Yes. To sum the components, I assumed a Bluewater capacity factor of 32%. I adjusted the quantity of Bluewater capacity that can be sold in the PJM capacity market consistent with its expected availability, which equates to $6.26/MWh.[13] Since Delmarva receives one Delaware REC for each MWh generated, the $15.23/Delaware REC price is added to the energy price, resulting in a total bundled 2007 base year price of $120.42/MWh Escalated to 2013 at the 2.5% annual Bluewater PPA escalator, the bundled price would be $139.65/MWh. Bundled Bluewater PPA prices for each year are

[13] $6.26/MWh = $70.23 /kW-yr * 1,000 kW/MW / 8,760 hr/yr / 32% capacity factor * 25% equivalent availability factor.

shown in Figure 5, along with the annual bundled prices for BIWF and Cape Wind, adjusted to a common 2013 starting year.

Figure 5. Bundled PPA Prices with Common Starting Year



Q: Is Bluewater's bundled PPA price of $139.65/MWh comparable to the Amended PPA price of $244/MWh and the Cape Wind bundled price of $207/MWh, all as of 2013?

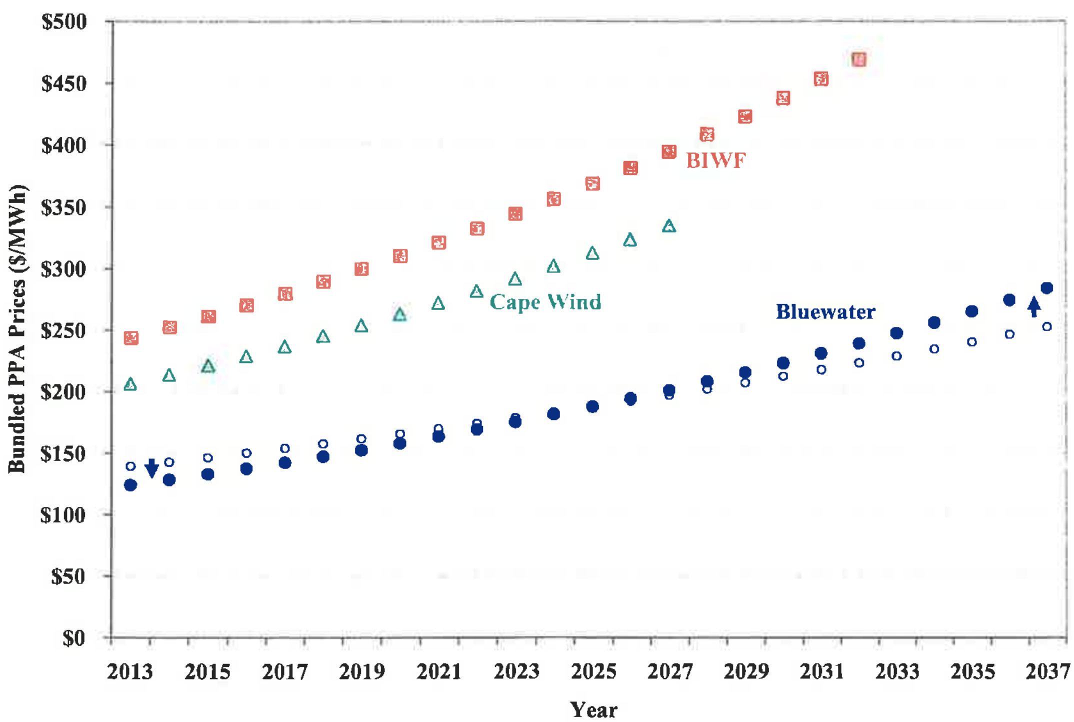
A: Not exactly. The Bluewater PPA escalator is 2.5%, whereas the escalators in the Amended PPA and Cape Wind PPA are 3.5%. The contract terms of the three PPAs also vary. In order to put the prices on a more comparable basis, I first adjusted the PPA price escalators to a common 3.5% value keeping the revenue stream associated with each project's PPA constant on a net present value ("NPV") basis. I used a discount rate of

7.2% to be consistent with CRA's Analysis.[14] The 3.5% PPA escalator lowers the Bluewater PPA prices in the early years and raises them in the later years

Q: What are the results of your analysis when you express the PPA prices on this more comparable basis?

A: Using the 7.2% discount rate and common 3.5% PPA escalator presented above, I computed 2013 bundled prices for each PPA. As shown in Figure 6, the 2013 starting prices for the 3.5% escalation price streams are \$244.00/MWh for BIWF, \$207.00/MWh for Cape Wind, and \$124.35/MWh for Bluewater.

Figure 6. Bundled PPA Prices with Common Starting Year and 3.5% PPA Escalator

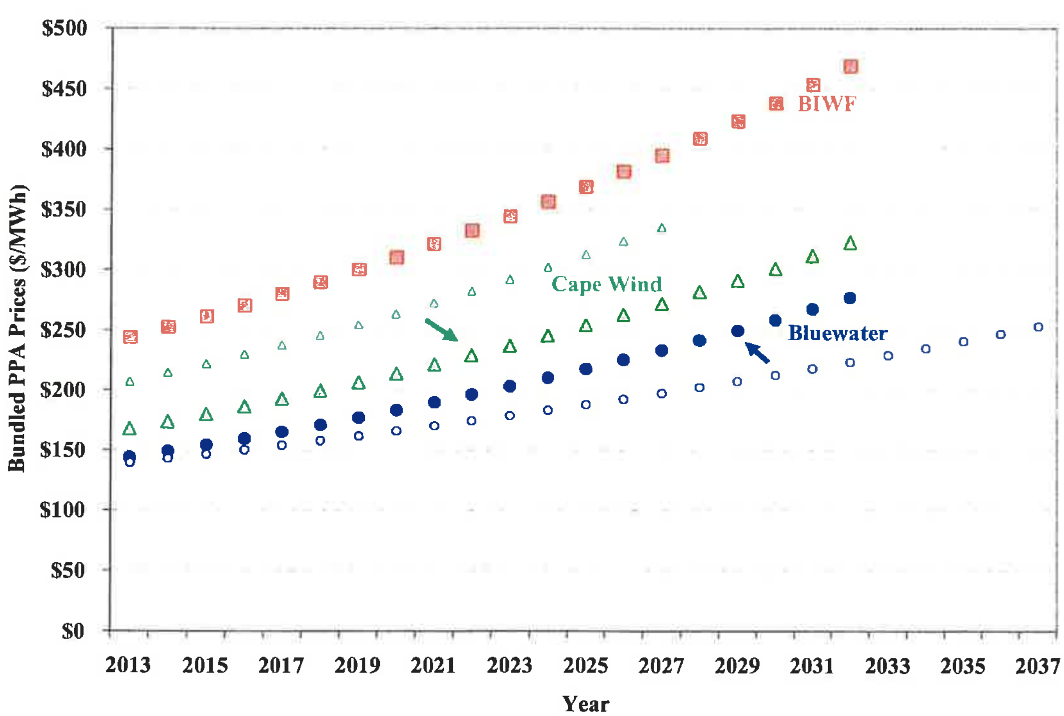


[14] We understand that this value is equal to National Grid's overall cost of capital as presented David Nickerson in PUC Docket No. 4065.

Q: Can further adjustments be made to reflect the differences in PPA terms among BIWF, Cape Wind, and Bluewater?

A: Yes, but these adjustments require assumptions regarding the recovery of capital costs under each PPA. In order to convert the 15-year Cape Wind PPA prices and the 25-year Bluewater PPA prices to equivalent 20-year prices, I assumed that all capital costs recovered during the unadjusted PPA terms would be recovered during the adjusted PPA terms, keeping the NPVs of the total revenues constant for each project. These 20-year PPA prices are shown in Figure 7. The 2013 price for the Amended PPA is unchanged at $244.00/MWh, but the 2013 price for Cape Wind is now $167.99/MWh and the 2013 price for Bluewater is $144.01/MWh.

Figure 7. Bundled Prices with Common Starting Year, 3.5% PPA Escalator and 20-Year PPA Term



Q: Are the BIWF and Cape Wind projects in similar locations?

A: The locations are similar to the extent that both projects are located in offshore sites in southern New England with similar average wind speeds.[15] BIWF will be constructed at a water depth of 25 m - 30 m and Cape Wind will be constructed at a water depth of somewhat less than 20 m. I do not know Bluewater's expected depth.

Q: Can differences in location account for PPA price differences between BIWF and Cape Wind?

A: Cape Wind's shallower depths and favourable seabed conditions allow it to utilize a monopile foundation design while the BIWF foundation will be a steel jacket design. While the fabrication costs for these two foundation designs are very similar, the shallower depths imply material and installation cost savings for Cape Wind.[16] I note that David P. Nickerson provided cost scaling factors in his December 9, 2009 testimony in Docket No. 4111 indicating a 6.7% total cost savings of offshore wind projects at 10 m - 20 m depths (Cape Wind) compared to 20 m - 30 m depths (BIWF).[17] There may be other differences in the technology or design between these two projects, but we do not have sufficient technical information to determine if those differences are significant.

Q: Are the Deepwater and Cape Wind projects of similar size?

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[15] Wind speeds based on June 2010 NREL offshore wind speed maps.
[16] Ballast Nedarn, "Optimal Integrated Combination of Foundation Concept and Installation Method" December 2009.
[17] Mr. Nickerson referenced an EEA Technical Report No. 6/2009 "Europe's onshore and offshore wind energy potential".

A: No. Cape Wind will consist of 130 wind turbines totalling 468 MW and BIWF will consist of eight wind turbines totalling 28.8 MW.

Q: Can the difference in size account for the difference in price between BIWF and Cape Wind?

A: Yes, I believe that economies of scale are the primary reason why the Cape Wind PPA prices are lower than the Amended PPA prices. Cape Wind is just over sixteen times larger that BIWF, and would benefit from greater bargaining power to purchase wind turbines, foundations, and other materials. Cape Wind would also be able to amortize mobilization and de-mobilization costs, and underwater cable costs, over a larger project. Modular construction projects, such as an offshore wind farm, typically enjoy significant economies of scale. When compared to Cape Wind, BIWF's higher capital costs per unit of capacity, as well as the resulting higher Amended PPA prices, are commercially reasonable.

Q: Can BIWF be reasonably compared to Bluewater with its PPA adjusted using a 3.5% escalator and a 20-year term?

A: Not without further adjustment. As explained above, Bluewater has the opportunity to sell standard compliance RECs not conveyed to Delmarva, potentially realizing an additional revenue stream to cover its fixed and variable costs. When the Bluewater PPA was negotiated, the highest valued standard compliance RECs in PJM were trading at a price roughly similar to the $15.23 firm base price embedded in the PPA.[18] If

[18] For example, the State of New Jersey Energy Data Center reports that average Class I REC prices for the 2007/2008 reporting period were $16.55/MWh.

those prices were to prevail and escalate over time, Bluewater would receive additional revenue of up to $12/MWh in 2013. However, compliance Tier I REC prices are currently priced at about $4.50/MWh for 2010 vintage RECs in Delaware, $1.62.MWh in New Jersey and $1.00/MWh in Maryland.[19] If, for example, we assume that Bluewater were to sell excess RECs to meet Maryland's RPS, it would realize a potential additional revenue stream of only about $0.72/MWh of energy generated. This factor alone is insufficient to account for the difference in PPA prices between Bluewater and Deepwater.

Q: Are there other differences which make the PPA pricing for Bluewater difficult to compare to those of BIWF?

A: Yes. First, Bluewater was envisioned to have an ultimate capacity of 600 MW, twenty times larger than BIWF, at the time the Bluewater PPA was executed. This size disparity makes comparisons difficult. Second, as of July 19, 2010, it has been reported that NRG, Bluewater's owner, negotiated a consent agreement tied to the Bluewater project to shut down a coal-fired unit at its Indian River site in Delaware. I do not know if NRG will receive any consideration for shutting down this unit, and what the value of such consideration would be for Bluewater. Thus the Bluewater PPA prices themselves may not represent the entire value NRG would receive from developing the Bluewater project.

Q: Did you also consider any commercial benchmarks outside of the U.S.?

A: Yes. I examined the terms of feed-in tariffs in Canada and in Europe.

Q: What is a feed-in tariff?

[19] Bloomberg, LLP.

A: A feed-in tariff establishes a guaranteed stream of payments for a specified length of time from a utility to any project that can meet its requirements. Feed-in tariffs are intended to stimulate investment in certain types of projects or technologies by facilitating development and financing. Feed-in tariffs are common in European countries, where virtually all off-shore wind projects are currently located. Ontario implemented a feed-in tariff in 2009, with different tariff rates specific to different renewable technologies. While there is a feed-in tariff rate for off-shore wind projects in Ontario, quite a few have been proposed but none have commenced construction.

Q: Are any of the proposed off-shore projects in Ontario comparable to BIWF?

A: The Wolfe Island Shoals Wind Farm is a sixty turbine, 300 MW project that would be located in Lake Ontario, near Kingston, Ontario. In April 2010 it was awarded a contract with the Ontario Power Authority through the feed-in tariff program. Under the contract, it has four years to achieve commercial operation. It is more comparable to the Cape Wind and Bluewater projects than to BIWF because of its size.

Q: What are the commercial terms of the Ontario Power Authority feed-in tariff for off-shore wind projects?

A: Ontario Power Authority will pay C$190/MWh for a term of 20 years for off-shore wind projects. An escalation rate indexed to inflation applies to 20% of the unit price. At the current exchange rate, this is equivalent to $183/MWh. The feed-in tariff price guarantees projects a fixed bundled price; any revenues received by the project for market sales of electricity are deducted from the feed-in tariff price.

Q: Is the Ontario feed-in tariff for offshore wind projects a good benchmark for determining the commercial reasonableness of the Amended PPA price?

A: Since no project has demonstrated that the Ontario feed-in tariff price is adequate to support actual project development, I do not believe it is an acceptable benchmark. Moreover, I am not aware of any potential offshore wind projects in Ontario that would be as small as BIWF.

Q: Have you reviewed the European feed-in tariff terms?

A: I have briefly examined feed-in tariff programs in Denmark, Germany, France, Great Britain, Spain, and Sweden.

Q: Are the European feed-in tariffs for offshore wind projects good benchmarks for determining the commercial reasonableness of the Amended PPA price?

A: At this point I cannot utilize the European feed-in tariffs as benchmarks to make this determination because many, and perhaps most, of the projects receiving those feed-in tariffs receive additional revenue streams from electricity or REC sales. In order to compare the commercial terms of the Amended PPA with offshore projects receiving European feed-in tariffs, I would also need to examine specific project characteristics to make adjustments for inflation from the time of construction, currency exchange rates, wind turbine sizes, and other factors that could explain any PPA price differences.

V. <u>Energy Price Suppression Benefits</u>

Q: What other power market impacts do you address in this testimony?

A: I address a number of other power market impacts: (i) energy price suppression effects, (ii) capacity price impacts, (iii) gas price suppression impacts, (iv) price stability, (v) future power market benefits, (vi) Narragansett Electric's remuneration, (vii) BIPCO reliability and price impacts, and (viii) the Transmission Cable.

Q: Please explain the additional impact of energy price suppression effects.

A: BIWF energy would displace energy from generators in RI that would otherwise be dispatched by ISO-NE as well as increase net exports from RI. Since ISO-NE dispatches generators under least cost economic principles, BIWF should allow ISO-NE to reduce purchases of high priced energy, and as a result, energy prices should decline in RI.[20]

Q: How did you calculate BIWF price suppression effects?

A: Under my supervision, we used MarketSym, a commonly used chronological dispatch simulation model, to simulate the operation of the ISO-NE power market and surrounding markets to calculate hourly LMPs by zone. We ran two cases, a base case that includes BIWF and an alternative case that did not include BIWF. We calculated zonal LMP in RI for the two cases through the 2013-2032 Amended PPA term. We calculated BIWF's energy price suppression effect by taking the hourly differences in RI energy prices multiplied by hourly RI energy load for the two cases. We summed up the energy price suppression values to calculate a total price suppression value for the full 20-year amended PPA term.

[20] While energy prices in RI should decline, energy prices across New England as a whole may not measurably change because we reduced wind generation in the other New England zones to match BIWF's generation to keep total wind generation constant between MarketSym cases.

Q: What were the basic assumptions you used to initialize MarketSym?

A: MarketSym requires many inputs that we provide based on the most current and reliable sources. The most important inputs were as follows. First, I utilized the most recent load and generation data from ISO-NE based on the CELT report and similar reports for surrounding power markets. Second, I divided New England into nine load zones to capture the key transmission limitations that can cause energy price differences. The nine load zones were RI, Connecticut, New Hampshire, Vermont, Maine and four zones in Massachusetts, including southeastern Massachusetts ("SEMA"). Third, I included the surrounding markets of New York, Quebec, Ontario, the Canadian Maritimes, and the Mid-Atlantic states to capture important power imports into and exports from ISO-NE.[21] Fourth, I used an updated power plant fuel cost forecast based on NYMEX prices for natural gas and oil products, as well as other sources for coal and nuclear fuel costs. Fifth, I assumed that enough renewable generation, mostly in the form of onshore wind, would be added in New England to meet most of the states' RPS requirements. Any RPS gap in required renewables would be met through imports from New York or other adjoining market areas. BIWF was the only offshore wind project assumed for RI, and Cape Wind was the only offshore wind project in SEMA.

Q: What did you assume about BIWF's operations?

A: I assumed that BIWF would achieve its target 40% capacity factor and generate 100,915.2 MWh per year, the Annual Production Target per Appendix Y of the Amended PPA, starting on January 1, 2013. I did not assume any reduction in BIWF's output during

[21] The mid-Atlantic states are the eastern portion of the Pennsylvania-New Jersey-Maryland ("PJM") market.

the first few years of operation due to possible start-up issues. I assumed that BIWF's output would first serve the needs of Block Island residents and that excess BIWF energy would flow through the Transmission Cable to the mainland.

Q: Please describe in more detail the two MarketSym cases that you ran to estimate BIWF's price suppression effects?

A: In our base case I included BIWF in the RI zone. In the alternative case I removed BIWF and re-balanced the ISO-NE system by adding an equivalent quantity of onshore wind resources in other zones throughout New England to ensure that RPS requirements would be met.

Q: How did you treat Block Island's load?

A: We understand that Block Island Power Company ("BIPCO") would no longer rely on its diesel generators to meet its load requirements once the Transmission Cable is installed. We understand that those generators would be kept in standby mode in case they are required, but would likely operate very little. Thus "gross" energy production from BIWF will flow onto Block Island, be used to satisfy Block Island load, and the remaining "net" BIWF energy will be delivered to the mainland via the Transmission Cable.

Q: How did you forecast Block Island's load?

A: We utilized the probable scenario energy load forecast that was contained in the BIPCO Planning Study, in which BIPCO energy load was forecasted to grow from 13,561.0 MWh in 2013 to 18,230.2 MWh in 2026. We then assumed that BIPCO's energy load would grow at 2.2%, the average growth rate over the BIPCO Planning Study forecast horizon, through 2032, the last year of the Amended PPA term.

Q: How does this forecast of Block Island's load compare to BIWF's expected production?

A: Using the BIPCO Planning Study values, BIPCO's load would be equal to about 13% of Deepwater's output in 2013 and grow to 21% by 2032.

Q: How did you calculate the hourly BIPCO loads for chronological dispatch simulation purposes?

A: We applied typical ISO-NE daily load profiles to the BIPCO monthly load profiles to develop daily BIPCO load profiles for each month.

Q: Given the forecast of BIPCO's energy loads, how much of BIWF's energy production would be available for delivery to the mainland, and thus assumed for your price suppression calculations?

A: We forecasted BIPCO's energy load to be 13.5 gigawatt-hours ("GWh") in 2013, so that 87.5 GWh of Deepwater's target production of 100.9 GWh would be exported into the ISO-NE system.[22] By 2032, BIPCO's load is forecasted to increase to 20.7 GWh, so that BIWF would export 80.2 GWh into the ISO-NE system.

Q: What were the results of your price suppression calculations?

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[22] 1 Gwh = 1,000 MWh.

A: We calculated that BIWF would save Narragansett Electric ratepayers an average of $370,000 annually and a total of $7.4 million over the 20-year Amended PPA term. RI LMPs would decrease on average by $0.02/MWh over the years 2013-2032 while the average LMPs would increase by $0.02/MWh in the rest of New England because we shifted wind resources away from those other regions.[23]

Q: Did Deepwater present a similar price suppression analysis of its project?

A: Yes, CRA conducted a price suppression study for BIWF, the CRA Analysis. CRA's approach of (i) using a dispatch simulation model to forecast ISO-NE wholesale market prices, (ii) netting out Block Island loads from BIWF deliveries to the mainland, and (iii) simulating two cases with and without BIWF Deepwater, was similar to LAI's approach. There was one major difference between our approach and theirs. CRA appeared to include BIPCO's lower cost of wholesale energy attributable to the Transmission Cable as a price suppression impact, while we treated that benefit separately. The CRA results were presented in Docket No. 4111 and summarized in Deepwater's Post-Hearing Brief.

Q: What conclusion did CRA reach regarding the energy price suppression benefits?

A: CRA found that BIWF would save ISO-NE ratepayers an average of $20 million annually and a total of $493 million over the 25 year study period. Of those amounts, Block Island ratepayers would save approximately $4 million annually and a total of $101

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[23] Any price suppression effects on Block Island ratepayers due to BIWF, excluding lower wholesale energy costs due to the Transmission Cable, were considered to be too small and were not calculated.

million due to substituting ISO-NE wholesale energy for BIPCO's diesel-generated energy, not due to price suppression. The CRA Analysis did not present results for RI ratepayers at this time.

Q: Did CRA present additional energy price suppression results for RI ratepayers later on?

A: Yes. First, Deepwater's Post-Hearing Brief claimed that BIWF would provide an estimated $59 million of savings to RI ratepayers on an NPV basis in 2013 dollars based on the CRA Analysis. Second, we recently received a draft of the Additional CRA Analysis that presented price suppression impacts for RI ratepayers. It appears that the Additional CRA Analysis was also based on the CRA Analysis. The Additional CRA Analysis estimated that BIWF would provide $6 million of savings annually and a total of $127 million to RI's ratepayers over the 20 year PPA term. Of these amounts, BIPCO ratepayers would save approximately $5 million annually and a total of $95 million. Thus the remaining price suppression benefit to Narragansett Electric ratepayers was approximately $1.6 million annually over the 20-year PPA term and a total of $32 million.

Q: Do you know why CRA's price suppression result for RI ratepayers of $32 million was so much higher than your estimate of $7.4 million?

A: No, I do not.

Q: Will BIWF affect market capacity prices in ISO-NE?

A: Any resource addition in ISO-NE would tend to depress market capacity prices while load growth and supply retirements would tend to increase market capacity prices. BIWF would depress market capacity prices in the short-term, but may not have a lasting impact. This is because wind and other renewable development in New England are being driven by state RPS requirements. Adding 28.8 MW of BIWF capacity to New England's resource mix might well reduce the need for an equivalent amount of capacity from other wind projects given those RPS requirements.

VI. <u>Gas Price Suppression Benefits</u>

Q: Will BIWF affect gas prices in RI?

A: BIWF will permit ISO-NE to avoid dispatching up to 28.8 MW, less BIPCO load, from high cost power plants in the hours that BIWF is operating. Most of those power plants that are "on the margin" in New England consume natural gas. To the extent these marginal units generate less energy, there will be a corresponding decrease in demand for natural gas and thus downward pressure on delivered natural gas prices due to BIWF. This effect will be most pronounced during the winter months when New England gas demand and prices are typically high. In order to meet this high seasonal demand, expensive supplemental gas supplies are necessary because the pipeline network constraints limit the amount of gas that can be transported into the region. These pipeline constraints can cause gas basis, *i.e.* the differential between local gas prices and the Henry Hub national benchmark, to increase. Gas demand reductions attributable to BIWF will help to alleviate the impact of pipeline constraints and drive down winter-time gas basis, reducing gas costs to certain RI customers.

Q: How did you calculate the reduction in gas basis?

A: LAI utilized the GPCM model to calculate gas price suppression benefits. GPCM is an industry-standard mixed integer, linear programming network model that represents all major natural gas supply basins, LNG facilities, pipelines, storage facilities, and demand areas in North America. We used our MarketSym results to forecast the reduced output from gas-fired power plants over the 20-year term of the Amended PPA.[24] GPCM was then run with forecasted gas demand reduced accordingly, and the price forecast was compared to the baseline forecast to identify reductions in gas basis.

In order to select the appropriate RI indices, we reviewed pipeline flow data to RI meters and determined that RI receives 56% of its gas from the Tennessee Gas Pipeline and 44% from the Algonquin Gas Transmission pipeline over that period. We calculated gas price reductions to RI customers as the weighted average of the price reductions for those two pipelines.

Q: Which RI customers would benefit from a reduction in gas basis?

A: Most gas utilities arrange gas supplies to meet core customer demands primarily based on long-term pipeline transportation agreements with fixed prices and supply

[24] We chose to calculate the combined effects of BIWF and Cape Wind to ensure more significant power market results in terms of changes in power plant gas consumption, recognizing that we would allocate the final GPCM results between those two wind projects.

agreements with pricing tied to Henry Hub indices rather than spot markets. Thus National Grid's core gas customers, including residential customers, are largely insulated from changes in gas basis will not significantly benefit from any reduction. The customers that will benefit are power plants and commercial and industrial ("C&I") customers who receive "unbundled" service from a non-utility third party suppliers.[25]

Q: How much will those C&I gas customers save?

A: According to EIA Form 176, National Grid (RI's only gas utility) delivered 9,648,029 million cubic feet ("Mcf") of unbundled gas to C&I customers. We applied a gas growth rate from the DOE Energy Information Agency of approximately 1.1% per year to National Grid's 2008 data to project future unbundled gas quantities. According to our GPCM results, the annual average reduction in gas basis that results from the addition of BIWF and Cape Wind ranges from $0.003/Mcf to $0.007/Mcf over the forecast term. BIWF was allocated approximately 5.8% of that benefit based on the relative sizes of those two projects. In 2013, we forecast that C&I customers in RI will save $1,035 due to BIWF. Over the term of the Amended PPA term, the total gas price suppression basis reduction attributable to BIWF is $46,873.

VII. Price Stability and Reliability Benefits

Q: Did you try to quantify the BIWF price stability benefits for Narragansett Electric ratepayers?

[25] Third-order benefits in the New England power market, due to winter-time gas basis reductions for gas-fired power plants, were considered to be too small and are not addressed.

A: No, we did not conduct a quantitative analysis of the variability of Rhode Island electric prices with and without BIWF. Such an analysis would require the historical measurement and forecast of the market volatility of wholesale energy prices on an average and on a marginal basis. It would also require assessing how much wholesale energy price volatility is mitigated though Narragansett Electric's periodic procurement process. In the end, Narragansett Electric ratepayers would have more stable prices if the fixed price BIWF energy displaced volatile market energy, but I do not expect those benefits to be significant given the BIWF project's small size.

Q: Why would the price stability benefits not be significant?

A: BIWF's expected annual energy production of 100,915.2 MWh is equivalent to about 1.2% of Narragansett Electric's annual energy load, a relatively small amount.[26] The remaining 99% of Narragansett Electric's load would remain exposed to wholesale energy market volatility.[27] As a rough estimate, therefore, the reduction in volatility would be about 1%.[28] While BIWF would reduce energy price volatility slightly, it would also likely increase ratepayer's total cost, except in the event of extremely high market prices, because it is priced higher than market prices are expected to be.

VIII. <u>Future Power Market Benefits</u>

[26] According to the most recent CELT report, RI's net energy load was expected to be 8.08 million MWh in 2010; Narragansett Electric's net energy load would be insignificantly lower since it serves virtually all of RI.

[27] I am not aware of any Narragansett Electric long-term energy supply contracts that would also partially insulate ratepayers from market energy price volatility.

[28] For example, if the standard deviation of annual average price was 5% of the expected value average price, say $100/MWh, the standard deviation without Deepwater would be $5.00/MWh, and with a 1% reduction due to the Amended PPA, it would be $4.95/MWh.

Q: **How much future offshore wind potential is there that could utilize Quonset Business Park?**

A: In order to address this question, I relied on the outlook contained in the EWIT Study, a comprehensive and current estimate of future offshore wind development in the eastern US. The goal of the EWIT Study was to objectively study future wind penetration in the eastern US in order to plan for the expansion of the electrical transmission system. The EWIT Study developed a number of wind penetration scenarios to estimate where and how many wind projects would be developed. I relied on the reference case that was based on "…the current state of wind development plus some expected level of near-term development guided by interconnection queues and state renewable portfolio standards…"

According to the EWIT Study, an estimated 3,000 MW of offshore wind could be developed off the RI and SEMA coasts for the ISO-NE power market, plus another 3,000 MW off Long Island for the NYISO power market, by 2024 under reference case conditions.[29] The total number of wind units depends on the size of the wind turbines. While planned offshore wind turbines are typically 3.6 MW - 5 MW, they are expected to become larger over the coming years. Assuming future offshore wind turbine sizes of 5 MW - 7.5 MW, the EWIT Study reference case would require 800 - 1200 wind turbines. Informal discussions with industry participants indicate that this level of offshore wind

[29] Another 13,242 MW of onshore wind was projected in ISO-NE and NYISO in the EWIT reference case. The reference case scenario had total wind generation meeting about 6% of the total 2024 projected load requirements for the eastern US. In three of the other four scenarios, wind generation would be significantly higher than the reference case.

development would be more than sufficient incentive for a wind turbine manufacturer to locate turbine and blade manufacturing facilities at Quonset Business Park.[30]

IX. Other Power Market Impacts

Q: Please explain any impacts associated with Narragansett Electric's remuneration for entering into the Amended PPA.

A: The long-term contracting statute, R.I. General Laws §39-26.1-4 - Financial Remuneration and Incentives, provides that electric distribution companies shall be entitled to receive incentives "over and above the base rate revenue requirement" in compensation for "accepting the financial burden of the long-term contracts." The annual compensation shall be "equal to two and three quarters percent (2.75%) of the actual annual payments made under the contracts for those projects that are commercially operating." With the Amended PPA 2013 price of $244/MWh and an expected annual energy amount of 100,915 MWh, Narragansett Electric will be entitled to collect roughly $0.7 million in 2013 from ratepayers if it executes the Deepwater PPA. This amount will escalate at 3.5% with the Amended PPA price over the 20-year term to about $1.3 million in 2032.

Q: Please explain any impacts associated with improved reliability of the BIPCO system due to the Transmission Cable.

A: We agree with other parties' claims that the proposed Transmission Cable between Block Island and the RI mainland will improve reliability and will lower rates for Block

[30] The economic development benefits associated with these business activities are addressed in the Advisory Opinion I submitted in the docket.

Island residents. We have not quantified these benefits, and we note that these benefits are due to the Transmission Cable, not to BIWF.

In its October 15, 2009 filing of a preliminary version of the Amended PPA, National Grid discussed the benefits of the proposed Transmission Cable in its transmittal letter: Specifically, the construction of the cable between Block Island and the mainland would bring electric reliability benefits to the residents of the island. It also would give Block Island access to the electric markets in New England.[31]

In his rebuttal testimony of February 16, 2010, William M. Moore of Deepwater also discussed the benefits of the Transmission Cable to Block Island: The project will improve the electric reliability for Block Island by connecting the Island to the mainland grid, an objective spelled out in the legislation passed by the General Assembly mandating National Grid's RFP process. In addition, we believe the project provides an opportunity for lower electricity prices on Block Island once it has access to the mainland grid. Residents will be less exposed to price volatility associated with the price of oil once they are no longer dependent on diesel generation.[32]

Q: Did the PUC recognize these reliability and price benefits in its Order in Docket No. 4111?

A: Yes, the PUC noted in its Findings:

[31] Page 8 of 10.
[32] Page 5 of 14 at 13

> …there is likelihood that the Project will, to a very limited extent, enhance the electric reliability of the Town of New Shoreham. The Commission agrees with the witness of the Town that "the PPA as currently structured would not have any direct effect on the reliability of the Town of New Shoreham" and that only "if the project is connected to New Shoreham and power is purchased from the mainland," would there "be some improvement" in reliability given that generation related outages are relatively small.[33]

Q: Will BIWF affect electricity rates for BIPCO ratepayers?

A: BIPCO rates are expected to come down due to the Transmission Cable that will be constructed to support BIWF. The above quotes from National Grid, Deepwater, and the PUC's Order in Docket No. 4111 make reference to rate savings and the reduction in price volatility due to the Transmission Cable. BIPCO ratepayers would also benefit from BIWF's price suppression across ISO-NE, but that impact would be insignificant relative to the considerable savings due to the Transmission Cable.

Q: How did you estimate the effect of BIWF and the associated Transmission Cable on BIPCO rates?

A: Based on information obtained from the testimony of Richard LaCapra on behalf of the Town of New Shoreham in this matter and on past filings by BIPCO, we were able to estimate a variable generation cost to supply forecasted Block Island energy loads from diesel generators such as those operated by BIPCO. We estimated the annual cost from 2013 through 2032 based on BIPCO's energy forecast, a heat rate of 10.4 MMBtu/MWh,

[33] Pages 65-66

and a distillate oil price. The heat rate was estimated by witness LaCapra, and the energy forecast was taken from the BIPCO Planning Study. I used the same forecast of New York Harbor No. 2 distillate oil as was used in the MarketSym simulations, and made adjustments to account for the relatively high delivery costs to Block Island and for other fuel-related costs incurred by BIPCO, such as inventory costs and urea used for emission control. I also relied on a December 2006 Long-Range Resource Planning Study commissioned by BIPCO to estimate the difference between the New York Harbor distillate oil price and average total fuel-related costs of about $0.28/gallon in 2006 dollars. Lastly we estimated the cost to procure BIPCO's energy requirements from the ISO-NE market by multiplying BIPCO's load by the average RI LMP from our MarketSym forecast assuming BIWF was in service. BIPCO's annual energy costs were projected to decline by $2.0 million in 2013, and by as much as $5.1 million by 2032.

Q: Have you factored in any benefits or costs of the Transmission Cable to Narragansett Electric ratepayers?

A: If the Transmission Cable is constructed and Narragansett Electric exercises its right to purchase, own, and operate it, its cost will be added to Narragansett Electric's rate base and recovered from ratepayers over its useful life. I note that that the Transmission Cable, estimated at $42-$44 million, is not part of the BIWF project but is necessary for BIWF's development, since Block Island cannot absorb BIWF's energy output. I assumed a mid-point cost of $43 million, a 30 year recovery period consistent with IRS regulations, and typical rate base treatment to estimate that

Narragansett Electric's ratepayers will pay approximately $6.9 million in 2013, the first year of operation, and successively lower amounts in succeeding years.

X. Conclusions

Q: Based on your review of the foregoing materials, your education, and your experience, do you believe that the Amended PPA is commercially reasonable based on your experience with other projects of similar size, technology, and location?

A: Yes, compared to the Cape Wind and Bluewater projects, and in light of BIWF's small size, the Amended PPA prices are commercially reasonable as required under part (c)(i) of the Statute. Narragansett Electric ratepayers are not unfairly exposed to project risks, and would see a decrease in pricing if the BIWF capital cost is less than $205.4 million or if BIWF achieves greater than a 40% capacity factor as required under part (c)(ii) of the Statute.

Q: Does this conclude your testimony?

A: At this time, yes. Should additional information become available, I will update my testimony as appropriate.

A

SETH G. PARKER

SUMMARY

An economic and financial manager with an international background in competitive markets and power project development, evaluation, financing, and divestiture/privatization/acquisition. Principal experience includes modeling and analyses of conventional and renewable power projects, inter-market transactions, contracts, market design, risk management, and valuation.

PROFESSIONAL EXPERIENCE

1998 -	**Levitan & Associates, Inc.** Principal & Vice President Managing Consultant
1988-1998	**Stone & Webster Management Consultants (US and UK)** Vice President Assistant Vice President Executive Consultant Senior Consultant
1984-1988	**J. Makowski Associates, Inc.** Financial Manager - Ocean State Power
1981-1983	**ThermoElectron Energy Systems** Senior Financial Analyst
1978-1981	**Pacific Gas and Electric Co.** Project Financing Analyst

CONSULTING ASSIGNMENTS

Project Development

Assisted NRG with economic analysis, financing structure, debt and equity sources, finance rates, PPA terms, and credit issues for large proposed offshore wind project.

Advised Maine Department of Transportation on proposed LNG terminal project, including project feasibility, site, safety, comparative economics, and pipeline routing.

Provided commercial advice on 15 MW cogeneration upgrade for New York University, including economic feasibility, contract structure, and utility backup arrangements; advised on renewable wind project development / contractual support.

Advised The Stanley Works on business strategy / financing of 8MW hydroelectric plant.

Completed pre-financing development work (permits, construction, and financing) for Ocean State Power Phase I, a 225 MW combined cycle plant in Rhode Island.

Market / Policy Analysis

Advising three NYC generators on the NYISO installed capacity demand curve reset process for 2011/12 – 2013/14 focusing on peaker proxy technology / cost / performance, transmission deliverability, site requirements / availability, and net energy revenues.

Provided written testimony on resource options and economics on behalf of Shell Energy North America regarding Dominion Virginia Power's (DVP's) 2009 Integrated Resource Plan; testified before the Virginia State Corporation Commission.

Prepared expert report and testimony on the DVP 2007 Solicitation for 2011 Unit Capacity for Shell Energy North America that addressed capacity needs, bidder qualifications, best competitive procurement practices, and bid evaluation methodology.

Provided advice on financial, operational, decommissioning funding, and ratepayer risk issues to the Vermont Department of Public Service regarding Entergy's application to restructure the ownership of its merchant nuclear plants, including Vermont Yankee.

Prepared major deregulation study for the Maryland Public Service Commission that evaluated new generation, transmission, and demand-side options; evaluated divestiture impact on profitability of generation fleet and financial contribution to parent company; updated study for rate-base utility or power authority generation ownership.

Advised New York Power Authority (NYPA) on inter-market transactions, including power economics, interconnection requirements grid upgrades, reliability impacts, permit issues, and regulatory considerations; represented NYPA at PJM committee meetings.

Advised generator group on PJM proposed Reliability Pricing Model (RPM) capacity valuation mechanism, including gas turbine capital & operating costs, expected net revenues, financing charges, etc.; represented group before FERC.

Assessed market prices and congestion costs relative to competing generation and transmission project bids for Long Island Power Authority (LIPA); responsible for ICAP forecasts across northeast markets and commercial analysis of hvdc cable proposals.

Evaluated market potential of PJM cable exports into NYC for potential purchaser of Linden simple / combined cycle project, including cable expansion issues.

Revised 2005/06 - 2007/08 capacity market demand curve parameters for NYISO based on levelized costs of gas turbine peaker capacity, including net energy revenues from multi-regional simulation model with stochastic treatment of hourly loads; evaluated demand curve slope and zero-crossing point; achieved consensus with stakeholder group.

Advised counsel for Mirant Equity Committee regarding NYISO, ISO-NE, and PJM capacity markets and the use of demand curve mechanisms to forecast ICAP prices.

Established feasibility of inter-pool wheeling into load pocket to reduce congestion costs; quantified maximum benefit and related reliability and portfolio effects for LIPA.

Evaluated alternatives to the Indian Point Nuclear Power Station for Westchester County and its Public Utility Service Agency, including power and local economic implications of shut-down, repowering, replacement with transmission / conventional / renewable resources, continued operation, and license extension.

Estimated market value of incremental energy and capacity from the Bonanza coal plant owned by the Deseret Generation and Transmission Cooperative in Utah.

Prepared analysis of US power markets and merchant plant business structures for overseas investor; recommended target areas and distressed asset screening model.

Advised stakeholder group on technical, environmental, operational, and regulatory issues of energy infrastructure projects across LI Sound and in southwest Connecticut for the Institute for Sustainable Energy; prepared guidelines for Connecticut Siting Council.

Prepared long-term market price forecasts by sub-regions in New England, New York, and PJM to capture congestion effects for PECO Energy's acquisition of Sithe assets.

Market analysis of conversion of Salem Harbor to gas for ISO-NE White Paper.

Assessed the market potential for independent power producers throughout the US; identified competitive capability of utility / non-utility developers and engineering firms.

New England cogeneration marketing and permitting assistance for Unitil gas utility.

Assessed state-by-state future demands for cogeneration systems based upon industrial activities, fuel costs, utility purchase and sales rates, and regulatory climates.

Project and Due Diligence Evaluations

Conducted economic evaluation of the Deepwater Wind project for the RI Economic Development Corporation, including PPA pricing, bonus / penalty provisions, and risk allocation, price suppression benefits, economic development impacts, and other issues.

Forecasted expected operating regime and changes in market power prices and regional air emissions for proposed Bayonne 512 MW GT peaker plant with HVAC u/w cable lead into NYC; report was part of Bayonne's petition for an Art. VII Certificate.

Prepared revenue and operating expense projections of PJM coal and combined cycle plants being sold by AES, including capacity revenues under alternative scenarios.

Conducted financial analysis of rival cogeneration projects at New York University, including operating cost savings, tax-exempt debt terms, and credit rating impacts; prepared project valuation and recommendation for Financial Committee.

Advised the New York State Housing Finance Agency as lender to a New York cogeneration project, including project review, contract negotiation, and financing terms.

Managed due diligence review, construction monitoring, and acceptance testing of the following cogeneration, combined cycle, fluidized bed, and industrial projects for commercial lenders, investment banks, and government, bilateral & multilateral agencies:

Brooklyn Navy Yard, a 220 MW cogeneration plant, New York
Derwent Cogeneration Project, a 210 MW cogeneration plant, England
East Java Power, a 500 MW combined cycle plant, Indonesia
EES Coke Battery, a 900,000 ton per year coke facility, Michigan
Guna Power Project, a 347 MW naphtha / gas combined cycle plant, India
Hadley Falls, a 43 MW hydroelectric plant, Massachusetts
Hub Power, a 1200 MW, $1.8 billion, World Bank-supported plant, Pakistan
Indiana Harbor Coke Battery, a 1.3 million ton per year facility, Indiana
Kot Addu, a 1600 MW oil / gas combined cycle plant, Pakistan
Midland Cogen Venture, a 1,370 MW $2.3 billion cogeneration plant, Michigan
Niagara Falls Resource Recovery, an 800,000 ton per year plant, New York
Panther Creek, an 80 MW fluidized bed power plant, Pennsylvania
Warrior Run, a 180 MW fluidized bed power plant, Maryland
York Research, financing of four plants, Texas, New York, and Trinidad

Established the economic value and financing plan for existing 43 MW hydroelectric power plant in support of acquisition and financing by a Massachusetts municipal utility.

Evaluated operating characteristics and economics of cogeneration expansion plans for the Massachusetts Institute of Technology, and recommended phased-in scheduling.

Managed due diligence reviews of US coal and gas-fired power plants in support of Manweb (UK) equity investments; helped negotiate transaction modifications as required.

Recommended cogeneration plant design and financing plan for Turkish Industrial Zone.

Evaluated the feasibility of converting the Bataan nuclear power station in The Philippines to a gas-fired combined cycle plant for Shell Oil Company.

Auctions & Procurement

Retained by the Illinois Power Authority as Procurement Administrator for the 2008, 2009, and 2010 competitive procurements of energy (financial swaps), capacity, and RECs (both physical delivery) for the Ameren Illinois Utilities; responsible for benchmark pricing, finance, credit, security, performance, and related contract issues.

Advised the Connecticut Department of Pubic Utility Control (DPUC) on economic costs / benefits and credit / collateral terms and conditions for long-term PPAs.

Conducted power and fuel price forecasts and financial analysis for a confidential equity investor in the auction of the 2,480 MW Ravenswood Facility in NYC.

Assisted Allegheny Electric Cooperative to identify power purchase and equity investment opportunities in PJM; evaluated economics and risk parameters of PPA, tolling, market purchases, and ownership options; reviewed ISDA and EEI agreements.

Part of Procurement Monitor team on behalf of DPUC to oversee United Illuminating and Connecticut Light & Power 2006-2008 supply procurements; responsible for credit issues and evaluating financial barrier options to protect against unanticipated price movements.

Advised LIPA on commercial and financial issues associated with multiple solicitations for on-island and off-island capacity and energy; refined contract terms on risk and credit.

Evaluated third party contracts and on-site generation alternatives for Visy Paper in NYC.

Evaluated design-build proposals for a CHP plant at Rochester Institute of Technology, including engineering / construction qualifications, O&M strategy, financial structure, utility interconnection issues, and lifecycle cost / ROI results.

Evaluated strategic electric and gas procurement strategy options for the Buffalo Fiscal Stability Authority; made implementation recommendations to BFSA and City officials.

Project Financing

Advised multiple clients on off-balance sheet financing structures, including tax-exempt operating leases and third-party ownership of CHP and cogeneration facilities.

Structured non-recourse construction and permanent debt financing for Ocean State Power, the first IPP in the US; provided liaison between investors and financial advisor.

Developed off-balance sheet financing plans for ThermoElectron cogeneration projects.

Applied to the US Synthetic Fuels Corporation for price supports and loan guarantees.

Managed PG&E's $60 million pollution control Industrial Development Bond financing.

Recommended financing structures for PG&E subsidiaries & joint venture projects - coal mine, generating plants, gas exploration / production, and residential conservation.

Privatization / Divestiture

Prepared comprehensive descriptions of Southern California Edison thermal generation (12 plants, 10,000 MW) and Commonwealth Edison coal stations (6 plants, 6,000 MW).

Technical and economic advisor to Maine Public Service, Fitchburg Gas and Electric, and Unitil Corp for hydro, thermal, and power purchase agreement divestiture.

Contractual advice to Empressa Electrica de Guatemala, S.A. for power plant divestiture.

Technical and commercial advice (including forward pricing) to a confidential bidder for the New England Electric System divestiture (2800 MW thermal & 1200 MW hydro).

Provided technical / environmental advice to the Government of Pakistan for the 1600 MW Kot Addu plant privatization; developed capacity / energy contract pricing structure.

Gas and Fuel Projects

Developed integrated gas supply, storage, and forward haul transportation project for utilities in the metropolitan NY / NJ area to expand wintertime deliveries.

Evaluated equity return / risk profiles and prepared cash flow forecasts of interstate gas pipelines and storage projects for independent power plants throughout the Northeast.

Prepared testimony on risk, financing, and capital cost for the Endicott Pipeline Co.

Evaluated throughput and rate impacts on financial returns of competing gas pipeline proposals to support the development of Iroquois Gas Pipeline.

Technical Advisor to the Government of Pakistan for the privatization of the Sui Northern Gas Pipeline Company (approx. 200 bcf annual sales with 24,000 km of pipe).

Determined the distribution links between major domestic gas production basins and demand markets to help allocate exploration and development funds of Sohio Petroleum.

World Bank commercial advisor on the Asia Pacific Ltd. oil storage & pipeline, Pakistan.

Energy / Power Plant Optimization

Evaluated contract terms and conditions governing energy options for Nassau County Hub commercial district including cogeneration, spot market purchases, etc.

Assisted NYC industrial firm with cogeneration development; drafting steam purchase, power purchase option, site lease, and development contracts.

Developed cost-effective energy strategy, including asset reconfiguration, permit modification, and contract restructuring, for Massachusetts Water Resources Authority.

Implemented direct gas service via Algonquin Gas Transmission and evaluated cogeneration options for Phelps Dodge copper plant in Connecticut.

Developed inside-the-fence cogeneration and fuel strategy for Arizona paper mill.

Identified optimal cogeneration plant configuration and fuel supply for City of Holyoke.

Financial Analysis

Evaluated the intended financing plan and resulting credit strength of the proposed owner of Entergy's merchant nuclear plants, including Vermont Yankee, for the Vermont Department of Public Service; prepared information requests and rebuttal testimony.

Prepared investment analysis for Massachusetts Institute of Technology cogen project.

Advised lessor on utility buyout offer of wood-fired plant including future residual value.

Evaluated pro forma assumptions and risk / return analysis of Malaysian power projects.

Reviewed financial feasibility of proposed clean coal demonstration projects for DOE.

Managed steam purchase contract evaluation and internal cogeneration feasibility study for petrochemical producer in The Netherlands.

Proposed project financing options for Elektrenai plant modernization in Lithuania.

Power and fuel negotiation support for Cumbria Power, Ltd., the first IPP in England.

Determined economic assumptions, prepared financial pro formas, and analyzed equity return / risk for numerous proposed power projects for ThermoElectron and other clients.

Prepared long-term financial and rate forecasts of PG&E for state commission filing.

Generation Planning / Resource Economics

Evaluated bidders for Indianapolis Power & Light's 1992 competitive power solicitation.

Audited Florida Power & Light's resource plan, including fuel, load, and generation.

Techno-economic cogeneration feasibility study for Algonquin Gas Transmission.

Valued existing plant based on alternative peaking capacity for Delmarva Power & Light.

Forecasted avoided energy / capacity costs for third-party generators throughout the US.

Supervised life cycle power plant economic analysis for a Fuel Use Act application.

Compared historic and projected electric use by major manufacturing industry for EPRI.

Litigation Support and Expert Testimony

Testified before the Virginia State Corporation Commission on behalf of Shell Energy NA regarding DVP's 2009 Integrated Resource Plan (Case No. PUE-2009-00096).

Submitted expert report and testified before the Virginia State Corporation Commission on behalf of Shell Energy NA regarding Dominion Virginia Power's 2007 Solicitation for 2011 Unit Capacity on RFP structure and bid evaluation issues (Case PUE-2008-00014).

Prepared information requests, submitted expert testimony, and testified before the VT Public Service Board on behalf of the VT Department of Public Service regarding the proposed restructuring of Entergy's merchant nuclear generation assets (Docket No. 7404).

Submitted expert report on behalf of generator group and participated in Technical Conference before FERC regarding proposed Reliability Pricing Model mechanism that sets market capacity prices in PJM (FERC Dockets Nos. EL05-148 and ER05-1410).

Prepared expert report on New York and New England capacity market mechanisms and plant valuation impacts for the Mirant Corp. equity committee in US Bankruptcy Court (Case No. 03-46590).

Submitted FERC affidavit regarding gas turbine engineering and economic parameters to reset locational ICAP demand curve; represented NYISO at FERC Technical Conference (FERC Docket No. ER05-428).

Expert witness regarding geothermal EPC contract performance and consequential damages based on market power rates before the American Arbitration Association.

Expert witness testimony for the Bridgeport RESCO waste-to-energy facility at the Connecticut DPUC re avoided cost pricing in the deregulated energy market (Docket 99-03-35REO3).

Provided tax valuation support for gas and electric assets for Yankee Gas Company and The Connecticut Light and Power Company in Connecticut Superior Court (Docket No. CV 95-0072561S).

Expert witness report supporting PECO Energy (Exelon) decision to cancel purchase of equity interest in the River Bend nuclear plant in US District Court for the Middle District of Louisiana (Adversary Proceeding No. 98-477-B-M3).

Expert witness report and testified regarding contractual benefits of major coal plant turbine upgrade based on future market power values in US District Court for the Middle District of Florida, Orlando Division, (Case No. 6:99-CV-76-ORL-22A); accepted as an expert in power project cost analysis and power price forecasting.

Expert witness regarding economic feasibility, financing, and profitability of Mid-Atlantic Energy's proposed cogeneration plant in West Virginia Circuit Court (Civil Action No. 95-C-214M).

Presented testimony on relationship of independent power development fees to project capital costs before the American Arbitration Association.

PESENTATIONS & PUBLICATIONS

Presentation to the NYISO Installed Capacity Working Group on peaker proxy technology / cost / performance, deliverability, site requirements, availability, etc.

Moderated panel on ISO-NE's Forward Capacity Market mechanism at the Northeast Energy & Commerce Association's 2009 Power Markets Conference.

Gas and electric market interdependency panel moderator at Platt's 4th Annual Northeast Power Forum, 2009.

Sponsor for the Northeast Energy and Commerce and Association conference "Northeast Capacity Markets"; moderator for panel on generation entry / attrition outlook, 2007.

Conference organizer and moderator for "Capacity Markets – Impacts on Assets and Power Pricing" regarding G&T investment decisions in ISO-NE, NYISO, and PJM, 2007.

Conducted half-day workshop, "Forecasting Capacity Prices in the Northeast" and panel moderator on generation financing at Infocast Northeast Power Supply Forum, 2006.

"Financing Projects with ICAP Revenues", Infocast Power Financing conference, 2004.

Panel moderator on New England and Canadian LNG Projects, Infocast Atlantic Coast LNG Conference, 2004.

Speaker, "Power Sales Contract Restructuring Issues", at Infocast Asset Optimization and Portfolio Management Conference, 2003.

Panelist on "Southwest Connecticut Congestion", 10th Annual New England Energy Conference, 2003.

"Fuel and Power Contracting", Int'l District Energy Association Conference, 2002.

"Contract Restructuring", Infocast QF & IPP conference, 2001.

"Successful Valuation and Value-Creation of Transmission Assets", Infocast Electric Asset & Portfolio Valuation conferences, 2001.

"Evaluation of Repowering the Cabot Street Steam Station" using gas turbine technology, International District Energy Association conference, 2001.

"Plant Repowering" at the Infocast Plant Acquisition conference, 2000.

"Equipment Performance Impacts", Infocast Merchant Peaking Plant conference, 2000.

"The Pros and Cons of Repowering" in Competitive Utility, 2000.

"The First Wave" (initial divestiture results) 1998 and "Gas versus Coal" (techno-economic study) 1995, Independent Energy magazine.

"Evaluating Technical and Construction Risk" and "The Due Diligence Process", classes and case studies on for the Infocast Project Finance Institute, 1996-1998.

Non-utility generation and project financing classes at Stone & Webster Utility Management Development Program, 1989-96; General Electric, 1991-94; IBM 1994.

"Self Generation under Competitive Bidding", 1989 Cogen & IPP Congress.

EDUCATION

Wharton Graduate School (Univ. of Penn.), MBA in Finance / Operation Research, 1978.

Brown University, Sc.B. in Applied Mathematics / Economics, 1976.

International Gas Turbine Institute course: Basic Gas Turbine Technology, 1996.

Kennedy School (Harvard University) courses: International Geopolitics of Oil, 1982, and International Political Economy, 1993.

MISCELLANEOUS

Board of Directors, Northeast Energy and Commerce Association, 2007-.

Adjunct faculty lecturer in finance, Golden Gate University, 1979-1980.

Optimum yield resource management, National Oceanic and Atmospheric Admin, 1977.

Mayor's Waterfront Development Committee and Interface: Providence, 1974-1976.