PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Astoria Generating Company, L.P. and TC Ravenswood, LLC	)	
Complainants	)	
v.	)	**Docket No. EL11-50-000**
New York Independent System Operator, Inc.	)	
Respondent	)	

CONFIDENTIAL SUPPLEMENTAL ANSWER OF THE NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

In accordance with Paragraph 25 and Ordering Paragraph "A" of the Commission's August 31, 2011 *Order Directing Submission of Supplemental Information and Issuing Protective Order*[1] ("August 31 Order"), the New York Independent System Operator, Inc. ("NYISO") respectfully submits this Confidential Supplemental Answer.[2] The body of this Confidential Supplemental Answer does not contain "Protected Materials." However, consistent with Paragraph 5 of the *Protective Order* that was issued as part of the August 31 Order, the

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[1] *Astoria Generating Co., L.P. and TC Ravenswood, LLC v. New York Independent System Operator, Inc.*, 136 FERC ¶ 61,155 (2011).

[2] The NYISO respectfully requests leave to submit this filing out-of-time. It was not possible to ensure that all of the confidential information included in the supporting affidavits was properly redacted from the public version of this filing by the Commission's 5 p.m. filing deadline. The NYISO was unable to make the filing overnight because of an outage affecting the Commission's website. The filing was electronically submitted and served as early as possible on the next business day. The NYISO concurrently sent copies of the unredacted version to all "Reviewing Representatives" that had confirmed their eligibility to receive it under the Protective Order.

NYISO has marked the pages of the supporting affidavits appended hereto, that contain "Highly Sensitive Protected Materials."[3] The NYISO has redacted the confidential information found on those pages from the public version of this filing. The NYISO will make a complete unredacted version of this filing available to "Reviewing Representatives" that satisfy the criteria established by Paragraph 9 of the Protective Order.[4] To the extent necessary, the NYISO is also requesting privileged treatment for all Highly Sensitive Protective Materials included in this Confidential Supplemental Answer and its Supporting Affidavits under Section 388.112 of the Commission's regulations.[5]

The six supporting affidavits appended to this Confidential Supplemental Answer explain in detail the inputs, and the analyses and methodology, that the NYISO used to conduct its buyer-side mitigation exemption examinations and make determinations under the Pre-Amendment Rules[6] for the Astoria Energy II LLC project ("AEII") and the Bayonne Energy Center, LLC project ("BEC"). The affidavits are:

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[3] The NYISO has not identified any confidential information relevant to this proceeding which constitutes "Protected Materials" and which does not also qualify as "Highly Sensitive Protected Materials," as defined in Paragraph 5 of the *Protective Order*. The NYISO has not included any information that would qualify as Critical Energy Infrastructure Information in this filing.

[4] The NYISO described its interpretation of Paragraph 9(b)(5) of the *Protective Order* in the *Notice* that it submitted in this docket on September 6, 2011.

[5] By its very nature, information that qualifies as "Highly Sensitive Protected Materials" under the *Protective Order* constitutes confidential commercial and financial information that ought to be exempt from disclosure under 18 C.F.R. 388.107 and 112 (2011).

[6] The "Pre-Amendment Rules" were the buyer-side capacity market power mitigation rules that existed in Attachment H to the NYISO Services Tariff prior to the effective date of the In-City Buyer-Side Capacity Mitigation Measures.

- Appendix I -- Confidential Affidavit of Joshua A. Boles Regarding Astoria Energy II.
- Appendix II -- Confidential Affidavit of Joshua A. Boles Regarding Bayonne Energy Center.
- Appendix III -- Affidavit of Dr. David B. Patton.
- Appendix IV -- Affidavit of Christopher D. Ungate Regarding Astoria Energy II.
- Appendix V -- Affidavit of Christopher D. Ungate Regarding Bayonne Energy Center.
- Appendix VI -- Affidavit of Eugene T. Meehan.

Together, the supporting affidavits demonstrate that the NYISO's decisions to exempt AEII and BEC from Offer Floor[7] mitigation were reasonable and conformed to the Pre-Amendment Rules, as discussed in the NYISO's August 3 Answer[8] and in this Confidential Supplemental Answer. They further demonstrate that the NYISO's determinations reflected the input and recommendations of the independent Market Monitoring Unit for the NYISO ("MMU"), Potomac Economics, Ltd. The affidavits therefore refute the Complainants'[9] claims that the NYISO's exemption determinations were "patently absurd,"[10] explicable only by

[7] Capitalized terms that are not otherwise defined herein shall have the meanings specified in the Pre-Amendment Rules, and if not defined therein, the terms shall have the meaning specified in the Answer.

[8] *See Answer and Request for Expedited Action of the New York Independent System Operator, Inc.* at 29-30, Docket No. EL11-50-000 (August 3, 2011) ("August 3 Answer"). *See also Motion to Intervene Out-of-Time and Request for Leave to Answer and Answer of the NYISO's Market Monitoring Unit* (August 9, 2011) at 3 ("Based on a review of NYISO's assumptions and accepting NERA's estimates of net revenues, the MMU finds no issues with the analysis that would cause the NYISO's determination that Astoria Energy II and the Bayonne Energy Center are exempt from buyer-side mitigation to be incorrect.")

[9] Complainants are Astoria Generating Company, L.P. and TC Ravenswood, LLC.

[10] *See Complaint Requesting Fast Track Proceeding, Emergency, Interim Relief and Shortened Comment Period*, Docket No. EL11-50-000 (filed July 11, 2011) ("Complaint") at 25, n. 25.

"contorted readings," or "outright violations" of the Services Tariff,[11] or tainted by a supposed "systematic bias" in favor of exempting new entrants.[12] The Commission should therefore act expeditiously to dismiss the Complaint.

I. SUPPLEMENTAL ANSWER

A. The Boles Affidavits

Appendices I and II to this Supplemental Answer are affidavits prepared by Mr. Joshua A. Boles, the Supervisor of Monitoring, Analysis, and Reporting for the Market Mitigation and Analysis Department ("MMA") of the NYISO. The two affidavits, together the "Boles Affidavits," provide detailed descriptions of the mitigation exemption analyses that the NYISO performed for AEII and BEC respectively. They also identify the differences between the NYISO's actual assumptions and analyses and those used by Mr. Mark Younger in his affidavits on behalf of the Complainants (together the "Younger Affidavits.")[13]

The Boles Affidavits first describe the two tests under the Pre-Amendment Rules for determining whether a proposed new project should be exempt from Offer Floor Mitigation, (*i.e.,*

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[11] *Id.* at 8.

[12] *See Complainants' Motion for Leave to Answer and Answer*, Docket No. EL11-50-000 (filed August 19, 2011) ("Complainants' Answer") at 15-16.

[13] *See* Complaint at Attachment A, Affidavit of Mark D. Younger ("Younger Affidavit"); Complainants' Answer at Attachment A Supplemental Affidavit of Mark D. Younger ("Younger Supplemental Affidavit" and together with the Younger Affidavit the "Younger Affidavits"). For the reasons specified in the August 11, 2011 *Answer of the New York Independent System Operator, Inc. to Comments and Protests,* at 14-15, the Boles Affidavits do not address the Affidavit of Scott W. Niemann ("Niemann Affidavit") that was attached to the August 3, 2011 Motion to Intervene and Comments of Brookfield Energy Marketing LP in Support of Complaint in this proceeding.

the "Part A Test" and the "Part B Test.")[14] Mr. Boles then explains that both AEII and BEC "failed" the Part A Test but passed the Part B Test and were therefore properly determined to be exempt under the Pre-Amendment Rules.[15] Because both projects failed the Part A Test, the arguments set forth in Section V.A.2(a) of the Complaint and the related portions of the Younger Affidavits regarding that test should be ignored by the Commission.[16]

The Part B Test compares the average annual price forecast for the first three years after entry, to the project's Unit Net CONE. The Boles Affidavits delineate and explain the inputs, methodology, and analyses that the NYISO used to calculate Unit Net CONE for AEII and BEC.[17] Mr. Boles describes how the NYISO calculated investment costs, the real levelized carrying charge, and fixed operations and maintenance costs, and their use in establishing the annualized cost of new entry for each project.[18] He also explains the NYISO's use of the NERA Economic Consulting ("NERA") econometric model, with certain adjustments, to estimate net energy revenues, and the NYISO's calculation of ancillary services revenues based on revenue

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[14] *See, e.g.,* Appendix I at Section III.

[15] *Id.* at Section IV.

[16] The August 3 Answer previously noted that Sections V.A.1 and V.A.3 of the Complaint should likewise be disregarded because they addressed speculative determinations that the NYISO did not actually make. *See Answer and Request for Expedited Action of the New York Independent System Operator, Inc.* (filed August 3, 2011) ("August 3 Answer") at 16-18. The affidavits appended to this Confidential Supplemental Answer respond in detail to the Complaint's only remaining substantive allegations, which are found in Section V.A.2(b) and the related portions of the Younger Affidavit.

[17] *See* Appendix I at Sections VI-VII ; Appendix II at Sections VI-VII.

[18] *See, e.g.,* Appendix I at Section VI.

information for similar in-service plants.[19] Mr. Boles discusses that the net energy and ancillary services revenues were subtracted from the annual CONE values to compute annual net CONEs for each of the first three years after entry.[20] Unit Net CONE for each of AEII and BEC were established by averaging the three values in ICAP terms and then converting them into UCAP values.[21] Mr. Boles also explains how the NYISO established the average annual price forecast for the first three years after entry.[22]

In Appendix I, Mr. Boles explains that the NYISO computed a Unit Net CONE for AEII in the confidential $/kW-year amount set forth therein, which was lower than the three-year average annual price forecast for Capability Years 2011/2012 through 2013/2014 of $78.06/kW year. AEII therefore passed the Part B Test. Mr. Younger had argued that AEII should fail the Part B Test because the Unit Net CONE values that he computed for his two scenarios were higher than his proposed price forecasts for those scenarios.[23]

Similarly, in Appendix II, Mr. Boles explains that the NYISO computed a Unit Net CONE for BEC in the confidential $/kW-year amount set forth therein, which was lower than its three-year average annual price forecast for Capability Years 2012/2013 through 2014/2015 of $35.67/kW-year. BEC therefore also passed the Part B test. Mr. Younger had contended that

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[19] *See, e.g.,* Appendix I at Section VI.e-f.

[20] *See, e.g.,* Appendix I at Section VI.g.

[21] *Id.*

[22] *See, e.g.,* Appendix I at Section VII.

[23] *See* Appendix I at PP 49-50.

BEC should fail the Part B Test because the Unit Net CONE values that he computed for his two scenarios were higher than his proposed price forecasts for those scenarios.[24]

Mr. Boles presents a table summarizing the NYISO's computation of the exemption determination,[25] and an exhibit detailing the computation.[26] At the relevant points in his discussion, he also compares what the NYISO actually did to what Mr. Younger claims the NYISO should have done. These comparisons demonstrate that Complainants were wrong to suggest that the NYISO had a "systematic bias" towards selecting "assumptions that were most likely to result in an exemption determination."[27] In reality, a number of the NYISO's assumptions were comparable to or more "conservative" than Mr. Younger's assumptions – *i.e.,* less likely to result in an exemption.[28] The Boles Affidavits also identify a number of differences between the analyses actually conducted by the NYISO, and Mr. Younger's versions, which resulted in their reaching different outcomes. When it is warranted, Mr. Boles explains why the NYISO's approach was reasonable and consistent with the Pre-Amendment Rules and cites to specific supporting information in the Ungate, Meehan and MMU affidavits to support his rationale.[29] Mr. Boles describes that the NYISO conferred with the MMU throughout its

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[24] *See* Appendix II at PP 48-49.

[25] *See* Appendix I at Table 1; Appendix II at Table 1.

[26] *See* Appendix I, Exhibit JAB-AEII-1; Appendix II, Exhibit JAB-BEC-1.

[27] Complainants' Answer at 15-16.

[28] *See, e.g.,* Appendix I at PP 27, 32, 44.

[29] *See, e.g.,* Appendix I at PP 29-31, 37.

examination process and delineates recommendations that the MMU discusses in the Patton Affidavit.

B. The Patton Affidavit

Appendix III is an affidavit prepared by Dr. David B. Patton, the President of the MMU, which discusses several recommendations that the MMU made to the NYISO during the course of the exemption analyses for AEII and BEC. These include the MMU's recommendations as to how the NYISO should: (1) consider the timing of the investment decision,[30] (2) treat costs incurred prior to the decision to invest (known as "sunk costs")[31], and (3) consider the financing terms obtained by a specific project.[32] Dr. Patton identifies a number of instances where Mr. Younger has taken positions that are contrary to the MMU's recommendations and explains why the approach recommended by the MMU, and adopted by the NYISO, was reasonable.

C. The Ungate Affidavits

Appendices IV and V are affidavits prepared by Mr. Christopher D. Ungate, a Senior Principal Management Consultant with Sargent & Lundy LLC ("S&L"). Mr. Ungate's affidavits provide information on the investment cost and performance inputs that were used to determine the CONE values for AEII and BEC respectively. As Mr. Ungate explains, he reviewed the detailed information that AEII and BEC provided to S&L, asked questions when it appeared to

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[30] *See* Appendix III at Section IV.

[31] *See* Appendix III at Section V.

[32] *See* Appendix III at Section VI.

him that data might fall outside of reasonable ranges, and determined the values he would recommend to the NYISO as appropriate to use to determine the cost of new entry.[33] The Ungate Affidavits describe in detail S&L's analyses and recommendations regarding technology performance, capital investment costs, operating costs, and carrying charges, for AEII and BEC respectively.

D. The Meehan Affidavit

Appendix VI is an affidavit prepared by Eugene T. Meehan of NERA. It describes the NERA econometric model and NERA's role in estimating energy revenue offsets for use in the Unit Net CONE calculations for AEII and BEC. It also explains the adjustments that were made to the version of the model that was used in the two most recent ICAP Demand Curve resets in order to determine reasonable net energy and ancillary services revenue estimates for use in the AEII and BEC Unit Net CONE analyses. Finally, it describes NERA's contribution to S&L's determination of the annual levelized carrying charge.

II. REQUEST FOR EXPEDITED ACTION

The NYISO renews its request that the Commission issue an order as expeditiously as possible, consistent with due process, to bring this case to a conclusion.[34] A timely Commission order will end any market uncertainty that the Complaint may have created.

In the context of this proceeding, due process requires that the NYISO and other parties be allowed a reasonable time to review, and if necessary to seek leave to respond to, any answers

[33] *See, e.g.,* Appendix IV at Section III.

[34] August 3 Answer at 3.

filed within fifteen days of the date of this filing.[35] Responses to such answers may, in fact, be permitted as of right depending on their nature and content.[36]

The supporting affidavits describe the exemption analyses for AEII and BEC in detail. Complainants and their supporters will have a reasonable time to raise any concerns that they may have to these analyses in their answers. Once interested parties have had an opportunity to respond to Complainants, the Commission will have a complete record that will allow it to address the only questions that are at issue in this proceeding, *i.e.,* whether the NYISO's exemption determinations for AEII and BEC were reasonable, and consistent with the Pre-Amendment Rules. Although these questions are important, they are relatively straightforward. They can be decided on their merits without an examination of the motives, intent, or credibility of the NYISO, the NYISO staff that conducted the exemption analyses, the NYISO's consultants, or the MMU.[37] To the extent that the Commission nevertheless concludes that one or more issues require additional review, the NYISO respectfully renews its request that they be resolved using expedited paper hearing procedures.[38]

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[35] *See* August 31 Order at P 25 (allowing fifteen days for parties to file answers to this Supplemental Answer.)

[36] For example, in the event that Complainants submit an answer that includes entirely new arguments and testimony the NYISO, and other interveners, should be permitted to answer, just as they would be entitled to do as a matter of right if the Complainants were to amend the Complaint.

[37] Complainants have provided no information to support their claims that the NYISO's determinations were not reached independently or somehow reflected a "systematic bias" in favor of artificial price suppression.

[38] As the NYISO has noted, Complainants have effectively conceded that paper hearing procedures would be an appropriate means to resolve any unsettled questions in this proceeding. *See Limited Answer of the New York Independent System Operator, Inc.,* (filed August 31, 2011) at 5.

III. CONCLUSION

For the reasons set forth above, and in the attached supporting affidavits, the NYISO respectfully requests that the Commission dismiss the Complaint in its entirety.

Respectfully submitted,

/s/ Ted J. Murphy

Ted J. Murphy
Counsel to the
New York Independent System Operator, Inc.

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC, this 8th day of September, 2011.

/s/ Vanessa A. Colón

Vanessa A. Colón
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
(202) 955-1500

APPENDIX I

CONFIDENTIAL AFFIDAVIT OF JOSHUA A. BOLES

REGARDING ASTORIA ENERGY II

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Astoria Generating Company, L.P	)	
and TC Ravenswood, LLC	)	
	)	**Docket No. EL11-50-000**
vs.	)	
	)	
New York Independent System Operator,	)	
Inc.	)	

CONFIDENTIAL AFFIDAVIT OF JOSHUA A. BOLES

REGARDING ASTORIA ENERGY II

Mr. Joshua A. Boles declares:

1. I have personal knowledge of the facts and opinions herein and if called to testify I could and would testify competently hereto.

I. Purpose of this Affidavit

2. I submit this affidavit in support of the New York Independent System Operator, Inc.'s ("NYISO") Confidential Supplemental Answer to which this affidavit is appended, the NYISO's August 3, 2011 Answer[1] in response to the Complaint filed by Astoria Generating Company, L.P. and TC Ravenswood, LLC (collectively, the

[1] *Answer and Request for Expedited Action of the New York Independent System Operating, Inc.* (filed August 3, 2011) ("Answer").

"Complainants") in this proceeding on July 11, 2011 ("Complaint"), and the August 11, 2011 Answer of the [NYISO] to Comments and Protests..

3. The Complaint challenges mitigation exemption determinations made by the NYISO in its implementation of the Pre-Amendment Rules.[2] The Complainants' supporting affidavit of Mark Younger[3] ("Younger Affidavit") and Mr. Younger's Supplemental Affidavit[4] ("Younger Supplemental Affidavit"; and collectively with the Younger Affidavit, the "Younger Affidavits") attempts to show that the analyses performed by the NYISO for the Astoria Energy II project ("AEII") could not have been reasonable. Complainants offer the outcomes of Mr. Younger's analyses as purported evidence that the NYISO erred in its determination that AEII is exempt from an Offer Floor. Complainants contend that the NYISO's supposed errors constitute violations of the Pre-Amendment Rules.

4. In this confidential affidavit I provide a detailed description of the Unit Net CONE analyses and mitigation exemption tests that the NYISO actually performed for AEII. I also identify the differences between the NYISO's assumptions and analyses and

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[2] Capitalized terms that are not otherwise defined herein shall have the meanings specified in the Pre-Amendment Rules, and if not defined therein, the terms shall have the meaning in the Answer. Citations to Attachment H herein are to the Pre-Amendment Rules.

[3] *See Complaint Requesting Fast Track Proceeding, Emergency, Interim Relief and Shortened Comment Period*, Docket No. EL11-50-000 (filed July 11, 2011) at Attachment A Affidavit of Mark D. Younger ("Younger Affidavit").

[4] *See Complainants' Motion for Leave to Answer and Answer*, Docket No. EL11-50-000 (filed August 19, 2011) ("Complainants' Answer") at Attachment A Supplemental Affidavit of Mark D. Younger ("Younger Supplemental Affidavit").

those in the Younger Affidavit. I show that the Younger Affidavits' incorrect conclusions are attributable to their use of cost data, methodologies, and assumptions that differed from those actually used by the NYISO. I also show that the methodology and assumptions used by the NYISO conform to the Pre-Amendment Rules and Commission orders. As discussed below, the NYISO's determinations reflected the input and recommendations of the independent Market Monitoring Unit ("MMU") for the NYISO, *i.e.,* Potomac Economics, Ltd.

II. Qualifications

5. I am the Supervisor of Monitoring, Analysis, and Reporting for the Market Mitigation and Analysis Department ("MMA") of the NYISO. My responsibilities include supporting the Director of MMA in administering the NYISO's market power mitigation measures, which encompasses the capacity market measures, including the Pre-Amendment Rules and the current In-City Buyer-Side Mitigation Measures.

6. I received an M.A. in Applied Economics and a B.A. in Economics from the State University of New York at Buffalo.

7. For the past six years I have been involved in numerous market power mitigation matters, including those involving the In-City Installed Capacity ("ICAP") market. I have been actively involved in the NYISO's development and implementation of capacity market mitigation rules since 2007. I was part of the NYISO team that developed the tariff provisions for the Pre-Amendment Rules and the tariff enhancements that now comprise the In-City Buyer-Side Mitigation Measures. I have

also worked on all of the subsequent NYISO filings in response to the Commission's orders, or other parties' pleadings addressing the In-City Buyer-Side Mitigation Measures.

8. I have submitted affidavits in support of several market power mitigation proceedings, including several In-City ICAP proceedings. Most recently, I submitted an affidavit in support of the NYISO answer in response to the complaint in Docket No. EL11-42-000.[5] In that affidavit, I addressed and refuted the claims made by the complainants that the NYISO's implementation of the In-City Buyer-Side Mitigation Measures has been flawed or will be flawed in the future. I also demonstrated that the NYISO's implementation of those measures adheres to Attachment H and Attachment O to the Services Tariff and Commission Orders.

III. Background

9. The Pre-Amendment Rules provide two tests to determine if a proposed new project is exempt from an Offer Floor. If the project satisfies either test (referred to herein as "passing" or "passed'), it is exempt from an Offer Floor.[6] If it does not pass at least one of the tests (*i.e.*, if it "fails" both tests), it is restricted to offering at a price equal to or greater than the project's Offer Floor, and it may only offer into the ICAP Spot Market Auctions.

[5] *Answer of the New York Independent System Operator, Inc.*, Docket No. EL11-42-000 (filed July 6, 2011) as modified by the Errata filed July 7, 2011 ("NYISO EL11-42 Answer"), at Attachment 2 Affidavit of Joshua A. Boles ("Boles EL11-42 Affidavit").

[6] Services Tariff Attachment H Section 23.4.5.7.2.

10. The Offer Floor is equal to the lower of the project's Unit Net CONE or the value based on 75 percent of Mitigation Net CONE[7] of the currently effective New York City ICAP Demand Curve.[8]

11. I will refer to the two exemption tests as the "Part A Test"[9] and the "Part B Test".[10] Under the Part A Test, "an Installed Capacity Supplier shall be exempt from an Offer Floor if … any ICAP Spot Market Auction price for the two Capability Periods beginning with the first Capability Period for any part of which the Installed Capacity Supplier is reasonably anticipated to offer to supply UCAP (the "Starting Capability Period") is projected by the ISO to be higher, with the inclusion of the Installed Capacity Supplier, than the highest Offer Floor based on the Mitigation Net CONE that would be applicable to such supplier in such Capability Periods." Generally stated, the Part A Test does not utilize Unit Net CONE values and assumes that the project offers into the ICAP Spot Market Auction at a price equal to zero.

12. When determining the value of Mitigation Net CONE, for purposes of the Part A Test, the Pre-Amendment Rules state that "Mitigation Net CONE for the first two years after the last year covered by the most recent Demand Curves approved by the

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[7] As described in the NYISO EL11-42 Answer the use of Mitigation Net CONE is in accordance with the Commission's May 2010 Order on In-City mitigation measures, *New York Independent System Operator, Inc.*, 131 FERC ¶ 61,170 (2010). *See* NYISO EL11-42 Answer at 10, n. 34.

[8] Services Tariff Attachment H Section 23.2.1 definition of "Offer Floor".

[9] *Id.* at Section 23.4.5.7.2(a).

[10] *Id.* at Section 23.4.5.7.2(b).

Commission shall be increased by the escalation factor approved by the Commission for such Demand Curves."[11]

13. Under the Part B Test, an "Installed Capacity Supplier shall be exempt from an Offer Floor if … the average of the ICAP Spot Market Auction prices in the six Capability Periods beginning with the Starting Capability Period is projected by the ISO to be higher, with the inclusion of the Installed Capacity Supplier, than the reasonably anticipated Unit Net CONE of the Installed Capacity Supplier."[12] Generally stated, under the Part B Test, the NYISO evaluates whether the project is projected to be economic over the first three years after it enters.

14. Unit Net CONE is defined as the "…localized levelized embedded costs of a specified Installed Capacity Supplier, including interconnection costs… net of likely projected annual Energy and Ancillary Services revenues, as determined by the ISO, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate."[13] The determination of reasonably anticipated Unit Net CONE requires inputs for a project's capital costs, operating costs, and performance characteristics to determine the annual levelized cost. The cost is offset with the energy and ancillary services revenues that the project is estimated to receive in the NYISO's markets.

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[11] *Id.* At Section 23.4.5.7.4.

[12] *Id.* at 23.4.5.7.2(b).

[13] *Id.* at Section 23.2.1 definition of "Unit Net CONE".

15. The following is an overview of the computation of the Unit Net CONE under the Pre-Amendment Rules. The NYISO examines the project's investment costs and expresses the costs in the year's dollars of the first year of entry.[14] The investment cost is then expressed on a per kilowatt basis by dividing by the net degraded ICAP MW at ICAP conditions.[15] This value is multiplied by the real levelized carrying charge determined for the project, producing the annual capital costs. The fixed operations and maintenance ("O&M") costs are added to produce the annual cost of new entry ("CONE"). The annual CONE is then reduced by net energy and ancillary services revenues.[16] The resulting difference for the first year represents the first year annual net CONE. The various components of the annual net CONE are escalated in years 2 and 3 after entry, and the three annual values are averaged. The average is converted from ICAP to UCAP by dividing by one minus EFORd. The resulting value is the project's Unit Net CONE, expressed in dollars per kilowatt per year, in UCAP terms.

16. As described in my affidavit in Docket EL11-42-000,[17] but also applicable to the NYISO's examination of AEII under the Pre-Amendment Rules, the NYISO

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[14] In the Unit Net CONE calculation, costs are expressed in the nominal dollars of the first year of entry. This is done by escalating costs to the year's dollars of the first year of entry, if the costs are expressed in a prior year's dollars.

[15] Net degraded ICAP MW represents the plant capacity, net of station load, and assuming an average degradation over the life of the plant.

[16] The methodology used to compute energy and ancillary services revenues is discussed below and in the Affidavit of Eugene Meehan ("Meehan Affidavit").

[17] Boles EL11-42 Affidavit at P 50.

contracted with Sargent & Lundy LLC ("Sargent & Lundy") and NERA Economic Consulting ("NERA") to assist with performing the Unit Net CONE calculations. These were the consultants utilized by the NYISO in the previous and current ICAP Demand Curve reset proceedings and for the Unit Net CONE determinations under the In-City Buyer-Side Mitigation Measures. Sargent & Lundy has comprehensive expertise in the engineering and business of power plants. Its primary role in the Unit Net CONE determinations is to examine plant characteristics and cost data, including all of the information submitted by developers. NERA is an economic consulting firm, and its primary roles are to calculate net energy revenues and advise the NYISO on economic matters, such as estimating costs of capital.

IV. AEII Mitigation Exemption Test

17. As provided by the Pre-Amendment Rules, the NYISO conducted the exemption analysis of AEII after AEII executed an Interconnection Facilities Study Agreement. The NYISO issued the determination on October 25, 2010, i.e., before the November 27, 2010 effective date of the In-City Buyer-Side Mitigation Measures and thus, while the Pre-Amendment Rules were effective. The NYISO determined that AEII failed the Part A Test but passed the Part B Test under the Pre-Amendment Rules and, therefore, was exempt from an Offer Floor. The analyses the NYISO performed in making these determinations are described below.

V. Part A Test

18. To perform the Part A Test, the NYISO compared the annual price forecast in the first year of entry to the default Offer Floor. The forecast the NYISO used to perform the Part A Test is the first year of the forecast described in Paragraph 19 below.

19. The ICAP Spot Market Auction price forecast for Capability Year 2011/2012, with the inclusion of AEII, was $63.51/kW-year as can be seen in Exhibit JAB AEII-1 to this affidavit. The NYISO determined Mitigation Net CONE in accordance with the Pre-Amendment Rules,[18] by applying the 7.8 percent escalation factor to escalate the Capability Year 2010/2011 reference point to the value for Capability Year 2011/2012.[19] The default Offer Floor based on Mitigation Net CONE was $96.69/kW-year as can be seen in Exhibit JAB AEII-1 to this affidavit. The annual price forecast of $63.51 was lower than the default Offer Floor of $96.69, so AEII did not pass the Part A Test. Mr. Younger had the same result of AEII failing the Part A Test.[20]

VI. Part B Test: Unit Net CONE Analysis

20. In order to perform the Part B Test, the NYISO first had to determine AEII's Unit Net CONE. The inputs, methodology, and analyses that the NYISO used to determine

[18] *See* Services Tariff Attachment H Section 23.4.5.7.4.

[19] The then-currently effective Demand Curves included a 7.8 percent escalation rate. *See New York Independent System Operator, Inc.,* 122 FERC 61,064 (2008) at PP 14, 54- 55 (2008), *reh'g,* 125 FERC 61,299 at P 35 (2008).

[20] Younger Affidavit at 50.

AEII's Unit Net CONE are described in this section and are compared to those suggested by Mr. Younger.

a. Investment Costs

21. AEII identified costs for, among other things, the generating unit, interconnection facilities, system upgrades, site costs, and financing fees. These costs are referred to herein collectively as the "investment cost."

22. In accordance with the Pre-Amendment Rules, the Unit Net CONE is determined for the three-year period starting with the Capability Period in which the project is reasonably anticipated to first offer to supply UCAP (the "Starting Capability Period").[21] AEII stated that it anticipated that it would enter in the Summer 2011 Capability Period. That date coincided with the information available to the NYISO at the time of the determination. Therefore, the investment cost was expressed in 2011 dollars.

23. The investment cost determined by the NYISO for AEII was $[redacted] which equals $[redacted]/kW, using a denominator of [redacted] MW or [redacted] kW. The [redacted] MW value is the net degraded Installed Capacity of the AEII plant. The net degraded ICAP value for AEII recognizes that the plant was planned with duct firing (*i.e.*, a specific plant technology for supplemental firing). The supporting affidavit of

[21] *See* Services Tariff Attachment H Section 23.4.5.7.2(b).

Christopher Ungate of Sargent & Lundy provides a detailed description of AEII's investment cost.[22]

24. The [redacted]/kW investment cost is net of "sunk costs." The independent MMU recommended that the NYISO exclude costs incurred prior to the time the developer made its investment decision. The NYISO agreed with the MMU's rationale, which is discussed in the Affidavit of David Patton ("MMU Affidavit").[23] The time of the investment decision was determined to be July 11, 2008, the date that Astoria Energy II LLC and the New York Power Authority executed the Master Power Purchase and Sale Agreement.[24] As discussed in the MMU Affidavit, the MMU recommended that date as an appropriate date to use for the timing of the investment decision because it was the date significant project commitments were made which would have been costly to unwind. The NYISO agreed with the MMU's recommendation.[25]

25. The sunk costs at the time of the investment decision were portions of the owner's costs and the cost of certain facilities constructed prior to the time of the investment decision, with the intent to be shared between Astoria Energy I and another generating unit at the site. Sargent & Lundy calculated the owner's sunk costs at

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[22] Appendix IV to the Confidential Supplemental Answer at Section V ("Ungate AEII Affidavit").

[23] Appendix III to the Confidential Supplemental Answer at Section VI.A ("MMU Affidavit").

[24] *Id.* at Section V.

[25] *Id.* at Section IV.B.

$[redacted] or $[redacted]/kW, which is the sum of one-half of priority distribution costs[26] and Sargent & Lundy's estimate of one-half of permitting costs, one-half of legal costs, and the cost of environmental studies and market studies costs. AEII made a one-time payment of $[redacted] or $[redacted]kW to Astoria Energy I for shared facilities that were constructed at the time Astoria Energy I was built. As discussed in the MMU Affidavit, the MMU recommended treating this payment as a sunk cost.[27] The NYISO agreed with the MMU's rationale and recommendation. Sargent & Lundy determined, based on its experience, that the net opportunity cost would be negligible and thus that a reasonable estimate was zero.[28] The MMU and the NYISO concurred with Sargent & Lundy.

26. Complainants, through the Affidavit of Astoria Generating's (US Power Generating's) employee Mr. Craig Hart, suggest that an opportunity cost should be included in AEII's CONE.[29] AEII is located on a site that was planned for two units. As discussed above and in the Ungate AEII Affidavit and MMU Affidavit, including such an opportunity cost would not have been appropriate for AEII given its site-specific circumstances. By contrast, Complainant Astoria Generating/US Power Generating's affiliated South Pier Improvement project made specific representations

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[26] Priority distribution is a type of success fee for reaching a project milestone, and it is an owner's development cost.

[27] MMU Affidavit at V.

[28] Ungate AEII Affidavit at P 20.

[29] Complainants' Answer at Attachment B Affidavit of Craig Hart P 9 ("Hart Affidavit"); Younger Supplemental Affidavit at PP 67, 70.

in a statement to the NYISO in response to the NYISO's questioning of that company's initial response regarding that cost. US Power Generating's/Astoria Generating specifically and affirmatively stated to the NYISO that "there are a number of other alternative industrial uses" and that Astoria Generating "assumed the opportunity cost was the fair market value to lease such a site ... to another industrial user."[30] Accordingly, and as disclosed by Mr. Hart, the NYISO included the South Pier Improvement project's opportunity cost in its Unit Net CONE. However, the site-specific facts of Complainant Astoria Generating's South Pier Improvement project have no bearing on the AEII site-specific facts.

27. Mr. Younger's estimate of the AEII investment cost was $1,924/kW.[31] AEII's investment cost determined by the NYISO was $[redacted]/kW, which is $[redacted]/kW higher than the value assumed by Mr. Younger.

b. Real Levelized Carrying Charge

28. The NYISO next multiplied the per kilowatt investment cost by a real levelized carrying charge to determine the annual capital costs of the project over the first three years after entry. Sargent & Lundy calculated a carrying charge of [redacted] percent, which the NYISO then escalated for years 2 and 3 to [redacted] percent and [redacted] percent, respectively. The [redacted] percent charge reflects AEII's actual debt and equity

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[30] Astoria Generating/US Power Generating (Ramineni, K.), communication June 8, 2011, "Re: South Pier site cost."

[31] Younger Affidavit at 59.

financing costs, capital structure percentages, estimated expected income taxes for AEII, and an assumption of a 30-year useful life. The carrying charge reflects the [redacted] that AEII [redacted] AEII will [redacted] and AEII will [redacted]

29. The carrying charge assumed by Mr. Younger was 12.10 percent.[32] To derive that sum, he began with the 11.68 percent 30-year ICIP rate for a gas turbine. He then added a 0.42 percent premium for a higher carrying charge on a combined cycle plant over a simple cycle gas turbine plant.[33] The carrying charge computed by Mr. Younger also used a 30-year useful life, and [redacted] The [redacted] percent difference between the [redacted] percent value used by the NYISO and the 12.10 percent value assumed by Mr. Younger results from the fact that the NYISO used AEII's project-specific financing and an income tax rate that was based on its actual organizational structure. As discussed below, Mr. Younger used an income tax rate that would not be applicable to AEII.

30. The MMU recommended using AEII's project-specific financing in the calculation of the carrying charges. The NYISO agreed with the MMU's rationale and

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[32] *Id.* at 62.

[33] *Id.* at 61-62.

recommendation, which is set forth in the MMU Affidavit.[34] AEII was financed with [redacted] percent debt at a nominal pre-tax cost of [redacted] percent, and [redacted] percent equity at a nominal cost of [redacted] percent. Sargent & Lundy used these numbers to calculate a real after-tax weighted average cost of capital ("WACC") of [redacted] percent. The real after-tax calculation performed by Sargent & Lundy removed 2.15 percent inflation net of technological progress and lowered the debt cost for federal income tax due to the deductibility of interest. Removing inflation from the carrying charge produces a carrying charge that is assumed to escalate through time with inflation, *i.e.*, it remains fixed in real terms but escalates with inflation in nominal terms.

31. Mr. Younger used financing assumptions of 50 percent debt at a nominal pre-tax cost of 7.25 percent, and 50 percent equity at a nominal cost of 12.48 percent. These values produce the real after-tax WACC of 6.35 percent that Mr. Younger used.[35] AEII's actual WACC of [redacted] percent is [redacted] than Mr. Younger's estimate due to the [redacted]

32. AEII's [redacted] composite income tax rate also [redacted] carrying charge. For AEII, Sargent & Lundy calculated a composite income tax rate of [redacted] percent,

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[34] MMU Affidavit at Section VI.B.

[35] *Id.* at Exhibit MDY-13 and MDY-17. The Net Present Value ("NPV") calculations in Mr. Younger's exhibits use a discount rate of 6.35 percent.

based on AEII's specific ownership and form of organization.[36] That composite rate was calculated with a federal income tax rate of [redacted] percent and a blended [redacted] percent [redacted]. State and city income taxes are deductible from federal taxable income. Thus, the blended [redacted] percent state and city income tax rate [redacted] the effective federal income tax rate from 35 percent to [redacted] percent. The blended state and city income tax rate of [redacted] percent for AEII is [redacted] than the individual 7.10 percent state and 8.85 percent city income tax rates Mr. Younger used in his calculation. The composite income tax rate of 45.37 percent used by Mr. Younger appears to be based on the rate used to calculate the carrying charge in the Demand Curve reset report.[37] Although those tax rates were accurate for the project used to compute the Demand Curve, it is appropriate for the NYISO to use the rate that is expected to be applicable to the specific project when computing its costs.

c. *Fixed Operations and Maintenance Costs*

33. Fixed O&M costs include labor, materials, contract services, administrative and general costs, site leasing costs, property taxes, and insurance. AEII's fixed O&M

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[36] Ungate AEII Affidavit at P 32a.

[37] *See* New York Independent System Operator, Inc., Tariff Revisions to Implement ICAP Demand Curves for Capability Years 2011/2012, 2012/2013, and 2013/2014, Docket No. ER11-2224-000 (filed November 30, 2010), at Attachment 2 (Meehan Affidavit) Exhibit B "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator" ("NERA/S&L Demand Curve Report") at 36. Mr. Younger has implicitly assumed a composite income tax rate of 45.37 percent, derived from federal, state, and city income tax rates of 35 percent, 7.10 percent, and 8.85 percent, respectively. The calculation of the composite tax rate is provided in Table II-8 of the NERA/S&L Demand Curve Report.

costs were calculated to be $[redacted]/kW-year, which equates to [redacted] percent of the investment cost. Property taxes are not included in this figure because they are included in the carrying charge. Mr. Younger used a fixed O&M and site lease cost of 1.47 percent, which equates to $28.28/kW-year, using the $1,924/kW investment cost.[38] The fixed O&M figures are therefore [redacted] dollar and percentage basis.

d. Annualized Cost of New Entry

34. The annual CONE is calculated as the product of the investment cost and the carrying charge, plus the annual costs of fixed O&M. Stated as a formula:

annual CONE = (investment cost * carrying charge) + annual fixed O&M

The NYISO Unit Net CONE analysis of AEII used a year 1 (2011) annual CONE of $[redacted]/kW-year in ICAP terms. The value calculated by Mr. Younger was $261.09/kW-year in ICAP terms.[39] The AEII annual CONE calculated by the NYISO is $[redacted]/kW-year [redacted] than the value calculated by Mr. Younger. The AEII annual capital costs calculated by the NYISO are $[redacted]/kW-year [redacted] and the fixed O&M is $[redacted]/kW-year higher than the values calculated by Mr. Younger. As delineated above, the primary difference is due to [redacted].

[38] Younger Affidavit at P 63.

[39] *Id.*

e. Net Energy Revenues

35. The NERA econometric model (referred to herein as the "NERA model") was used as the basis for calculating net energy revenues for AEII. It is the same model used in the two most recent ICAP Demand Curve resets,[40] with certain adjustments, as discussed in the Affidavit of Eugene T. Meehan ("Meehan Affidavit")[41] The NERA model provided an estimate of likely net energy revenues. Utilizing the NERA model, with the described adjustments, NERA calculated net energy revenues for AEII of $[redacted]/kW-year. Given that the net energy revenues produced by the NERA model have been approved by the Commission for the Demand Curve peaking plant, and that the adjustments described by Mr. Meehan were tailored to determine a project-specific net CONE, I believe that the methodology, and the resulting AEII net energy revenues, are reasonable.

36. Combined with the ancillary services revenues estimated by the NYISO (determined as described below), the total year 1 net energy and ancillary services revenues were estimated to be $[redacted]/kW-year, as shown in Table 1. This value is [redacted] than Mr. Younger's year 1 values of $146.26/kW-year and $123.22/kW-year, (each computed

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[40] *See* NERA/S&L Demand Curve Report at 7-11, *see also New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 at P 136; *New York Independent System Operator, Inc.*, 122 FERC 61,064 at P 47 (2008), *reh'g,* 125 FERC 61,299 (2008).

[41] Appendix VI to Confidential Supplemental Answer at P 16 ("Meehan Affidavit").

based on his different energy forecasts, as discussed below).[42] The differences between the NYISO's methodology and assumptions and those used by Mr. Younger are described below.

37. The NERA model estimates net energy revenues relative to the Zone J price, which is a load-weighted average price, and is the price used in the ICAP Demand Curve reset. AEII connects at the 345 kV level. Although I believe the estimate produced by the NERA model for AEII is reasonable, an alternate approach would be to further adjust the net energy revenues estimated by the NERA model to account for prices at the 345-kV level. This adjustment was not included in the exemption analysis for AEII but the methodology and the impacts that its application would have had on AEII's Unit Net CONE are described below. With or without making a "345 kV adjustment," AEII would still be exempt under the Part B Test.

*i. **Gas Futures***

38. The net energy revenues used to compute the Unit Net CONE value of $[redacted]/kW-year in UCAP terms were calculated for the first three years of entry, Summer 2011 through Winter 2013/2014. The net energy revenue model utilized gas futures prices for the same period for which net energy revenues were computed: November 2010 through October 2013, as discussed in the Meehan Affidavit.[43] At the

[42] Younger Affidavit at P 73. The $146.26/kW-year value includes AEII and BEC in the energy forecasts. The $123.22/kW-year value includes AEII, BEC, and the Hudson Transmission Partners project.

[43] Meehan Affidavit at P25.

recommendation of the MMU, the NYISO used the projected gas futures prices at the time of the investment decision; *i.e.*, July 11, 2008. The average gas futures price used in the analysis, observed as of July 11, 2008, was \$12.10/MMBtu. The fuel price used for AEII was \$13.15/MMBtu, which reflects fuel taxes and local distribution charges, as explained in the Meehan Affidavit. Mr. Younger, however, relied on the calculations from the NERA/S&L Demand Curve Report filed in November 2010, which used actual gas prices over the period November 1, 2006 to October 31, 2009 (the "Historic Period"). The average gas price over the Historic Period was \$8.00/MMBtu. Higher gas prices result in higher net revenues for AEII because AEII has a [redacted] heat rate and a [redacted] capacity factor. The use of gas futures is [redacted] AEII's net energy revenues being [redacted] than the plant referenced by Mr. Younger. The Meehan Affidavit describes the application of gas futures in the calculation of the net energy revenues for AEII.[44]

39. The positive correlation between natural gas prices and the net energy revenues of combined cycle units has been demonstrated in the State of the Market ("SOM") Reports prepared by the MMU (which was formerly the Independent Market Advisor for the NYISO). For example, The 2008 SOM Report calculated net energy revenues at the New York City 345-kV level of approximately \$220/kW-year during 2008, a

[44] *Id.* at PP 17-20.

year with higher gas prices.[45] The effect was also recently acknowledged in an affidavit that Mr. Younger filed with the Commission. Mr. Younger stated: "[w]here natural gas is the predominant marginal fuel, efficient natural gas generators… will secure most of their net energy revenues from having a lower heat rate than the unit that sets the clearing price. As natural gas prices rise, so, too, the net energy revenues for these facilities will rise."[46]

ii. Level of Excess

40. The average level of excess that the NYISO used for the three year period used to calculate net energy revenues was 10 percent. This value is slightly lower than the value used by Mr. Younger because the NYISO's analysis used July 2008 as the date of the investment decision. It was appropriate to not include Bayonne Energy Center ("BEC") and the Hudson Transmission Project ("HTP") in the analysis for the reasons specified in the discussion of "Existing Capacity and Resource Additions" below. The NYISO also used the load forecast from the NYISO's 2008 Load and Capacity Data ("Gold Book"),[47] which is higher than that used by Mr. Younger. Mr. Younger used the load forecast from the NYISO's 2010 Gold Book. His stated

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[45] Potomac Economics (Patton, D.) *2008 State of the Market Report New York ISO Electricity Markets* (May 2009) at 19, *available at* < http://www.nyiso.com/public/webdocs/committees/mc/meeting_materials/2009-05-27/2008_NYISO_SOM_Draft_5-27-09_Highlights.pdf.>

[46] *Complainants' Motion for Leave to Answer and Answer*, at Attachment A, Second Supplemental Affidavit of Mark Younger at P 11, Docket No. EL11-42-000 (filed July 21, 2011).

[47] 2008 Gold Book *available at* <http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2008_goldbook.pdf>

rationale for using the 2010 data is that it was "the same data that the NYISO would have had available to it for an AEII [mitigation exemption] evaluation during 2010."[48] The use of the 2010 data to evaluate AEII is not reasonable. As stated above, AEII made its investment decision in July 2008. Using the 2010 data that Mr. Younger used would have caused the NYISO to incorrectly apply the Pre-Amendment Rules, to contravene the intent of the buyer side mitigation measures, and to violate Commission precedent because it would not have been performed in relation to the time of the investment decision.[49]

41. Mr. Younger calculated levelized net revenues over 30 years and 3 years; the excess levels from the 3 year analysis are reviewed here for comparison purposes. Mr. Younger's calculation of the average excess level over the first 3 years was 13.2 percent for the scenario in which AEII and BEC enter, and 15.5 percent for the scenario in which AEII, BEC, and HTP enter.[50] The higher excess levels calculated by Mr. Younger are attributable to his analysis being based on 2010 Gold Book data, which has more supply additions, a higher amount of available capacity, and a lower

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[48] Younger Affidavit at P 42.

[49] *See New York Independent System Operator, Inc.*, 136 FERC ¶ 61,077 at PP 25-28 (2011) (explaining that the offer floor determination should be made prior to when a project accepts its cost allocation and enters the capacity market).

[50] Younger Affidavit at Exhibit MDY-12. The 13.2 percent and 15.5 percent values are the averages of the excess levels in years 2011-2013 in each scenario.

load forecast, which also lowers the New York City Locational Capacity Requirement.

iii. 345-kV Adjustment

42. The NERA model predicts the Zone J LBMP, which is a load-weighted average of the LBMPs at the load buses in Zone J. Although it was reasonable for the NYISO to use the NERA model, with adjustments, to compute the likely AEII net energy revenues, an adjustment to the value produced by the NERA model could be made to account for prices at the 345 kV level historically being lower than the Zone J load-weighted average of the LBMPs.

43. To determine the 345 kV adjustment, the NYISO calculated the average difference between the day-ahead Zone J price, and the day-ahead price on the New York City 345-kV system at the Poletti bus, over the Historic Period. The average difference over all hours was $1.70 per MWh. This value was then multiplied by the average annual number of run hours for AEII in the NERA model, which was [redacted] hours (*i.e.*, [redacted] hours reduced by the AEII EFORd of [redacted] percent). The product of $1.70/MWh and [redacted] hours was divided by 1,000 to convert to kilowatts, which produced [redacted]/kW-year. The value is not escalated for inflation because it represents a spread between two numbers; the effect of inflation is negligible when both numbers escalate concurrently. The adjustment and its effects on AEII's Unit Net CONE are shown below in Table 1.

44. Mr. Younger made a similar adjustment in his analysis, which was also based on the average price difference over the Historic Period. Mr. Younger calculated the average Poletti bus LMBP as $68.79/MWh and the average Zone J LBMP as $70.49/MWh, and he reported the difference as 1.7 percent.[51] He then calculated net energy revenues at the Poletti bus and Zone J, using the $8.00/MMBtu average gas price over the Historic Period and an assumed heat rate of 7,000 Btu/kWh. According to Mr. Younger's calculations, the net energy revenues at the 345-kV level were 12.3 percent less than the net revenues at the Zone J prices. Mr. Younger uses this finding to apply a 10 percent reduction to net energy revenues from the NERA model. The net energy revenues at the 0.1 reserve margin (*i.e.*, 10 percent excess level) reported by Mr. Younger are $148.7/kW-year.[52] Mr. Younger has reduced this value by 10 percent, or $14.87/kW-year, to account for lower net energy revenues at the 345-kV level. This reduction is [redacted] than the $[redacted]/kW-year net energy revenue reduction calculated by the NYISO.

f. Ancillary Services

45. The NYISO estimated ancillary services revenues for AEII to be $[redacted]/kW-year in year 1. The NYISO computed the ancillary services revenues using actual ancillary services revenues received by combined cycle plants, escalated for the 3 year period.

[51] *Id.* at P 67. Mr. Younger's calculation of a 1.7 percent difference appears to be an error. Based on Mr. Younger's numbers, the dollar per MWh difference is $1.70/MWh, consistent with the NYISO's calculation.

[52] *Id.* at Exhibit MDY 11.

The $[redacted]/kW-year number is [redacted] than the $7.00/kW-year used by Mr. Younger.[53] [redacted] AEII's ancillary services revenues.

g. Unit Net CONE

46. The annual net CONE in each of the first three years after entry is calculated by subtracting the net energy and ancillary services revenues from the annual CONE value. The Unit Net CONE is then calculated by averaging the three values in ICAP terms. The ICAP value is then converted to UCAP by dividing by one minus EFORd. AEII's Unit Net CONE was $[redacted]/kW-year ICAP, which is $[redacted]/kW-year UCAP. These calculations are shown in Table 1.

47. Mr. Younger calculates a Unit Net CONE of $121.29/kW-year UCAP in the scenario with AEII and BEC in the capacity forecast, and $144.38/kW-year UCAP in the scenario with AEII, BEC, and HTP in the forecast.[55] Mr. Younger's higher numbers are attributable to his selection of inputs which resulted in a higher annual CONE and lower net energy and ancillary services revenues, as demonstrated above.

48. At the final step of calculating Unit Net CONE, there is one methodological difference between the calculations of the NYISO and Mr. Younger. First, Mr. Younger calculated a value in 2011 dollars, whereas the NYISO has calculated a Unit

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[53] *Id.* at P 64.

[54] Younger Affidavit at P 52.

[55] *Id.* at P 75.

Net CONE using the value equal to the average of the annual net CONE values for 2011, 2012, and 2013. For purposes of the Part B Test, Mr. Younger calculated Unit Net CONE by escalating the value in 2011 dollars to Years 2 and 3, and then averaging the three values.[56] The NYISO does not calculate a Unit Net CONE in 2011 dollars, and then escalate it and average it to create another Unit Net CONE value. The Part B test requires one value for Unit Net CONE. That test states that a project will be exempt from an Offer Floor if "the average of the ICAP Spot Market Auction prices in the six Capability Periods beginning with the Starting Capability Period is projected by the ISO to be higher, with the inclusion of the Installed Capacity Supplier, than the reasonably anticipated Unit Net CONE of the Installed Capacity Supplier."[57] Accordingly, the NYISO calculated the Unit Net CONE as the straight average of the three annual net CONE values.

Table 1: Summary of NYISO Computation of AEII Unit Net CONE

[56] *Id.* at P 12, Table 2, and P 77.

[57] Services Tariff Attachment H Section 23.4.5.7.2(b).

AEII Unit Net CONE Calculation

	Capability Year	2011/2012	2012/2013	2013/2014	Notes
A	Total investment cost per kW	[redacted]			Capital costs escalated to 2011 dollars
B	Real levelized carrying charge				Years 2 and 3 escalated
C	Annual fixed O&M				Years 2 and 3 escalated
D	CONE (ICAP)				= A * B + C
E	Net energy revenues (10% excess)				Average annual net revenues (zonal)
F	Ancillary services revenues				Years 2 and 3 escalated
G	Net E&AS revenues				= E + F
H	Annual net CONE				= D - G
I	Unit Net CONE (ICAP)				= Average (CY2011/12, CY2012/13, CY2013/14)
J	Unit Net CONE (UCAP)				= I / (1 - EFORd)
	Summer month Offer Floor (UCAP)				
	Winter month Offer Floor (UCAP)				
	With Alternate 345 kV Approach				
K	345 kV adjustment				Reduction for 345 kV price
L	Annual net CONE				= D - G + K
M	Unit Net CONE (ICAP)				= Average (CY2011/12, CY2012/13, CY2013/14)
N	Unit Net CONE (UCAP)				= M / (1 - EFORd)
	Summer month Offer Floor (UCAP)				
	Winter month Offer Floor (UCAP)				

VII. AEII Part B Test Determination

49. The Part B Test compares the average annual price forecast over the first three years after entry, to the project's Unit Net CONE. The forecast the NYISO used to perform the Part B Test and its inputs, and the differences with those used by Mr. Younger, are described below.

50. The NYISO determined that the three-year average annual price forecast for Capability Year 2011/2014 was $78.06/kW-year. AEII's Unit Net CONE was $[redacted]kW-year. The price forecast is higher than AEII's Unit Net CONE, so AEII passes the Part B Test and is exempt from an Offer Floor.

51. Mr. Younger's analysis found that AEII failed the Part B Test. As discussed above, Mr. Younger performed the test under two scenarios: first, assuming additions of AEII, BEC, and HTP, and second, assuming additions of AEII and BEC.[58] In his first scenario, the price forecast of $26.18/kW-year was lower than the Unit Net CONE of $147.50/kW-year. In his second scenario, the price forecast of $34.08/kW-year was lower than the Unit Net CONE of $123.92/kW-year. The differences between the NYISO's Unit Net CONE calculation and Mr. Younger's were presented above.

a. ICAP Spot Market Auction Price Forecasts

52. The Part B Test requires forecasting six Capability Periods of In-City ICAP prices, beginning with the Capability Period that the project is expected to first enter. For AEII, this first Capability Period was Summer 2011, so that the first six Capability Periods spanned Summer 2011 through Winter 2013/2014. The AEII Part B Test price forecast of $78.06/kW-year represents the average annual price forecast for these six Capability Periods. This value differs from the values calculated by Mr. Younger because he assumed different Demand Curve parameters and different resource additions, and made other assumptions, as discussed below.

i. ICAP Demand Curve Parameters

53. The NYISO performed its analysis using the ICAP Demand Curves accepted by the Commission for Capability Years 2008/2009, 2009/2010, and 2010/2011.[59]

[58] Younger Affidavit at P 77.

Accordingly, the NYISO obtained the reference points and escalation rate from those New York City Demand Curves.

54. In accordance with the Pre-Amendment Rules, to obtain the reference point for the Summer 2011 Capability Period, the NYISO escalated the $15.99/kW-year Summer 2010 reference point on the 2010/2011 New York City Demand Curve by the escalation rate of 7.8 percent approved by the Commission for that ICAP Demand Curve. The 2012 and 2013 reference points were escalated at the same rate. This produced a 2011 ICAP reference point of $17.24/kW-year. The ICAP Demand Curves used a reference point in ICAP terms: the $15.99/kW-year value as the starting point to which the 7.8 percent annual escalation is applied.[60]

ii. ICAP to UCAP Conversion, EFORd, and Load Forecast

55. The $17.24/kW-year ICAP reference point was then converted to a UCAP value of $18.51/kW-year using the New York City Locality EFORd of 6.9 percent. The EFORd used was the then-current New York City EFORd for Summer 2008.[61] Mr. Younger uses a slightly lower EFORd of 6.85 percent to convert the $17.24/kW-year ICAP reference point to a value of $18.50/kW-year in UCAP terms. The 6.85 percent EFORd is the Winter 2010/2011 EFORd.

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[59] *See New York Independent System Operator, Inc.*, 122 FERC 61,064 at P1 (2008), *reh'g*, 125 FERC 61,299 (2008).

[60] Younger Affidavit at Exhibit MDY-9.

[61] NYISO ICAP AMS, Season Summer 2008 Derating Factor %, *available at* <http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do>.

56. The load forecasts from the 2008 Gold Book were used. The New York City load forecasts from Table I-2a of the 2008 Gold Book for Summer 2011, Summer 2012, and Summer 2013 were 12,320 MW, 12,455 MW, and 12,590 MW, respectively. The 2008 Gold Book load forecasts were used because these were the values that were available at the time of AEII's investment decision: July 11, 2008. The MMU recommended using the ICAP forecasts available at this time.[62]

57. Mr. Younger uses load forecasts from Table I-2a of the 2010 Gold Book forecasts of 11,775 MW, 11,815 MW, and 11,925 MW.[63] These load forecasts are significantly lower than the values that were available at the time of the investment decision. The higher load forecasts used by the NYISO increased the average annual ICAP forecast by $39.19/kW-year. The $78.06/kW-year ICAP forecast would have been $38.87/kW-year with the load forecasts used by Mr. Younger.

iii. Existing Capacity and Resource Additions

58. The NYISO used the 2008 Gold Book to determine the levels of existing capacity, scheduled retirements, and resource additions to use in the ICAP forecasts. From the 2008 Gold Book, the level of existing capacity, net of the scheduled retirement of the New York Power Authority's Poletti I plant, was 9,160.9 MW for Summer and 10,146.1 MW for Winter. These capacity values were assumed as the summer/winter

[62] MMU Affidavit at Section IV.

[63] Younger Affidavit at Exhibit MDY-9.

values in the NYISO's analysis. Mr. Younger used the 2010 Gold Book to determine existing capacity and retirements. The values that he used were 8,969.6 MW for Summer and 9,998.6 MW for Winter. Thus, the NYISO used higher values for existing capacity net of retirements from the 2008 Gold Book than Mr. Younger used from the 2010 Gold Book.

59. The NYISO forecasted generator additions using Table IV-1 of the 2008 Gold Book. That table listed six proposed generator additions in Zone J: NYC Energy LLC (queue position 19), Astoria Energy (Phase 2) (queue pos. 31), CPN 3rd Turbine, Inc. (JFK) (queue pos. 96), Fortistar VP (queue pos. 90), Fortistar VAN (queue pos. 91), and TransGas Energy (queue pos. 106). The Linden VFT was also listed in Table VIII-1 as a proposed transmission facility that would be capable of supplying In-City ICAP. The NYISO next excluded projects from the ICAP and energy forecasts if the NYISO determined that at the time of the investment decision, the project was not reasonably anticipated to be online during the three-year period after AEII's entry. The additions of CPN 3rd Turbine, Inc. (JFK) and TransGas Energy were excluded on this basis. The NYISO Planning Department removed CPN 3rd Turbine, Inc. (JFK) from the Interconnection Request queue, pursuant to Section 3.6 of Attachment X of the NYISO's Open Access Transmission Tariff. The New York State Board on Electric Generation Siting and the Environment dismissed TransGas Energy System LLC's application for a certificate that would have been required for the project to be constructed. The remaining four projects from the proposed generator additions

Table IV-1 and Linden VFT were included in the ICAP forecasts and assumed to be price takers, *i.e.*, offering at $0.00/kW-month.

60. The supply additions assumed by Mr. Younger include AEII, BEC, and HTP in one scenario and AEII and HTP in another. However, for the Linden VFT, Mr. Younger used 300 MW of ICAP in his analysis. The NYISO used 345 MW in its analysis based upon the expectation regarding the Linden VFT's capacity.[64] The NYISO analysis did not include BEC and HTP because at the time of AEII's investment decision there was not a reasonable basis to include them. They were not in the 2008 Gold Book or the 2008 Reliability Needs Assessment supply assumptions. Thus, Mr. Younger's assumptions regarding supply additions vary considerably from the NYISO's assumptions.

iv. Unoffered UCAP

61. The ICAP forecasts used by the NYISO excluded seasonal average historic values of unoffered UCAP. Unoffered UCAP is UCAP that is available for sale but is not sold through NYISO auctions, certified toward bilateral transactions, or used for self-supply. For Summer, the monthly average value of 82.9 MW was used, and for Winter the monthly average value of 18.3 MW was used. The ICAP forecasts performed by Mr. Younger did not exclude unoffered capacity.

[64] The 2008 Gold Book did not state MW of capacity for the Linden VFT.

v. Minimum Clearing Price

62. Mr. Younger acknowledged that there would be a positive minimum clearing price in the ICAP auctions. He identified it at $0.50/kW-month.[65] The NYISO utilized $1.00/kW-month, which is reasonable. A reduction in ICAP Spot Market Auction Clearing Prices in the very short term can be expected to occur after an increase in supply. However, it is not reasonable to expect that such a reduction would persist because, if the price level was low for a period of time, some units would be expected to mothball or retire. Since the exemption test requires that the analyses be performed for a three-year period beginning upon entry, it is not reasonable to only apply a very short term assumption to forecasting capacity prices. Therefore, the use of the $1.00/kW-month minimum is a more appropriate representation of a minimum clearing price.

VIII. Conclusion

63. My affidavit supports that the above-described data, methodologies, assumptions, and analyses utilized by the NYISO, and its exemption determination for AEII, conform to the Pre-Amendment Rules. It also demonstrates that Mr. Younger's data, methodology, assumptions, and analyses are flawed in several significant aspects and fail to show that the NYISO's determinations do not conform to the Pre-Amendment Rules.

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[65] Younger Affidavit at P 42.

This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing Confidential Supplemental Affidavit of Joshua A. Boles Regarding Astoria Energy II (the "Affidavit"). I have read the Affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Joshua A. Boles
Supervisor, Market Mitigation and Analysis
New York Independent System Operator, Inc.
September 7, 2011

Subscribed and sworn to before me this 7th day of September 2011.

DIANE L. EGAN
Notary Public, State of New York
Qualified in Schenectady County
No. 4924890
Commission Expires March 21, 20 13

Diane L. Egan

Exhibit JAB AEII-1

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

Exhibit JAB AEII-1

Mitigation Exemption Tests: Astoria Energy II										
					Summer			Winter		
Input/Calculation	*Units*	*ICAP Summer*	*Winter*	*Escalation/ EFORd*	2011	2012	2013	2011	2012	2013
NYC Load Forecast	ICAP				12,320.0	12,455.0	12,590.0	12,320.0	12,455.0	12,590.0
NYC Installed Reserve Margin Percentage	%				80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
NYC Demand Curve ICAP Ref Point		$ 15.99		7.80%	$ 17.24	$ 18.58	$ 20.03	$ 17.24	$ 18.58	$ 20.03
ICAP/UCAP derating factor	%				6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
NYC UCAP Ref Point	UCAP				$ 18.51	$ 19.96	$ 21.52	$ 18.51	$ 19.96	$ 21.52
NYC UCAP Requirement	UCAP				9,175.9	9,276.5	9,377.0	9,175.9	9,276.5	9,377.0
Demand Curve Zero Crossing	%				118%	118%	118%	118%	118%	118%
UCAP at $0	UCAP				10,827.6	10,946.3	11,064.9	10,827.6	10,946.3	11,064.9
Demand Curve Slope. Per 100 MW	$/MW*100				$ (1.1207)	$ (1.1954)	$ (1.2750)	$ (1.1207)	$ (1.1954)	$ (1.2750)
Existing Generation Capacity	ICAP				10,051.9	10,051.9	10,051.9	11,036.1	11,036.1	11,036.1
Subtotal	UCAP				9,358.3	9,358.3	9,358.3	10,274.6	10,274.6	10,274.6
Special Case Resources	UCAP				445.6	445.6	445.6	375.6	375.6	375.6
Historic Unoffered Capacity	UCAP				(82.9)	(82.9)	(82.9)	(18.3)	(18.3)	(18.3)
Subtotal Existing Capacity	UCAP				9,721.0	9,721.0	9,721.0	10,632.0	10,632.0	10,632.0
Additions										
NYC Energy LLC (2008/Q4)		79.9	79.9	6.90%	74.4	74.4	74.4	74.4	74.4	74.4
Astoria Energy Phase 2 (2010/05)		576.0	617.2	6.90%	536.3	536.3	536.3	574.6	574.6	574.6
CPN 3rd Turbine, Inc. JFK (2011)		45.0	45.0	6.90%						
Fortistar VP (2010/Q2)		79.9	79.9	6.90%	74.4	74.4	74.4	74.4	74.4	74.4
Fortistar VAN (2010/Q2)		79.9	79.9	6.90%	74.4	74.4	74.4	74.4	74.4	74.4
TransGas Energy (2012/Q3)		1,100.0	1,100.0	6.90%						
Linden VFT (2010)		345.0	345.0	6.90%	321.2	321.2	321.2	321.2	321.2	321.2
Retirements										
Poletti 1 (2/1/10)		(890.7)	(894.8)	6.90%	(829.2)	(829.2)	(829.2)	(833.1)	(833.1)	(833.1)
Net Additions	UCAP				251.4	251.4	251.4	285.9	285.9	285.9
Total Forecast Capacity	UCAP				9,972.4	9,972.4	9,972.4	10,917.9	10,917.9	10,917.9
Forecast Clearing Price	$/kW-mo				$ 9.58	$ 11.64	$ 13.93	$ 1.00	$ 1.00	$ 1.87
Part A Test: First Year Forecast	$/kW-yr				$ 63.51				*minimum price*	*$1.00*
Part B Test: Average Annual Forecast	$/kW-yr				$ 78.06					

Exhibit JAB AEII-1

Part A Test	MST Att. H, Section 23.4.5.7.2(a)			
Part A Test Inputs			*Capability Year 2011/2012*	
NYC Annual ICAP Revenue Requirement, Capability Year 2010/2011	$/kW-yr		$ 143.15	$ 143.15
Demand Curve Escalation Factor	%		7.8%	$ 154.32
Mitigation Net CONE	$/kW-yr		77.8%	$ 120.02
Default Offer Floor, ICAP	$/kW-yr		75.0%	$ 90.02
Default Offer Floor, UCAP	$/kW-yr		6.90%	$ 96.69
Part A Test Determination				
First Year Price Forecast				$ 63.51
Offer Floor based on 75% of Mitigation Net CONE				$ 96.69
Determination				Not Exempt
Part B Test	MST Att. H, Section 23.4.5.7.2(b)			
Part B Test Determination				
Three Year Average Annual Price Forecast				$ 78.06
Unit Net CONE				[redacted]
Determination				Exempt
Key				
Green shading denote spreadsheet input				
Yellow shading denots spreadsheet calculation				

APPENDIX II

CONFIDENTIAL AFFIDAVIT OF JOSHUA A. BOLES REGARDING BAYONNE ENERGY CENTER

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Astoria Generating Company, L.P and TC Ravenswood, LLC	)	
	)	**Docket No. EL11-50-000**
vs.	)	
	)	
New York Independent System Operator, Inc.	)	

CONFIDENTIAL AFFIDAVIT OF JOSHUA A. BOLES

REGARDING BAYONNE ENERGY CENTER

Mr. Joshua A. Boles declares:

1. I have personal knowledge of the facts and opinions herein and if called to testify I could and would testify competently hereto.

I. Purpose of this Affidavit

2. I submit this affidavit in support of the New York Independent System Operator, Inc.'s ("NYISO") Confidential Supplemental Answer to which this affidavit is appended, the NYISO's August 3, 2011 Answer[1] in response to the Complaint filed by Astoria Generating Company, L.P. and TC Ravenswood, LLC (collectively, the

[1] *Answer and Request for Expedited Action of the New York Independent System Operating, Inc.* (filed August 3, 2011) ("Answer").

"Complainants") in this proceeding on July 11, 2011 ("Complaint"), and August 11, 2011 Answer of the [NYISO] to Comments and Protests.

3. The Complaint challenges mitigation exemption determinations made by the NYISO in its implementation of the Pre-Amendment Rules.[2] The Complainants' supporting affidavit of Mark Younger [3]("Younger Affidavit") and Mr. Younger's Supplemental Affidavit[4] ("Younger Supplemental Affidavit"; and collectively with the Younger Affidavit, the "Younger Affidavits") attempt to show that the analyses performed by the NYISO for the Bayonne Energy Center project ("BEC") could not have been reasonable. Complainants offer the outcomes of Mr. Younger's analyses as purported evidence that the NYISO erred in its determination that BEC is exempt from the Offer Floor. Complainants contend that the NYISO's supposed errors constitute violations of the Pre-Amendment Rules.

4. In this confidential affidavit I provide a detailed description of the Unit Net CONE analyses and mitigation exemption tests that the NYISO actually performed for BEC.

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[2] Capitalized terms that are not otherwise defined herein shall have the meanings specified in the Pre-Amendment Rules, and if not defined therein, the terms shall have the meaning in the Answer. Citations to Attachment H herein are to the Pre-Amendment Rules.

[3] *See Complaint Requesting Fast Track Proceeding, Emergency, Interim Relief and Shortened Comment Period*, Docket No. EL11-50-000 (filed July 11, 2011) at Attachment A Affidavit of Mark D. Younger ("Younger Affidavit").

[4] *See Complainants' Motion for Leave to Answer and Answer*, Docket No. EL11-50-000 (filed August 19, 2011) ("Complainants' Answer") at Attachment A Supplemental Affidavit of Mark D. Younger ("Younger Supplemental Affidavit").

I show that the Younger Affidavits' incorrect conclusions are attributable to their use of cost data, methodologies, and assumptions that differed from those actually used by the NYISO. I also show that the methodology and assumptions used to perform the exemption determination for BEC conform to the Pre-Amendment Rules and Commission orders. As discussed below, the NYISO's determinations reflect the input and recommendations of the independent Market Monitoring Unit ("MMU") for the NYISO, *i.e.* Potomac Economics, Ltd.

II. Qualifications

5. I am the Supervisor of Monitoring, Analysis, and Reporting for the Market Mitigation and Analysis Department ("MMA") of the NYISO. My responsibilities include supporting the Director of MMA in administering the NYISO's market power mitigation measures, which encompasses the capacity market measures, including the Pre-Amendment Rules and the current In-City Buyer-Side Mitigation Measures.

6. I received an M.A. in Applied Economics and a B.A. in Economics from the State University of New York at Buffalo.

7. For the past six years I have been involved in numerous market power mitigation matters, including those involving the In-City Installed Capacity ("ICAP") market. I have been actively involved in the NYISO's development and implementation of capacity market mitigation rules since 2007. I was part of the NYISO team that developed the tariff provisions for the Pre-Amendment Rules and the tariff

enhancements that now comprise the In-City Buyer-Side Mitigation Measures. I have also worked on all of the subsequent NYISO filings in response to the Commission's orders, or other parties' pleadings addressing the In-City Buyer-Side Mitigation Measures.

8. I have submitted affidavits in support of several market power mitigation proceedings, including several In-City ICAP proceedings. Most recently, I submitted an affidavit in support of the NYISO answer in response to the complaint in Docket No. EL11-42-000.[5] In that affidavit, I addressed and refuted the claims made by the complainants that the NYISO's implementation of the In-City Buyer-Side Mitigation Measures has been flawed or will be flawed in the future. I also demonstrated that the NYISO's implementation of those measures adheres to Attachment H and Attachment O to the Services Tariff and Commission Orders.

III. Background

9. The Pre-Amendment Rules provide two tests to determine if a proposed new project is exempt from an Offer Floor. If the project satisfies either test (referred to herein as "passing" or "passed"), it is exempt from the Offer Floor.[6] If it does not pass at least one of the tests (*i.e.*, if it "fails" both tests), it is restricted to offering at a price equal

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[5] *Answer of the New York Independent System Operator, Inc.*, Docket No. EL11-42-000 (filed July 6, 2011) as modified by the Errata filed July 7, 2011 ("NYISO EL11-42 Answer"), at Attachment 2 Affidavit of Joshua A. Boles ("Boles EL11-42 Affidavit").

[6] Services Tariff Attachment H Section 23.4.5.7.2.

to or greater than the project's Offer Floor, and it may only offer into the ICAP Spot Market Auctions.

10. The Offer Floor is equal to the lower of the project's Unit Net CONE or the Offer Floor based on 75 percent of Mitigation Net CONE[7] of the currently effective New York City ICAP Demand Curve.[8]

11. I will refer to the two exemption tests as the "Part A Test"[9] and the "Part B Test."[10] Under the Part A Test, "an Installed Capacity Supplier shall be exempt from an Offer Floor if … any ICAP Spot Market Auction price for the two Capability Periods beginning with the first Capability Period for any part of which the Installed Capacity Supplier is reasonably anticipated to offer to supply UCAP (the "Starting Capability Period") is projected by the ISO to be higher, with the inclusion of the Installed Capacity Supplier, than the highest Offer Floor based on the Mitigation Net CONE that would be applicable to such supplier in such Capability Periods." Generally stated, the Part A Test does not utilize Unit Net CONE values and assumes that the project offers into the ICAP Spot Market Auction at a price equal to zero.

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[7] As described in the NYISO EL11-42 Answer, the use of Mitigation Net CONE is in accordance with the Commission's May 2010 Order on In-City mitigation measures, *New York Independent System Operator, Inc.*, 131 FERC ¶ 61,170 (2010). *See* NYISO EL11-42 Answer at 10, n. 34.

[8] Services Tariff Attachment H Section 23.2.1 definition of "Offer Floor."

[9] *Id.* Section 23.4.5.7.2(a).

[10] *Id.* Section 23.4.5.7.2(b).

12. When determining the value of Mitigation Net CONE, for purposes of the Part A Test, the Pre-Amendment Rules state that "Mitigation Net CONE for the first two years after the last year covered by the most recent Demand Curves approved by the Commission shall be increased by the escalation factor approved by the Commission for such Demand Curves."[11]

13. Under the Part B Test, an "Installed Capacity Supplier shall be exempt from an Offer Floor if ... the average of the ICAP Spot Market Auction prices in the six Capability Periods beginning with the Starting Capability Period is projected by the ISO to be higher, with the inclusion of the Installed Capacity Supplier, than the reasonably anticipated Unit Net CONE of the Installed Capacity Supplier."[12] Generally stated, under the Part B Test, the NYISO evaluates whether the project is projected to be economic over the first three years after it enters.

14. Unit Net CONE is defined as the "... localized levelized embedded costs of a specified Installed Capacity Supplier, including interconnection costs... net of likely projected annual Energy and Ancillary Services revenues, as determined by the ISO, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate."[13] The determination of reasonably anticipated Unit Net CONE requires inputs for a project's capital costs, operating costs, and performance characteristics to

[11] *Id.* Section 23.4.5.7.4.

[12] *Id.* Section 23.4.5.7.2(b).

determine the annual levelized cost. The cost is offset with the energy and ancillary services revenues that the project is estimated to receive in the NYISO's markets.

15. The following is an overview of the computation of the Unit Net CONE under the Pre-Amendment Rules. The NYISO examines the project's investment costs and expresses the costs in the year's dollars of the first year of entry.[14] The investment cost is then expressed on a per kilowatt basis by dividing by the net degraded ICAP MW at ICAP conditions.[15] This value is multiplied by the real levelized carrying charge determined for the project, producing the annual capital costs. The fixed operations and maintenance ("O&M") costs are added to produce the annual cost of new entry ("CONE"). The annual CONE is then reduced by net energy and ancillary services revenues.[16] The resulting difference for the first year represents the first year annual net CONE. The various components of the annual net CONE are escalated in years 2 and 3 after entry, and the three annual values are averaged. The average is converted from ICAP to UCAP by dividing by one minus EFORd. The resulting

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[13] *Id.* Section 23.2.1 definition of "Unit Net CONE."

[14] In the Unit Net CONE calculation, costs are expressed in the nominal dollars of the first year of entry. This is done by escalating costs to the year's dollars of the first year of entry, if the costs are expressed in a prior year's dollars.

[15] Net degraded ICAP MW represents the plant capacity, net of station load, and assuming an average degradation over the life of the plant.

[16] The methodology used to compute energy and ancillary services revenues is discussed below and in the Affidavit of Eugene Meehan ("Meehan Affidavit").

value is the project's Unit Net CONE, expressed in dollars per kilowatt per year, in UCAP terms.

16. As described in my affidavit in Docket EL11-42-000,[17] but also applicable to the NYISO's examination of BEC under the Pre-Amendment Rules, the NYISO contracted with Sargent & Lundy LLC ("Sargent & Lundy") and NERA Economic Consulting ("NERA") to assist with performing the Unit Net CONE calculations. These were the consultants utilized by the NYISO in the previous and current ICAP Demand Curve reset proceedings and for the Unit Net CONE determinations under the In-City Buyer-Side Mitigation Measures. Sargent & Lundy has comprehensive expertise in the engineering and business of power plants. Its primary role in the Unit Net CONE determinations is to examine plant characteristics and cost data, including all of the information submitted by developers. NERA is an economic consulting firm, and its primary roles are to calculate net energy revenues and advise the NYISO on economic matters, such as estimating costs of capital.

IV. BEC Mitigation Exemption Test

17. As provided by the Pre-Amendment Rules, the NYISO conducted the exemption analysis of BEC after BEC executed an Interconnection Facilities Study Agreement. The NYISO issued the determination on October 25, 2010, *i.e.*, before the November

[17] Boles EL11-42 Affidavit at P 50.

27, 2010 effective date of the In-City Buyer-Side Mitigation Measures and thus, while the Pre-Amendment Rules were effective. The NYISO determined that BEC failed the Part A test but passed the Part B Test under the Pre-Amendment Rules and, therefore, was exempt from an Offer Floor. The analyses the NYISO performed in making these determinations are described below.

V. Part A Test

18. To Perform the Part A Test, the NYISO compared the annual price forecast in the first year of entry to the default Offer Floor. The forecast the NYISO used to perform the Part A Test is the first year of the forecast described in Paragraph 19 below.

19. The ICAP Spot Market Auction price forecast for Capability Year 2012/2013, with the inclusion of BEC, was \$27.02/kW-year, as can be seen in Exhibit JAB BEC-1 to this affidavit. The NYISO determined Mitigation Net CONE in accordance with the Pre Amendment Rules,[18] by applying the 7.8 percent escalation factor to escalate the Capability Year 2010/2011 reference point to the value for Capability Year 2012/2013.[19] The default Offer Floor based on Mitigation Net CONE was \$104.17/kW-year as can be seen in Exhibit JAB BEC-1 to this affidavit. The annual price forecast of \$27.02/kW-year was lower than the default Offer Floor of

[18] *See* Services Tariff Attachment H Section 23.4.5.7.4.

$104.17/kW-year, so BEC did not pass the Part A Test. Mr. Younger had the same result of BEC failing the Part A Test.[20]

VI. Part B Test: Unit Net CONE Analysis

20. In order to perform the Part B Test, the NYISO had to first determine BEC's Unit Net CONE. The inputs, methodology, and analyses that the NYISO used to determine BEC's Unit Net CONE are described in this section and are compared to those suggested by Mr. Younger.

a. *Investment Costs*

21. BEC identified costs for, among other things, the generating unit, interconnection facilities, system upgrades, site costs, and financing fees. These costs are referred to herein collectively as the "investment cost."

22. In accordance with the Pre-Amendment Rules, the Unit Net CONE is determined for the three-year period starting with the Capability Period in which the project is reasonably anticipated to first offer to supply UCAP (the "Starting Capability Period").[21] The month in which BEC was expected to first offer capacity was May

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[19] The then-currently effective Demand Curves included a 7.8 percent escalation rate. *See New York Independent System Operator, Inc.*, 122 FERC 61,064 (2008) at PP 14, 54- 55 (2008), *reh'g*, 125 FERC 61,299 at P 35 (2008).

[20] Younger Affidavit at P 53.

[21] *See* Services Tariff Attachment H Section 23.4.5.7.2(b).

2012, so the Starting Capability Period for its analysis was the Summer 2012 Capability Period. Therefore, the investment cost was expressed in 2012 dollars.

23. The investment cost determined by the NYISO for BEC was $[redacted] which equals $[redacted]/kW, using a denominator of [redacted] MW or [redacted] kW. The [redacted] MW value is the net degraded Installed Capacity of BEC. The supporting affidavit of Christopher Ungate of Sargent & Lundy provides a detailed description of BEC's investment cost.[22]

24. The $[redacted]/kW investment cost is net of "sunk costs", as described herein. The independent MMU recommended that the NYISO exclude costs incurred prior to the time the developer made its investment decision. The NYISO agreed with the MMU's rationale, which is discussed in the Affidavit of David Patton ("MMU Affidavit").[23] Sargent & Lundy's examination of BEC's development indicated that BEC, like many other projects, appeared to have multiple "go forward" dates in the advancement of development. Therefore, based on Sargent & Lundy experience, it estimated BEC's sunk costs to be a portion of certain owner's costs. Sargent & Lundy calculated owners sunk costs to be $[redacted] or $[redacted]/kW, which is the sum of Sargent & Lundy's estimate of one-half of permitting costs, one-half of legal costs, and the cost of environmental studies and market studies costs.

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[22] Appendix V to the Confidential Supplemental Answer at Section V ("Ungate BEC Affidavit").

[23] Appendix III to the Confidential Supplemental Answer at Section V ("MMU Affidavit").

25. Mr. Younger's estimate of the BEC investment cost was $1,907/kW.[24] BEC's investment cost determined by the NYISO was $[redacted]/kW, which is $[redacted]/kW [redacted] than the value assumed by Mr. Younger.

b. Real Levelized Carrying Charge

26. The NYISO next multiplied the per kilowatt investment cost by a real levelized carrying charge to determine the annual capital costs of the project over the first three years of entry. Sargent & Lundy calculated a carrying charge of [redacted] percent, which the NYISO then escalated for years 2 and 3 to [redacted] percent and [redacted] percent, respectively. The [redacted] percent charge reflects BEC's actual debt and equity financing costs, capital structure percentages, estimated expected income taxes for BEC, and an assumption of a 30-year useful life.[25]

27. The carrying charge assumed by Mr. Younger was 9.88 percent.[26] Mr. Younger based his rate on the carrying charge for the hypothetical financing structure used in the Demand Curve reset.[27] Mr. Younger assumed no property taxes, and he used a corresponding carrying charge. Mr. Younger also used a 30-year useful life.

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[24] Younger Affidavit at P 79.

[25] As discussed below BEC has [redacted] which are included in [redacted] Thus, [redacted]

[26] *Id.* at P 81.

[27] *See* New York Independent System Operator, Inc., Tariff Revisions to Implement ICAP Demand Curves for Capability Years 2011/2012, 2012/2013, and 2013/2014, Docket No. ER11-2224-000 (filed November 30, 2010), at Attachment 2 (Meehan Affidavit) Exhibit B "Independent Study to Establish

28. There is [redacted] percent difference between the [redacted] percent carrying charge value used by the NYISO and the 9.88 percent value assumed by Mr. Younger. The difference is mainly due to the fact that the NYISO used BEC's actual financing. Another reason for the difference is that the NYISO used a [redacted] composite income tax rate than Mr. Younger did in his analysis. The bases underlying these differences are as follows.

29. The MMU recommended using Bayonne's project-specific financing in the calculation of the carrying charges. The NYISO agreed with the MMU's rationale and recommendation, which is set forth in the MMU Affidavit.[28] BEC was financed with [redacted] percent debt at a nominal pre-tax cost of [redacted] percent, and [redacted] percent equity at a nominal cost of [redacted] percent. Sargent & Lundy used these numbers to calculate a real after-tax weighted average cost of capital ("WACC") of [redacted] percent. The real after-tax calculation performed by Sargent & Lundy removed 2.15 percent inflation net of technological progress and lowered the debt cost for federal income tax due to the deductibility of interest. Removing inflation from the carrying charge produces a carrying charge that is assumed to escalate through time with inflation, *i.e.*, it remains fixed in real terms but escalates with inflation in nominal terms.

30. Mr. Younger used financing assumptions of 50 percent debt at a nominal pre-tax cost of 7.25 percent, and 50 percent equity at a nominal cost of 12.48 percent. These

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Parameters of the ICAP Demand Curve for the New York Independent System Operator" ("NERA/S&L Demand Curve Report") at 36.

values produce the real after-tax WACC of 6.35 percent that Mr. Younger used.[29] BEC's actual WACC of [redacted] percent is [redacted] than Mr. Younger's estimate due to the [redacted], which is [redacted] on both pre-tax and after-tax bases, and the [redacted] nominal costs of debt and equity.

31. Sargent & Lundy utilized an estimated composite income tax rate. That rate is [redacted] than the rate implicitly assumed by Mr. Younger. For BEC, Sargent & Lundy calculated a composite income tax rate of [redacted] percent. That composite rate is calculated with a federal income tax rate of [redacted] percent, state income taxes of [redacted] percent, and New York City income tax rate of [redacted] percent.[30] Mr. Younger's composite income tax rate appears to be based on the rate used to calculate the carrying charge of 45.37 percent in the NERA/S&L Demand Curve Report.[31] Although those tax rates were accurate for the project used to compute the New York City ICAP Demand Curves, it is appropriate for the NYISO to use the rate that is expected to be applicable to the specific project when computing its costs.

c. Fixed Operations and Maintenance Costs

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[28] MMU Affidavit at Section VI.A.

[29] Younger Affidavit in Exhibit MDY-13 and MDY-17. The Net Present Value ("NPV") calculations in Mr. Younger's exhibits use a discount rate of 6.35 percent.

[30] BEC provided information that [redacted] percent.

[31] *See* NERA/S&L Demand Curve Report at 36. Mr. Younger has implicitly assumed a composite income tax rate of 45.37 percent, derived from federal, state, and city income tax rates of 35 percent, 7.10

32. Fixed O&M costs include labor, materials, contract services, administrative and general costs, site leasing costs, property taxes, and insurance. BEC's fixed O&M costs were calculated to be $[redacted]/kW-year, which equates to [redacted] percent of the investment cost. The fixed O&M figure includes [redacted] of $[redacted] and $[redacted] for [redacted]

33. Mr. Younger used a fixed O&M and site lease cost of 1.06 percent, which equates to $20.21/kW-year, using the $1,907/kW investment cost.[32] He based the fixed O&M value on the LMS100 proxy unit in the ICAP Demand Curve reset. Mr. Younger assumed zero property taxes.

d. Annualized Cost of New Entry

34. The annual CONE is calculated as the product of the investment cost and the carrying charge, plus the annual costs of fixed O&M. Stated as a formula:

annual CONE = (investment cost * carrying charge) + annual fixed O&M

The NYISO Unit Net CONE analysis of BEC used a year 1 (2012) annual CONE of $[redacted]/kW-year in ICAP terms. The value calculated by Mr. Younger was $208.63/kW-year in ICAP terms.[33] The BEC annual CONE calculated by the NYISO is $[redacted]/kW-year [redacted] than the value calculated by Mr. Younger. The BEC annual

percent, and 8.85 percent, respectively. The calculation of the composite tax rate is provided in Table II-8 of the NERA/S&L Demand Curve Report.

[32] Younger Affidavit at P 82.

[33] *Id.*

capital costs calculated by the NYISO are $[redacted]/kW-year [redacted] and the fixed O&M is $[redacted]/kW-year [redacted] than the values calculated by Mr. Younger. As delineated above, the primary differences are BEC's [redacted] than the values assumed by Mr. Younger.

e. Net Energy Revenues

35. The NERA econometric model (referred to herein as the "NERA model") was used as the basis for calculating net energy revenues for BEC. It is the same model used in the two most recent ICAP Demand Curve resets,[34] with certain adjustments, as discussed in the Affidavit of Eugene T. Meehan ("Meehan Affidavit")[35] The NERA model provided an estimate of likely net energy revenues. Utilizing the NERA model, with the described adjustments, NERA calculated net energy revenues for BEC of $[redacted]/kW-year. Given that the net energy revenues produced by the NERA model have been approved by the Commission for the Demand Curve peaking plant, and that the adjustments described by Mr. Meehan that were tailored to determine a project-specific net CONE, I believe that the methodology, and the resulting BEC net energy revenues, are reasonable.

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[34] *See* NERA/S&L Demand Curve Report at 7-11, *see also New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 at P 136; *New York Independent System Operator, Inc.,* 122 FERC 61,064 at P 47 (2008), *reh'g,* 125 FERC 61,299 (2008).

[35] Appendix VI to Confidential Supplemental Answer at P 16 ("Meehan Affidavit").

36. Combined with the ancillary services revenues estimated by the NYISO (determined as described below), the total year 1 net energy and ancillary services revenues were estimated to be $[redacted]/kW-year, as shown in Table 1. This value is [redacted] than Mr. Younger's year 1 values of $51.35/kW-year and $43.54/kW-year, (each computed based on his different energy forecasts, as discussed below).[36] The differences between the NYISO's methodology and assumptions and those used by Mr. Younger are described below.

37. The NERA model estimates net energy revenues relative to the Zone J price, which is a load-weighted average price, and is the price used in the ICAP Demand Curve reset. BEC connects at the 345 kV level. Although I believe the estimate produced by the NERA model for BEC is reasonable, an alternate approach would be to further adjust the net energy revenues estimated by the NERA model to account for the prices at 345-kV level. This adjustment was not included in the exemption analysis for BEC, but the methodology and the impacts that its application would have had on BEC's Unit Net CONE are described below. With or without making a "345 kV adjustment," BEC would still be exempt under the Part B Test.

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[36] Younger Affidavit at P 87. The $51.35/kW-year value includes AEII and BEC in the energy forecasts. The $43.54./kW-year value includes AEII, BEC, and the Hudson Transmission Partners project.

i. Gas Futures

38. The net energy revenues used to compute the Unit Net CONE value of $[redacted]/kW-year in UCAP terms were calculated for the first three years of entry, Summer 2012 through Winter 2014/2015. The net energy revenue model utilized gas futures prices for the same period for which net energy revenues were computed: November 2011 through October 2014, as discussed in the Meehan Affidavit.[37] At the recommendation of the MMU, the NYISO used the projected gas futures prices at the time of the investment decision, *i.e.*, October 20, 2010. The average gas futures price used in the analysis, observed as of October 20, 2010, was $5.85/MMBtu. The fuel price used for BEC did not reflect the NYC taxes and local distribution charges, as explained in the Meehan Affidavit. Mr. Younger,[38] however, relied on the calculations from the NERA/S&L Demand Curve Report filed in November 2010, which used actual gas prices over the period November 1, 2006 to October 31, 2009 (the "Historic Period"). The average gas price over the Historic Period was $8.00/MMBtu. The Meehan Affidavit describes the application of gas futures in the calculation of the net energy revenues for BEC.[39]

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[37] Meehan Affidavit at P 26.

[38] Younger Affidavit at P 67.

[39] Meehan Affidavit at PP 17-20.

ii. Level of Excess

39. The average level of excess that the NYISO used for the three year period used to calculate net energy revenues was 15 percent. Mr. Younger used a 14.28 percent average level of excess over the first three years under one of his two scenarios. In his alternate scenario in which he included Hudson Transmission Partners project ("HTP") in the forecast, he used a level of excess of 18.87 percent. The NYISO did not include HTP in the forecast because it was not appropriate to do so. At the time of the NYISO's determination, it was reasonable to believe that HTP, which entered the NYISO's Interconnection Queue in 2005 with an original entry date of the second quarter of 2009, would not enter the market during the period for which BEC was being examined. The NYISO used the load forecast from the NYISO's 2010 Load & Capacity Data report (the "2010 Gold Book"),[40] as described below. Mr. Younger also utilized the 2010 Gold Book; however, he calculated levelized net revenues over 30 years and 3 years.

iii. 345-kV Adjustment

40. The NERA model predicts the Zone J LBMP, which is a load-weighted average of the LBMPs at the load buses in Zone J. The BEC project is connecting to the transmission system at the Gowanus Substation in Brooklyn, NY on the 345-kV

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[40] 2010 Gold Book *available at* <http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2010_GoldBook_Public_Final_033110.pdf>

system. Although it was reasonable for the NYISO to use the NERA model, with adjustments, to compute the likely BEC net energy revenues, an adjustment to the value produced by the NERA model could be made to account for prices at the 345 kV level historically being lower than the Zone J load-weighted average of the LBMPs.

41. To determine the 345 kV adjustment, the NYISO calculated the average difference between the day-ahead Zone J price, and the day-ahead price on the New York City 345-kV system at the Poletti bus,[41] over the Historic Period. The average difference over all hours was $1.70 per MWh. This value was then multiplied by the average annual number of run hours for BEC in the NERA model, which was [redacted] hours (*i.e.*, [redacted]ours reduced by the BEC EFORd of [redacted] percent). The product of $1.70/MWh and [redacted] hours was divided by 1,000 to convert to kilowatts, which produced [redacted]kW-year. The value is not escalated for inflation because it represents a spread between two numbers; the effect of inflation is negligible when both numbers escalate concurrently. The adjustment and its effects on BEC's Unit Net CONE are shown below in Table 1.

42. Mr. Younger made a similar adjustment in his analysis, which was also based on the average price difference over the Historic Period. Mr. Younger calculated the

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[41] The Poletti generator bus is located on the 345 kV system and the prices at that location provide the basis to compute the delta between the 345 kV prices and the zonal prices which include prices at the 138 kV systems.

average Poletti bus LMBP as $68.79/MWh and the average Zone J LBMP as $70.49/MWh, and he reported the difference as 1.7 percent.[42] He then calculated net energy revenues at the Poletti bus and Zone J, using the $8/MMBtu average gas price over the Historic Period and an assumed heat rate of 7,000 Btu/kWh. According to Mr. Younger's calculations, the net energy revenues at the 345-kV level were 12.3 percent less than the net revenues at the Zone J prices. Mr. Younger uses this finding to apply a 10 percent reduction to net energy revenues from the NERA model. The net energy revenues at the 0.15 reserve margin (*i.e.*, 15 percent excess level) reported by Mr. Younger are $41.27/kW-year.[43] Mr. Younger has reduced this value by 15 percent or $37.14/kW-year, to account for lower net energy revenues at the 345 kV level. The adjusted value reflects a reduction of $4.17/kW-year, which is [redacted] than the [redacted]/kW-year net energy revenue reduction calculation by the NYISO.

f. Ancillary Services

43. The NYISO estimated ancillary services revenues for BEC to be [redacted]/kW-year in year 1. The NYISO computed the ancillary services revenues using actual ancillary services revenues received by simple cycle gas turbines in NYC. Contrary to Mr. Younger's assertions, the NYISO's estimate of BEC's ancillary services does not

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[42] Younger Affidavit at P 67. Mr. Younger's calculation of a 1.7 percent difference appears to be an error. Based on Mr. Younger's numbers, the dollar per MWh difference is $1.70/MWh, consistent with the NYISO's calculation.

[43] Younger Affidavit at Exhibit MDY 16.

include revenues from regulation service, for which BEC would be eligible, and [redacted]. The NYISO's estimate of $[redacted]/kW-year number is [redacted] used by Mr. Younger.[45] BEC's estimated ancillary services revenues are [redacted] percent of BEC's estimated total revenues. The optionality of being able to provide several ancillary services as well as energy could only serve to make the NYISO's total revenue estimate conservative.

g. Unit Net CONE

44. The annual net CONE in each of the first three years after entry is calculated by subtracting the net energy and ancillary services revenues from the annual CONE value. The Unit Net CONE is then calculated by averaging the three values in ICAP terms. The ICAP value is then converted to UCAP by dividing by one minus EFORd. BEC's Unit Net CONE was $[redacted]/kW-year ICAP, which is $[redacted]/kW-year UCAP. These calculations are shown in Table 1.

45. Mr. Younger calculates a Unit Net CONE of $163.15/kW-year UCAP in the scenario with BEC and AEII in the capacity forecast, and $171.27/kW-year UCAP in the scenario with BEC, AEII, and HTP in the forecast.[46] Mr. Younger's higher numbers

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[44] *Id.* at P 52.

[45] *Id.* at P 83.

[46] *Id.* at P 89.

are attributable to his selection of inputs which resulted in a higher annual CONE and the lower net energy and ancillary services revenues, as demonstrated above.

46. At the final step of calculating Unit Net CONE, there is a methodological difference between the calculations of the NYISO and Mr. Younger. First, Mr. Younger calculated a value in 2012 dollars, whereas the NYISO has calculated a Unit Net CONE using the value equal to the average of the annual net CONE values for 2012, 2013, and 2014. For purposes of the Part B Test, Mr. Younger calculated Unit Net CONE by escalating the value in 2012 dollars to Years 2 and 3, and then averaging the three values.[47] The NYISO does not calculate a Unit Net CONE in 2011 dollars, and then escalate it and average it to create another Unit Net CONE value. The Part B test requires one value for Unit Net CONE. That test states that the project will be exempt from an Offer Floor if "the average of the ICAP Spot Market Auction prices in the six Capability Periods beginning with the Starting Capability Period is projected by the ISO to be higher, with the inclusion of the Installed Capacity Supplier, than the reasonably anticipated Unit Net CONE of the Installed Capacity Supplier."[48] Accordingly, the NYISO calculated the Unit Net CONE as the straight average of the three annual net CONE values.

[47] *Id.* at P 12, Table 2, and P 90.

[48] Services Tariff Attachment H Section 23.4.5.7.2(b).

Table 1: Summary of NYISO Computation of BEC Unit Net CONE

	Capability Year	2012/2013	2013/2014	2014/2015	Notes
A	Total investment cost per kW	[redacted]			Capital costs escalated to 2012 dollars
B	Real levelized carrying charge				Years 2 and 3 escalated
C	Annual fixed O&M				Years 2 and 3 escalated
D	CONE (ICAP)				= A * B + C
E	Net energy revenues (15% excess)				Average annual net revenues (zonal)
F	Ancillary services revenues				Years 2 and 3 escalated
G	Net E&AS revenues				= E - F + G
H	Annual net CONE				= D - H
I	Unit Net CONE (ICAP)				= Average (CY2012/13, CY2013/14, CY2014/15)
J	Unit Net CONE (UCAP)				= I / (1 - EFORd)
	Summer month Offer Floor (UCAP)				
	Winter month Offer Floor (UCAP)				
With Alternate 345 kV Approach					
K	345 kV adjustment				Reduction for 345 kV price
L	Annual net CONE				= D - G + K
M	Unit Net CONE (ICAP)				= Average (CY2012/13, CY2013/14, CY2014/15)
N	Unit Net CONE (UCAP)				= M / (1 - EFORd)
	Summer month Offer Floor (UCAP)				
	Winter month Offer Floor (UCAP)				

VII. BEC Part B Test Determination

47. The Part B Test compares the average annual price forecast over the first three years after entry, to the project's Unit Net CONE. The forecast the NYISO used to perform the Part B Test and its inputs, and the differences with those used by Mr. Younger, are described below.

48. The NYISO determined that the three-year average annual price forecast for Capability Year 2012/2013 through Capability Year 2014/2015 was $35.67/kW-year. BEC's Unit Net CONE was $[redacted]/kW-year. The price forecast is higher than BEC's Unit Net CONE, so BEC passes the Part B Test and is exempt from the Offer Floor.

49. Mr. Younger's analysis found that BEC failed the Part B Test. As discussed above, Mr. Younger performed the test under two scenarios: first, assuming additions of BEC and AEII, and second, assuming additions of BEC, AEII, and HTP.[49] In his first scenario, his price forecast of $29.62/kW-year was lower than his Unit Net CONE of $170.27/kW-year. In the second scenario, his price forecast of $11.40/kW-year was lower than his Unit Net CONE of $178.74/kW-year. The differences between the NYISO's Unit Net CONE calculations and Mr. Younger's were presented above.

a. ICAP Spot Market Auction Price Forecasts

50. The Part B Test requires forecasting six Capability Periods of In-City ICAP prices, beginning with the Capability Period that the project is expected to first enter. For BEC, this first Capability Period is Summer 2012, so that the first six Capability Periods span Summer 2012 through Winter 2014/2015. The BEC Part B Test price forecast of $35.67/kW-year represents the average annual price forecast for these six Capability Periods. This value differs from the values calculated by Mr. Younger because of the resource additions he selected to use.

i. Demand Curve Parameters

[49] Younger Affidavit at P 91.

51. The NYISO performed its analysis using the Demand Curves accepted by the Commission for Capability Years 2008/2009, 2009/2010, and 2010/2011.[50] Accordingly, the NYISO obtained the reference points and escalation rate from those New York City Demand Curves.

52. In accordance with the Pre-Amendment Rules, to obtain the reference point for the Summer 2012 Capability Period, the NYISO escalated the $15.99/kW-year Summer 2010 reference point on the 2010/2011 New York City Demand Curve by the escalation rate of 7.8 percent approved by the Commission for that ICAP Demand Curve. Escalation was applied for two years in order to convert the 2010 reference point into a value in 2012 dollars. The 2013 and 2014 reference points were escalated at the same rate. This produced a 2012 ICAP reference point of $18.58/kW-year. The ICAP Demand Curves used a reference point in ICAP terms: the $15.99/kW-year value as the starting point to which the 7.8 percent annual escalation is applied.[51]

ii. ICAP to UCAP Conversion, EFORd, and Load Forecast

53. The $18.58/kW-year ICAP reference point was then converted to a UCAP value of $19.95/kW-year using the New York City Locality EFORd of 6.85 percent. The EFORd used was the then-current New York City EFORd for Winter 2010/2011,

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[50] *See New York Independent System Operator, Inc.*, 122 FERC 61,064 (2008) at P 1 *reh'g*, 125 FERC 61,299 (2008).

[51] Younger Affidavit at Exhibit MDY-9.

which was available in September 2010.[52] The load forecasts from the 2010 Gold Book were used. The NYC load forecasts from Table I-2a of the 2010 Gold Book for 2012, 2013, and 2014 were 11,815 MW, 11,925 MW, and 11,995 MW, respectively.

54. The ICAP Demand Curves used by Mr. Younger in his analysis use the same reference points; the $15.99/kW-year value is the starting point to which the 7.8 percent annual escalation is applied.[53] Mr. Younger also assumes the same New York City Locality EFORd of 6.85 percent.

55. Mr. Younger also uses load forecasts from Table I-2a of the 2010 Gold Book forecasts of 11,775 MW, 11,815 MW, and 11,925 MW.[54]

iii. Existing Capacity and Resource Additions

56. The NYISO used the 2010 Gold Book to determine the levels of existing capacity, scheduled retirements, and resource additions to use in the ICAP forecasts. From the 2010 Gold Book, the level of existing capacity, net of the scheduled retirements of zero MW, was 8,969.6 MW for Summer and 9,998.6 MW for Winter. These capacity values were assumed as the Summer/Winter values in the NYISO's analysis. Mr. Younger also used the 2010 Gold Book to determine values for existing capacity and

[52] NYISO ICAP AMS, Season Winter 2010/2011 Derating Factor %, *available at* <http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do>.

[53] Younger Affidavit at Exhibit MDY-9.

[54] *Id.*

retirements. For the Linden VFT, the NYISO included 307.5 MW ICAP whereas Mr. Younger assumed 300 MW ICAP.[55]

57. The NYISO forecast generator additions using Table IV-1 of the 2010 Gold Book. That table listed six proposed generator additions in Zone J: NYC Energy LLC (queue position 19), Bayonne Energy Center (queue pos. 232), Astoria Energy II (queue pos. 308), South Pier Improvement (queue pos. 261), Berrians GT III (queue pos. 266), and Co-op City (no queue pos.). The Hudson Transmission Project (queue pos. 206) was listed in Table VIII-1 as a proposed transmission facility. Of these projects, the NYISO included BEC and AEII in the ICAP forecasts as price takers; *i.e.*, offering at $0.00/kW-month. NYC Energy was withdrawn from the Interconnection Queue at the time of the analysis.

58. The supply additions assumed by Mr. Younger include BEC and AEII in one scenario and BEC, AEII, and HTP in another. The NYISO analysis did not include HTP because at the time of BEC's investment decision it was reasonable to assume that HTP would not enter the capacity market during the three-year period after BEC's entry. Thus, the difference in the assumptions of the MW of supply additions in the BEC forecast is that, in one scenario, Mr. Younger has included HTP.

iv. Unoffered UCAP

[55] *Id.*

59. The ICAP forecasts used by the NYISO excluded average historic values of unoffered UCAP. Unoffered UCAP is UCAP that is available for sale but is not sold through NYISO auctions, certified toward bilateral transactions, or used for self-supply. The unoffered UCAP values were calculated from the seasonal averages of previous like-Capability Periods. For Summer, the value of 14.1 MW was used, and for Winter, the value of 18.3 MW was used. The ICAP forecasts performed by Mr. Younger did not exclude unoffered capacity.

v. Minimum Clearing Price

60. Mr. Younger acknowledged that there would be a positive minimum clearing price in the ICAP auctions. He identified it at $0.50/kW-month.[56] The NYISO utilized $1.00/kW-month, which was reasonable. A reduction in ICAP Spot Market Auction Clearing Prices in the very short term can be expected to occur after an increase in supply. However, it is not reasonable to expect that such a reduction would persist because, if the price level was low for a period of time, some units would be expected to mothball or retire. Since the exemption test requires that the analyses be performed for a three-year period beginning upon entry, it is not reasonable to only apply a very short term assumption to forecasting capacity prices. Therefore, the use of the $1.00/kW-month minimum is a more appropriate representation of a minimum clearing price.

[56] Younger Affidavit at P 42.

VIII. Conclusion

61. My affidavit supports that the above-described data, methodologies, assumptions, and analyses utilized by the NYISO, and its exemption determination for BEC, conform to the Pre-Amendment Rules. It also demonstrates that Mr. Younger's data, methodology, assumptions, and analyses are flawed in several significant aspects and fail to show that the NYISO's determinations do not conform to the Pre-Amendment Rules.

This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing Confidential Supplemental Affidavit of Joshua A. Boles Regarding Bayonne Energy Center (the "Affidavit"). I have read the Affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

J. A. Boles

Joshua A. Boles
Supervisor, Market Mitigation and Analysis
New York Independent System Operator, Inc.
September 7, 2011

Subscribed and sworn to before me
this 7th day of September 2011.

DIANE L. EGAN
Notary Public, State of New York
Qualified in Schenectady County
No. 4924890
Commission Expires March 21, 20 13

Diane L. Egan

Exhibit JAB BEC-1

Exhibit JAB BEC-1

Mitigation Exemption Tests: Bayonne Energy Center

Input/Calculation	*Units*	*ICAP Summer*	*Winter*	*Escalation/ EFORd*	Summer 2012	2013	2014	Winter 2012	2013	2014
NYC Load Forecast	ICAP				11,815.0	11,925.0	11,995.0	11,815.0	11,925.0	11,995.0
NYC Installed Reserve Margin Percentage	%				80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
NYC Demand Curve ICAP Ref Point		$ 15.99		7.80%	$ 18.58	$ 20.03	$ 21.59	$ 18.58	$ 20.03	$ 21.59
ICAP/UCAP derating factor	%				6.85%	6.85%	6.85%	6.85%	6.85%	6.85%
NYC UCAP Ref Point	UCAP				$ 19.95	$ 21.50	$ 23.18	$ 19.95	$ 21.50	$ 23.18
NYC UCAP Requirement	UCAP				8,804.5	8,886.5	8,938.7	8,804.5	8,886.5	8,938.7
Demand Curve Zero Crossing	%				118%	118%	118%	118%	118%	118%
UCAP at $0	UCAP				10,389.4	10,486.1	10,547.6	10,389.4	10,486.1	10,547.6
Demand Curve Slope. Per 100 MW	$/MW*100				$ (1.2588)	$ (1.3441)	$ (1.4407)	$ (1.2588)	$ (1.3441)	$ (1.4407)
Existing Generation Capacity	ICAP				8,969.6	8,969.6	8,969.6	9,998.6	9,998.6	9,998.6
Subtotal	UCAP				8,355.2	8,355.2	8,355.2	9,313.7	9,313.7	9,313.7
Special Case Resources	UCAP				481.2	481.2	481.2	371.3	371.3	371.3
Historic Unoffered Capacity	UCAP				(14.1)	(14.1)	(14.1)	(18.3)	(18.3)	(18.3)
Subtotal Existing Capacity	UCAP				8,822.3	8,822.3	8,822.3	9,666.7	9,666.7	9,666.7
Additions										
NYC Energy LLC (2010/Q4)		79.9	79.9	6.85%						
Bayonne Energy Center		500.0	500.0	6.85%	465.8	465.8	465.8	465.8	465.8	465.8
Astoria Energy II, LLC (2011/05)		576.0	617.2	6.85%	536.5	536.5	536.5	574.9	574.9	574.9
South Pier Improvement (2012/05)		91.2	95.5	6.85%						
Berrians GT III (2012/06)		789.0	789.0	6.85%						
Riverbay Co-op City		24.0	24.0	6.85%						
Linden VFT (2010)		307.5	307.5	6.85%	286.4	286.4	286.4	286.4	286.4	286.4
HTP		660.0	660.0	6.85%						
Total Additions	UCAP				1,288.7	1,288.7	1,288.7	1,327.1	1,327.1	1,327.1
Total Forecast Capacity	UCAP				10,111.0	10,111.0	10,111.0	10,993.8	10,993.8	10,993.8
Forecast Clearing Price	$/kW-mo				$ 3.50	$ 5.04	$ 6.29	$ 1.00	$ 1.00	$ 1.00
Part A Test: First Year Forecast	$/kW-yr				$ 27.02				*minimum price*	*$1.00*
Part B Test: Average Annual Forecast	$/kW-yr				$ 35.67					

Exhibit JAB BEC-1

Part A Test	MST Att. H, Section 23.4.5.7.2(a)			
Part A Test Inputs		*Capability Year 2012/2013*		
NYC Annual ICAP Revenue Requirement, Capability Year 2010/2011	S/kW-yr		$ 143.15	$ 143.15
Demand Curve Escalation Factor	%		7.8%	$ 166.35
Mitigation Net CONE	S/kW-yr		77.8%	$ 129.39
Default Offer Floor, ICAP	S/kW-yr		75.0%	$ 97.04
Default Offer Floor, UCAP	S/kW-yr		6.90%	$ 104.17
Part A Test Determination				
First Year Price Forecast				$ 27.02
Offer Floor based on 75% of Mitigation Net CONE				$ 104.17
Determination				Not Exempt
Part B Test	MST Att. H, Section 23.4.5.7.2(b)			
Part B Test Determination				
Three Year Average Annual Price Forecast				$ 35.67
Unit Net CONE				[redacted]
Determination				Exempt
Key				
Green shading denote spreadsheet input				
Yellow shading denots spreadsheet calculation				

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

APPENDIX III

CONFIDENTIAL AFFIDAVIT OF DR. DAVID B. PATTON

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Astoria Generating Company, L.P	)	
and TC Ravenswood, LLC	)	
	)	**Docket No. EL11-50-000**
vs.	)	
	)	
New York Independent System Operator,	)	
Inc.	)	

AFFIDAVIT OF DAVID B. PATTON, PH.D.

September 7, 2011

I. Qualifications

1. My name is David B. Patton. I am an economist and President of Potomac Economics. Our offices are located at 9990 Fairfax Boulevard, Fairfax, Virginia 22030. Potomac Economics is a firm specializing in expert economic analysis and monitoring of wholesale electricity markets, and is the Market Monitoring Unit ("MMU") for the New York Independent System Operator, Inc. ("NYISO"). Potomac Economics serves in a substantially similar role for ISO New England, the Midwest Independent Transmission System Operator, Inc., and the Electric Reliability Council of Texas.

2. As the MMU for the NYISO, Potomac Economics is responsible for assessing the competitive performance of the markets that the NYISO administers, including the ICAP[1] market, and for assisting in the implementation of a monitoring plan to identify and remedy potential market design flaws and abuses of market power. This work has included preparing a number of reports that assess the performance of these markets and providing advice on numerous issues related to market design and economic efficiency. Prior to Potomac Economics becoming the MMU, I served as the independent Market Advisor to the NYISO.

3. I have worked as an energy economist for twenty years, focusing primarily on the electric utility and natural gas industries. I have provided strategic advice, analysis, and expert testimony in the areas of electric power industry restructuring, pricing, mergers, and market power. I have also advised Regional Transmission Organizations on transmission pricing, market design, and congestion management issues. With regard to competitive analysis, I have provided expert testimony and analysis regarding market power issues in a number of

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1 Terms with initial capitalization not defined herein or in the Confidential Supplemental Affidavit to which this Affidavit is appended, have the meaning set forth in the NYISO's Market Administration and Control Area Services Tariff, and if not defined therein, then as defined in the NYISO's Open Access Transmission Tariff.

mergers and market-based pricing cases before the Federal Energy Regulatory Commission ("Commission"), state regulatory commissions, and the U.S. Department of Justice.

4. Prior to my experience as a consultant, I served as a Senior Economist in the Office of Economic Policy at the Commission, advising on a variety of policy issues including transmission pricing and open-access policies, market design issues, and electric utility mergers. As a member of the Commission's advisory staff, I worked on policies reflected in Order No. 888, particularly on issues related to power pool restructuring, independent system operators ("ISOs"), and functional unbundling. I also analyzed the competitive characteristics of alternative transmission pricing and electricity auctions proposed by ISOs.

5. Before joining the Commission, I worked as an economist for the U.S. Department of Energy. During this time, I helped to develop and analyze policies related to investment in oil and gas exploration, electric utility demand side management, residential and commercial energy efficiency, and the deployment of new energy technologies.

6. I have a Ph.D. in Economics and a M.A. in Economics from George Mason University, and a B.A. in Economics with a minor in Mathematics from New Mexico State University.

II. Purpose and Summary of this Affidavit

7. The NYISO's Buyer-Side Mitigation ("BSM")[2] rules were designed to deter uneconomic entry that would otherwise reduce capacity prices below competitive levels, while avoiding any market intervention that would serve as a barrier to economic entry. In order to properly distinguish economic entry from uneconomic entry, under the Pre-Amendment

[2] The NYISO refers to the version of the BSM rules that were in effect at the time that it made the exemption determinations for AEII and Bayonne as the "Pre-Amendment Rules."

Rules the NYISO performs Mitigation Exemption Test ("MET") evaluations on all prospective entrants to the New York City market that request it.[3]

8. The purpose of my affidavit is to describe the advice I have given to the NYISO related to three aspects of the MET evaluations for the Astoria Energy II ("AEII") project and the Bayonne Energy Center ("Bayonne") project. Specifically, this affidavit describes my recommendations to the NYISO regarding how to (1) consider the timing of the investment decision, (2) treat costs incurred prior to the decision to invest (known as "sunk costs"), and (3) consider the financing terms obtained by the specific project.

9. My affidavit is divided into the following sections. Section III discusses several general principles that should be applied in MET evaluations to ensure that the BSM rules deter uneconomic entry, while avoiding any market intervention that would discourage economic entry. The NYISO adhered to these principles when it conducted the AEII and Bayonne MET evaluations. Section IV explains how the timing of the investment affects the forecasted economics of the project. Section V discusses how a rational investor would treat sunk costs when deciding whether to move forward with an investment. Section VI explains how the financing terms available to a rational investor affect its investment decision. Each of these sections addresses how these principles should be applied in the MET determinations for the AEII and Bayonne projects. The Boles Affidavits, Ungate Affidavits, and Meehan Affidavit demonstrate that the NYISO did apply these principles in the AEII and Bayonne determinations.

III. General Principles Used in MET Evaluations

10. The fundamental purpose of the BSM rules is to deter uneconomic entry that would otherwise reduce capacity prices below competitive levels. Uneconomic entry is building

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3 Under the current In-City Buyer-Side Mitigation Measures, the timing of the determination is prescribed.

new resources or expanding existing resources when a rational investor would expect them to be uneconomic based on a reasonable expectation of future wholesale market prices. Accordingly, the basic methodology used in the MET evaluations is to assess whether a rational investor would expect the future wholesale market revenues earned by the project to exceed the future costs of building the project. The conditions prevailing at the time the new resource enters the market and begins selling capacity are not relevant since the binding decision to enter generally occurs years in advance. Hence, it is critical that the MET evaluation consider only the expected costs and future market conditions that existed at the time the investor decided to move forward with the investment.

11. Each MET evaluation estimates the annual levelized Cost of New Entry ("CONE") of the new project based on what a rational investor would expect regarding construction costs, capital costs, and other costs. Under the the MET evaluation that the NYISO refers to as the "Part B Test," the NYISO computes a project's estimated annual fixed operating costs and then subtracts the estimated annual net revenues that the project would earn from the wholesale energy and ancillary services markets. In this manner, the MET evaluation determines the Unit Net CONE of the project. If the Unit Net CONE of the project is less than the projected capacity prices during the first three years of expected operation, the project is exempted from mitigation. The MET evaluations require the NYISO to make reasonable projections of a number of factors that are subject to uncertainty, which is entirely consistent with the assessment that a rational investor must make before determining that a particular project is likely to be economic.

12. The MET evaluations do not, as Mr. Younger recommends, consider the actual revenues received by the project under a Power Purchase Agreement ("PPA").[4] Such payments are

[4] *See Complainants' Motion for Leave to Answer and Answer*, Docket No. EL11-50-000 (filed August 19, 2011, Attachment A at PP. 18-29. Mr. Younger's assertion at P. 22 that the PPA provides useful information about the CONE of AEII is inconsistent with economic theory. He states: "Given that the process was, according to NYPA, competitive, a rational respondent to the

not relevant to an evaluation of whether the project would be economic ***without*** such payments. While such payments might allow a supplier to receive a return on investment that exceeds the revenues it would likely earn in the wholesale market, this would not by itself indicate that the project is uneconomic, just that the project received an above-market rate of return. This is why the MET evaluations seek to determine whether a rational investor would expect the wholesale market revenues earned by the project to exceed the investment cost of the project. If this is true, it is economic regardless of the subsidies. If not, it is uneconomic regardless of the subsidies and should be mitigated.

13. The MET evaluations should not mitigate conduct that constitutes economic entry. Therefore, a project that is expected to be economic because it has a legitimate competitive advantage over other projects should not be mitigated. Such a project will have a lower Unit Net CONE than other projects. For this reason, MET evaluations incorporate information on project-specific cost advantages.

14. Lastly, when estimating the Unit Net CONE of a project, it is important to balance the risks of over-estimation against the risks of under-estimation. Under-estimating the Unit Net CONE may lead to under-mitigation, which could reduce the deterrence value of the BSM rules and reduce capacity prices below competitive levels. Over-estimating the Unit Net CONE may lead to over-mitigation, which would hinder economic investment and raise capacity prices above competitive levels. To balance these two concerns, it is important to

RFP would have offered to supply NYPA at, or close to, its actual cost to ensure its best opportunity of being the winning bidder in the RFP." In a competitive procurement, economic theory predicts that a rational respondent that has the lowest cost will bid just below the second most competitive respondent. If the winning respondent has a significantly lower cost than other respondents (as AEII is likely to have with the advantage of a preexisting site that was previously prepared for an additional generator), the winning respondent's bid will exceed its costs by a substantial margin.

be unbiased in the application of the BSM rules. I believe that the NYISO took such a balanced approach in the MET evaluations at issue here.

IV. Timing of Investment

15. A rational investor must decide whether to incur the costs of investment based on an imperfect knowledge of the future before it actually enters and begins to realize revenues from the investment. Therefore, an MET evaluation should assess whether a rational investor could reasonably expect a project to be economic based on information available at the time the investor committed to going forward.

16. Investment in new generation is risky, requiring large up front expenditures that are typically recouped over a period of decades. After a rational investor begins to incur costs, wholesale prices may fluctuate due to unforeseen market factors and competitive pressures. Between the time when an investor decides to move forward and the actual start of operations, the estimated profitability of an investment may change considerably.

17. The purpose of the BSM rules is to mitigate the decision to build when a rational investor would predict that it would be uneconomic to do so. Hence, it would not be appropriate to mitigate a project because the investor failed to predict a downward change in market conditions. Accordingly, each MET evaluation should be based on information that would have been available at the time when the investor began to incur significant costs. To the extent information is not available regarding what an investor thought at the time, the MET evaluations should use information available about what a rational investor would likely have expected at the time.

18. The Commission has consistently recognized and affirmed that the BSM rules are intended to determine whether an investment could reasonably be expected to be economic based on information available at the time the decision was made to move forward. In its November 26, 2010 Order in Docket No. ER10-3043, the Commission stated: "An entity whose

resource is forecast to be economic at the time its construction begins is not attempting to artificially depress market prices through uneconomic entry. Thus, it would not be reasonable to impose an offer floor on such a resource that prevented it from clearing in the capacity auction if market conditions unexpectedly worsened by the time that construction is completed." [5]

19. In the MET evaluation, it is important to identify the point in time the investor committed to the investment. This would normally be the time at which the investor began to incur significant costs that could not recouped if it decided to discontinue the project. To the extent that information is available, all assessments of the reasonably expected costs and revenues should be based on information that would have been available at the time the decision was made to move forward with the investment.

20. The remainder of the section discusses my advice to the NYISO regarding when the Bayonne and AEII projects began to move forward.

A. Evaluation of the Timing of the Bayonne Project

21. In its MET evaluation of the Bayonne project, the NYISO determined that the Hess Corporation was making its decision to move forward with the project in relation to obtaining the NYISO's MET determination, which was made in October 2010. It expected to be in service in April 2012, and thus would enter the capacity market in May 2012. Accordingly, energy and ancillary services net revenue estimates and the estimated capacity clearing prices for the three-year period from May 2012 to April 2015 were estimated based on information available in October 2010.

22. It is likely that Hess committed to proceeding with the investment earlier than October 2010 because it would likely have had to incur significant costs before this date to enter the

5 *See* P. 71.

NYISO market in April 2012. We understand that BEC incurred significant investment expenses beginning in April 2010, although it closed on project financing on September 30, 2010. While it may have been reasonable to have selected a date in early 2010, using information consistent with the earlier selected date, this would not likely have affected the outcome of the MET evaluation. Both natural gas prices and forecasted load decreased in 2010, which would both reduce the apparent profitability of the project. Therefore, by selecting October 2010 as the assumed decision date by BEC, the NYISO reduced the likelihood that Bayonne would be exempted and selecting an earlier assumed decision date should produce the same outcome.

B. Evaluation of the Timing of the AEII Project

23. In its MET evaluation of the AEII project, the NYISO determined that the project developer made its decision to move forward with the project in July 2008 for three reasons.

- AEII signed its contract with NYPA to develop the project on July 11, 2008;
- AEII signed agreements with key suppliers in July 2008, including a contract with General Electric for purchase of the generators;
- AEII began to incur significant expenses in July 2008.

24. Accordingly, although the NYISO performed the MET evaluation for the AEII project in 2010, I recommended that the NYISO base the evaluation on information that would have been available in July 2008 in order to determine whether the project would have been expected to be economic at the time the decision was made to move forward. Hence, the energy and ancillary services net revenue estimates and the reasonably anticipated capacity clearing prices for the three-year period from May 2011 to April 2014 were estimated based on information that would have been available in July 2008 to the extent that information was available from that time.

25. From the time of the decision to go forward in July 2008 to the time the MET evaluation was finalized in October 2010, several key inputs to the MET evaluation changed considerably. Although these changes may cause the project to appear uneconomic as of the evaluation date, they do not affect the expectations that would have prevailed at the time of the decision in 2008.

V. Treatment of Sunk Costs

26. When a rational investor commits to move forward with an investment project, costs incurred prior to the decision cannot be recouped (these costs are generally referred to as "sunk costs"). A rational investor excludes such costs from its assessment of whether an investment is profitable. For example, suppose an investor has spent $10 on research to estimate that a $100 investment would provide a likely revenue stream of $105. A rational investor would move forward with the investment, since the $10 research cost cannot be saved by not making the investment and earning a $5 profit on the investment is superior to earning no profit.

27. Because sunk costs are not germane to an investor's decision to move forward with a project, the MET evaluation should also exclude such costs from its assessment of whether a project would be expected to be economic. This is important because if the MET evaluation included sunk costs, it could result in mitigation of an economic project.

28. The remainder of the section discusses my advice to the NYISO regarding the application of this principle to the Bayonne and AEII projects.

A. Regulatory and Legal Sunk Costs

29. Investors typically incur relatively modest costs to evaluate the investment and take initial legal and regulatory steps to prepare to make the investment. Sargent & Lundy estimated the typical magnitude of these costs, which were used to identify the sunk cost amounts in these areas for the Bayonne and AEII projects. Based on the recommendation from

Sargent & Lundy, the NYISO estimated the preliminary legal and regulatory costs that were likely sunk prior to the investors' decisions to move forward. These estimated costs represent a relatively small portion of the overall costs of each project. I believe these estimates are reasonable and have recommended that they be excluded from the MET evaluations.

B. Existing Shared Facilities in the AEII Project

30. The NYISO found that the AEII project had an additional category of sunk costs associated with "Existing Shared Facilities," which I recommended also be excluded from the MET evaluation for the project. This part of the section explains why the expenses associated with the Existing Shared Facilities should be considered sunk costs.

31. Sargent & Lundy indicated that AEII's Owner's Development Costs include the confidential dollar amount stated in the Ungate Affidavit for the purchase of shared facilities.[6] This cost is based on a cost allocation to AEII for it use of shared facilities, which is embodied in the Common Facilities Ownership Agreement (CFOA) between AEII and Astoria Energy I. Astoria Energy II LLC must make actual payments to Astoria Energy I LLC for use of the Existing Shared Facilities under the CFOA.

32. The Sargent & Lundy determined that these are costs that have already been incurred by Astoria Energy I before July 2008 and reflect that AE II will be sharing facilities such as land, electrical interconnect, NYISO system upgrade, gas pipeline interconnect, pre-construction development/permitting, demolition, and other costs. Once built, the economic cost of the Existing Shared Facilities to support the operation of the AEII project or any new electric generator at the site was negligible, since no significant additional costs were incurred to allow AE II to use the facilities. If an electric generator had not been built at the site, none of the costs incurred to construct the Existing Shared Facilities would have

6 *See* Affidavit of Christopher D. Ungate attached to this filing.

been reduced or recouped because they have no other purpose. Hence, the costs were sunk at the time the investors initiated the AE II project.

33. The fact that a transfer payment was made from one firm to another firm does not change the reality that the economic cost of the Existing Shared Facilities to support the operation of an electric generator was negligible. In other words, when AEII entered, no incremental costs were actually incurred associated with the Existing Shared Facilities and no opportunity to sell or lease the facilities was foregone (*i.e.*, no opportunity costs were incurred). Therefore, the costs of the Existing Shared Facilities were sunk.

34. To conclude that there were no opportunity costs of allowing AEII to use the facilities, I considered whether the facilities could have been used for some other purpose besides supporting the operation of an electric generator at the site. If the Existing Shared Facilities could have been leased to another type of firm for a different purpose, the opportunity cost of AEII using them would have been the foregone lease revenue. However, Sargent & Lundy indicated that the Existing Shared Facilities would not be suitable for any purpose other than supporting the operation of an electric generator at the site. This reaffirms the conclusion that the costs associated with the Existing Shared Facilities are sunk and, therefore, should be excluded from the costs incorporated in the MET evaluation for the AEII project.

35. Mr. Younger disagrees with my assessment of the appropriate standard for evaluating the opportunity cost of using the Existing Shared Facilities, stating: "The NYISO should have measured the value of such benefits at the opportunity costs of selling the asset or service to a competing new entrant."[7] However, Mr. Younger's criteria for evaluating opportunity cost are inappropriate for the MET evaluation, which seeks to determine whether the entry of an electric generator would be expected to be economic. Asserting that the Existing

7 *See* Supplemental Affidavit of Mark D. Younger in Docket No. EL11-50-000, P. 67.

Shared Facilities could be rented to another new entrant concedes that entry would have been sufficiently economic for another entrant to be willing to pay for the use of the Facilities. If entry were not economic, no competing entrant would be willing to pay anything for the use of the Existing Shared Facilities, which means there is no opportunity cost associated with AEII using them. Hence, the appropriate standard for assessing the opportunity cost of the Existing Shared Facilities is the potential lease revenue from non-electricity generating firm. Since there are no potential alternative uses of these facilities, their costs should be considered sunk in the MET evaluation.

VI. Use of Project-Specific Financing Terms

36. As with any other portion of the overall investment cost, financing costs vary from project to project. Consequently, one investor may have a competitive advantage over other investors due to its ability to obtain financing on advantageous terms. Therefore, I have recommended that the NYISO consider the financing terms of a specific project when evaluating whether its should be exempted from the BSM rules.

37. New generation projects are financed with a combination of borrowed capital and project owner's capital (equity). Lenders demand higher interest rates when there is more default risk (*i.e.*, risk they will not be paid back in full). Project developers will only invest their equity when the risks are outweighed by the potential returns.

38. Project developers that have a low cost of capital have a significant competitive advantage over competing projects because it enables them to invest at a lower overall cost. This is reflected in the weighted-average cost of capital ("WACC"), which combines the costs of both the debt and equity used to finance the investment. The WACC is calculated by Sargent & Lundy in the MET evaluations and the Demand Curve reset process.

39. Developers with a low cost of capital have the ability to develop new generation projects at lower cost than other firms. The levelized CONE calculated in the most recent demand

curve reset was $215/kW-year for a new peaking unit in New York City, assuming 50 percent debt financing at a 7.25 percent rate of interest. If 60 percent could be financed at a 6.25 percent rate of interest, the levelized CONE of the same project would be reduced $195/kW-year.

40. Hence, well-capitalized firms with a lower cost of capital have a legitimate competitive advantage that benefits consumers because it enables firms to invest profitably at a lower cost. This cannot reasonably be ignored in the MET evaluation. Accordingly, the MET evaluations should consider financing terms when assessing the levelized CONE for a new generation project. Failing to do so could create a significant barrier to new investment from firms that have relatively low costs of capital.

A. Evaluation of the Bayonne Project's Cost of Capital

41. The Bayonne project is held on [redacted] balance sheet of the [redacted], whose senior unsecured debt received an investment grade credit rating ('BBB/Stable') from Standard & Poors in the summer of 2010. [redacted] also had a debt ratio of approximately [redacted] percent and a market capitalization of over [redacted] at that time. In comparison, the independent power producers that were used as the basis for the capital costs of the NYC Demand Curve plant identified in the NERA/S&L Demand Curve Report had senior secured debt ratings that were not investment grade (from 'B+' to 'BB+') with an average debt ratio of 63 percent and market capitalizations well below $10 billion.

42. Given that the total CONE for a new combined cycle project in New York City exceeds $1 billion, which is large relative to the size of most independent power producers, it is no surprise that the owner of the Bayonne project was able to obtain financing on terms considerably better than the NYC Demand Curve plant. The NYISO found that Hess obtained [redacted] percent debt financing at a rate of [redacted] percent, while the NYC Demand Curve plant was assumed to obtain 50 percent debt financing at a 7.25 percent interest rate. Hence, the NYISO concluded that the Bayonne project enjoys a much lower weighted-

average cost of capital than the demand curve unit. If larger, better capitalized firms are able to obtain financing at lower cost, the MET evaluations should consider such costs savings to avoid the mitigation serving as a barrier to efficient investment.

B. Evaluation of the AEII Project's Cost of Capital

43. In 2008, AEII project won a Request For Proposals issued by the New York Power Authority ("NYPA") in late 2007, and the parties entered into a series of agreements including a PPA in July 2008 that provided the owners of AEII with a predictable revenue stream for a twenty year period. Since NYPA enjoys a very good credit rating as a state-chartered instrumentality, this greatly reduced the risk that the Astoria Energy II LLC would default on the obligations to its lenders. As a result, the Astoria Energy II LLC was able to obtain financing on relatively good terms, including [redacted] percent debt financing at an interest rate of [redacted] percent and a weighted-average cost of capital of [redacted] percent.

44. Such PPAs and other types of long-term contracts are not uncommon. These arrangements are also likely an efficient means to allocate the market risk associated with the project. For a merchant developer, an investment without such a contract would be a highly speculative position, which can create substantial default risk if the developer is small relative to the size of the investment. Alternatively, the purchase of a generating asset through such a contract serves as a hedge against volatile short-term capacity prices for an LSE with long-term capacity obligations. Therefore, it is rational for such developers to enter into long-term contracts, which also improves the developer's access to capital by lowering its default risk. Although the existence of a PPA with a credit-worthy counterparty can substantially change a developers cost of capital, it does not constitute a subsidy. Therefore, it would be inappropriate to consider any cost of capital other than the investor's actual cost of capital.

45. Mr. Younger asserts in the footnote to P. 30 of the Supplemental Younger Affidavit that the PPA with NYPA is "discriminatory." Whether the contract is discriminatory or not is not

relevant to the MET evaluation of the AEII project. The PPA simply provides a cost advantage to the AEII project that is comparable to what a firm with a good credit rating enjoys when making a large capital investment. The fact that this advantage is not available to developers without a comparable credit rating or a PPA does not mean that the project is not economic.

46. To illustrate, suppose oil reserves were discovered on government land where a single facility could be built to extract the oil at a cost substantially below the current market price of oil. It would be economic to extract the oil as a result of the unique advantages provided by the land. If the government gave the drilling rights to a single firm in exchange for less than the market value of the drilling rights, there might be a sense in which its action was "discriminatory." However, one could not reasonably assert that this would make it uneconomic for the firm to extract the oil.

47. Hence, for purposes of the MET evaluation, the NYISO appropriately assumed the actual cost of capital realized by AEII.

48. This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing Affidavit of David B. Patton, Ph.D. dated September 7, 2011 (the "Affidavit"). I have read the Affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

David B. Patton
September 7, 2011

Subscribed and sworn to before me
this 7th day of September 2011

Notary Public

MATTHEW JAMES CARRIER
Notary Public
City/County of Fairfax
Commonwealth of Virginia
Notary registration number - 7233763
My commission expires - Nov. 30, 2013

My commission expires: Nov. 30 2013

APPENDIX IV
CONFIDENTIAL AFFIDAVIT OF CHRISTOPHER D. UNGATE REGARDING ASTORIA ENERGY II

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Astoria Generating Company, L.P and TC Ravenswood, LLC	)	
	)	**Docket No. EL11-50-000**
vs.	)	
	)	
New York Independent System Operator, Inc.	)	

AFFIDAVIT OF
CHRISTOPHER D. UNGATE
REGARDING ASTORIA ENERGY II

Mr. Christopher D. Ungate declares:

1. I have personal knowledge of the facts and opinions herein and if called to testify could and would testify competently hereto.

I. Purpose of this Affidavit

2. The purpose of my Affidavit is to present the cost and performance inputs for the Astoria Energy II ("AEII") project for use in determining the Cost of New Entry ("CONE") for the project.

II. Qualifications

3. I am a Senior Principal Management Consultant with Sargent & Lundy LLC ("Sargent & Lundy" or "S&L") and have over thirty years of experience in electric utility operations, planning, and consulting. Prior to joining S&L in 2006, my professional work experience included management of generation resource planning for a 30,000 megawatt ("MW") portfolio of nuclear, coal, hydro and gas generation, providing

annual power supply plans, monthly cost forecast updates, and system reliability analyses; hydro operations business planning; re-engineering and process improvement initiatives in utility planning and operations; and laboratory and prototype testing for hydro and thermal generating plants.

4. My consulting practice at Sargent & Lundy focuses on the areas of integrated resource planning, financial modeling and analysis for the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. I also perform due diligence reviews of new technology development, new projects, modification and refurbishment of existing facilities, asset transactions, and operational assessments.

5. My resume is provided in Exhibit CDU-1.

III. Process for Determining Cost and Performance Inputs to CONE Determinations

6. The New York Independent System Operator ("NYISO") contracted with NERA Economic Consulting ("NERA"), supported by Sargent & Lundy, to develop the recommended ICAP Demand Curves for the 2011/12, 2012/13, and 2013/14 Capability Periods. The ICAP Demand Curve reset report that was prepared in conjunction with that effort describes in detail the potential technology choice for the New York City ("NYC"), Long Island, and New York Control Area ("NYCA") regions, derivation of cost and performance estimates for those technologies, calculation of annual carrying charges, estimation of energy and ancillary service revenues, and development of

recommended demand curves.[1] As part of that work, I managed the estimation of capital costs, fixed operations and maintenance costs, and other costs for quantifying the CONE in NYC, Long Island, and for the NYCA (with a unit located in Rest of State).

7. As a separate undertaking, the NYISO contracted with Sargent & Lundy to derive the cost and performance inputs used to determine the CONE for the AEII project. AEII is a natural gas-fired combined-cycle plant with a 2 x 2 x 1 configuration utilizing two General Electric Frame 7FA combustion turbines and one steam turbine with a total nominal plant capacity of 600 MW. The project is located in Queens, New York, and connected to the grid at Consolidated Edison Company of New York's ("Con Edison") Astoria Annex 345-kV Substation. At the time of S&L's analysis, the project was under development by Astoria Energy II LLC ("Astoria Energy") with a commercial operation date of June 2011. AEII's CONE and performance inputs include the direct and indirect capital costs, owner's costs, financing costs, working capital and inventories, fixed and variable operation and maintenance ("O&M") costs, site leasing or purchase costs, property taxes, start fuel, equivalent forced outage rate, net plant capacity, and net plant heat rate.

8. Astoria Energy representatives provided detailed information on AEII to S&L, responded to S&L's questions, and provided clarifications. S&L determined whether or not these data were within reasonable ranges and, if not, recommended reasonable

[1] *See* New York Independent System Operator, Inc., Tariff Revisions to Implement ICAP Demand Curves for Capability Years 2011/2012, 2012/2013, and 2013/2014, Docket No. ER11-2224-000 (filed November 30, 2010), at Attachment 2 (Meehan Affidavit) Exhibit B "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator" ("NERA/S&L Demand Curve Report").

values to the NYISO. The AEII costs that were examined included costs under a fixed price contract and costs that were incurred at the time of the examination. The CONE values were then used by NERA to estimate the net energy revenues, and along with estimated ancillary services revenues provided by the NYISO, to compute AEII's Unit Net CONE.

IV. Technology Performance

9. The AEII project consists of two General Electric ("GE") 7FA.03 combustion turbines and one steam turbine in a 2 x 2 x 1 combined-cycle configuration. Astoria Energy provided expected performance data for AEII, which is presented in Exhibit CDU-6. S&L reviewed the reasonableness of this information for the CONE calculation. The AEII information was also compared with the cost and operating characteristics for a combined cycle plant in NYC estimated using the same approach to estimating capital and O&M costs and operating performance presented in the NERA/S&L Demand Curve Report. The hypothetical combined cycle plant in the NERA/S&L Demand Curve Report uses GE 7FA combustion turbines in a 2x2x1 configuration.

   a. AEII uses GE 7FA.03 turbines, each with a nominal capacity of 170 MW. The CONE input values for plant capacity are based on the average degraded summer and winter net values. AEII values were provided across a range of cases from which the conditions used in the CONE derivation were selected: [redacted]°F summer and [redacted]°F winter and the ICAP condition ([redacted]°F summer). AEII values also included the use of duct firing. AEII will not likely operate with duct firing on a continuous basis. The decision to duct fire will depend on how the unit is dispatched. The recommended net capacity values with and without duct firing are shown below. These include long-term average degradation of [redacted] percent.

Net Plant Capacity (Avg. Degraded Value)	AEII Project (without duct firing)	AEII Project (with duct firing)	Duct Firing Capacity Increment
Summer (MW)	[redacted]	[redacted]	[redacted]
Winter (MW)	[redacted]	[redacted]	[redacted]
Summer / Winter Average (MW)	[redacted]	[redacted]	[redacted]
ICAP (MW) - Degraded	[redacted]	[redacted]	[redacted]
ICAP (MW) – New and Clean	[redacted]	[redacted]	[redacted]

b. The CONE input values for plant heat rate are based on the average degraded summer and winter net values, expressed on a full-load, higher heating value ("HHV") basis. As with the capacity values presented in the previous paragraph, the AEII heat rate values were provided across a range of cases from which the conditions used in the CONE derivation were selected. The AEII values also included the use of duct firing. The recommended net plant heat rates with and without duct firing are shown below. These include long-term average degradation of [redacted] percent. The heat rate with duct firing is shown for the entire plant capacity and for the incremental capacity increase, corresponding to the capacity values presented in the previous section.

Net Plant Heat Rate (Avg. Degraded Value)	AEII Project (without duct firing)	AEII Project (with duct firing)	Duct Firing Capacity Increment
Summer (Btu/kWh, HHV)	[redacted]	[redacted]	[redacted]
Winter (Btu/kWh, HHV)	[redacted]	[redacted]	[redacted]
Summer / Winter Average (Btu/kWh, HHV)	[redacted]	[redacted]	[redacted]
ICAP (Btu/kWh, HHV) - Degraded	[redacted]	[redacted]	[redacted]
ICAP (Btu/kWh, HHV) – New and Clean	[redacted]	[redacted]	[redacted]

c. The Demand Equivalent Forced Outage Rate ("EFORd") is used to reduce net revenues associated with energy revenues. EFORd refers to the Equivalent Forced Outage Rate during the period when the plant is actually dispatched. The Unforced Capacity ("UCAP") value, which is the maximum capacity a generator is able to sell in the capacity auction, is equivalent to ICAP x (1 - EFORd).

d. The EFORd assumption used for the hypothetical 2 x 2 x 1 GE 7FA combined cycle plant in the NERA/S&L Demand Curve Report was estimated to be 4.51 percent on the basis of historical outage data from similar units. AEII has a projected EFORd of [redacted] percent. S&L recommended using the [redacted] value of the two ([redacted] percent) since this number is already considered to be very conservative for a well-maintained new plant.

e. The recommended value for the natural gas consumed during each start of AEII is estimated to be [redacted] mmBtu per start, which is [redacted] used for the hypothetical unit in the NERA/S&L Demand Curve Report. This is the amount of fuel consumed by the entire plant for a warm start through the point of reaching the steam turbine maximum load, which corresponds to the plant maximum load. The duration of each warm startup is approximately [redacted] minutes.

f. The CONE input values for Nitrogen Oxide ("NOx") and Carbon Dioxide ("CO2") emissions are based on the summer and winter values, expressed in lb/hr per CT unit. The recommended values are based on the net output and heat rate values discussed above.

Per Unit	AEII (without duct firing)		AEII (with duct firing)	
	NO_X	CO_2	NO_X	CO_2
Summer (lb/hr per CT unit)	[redacted]	[redacted]	[redacted]	[redacted]
Winter (lb/hr per CT unit)	[redacted]	[redacted]	[redacted]	[redacted]
Spring-Fall (lb/hr per CT unit)	[redacted]	[redacted]	[redacted]	[redacted]
Average (lb/hr per CT unit)	[redacted]	[redacted]	[redacted]	[redacted]
ICAP (lb/hr per CT unit)	[redacted]	[redacted]	[redacted]	[redacted]

V. Capital Investment Costs

10. Capital investment costs for the AEII project were provided by Astoria Energy showing the direct costs, owner's costs, financing costs during construction, and working capital and inventories. The direct costs include project costs awarded on an Engineering, Procurement, and Construction ("EPC") contract basis. The scope of the estimate includes the two gas turbines, two heat recovery steam generators ("HRSG"), steam turbine and balance of plant, and electrical and gas interconnections and upgrades.

11. The AEII cost estimate breakdown, along with explanatory notes, is presented in Exhibit CDU-2. Astoria Energy assembled the cost data from various sources including the following:

    a. CH2M Hill's engineering study of the proposed costs.

    b. Levitan & Associates, Inc.'s economic evaluation of bids received by the New York Power Authority including the winning AEII bid.

    c. Black & Veatch's independent analysis of capital and O&M costs.

12. S&L reviewed the reasonableness of the AEII cost breakdown on the basis of discussions with representatives from Astoria Energy and on the basis of similar projects. The AEII information was also compared with the values derived for a hypothetical 2 x 2 x 1 combined-cycle plant for the NERA/S&L Demand Curve Report, which also used GE 7FA combustion turbines and was located in New York City. The estimated values reflect plant features typically found in modern combined-cycle facilities and are intended to reflect representative costs for new plants of their type. The estimates are conceptual and were not based on preliminary engineering activities for any specific site. The estimates were converted to 2011 price levels to match the in-service year of the AEII project and are included in Exhibits CDU-2 and CDU-3.

13. The recommended CONE input values for AEII capital investment costs are discussed below.

    a. The EPC costs for AEII are based on actual fixed price contracts. The EPC estimates for the hypothetical 2 x 2 x 1 combined-cycle plant are based on assumptions developed for the 2010 ICAP Demand Curve Reset Report. The following is a summary comparing the basis the two EPC costs:

i. GE 7FA.05 combustion turbines were assumed with dry low-NOx burners, inlet air filters, and evaporative coolers for the hypothetical unit. AEII, however, uses GE 7FA.03 combustion turbines.

ii. Three-pressure HRSG was assumed with reheat, supplemental duct burners, integral deaerator, selection catalytic reduction ("SCR"), and carbon monoxide ("CO") catalyst for the hypothetical unit [redacted]

iii. Condensing reheat steam turbine was assumed with standard accessories for [redacted] the hypothetical unit [redacted].

iv. Water cooled condensers were assumed for the hypothetical plant [redacted].

v. Brownfield site conditions were assumed for both the hypothetical plant and AEII was constructed on brownfield site.

vi. Inlet air chillers [redacted].

vii. Dual fuel capability [redacted].

viii. A contingency of 10 percent was applied to the total of direct and indirect project costs. [redacted] the AEII contingency was [redacted] percent [redacted]

ix. All equipment and material costs for the hypothetical plant were based on S&L in-house data, vendor catalogs, or publications. Labor rates were developed based on union craft rates in 2010. Costs were added to cover FICA, fringe benefits, worker's compensation insurance, small tools, construction equipment, and contractor site overheads. Work was assumed to be performed on a 50-hour work week by qualified craft labor available in the plant area. Labor rates were based on New York County for Zone J. An allowance to attract and keep labor was included. A labor productivity adjustment of 1.40 was applied to Zone J. Materials costs were based on data for New York City in Zone J.

x. Black start capability [redacted]

xi. Foundation piles [redacted]

xii. Use of rental trailer-mounted water treating equipment was assumed for the hypothetical plant. AEII [redacted]

xiii. A steam turbine building and control/administration building for the hypothetical unit and constructed for AEII.

b. Some of the EPC cost differences in Exhibits CDU-2 and CDU-3 between the hypothetical 2 x 2 x 1 combined-cycle plant and the AEII costs are a result of [redacted]. The major components of the EPC costs for AEII are described below.

i. The Equipment and Spare Parts portion of the EPC cost for AEII is $[redacted]. This amount includes the cost of the gas turbines, HRSG, steam turbine, and balance of plant.

ii. The Construction portion of the EPC cost for AEII is $[redacted]. This amount includes $[redacted] for construction labor and materials, $[redacted] for electrical connection and substation, $[redacted] for interconnection and upgrades, $[redacted] for site preparation, $[redacted] for engineering and design, and $[redacted] for construction management and field engineering.

iii. The Startup and Testing portion of the EPC cost for AEII is $[redacted], which includes mobilization for startup and O&M, startup services, testing, and startup fuel.

iv. The contingency of $[redacted] represents approximately [redacted] percent of the EPC amount. This amount was derived from the sum total of the contingencies of the EPC component costs, recognizing that many costs are covered under fixed price contracts and require minimal contingency and accounting for the current status of the other non-fixed price components.

v. The sum total of the above EPC costs for equipment, construction, start-up and testing, and contingency is $[redacted].

14. Owner's costs include items not covered by the EPC scope such as owner's development costs, social justice costs, oversight, legal fees, financing fees, startup and testing, and training. The owner's costs for AEII project are based on actual costs and expected remaining costs through the start of commercial operation in mid-2011. AEII owner's development costs include the payment for existing shared facilities, interest on bridge equity, and [redacted]. AEII [redacted]. AEII did not identify, and S&L did not include, an amount for social justice costs. The total owner's costs for AEII are [redacted] percent of the EPC costs. That amount excludes from the Owner's Development Costs the interest on bridge equity of $[redacted] and payment for existing shared facilities (to the existing adjacent plant) of $[redacted]. This aggregate total is within the expected range for this type of installation.

15. Financing costs during construction refer to the cost of debt and equity required over the periods from each construction expenditure date through the plant in-service date. These costs were calculated from the monthly construction cash flows and the cost of project debt and equity. Total financing costs for AEII, with the inclusion of the interest on bridge equity of $[redacted] as an additional financing cost, are [redacted] percent of the EPC costs, which is within the expected range of values. By comparison, total financing costs for the hypothetical 2 x 2 x 1 combined-cycle plant are 10.1 percent of the EPC costs.

16. Working capital and inventories refer to the initial inventories of fuel, consumables, and spare parts that are normally capitalized. It also includes working capital cash for the payment of monthly operating expenses. Working capital and inventories for AEII are [redacted] percent of the EPC costs compared to 2.0 percent of EPC costs for the hypothetical 2 x 2 x 1 combined-cycle plant. The [redacted] value for AEII is within the range of values used for other combined cycle projects with similar configurations and accounts for the anticipated O&M program. As indicated in the upcoming paragraphs on Operating Costs, Astoria Energy [redacted] O&M budgets for materials, contract services, and annual accruals for major maintenance parts.

17. The total capital investment indicated above and in Exhibit CDU-2 is $[redacted] Approximately [redacted] percent of this amount will be debt-financed and includes fees for letter of credit ("LC") facilities. These include a debt service reserve LC of $[redacted] LC of $[redacted] LCs of $[redacted], and a [redacted] LC of $[redacted]. The LC facilities [redacted] and thus, [redacted] of the project cost.

18. S&L discussed sunk costs with the independent Market Monitoring Unit for the NYISO ("MMU") and the NYISO at the time of the examination. The decision to move forward with a project is not necessarily tied to a specific date, but rather a series of decision points over an extended period of time. Over time, the estimated project costs and the cost of backing out become more significant. A key decision point for AEII

would have been July 11, 2008 when AEII executed the Master Power Purchase and Sale Agreement with NYPA. At that point, the cost to AEII of backing out of the project would have been significant. At the direction of the NYISO, based on the recommendation of the Market Monitoring Unit ("MMU"), costs incurred before the decision point described below are "sunk" and were excluded from the evaluation. The AEII sunk costs were portions of the owner's costs up to that date and certain shared facilities with Astoria Energy I.

19. S&L determined based on project experience, that a portion of owner's costs for project development are incurred before the decision point and are sunk costs. S&L estimated the sunk portion of owner's costs as the sum of the following:

    a. One-half of permitting costs

    b. One-half of legal costs

    c. One-half of the priority distribution

    d. Environmental studies costs

    e. Market studies costs

20. As mentioned previously, the Owner's Development Costs include $[redacted] million for the purchase of shared facilities. This amount represents the cost allocation for shared facilities with Astoria Energy I. These are costs that have already been incurred by

Astoria Energy I and reflect that AEII will be sharing facilities such as land, electrical interconnect, NYISO system upgrade, gas pipeline interconnect, pre-construction development/permitting, demolition, and other costs. These costs were incurred before July 2008 and thus are considered sunk. S&L considered that an opportunity cost for the use of these facilities, such as through a sale or lease to a third-party business enterprise other than an electricity generator, may also apply. S&L determined that the net opportunity cost was negligible considering the type of facilities involved and the site.

21. S&L judged the [redacted] to be a reasonable estimate of the AEII expectations in July 2008. By the time AEII submitted its proposal to NYPA in late 2007, it would have needed to develop project cost estimates as accurately as possible, accounting for all expenditures and price escalation through the 2011 commercial operating date. Astoria Energy's pricing outlook for AEII would have been influenced by Astoria Energy's assessments of market trends and quotes from potential EPC contractors.

22. The recommended capital cost inputs for determining the CONE for AEII are summarized in the table below based on the expected costs through the commercial operation date and the estimated costs at July 2008, the approximate time AEII decided to move forward with the project.

Parameter	Expected Costs (2011 $)	Estimated Costs as of July 2008
EPC Costs - Plant	[redacted]	[redacted]
Owner's Costs and Other Capital Costs	[redacted]	[redacted]
Sunk Costs –Shared Facilities	[redacted]	[redacted]
Sunk Costs – Owner's Costs	[redacted]	[redacted]
Total Capital Investment	[redacted]	[redacted]
Net Degraded ICAP MW (with duct firing)	[redacted]	[redacted]
Net Degraded ICAP MW (without duct firing)	[redacted]	[redacted]
$/kW (with duct firing)	[redacted]	[redacted]
$/kW (without duct firing)	[redacted]	[redacted]

VI. Operating Costs

23. In addition to the capital investment costs presented in the previous section, other cost inputs to the CONE calculation include fixed operation and maintenance (O&M), variable O&M, and fuel. Fixed and variable O&M costs for AEII were provided by Astoria Energy. The AEII O&M cost breakdowns, along with explanatory notes, are presented in Exhibits CDU-4 and CDU-5.

24. S&L reviewed the reasonableness of these estimates on the basis of discussions with representatives from Astoria Energy and on the basis of similar projects. The AEII project information was also compared with the values for a hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant based on assumptions developed for the NERA/S&L Demand Curve Report. The estimates were converted to 2011 price levels to match the in-service year of AEII and are included in Exhibits CDU-4 and CDU-5.

25. The recommended CONE input values for AEII fixed and variable O&M costs are discussed below.

a. Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance). The fixed O&M costs for AEII project are based on expected labor, contract services, leasing costs, property taxes, insurance, and other items. The fixed O&M estimates for the hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant are based on assumptions developed for the NERA/S&L Demand Curve Report.

b. Some of the fixed O&M cost for a hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant and the AEII costs are a result of different underlying assumptions, splits between fixed and variable components, and site-specific factors, which are identified below. The major components of the fixed O&M costs for AEII are described below and summarized in Exhibit CDU-4.

c. Routine labor costs of $[redacted] (2011 $) for the hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant were based on a staff of [redacted] full-time equivalents and an average labor rate, including benefits, of $[redacted]/hour. The AEII budget for this category is $[redacted], which is a reasonable labor budget for this facility type and configuration.

d. Fixed materials and contract services of $3,840,000 (2011 $) for the hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant were derived from published industry data and similar projects in operation. The AEII budget of $[redacted] for this category is [redacted]

[redacted] for the hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant.

e. Administrative and general costs of $614,000 (2011 $) for the hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant were derived from published industry data and similar projects in operation. The AEII budget of $[redacted] is [redacted] within the range of values found at similar projects in operation.

f. Site leasing costs of $7,373,000 for a hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant are equal to an assumed annual lease rate of $246,000/acre-yr multiplied by a land requirement of 30 acres. The AEII budget of $[redacted] is the actual annual lease payment for its site.

g. Property taxes of $48,688,000 for a hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant are equal to the NYC property tax rate of 10.426% of the plant market value, multiplied by an assessment ratio of 45.00%. The AEII budget of $[redacted]. The $[redacted]. The property tax [redacted] captured in the carrying charge rate, as described below.

h. Insurance costs of $3,113,000 for the hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant are equal to 0.30 percent of the initial capital investment, escalating each year with inflation, on the basis of actual data for recent independent power projects. The AEII budget of $[redacted] is approximately [redacted] percent of the initial capital investment, which is within a reasonable range of expected values.

26. Variable costs, consisting of fuel and variable O&M, are used to develop net energy revenues in NERA's econometric model of NYISO market prices. The variable O&M costs for AEII are based on [redacted] along with current local pricing and material balances for ammonia, water treatment chemicals, water and sewer, and other consumable items. [redacted] the variable O&M estimates for a hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant are based on assumptions developed for the NERA/S&L Demand Curve Report. Some of the variable O&M cost [redacted] the hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant and the AEII costs are [redacted]. The major components of the variable O&M costs for AEII are described below and summarized in Exhibit CDU-5.

a. Over the long-term operating life of a peaking facility, the largest component of variable O&M is the allowance for major maintenance expenses. Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. For the 7FA units, GE recommends a major maintenance overhaul every 48,000 factored operating hours or 2,400 factored starts, whichever occurs first. Normal operating hours or starts would be factored, that is, increased to account for severe operating conditions such as for hours of operation on fuel oil.

b. Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. For hours-based major maintenance, the average variable O&M cost ($/megawatt-hour ("MWh")) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored operating hours between overhauls, divided by the unit capacity in megawatts. For starts-based major maintenance, the average variable O&M cost ($/factored start, per turbine) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored starts between overhauls. The major maintenance was assumed to be starts-based for a hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant and hours-based in the AEII budget.

c. Major maintenance costs of $9,279 per factored start per turbine (2011 $) for the hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant are based on parts costs of $21,311,000 and 15,000 labor-hours over a 2,400 factored start major maintenance interval. The AEII budget of $[redacted]/MWh (2011 $) is based on the annual operating hours and reserve [redacted] Adjusting for the different categorization of major maintenance components, the AEII budget for major maintenance is within a reasonable range.

d. Other variable O&M costs are directly proportional to plant generating output, such as unscheduled maintenance, SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. These items are always expressed in $/MWh, regardless of whether the maintenance component is hours-based or starts-based. The combined estimated cost for these items is $0.71/MWh (2011 $) for the hypothetical 2 x 2 x 1 GE 7FA combined-cycle plant compared with $[redacted]/MWh in the AEII budget. Adjusting for the different categorization of the major maintenance components (starts-based vs. hours-based), the AEII budget for other variable O&M is within a reasonable range.

27. The recommended fixed and variable O&M cost inputs for determining the CONE for AEII are summarized in the table below based on the expected costs through the June 2011 commercial operation date, and the estimated costs at the approximate time AEII decided to move forward with the project. The expected O&M costs were judged to be a reasonable estimate of AEII's expectations in July 2008. As with the project capital costs discussed in the previous section, AEII would have needed to adjust 2008 O&M prices to 2011 prices of the commercial operating year. As noted below, the actual rate of increase in gas turbine plant costs since the time AEII decided to move forward in July 2008 has been consistent with the general trends that AEII would have observed at the time. O&M cost escalation would not have been as steep as gas turbine plant costs. For example, general inflation as measured by the Gross Domestic Product Implicit

Price Deflator ("GDPD"), published by the U. S. Department of Commerce, was between 2 percent/year and 3 percent/year in the years before 2008 and falling below 2 percent after 2008. While this decline in general inflation may have resulted in a slight decrease in the 2011 O&M costs relative to 2008 expectations, the net effect is not significant.

Parameter	Expected Costs (2011 $)	Estimated Costs as of July 2008
Fixed O&M - Plant ($/yr)	[redacted]	[redacted]
Other Fixed O&M (Site Leasing, Property Taxes, and Insurance, including ICIP property tax exemption)	[redacted]	[redacted]
Property Taxes (first year, with abatement)	[redacted]	[redacted]
Total Fixed O&M ($/yr)	[redacted]	[redacted]
$/kW (with property taxes; with duct firing)	[redacted]	[redacted]
$/kW (with property taxes; without duct firing)	[redacted]	[redacted]
$/kW (without property taxes; with duct firing)	[redacted]	[redacted]
$/kW (without property taxes; without duct firing)	[redacted]	[redacted]
Variable O&M ($/MWh, assuming hours-based major maintenance)	[redacted]	[redacted]

28. Fuel costs, along with variable O&M, are used to develop net energy and ancillary service revenues in NERA's econometric model of NYISO market prices. The fuel costs are derived from the delivered price of fuel, the net plant heat rate, and the plant dispatch. The fuel price would be tied to pricing at the Transco Zone 6 trading point. Local fuel transportation charges are based on the rate set forth in Con Edison PSC No. 9-Gas (Leaf 277) for New York City. The total delivered fuel price to an end user for interruptible service is the sum of the following:

a. Transco Z6 Price

b. System Cost Component

c. Marginal Cost Component

d. Value Added Charge

e. Taxes

f. Imbalance Charges

29. The System Cost Component, Marginal Cost Component, Value Added Charge, and Taxes are all subject to a minimum monthly bill that is based on a 50 percent capacity factor. According to discussions with representatives from Con Edison and National Grid (in respect of its Keyspan New York City tariffs), the Imbalance Charges are minimal in the day-ahead market. Imbalance Charges for the real-time market would be proportional to the degree of imbalances above a 10 percent threshold. The imbalances are measured by the difference between the customer's nomination schedule for the next day's deliveries and the actual quantity of gas transported. The total delivered fuel price is summarized in the following table.

	NYC
Gas Transportation Service ($/mmBtu) *	
System Cost Component	[redacted]
Marginal Cost Component	[redacted]
Value Added Charge	[redacted]
Taxes	[redacted]

* The minimum bill must be based on a capacity factor of 50%.

VII. Carrying Charges

30. As part of the CONE derivation, capital investment costs were converted to annual capacity charges using annual carrying charge rates. The annual carrying charge rate multiplied by the original capital investment yields the annual carrying charges. Carrying charges typically include all annual costs that are a direct function of the capital investment amount: principal and interest payments on project debt, equity returns, income taxes, property taxes, and insurance. Expected first-year property taxes and insurance for AEII are included under the fixed O&M.

31. As previously discussed, AEII [redacted]. Carrying charges were calculated with and without property taxes to [redacted]

32. Income tax and financing inputs were provided by Astoria Energy. S&L reviewed these inputs with Astoria Energy and calculated real levelized carrying charge rates. The inputs and resulting carrying chart rates were compared to the values used in the NERA/S&L Demand Curve Report.

    a. Income taxes are a significant component of carrying charge rates. A portion of these charges must be grossed up to account for the income taxes due on plant revenues such that the desired return on equity is achieved. Income taxes include the federal corporate tax rate of 35.00 percent and a combined New York State and New York City income tax rate of 9.00 percent. AEII is structured as a limited liability company, [redacted]

[redacted] According to Astoria Energy, the state income tax rate of [redacted] percent and the New York City General Corporation Tax (city income tax) of [redacted] percent are [redacted] The composite federal/state/city tax rate is the sum of these rates, reduced by the portion that is deductible from taxable income. Income tax assumptions for AEII project are summarized in the following table.

	AEII
Federal Tax Rate	[redacted]
State Tax Rate	[redacted]
City Tax Rate	[redacted]
Composite Tax Rate *	[redacted]

* Federal tax rate + State tax rate + City tax rate – [Federal tax rate x (State tax rate + City tax rate)], to account for the deductibility of state and local taxes from federal taxable income.

b. Financing assumptions provided by Astoria Energy for AEII are summarized in the following table. The costs of debt and equity are shown on a nominal basis and a real basis. Real rates are derived by removing the inflation component of 2.15 percent, which reflects 2.4 percent inflation net of 0.25 percent technological process. The real rates are then used to calculate the real weighted average cost of capital ("WACC") and the real levelized carrying charge rates. Note that the "pre-tax" WACC as commonly calculated uses a pre-tax cost of debt with an after-tax cost of equity. The pre-tax WACC is shown here for reference but is not used in the CONE determination.

	AEII
Equity Fraction	[redacted]
Debt Fraction	[redacted]
Cost of Equity (nominal)	[redacted]
Cost of Debt (nominal)	[redacted]
Cost of Equity (real)	[redacted]
Cost of Debt (real)	[redacted]
Weighted Average Cost of Capital *	
Pre-Tax (nominal)	[redacted]
After-Tax (nominal)	[redacted]
Pre-Tax (real)	[redacted]
After-Tax (real)	[redacted]
Tax Depreciation **	20-year MACRS
Inflation Rate, Net of Technological Progress	2.15%

* (Equity Fraction x Cost of Equity) + (Debt Fraction x Cost of Debt), before tax; and (Equity Fraction x Cost of Equity) + [(Debt Fraction x Cost of Debt) x (1 – Composite Tax Rate)], after tax.

** Federal tax code schedule (Modified Accelerated Cost Recovery System or MACRS) for a combined-cycle facility, adjusted for residual depreciation if the amortization period is less than 20 years.

33. The annual carrying charges were calculated over amortization periods of 10 to 35 years. Annual carrying charges are equal to the sum of the following components:

a. Principal. Based upon mortgage style amortization.

b. Interest. Equal to the cost of debt multiplied by the loan balance for the given year.

c. Target Cash Flow to Equity. Equal to the initial equity investment multiplied by an annuity factor over the amortization period, using the cost of equity as the annuity rate.

d. Income Taxes. Calculated by the formula: [t/(1-t)] x [Target Cash Flow to Equity + Principal – Annual Tax Depreciation], where t = Composite Tax Rate.

Annual tax depreciation is based on 20-year Modified Accelerated Cost Recovery System ("MACRS") depreciation in accordance with the federal tax code for a combined-cycle combustion turbine.

34. The levelized carrying charge is equal to the annual carrying charges over a given amortization period converted to an annuity using the after-tax WACC. In other words, the annual carrying charges are considered to be "revenue requirements" that are discounted at the after-tax WACC. The real levelized carrying charges are expressed in reference year price levels. Nominal carrying charge rates for future years are equal to the reference year real rate escalated by the inflation rate net of technological progress of 2.15 percent/year.

35. The real levelized carrying charge rates as a function of amortization period are summarized in the following table. As previously mentioned, the rates in the first two columns do not include property taxes and insurance since those items are included in the fixed O&M. [redacted] the carrying charge rates for AEII are also shown with property taxes.

	Without Property Taxes and Insurance	With Property Taxes and Exemptions; Without Insurance
	AEII	AEII
10-year amortization	[redacted]	[redacted]
15-year amortization	[redacted]	[redacted]
20-year amortization	[redacted]	[redacted]
25-year amortization	[redacted]	[redacted]

30-year amortization	[redacted]	[redacted]
35-year amortization	[redacted]	[redacted]

36. The above carrying charge rates are shown for each amortization period in Exhibit CDU-7.

This concludes my Affidavit.

ATTESTATION

I am the witness identified in the foregoing affidavit. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Christopher D. Ungate
Christopher D. Ungate

Subscribed and sworn to before me
this 7th day of September 2011

Tira L. Seals
Notary Public

OFFICIAL SEAL
TIRA L SEALS
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:05/04/15

My commission expires: May 4, 2015

EXHIBIT CDU-1

CHRISTOPHER D. UNGATE RESUME

CHRISTOPHER D. UNGATE
Senior Principal Management Consultant
Sargent & Lundy Consulting

Sargent & Lundy LLC

EDUCATION

University of Tennessee, Master of Business Administration, 1984
Massachusetts Institute of Technology, M.S. Civil Engineering, 1974
Massachusetts Institute of Technology, B. S. Civil Engineering, 1973

REGISTRATIONS

Professional Engineer - Tennessee

EXPERTISE

Resource Planning
Business and Strategic Planning
Process Improvement and Re-engineering
Market Analysis and Price Forecasting
Decision Analysis
Asset Valuation and Due Diligence
Generation Portfolio Analysis
Risk Analysis

RESPONSIBILITIES

Mr. Ungate is accountable for Sargent & Lundy offerings in the Utility Planning business segment. He develops and evaluates integrated resource plans and associated analyses to identify and evaluate the optimum power supply options. He reviews and evaluates power supply planning and procurement options such as generation options available in the region (potential greenfield or plant expansion options), the viability of siting and permitting new nuclear, coal, gas, wind, solar, biomass or other alternative generation, the prospects for purchase of existing assets, and the potential for partnering with other load serving entities or power generators. He also assesses the potential and/or required renewable energy resource options, the state of transmission planning and upgrade programs, recent wholesale prices in the Client's load zone, and the fuel market and transportation capacities. He assures consistency with the Client's long-term plans and objectives and Client-specific economic factors (such as standard inflation, inflation, discount, or escalation rates).

Mr. Ungate develops financial models and analyses utilized in the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. He bases the models on appropriate economic, project, operating, and client-specific inputs related to base-case scenarios, as well as associated sensitivity analyses. He also reviews existing financial models and analyses to determine if they are reasonable and appropriate, and to evaluate or develop resulting conclusions and recommendations. He also performs forward pricing analyses and evaluations, system reliability studies, load forecasting, and electric market forecasts and projections in support of power supply planning or other Client needs.

Mr. Ungate also performs due diligence reviews of new technology development, new projects, modifications and refurbishment of existing facilities, asset transactions, and operational assessments. He evaluates and develops plans to optimize the utilization of conventional hydropower plants and pumped storage plants with thermal generating units.

EXPERIENCE

Mr. Ungate has over 35 years of experience in engineering and planning for electric utilities. Since joining Sargent & Lundy in 2006, his assignments have included:

ALTERNATIVES ANALYSIS

- **San Miguel Electric Cooperative**
  - Conducted study of generation alternatives to meet federal and state requirements for justification of new coal project.

- **CPS Energy**
  - Developed cost and performance assumptions for alternative technologies for use in integrated resource planning studies. Compared published estimates of costs for new nuclear plants.

- **Entegra Power Services**
  - Conducted a planning study of adding 300 MW of natural gas-fired peaking capacity to an existing power station in the southwest US. Estimated capital costs, operating performance, and operations and maintenance (O&M) costs for three aeroderivative combustion turbine models with and without selective catalytic reduction (SCR), and two frame combustion turbine models without SCR.

- **South Mississippi Electric Power Association**
  - Reviewed renewable energy alternatives for this G&T cooperative in anticipation of future Renewable Portfolio Standard requirements. Directed the evaluation of responses to an RFP for renewable energy and capacity.

- **Department of Energy and Sandia Renewable Energy Laboratory**
  - Updated the 2003 report, “Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts” with the Dish technology.

- **Oklahoma Gas & Electric**
  - Contributed to the analysis of generating alternatives for a study of how to reduce carbon emissions from the OG&E generating portfolio.

RISK ANALYSIS

- **Various Clients**
  - Analyzing the risks associated with the cost, schedule, and performance impacts of proposed projects.

- **Globaleq**
  - Identified and quantified key drivers of increases in capital estimates for coal fired power plants.

- **American Electric Power**
  - Identified and compared key characteristics of new nuclear plant technologies. Assessed the risk of each technology relative to client objectives.

- **Allegheny Energy**
  - Developed a comprehensive risk analysis model to determine the expected outage days, generation and costs for a fleet of supercritical coal-fired units based on a high level condition assessment. The objectives were to assess the impacts of the risk issues and associated mitigation projects and to provide support the development of capital spending plans.

- **Confidential Client**
  - Let a due diligence study of a potential investment in temporary power services to countries with developing economies based on diesel engine technology.

PLANNING AND PROJECT SUPPORT

- **PSEG**
  - Developed the need for power and energy alternatives analyses to satisfy the NUREG 1555 requirements for Environmental Reports associated with an Early Site Permit Application for a new nuclear plant project.

- **Tennessee Valley Authority, PSEG**
  - Developed the need for power analysis to satisfy the NUREG 1555 requirements for Environmental Reports associated with a Combined Operating License Application for a new nuclear plant project.

- **New York Independent System Operator**
  - Estimated the cost of new entrant peaking units used in the formulation of demand curves for the NYISO capacity market. Estimated going forward costs of existing generation used in determining need for market power mitigation.

- **New England Power Generators Association**
  - Estimated the cost of new entrant peaking units in New England for a NEPGA proposal to revise the basis for capacity payments in ISO-NE.

- **Eskom**
  - Surveyed major equipment suppliers with capabilities to support a large coal-fired project in Africa to assess the potential effect of current and projected production capacity, resource availability, and transportation requirements on project schedule, quality, and costs.

- **EPB**
  - Conducted seminars on selected generation, transmission and electricity market topics to prepare senior management on current trends and issues.

- **Tennessee Valley Authority**
  - Developed the need for power and alternatives section for the 2010-11 integrated resource planning effort.

- **Confidential Client**
  - Led the preparation of a business plan for a client considering whether to develop a fleet of generating plants based on small modular nuclear reactor technology.

- **Confidential Client**
  - Estimated potential market volume for a cable manufacturer exploring entering the utility market.

Prior to joining Sargent & Lundy, Mr. Ungate had over 30 years of experience at the Tennessee Valley Authority in a variety of engineering and planning assignments. Examples of assignments include the following:

POWER SUPPLY PLANNING

- Directed supply planning for 30,000 MWs of nuclear, coal, gas, renewable, and hydro generation, and determined peak season power purchase requirements. Directed the preparation of power supply plans, and the valuation of capacity additions, major projects, product offerings, and bulk power transactions. Plans provided the basis for purchase and sale decisions; fuel purchase and inventory decisions; and hedging strategies for the commodity book.
- Led environmental controls optimization study to determine least cost approach to meeting CAIR/CAMR requirements for TVA's 15,000 MW coal generation portfolio. Alternatives included mothballing of units; increased allowance purchases; modified capital improvement programs; re-powering; and replacement with capacity and energy purchases from gas-fired units. Developed approach that resulted in reduction of projected end of period debt by more than $1 billion.
- Provided cost analysis for product pricing for industrial customers. Determined analytical approach and oversaw analyses to determine value of interruptible products, standby power, customer co-generation, long vs. short term contracts, and dispersed power products.

BUSINESS AND STRATEGIC PLANNING

- Directed business planning for portfolio of 109 conventional hydropower units at 29 sites and four pumped storage units. Portfolio supplies 10-15% of company sales with 5000 MWs of capacity. Forced outage rates, recordable injury incident rates, and reportable environmental events were increasing over the previous six years. Developed a five year business plan to increase resources to facilitate the transition to a process management maintenance strategy, and to integrate plant modernization and automation projects to change technology and workflow at the plants.

- Directed the first reassessment of the operating policies of Tennessee Valley Authority reservoirs since the system was designed in the 1930's. Stakeholders were concerned about water quality issues affecting the reservoirs and about the adverse impact of lake levels on property values and recreation-oriented businesses. Led initiative to redefine operating policies, examine environmental concerns, expand public interest and support, and more effectively meet the needs of multi-state customer base. Directed the development of an operating scheme that preserved hydropower value while improving summer lake levels for recreation and increasing minimum flows for water quality.
- Developed competitive analysis for an electric utility. Customers seeking choice of energy suppliers created need for a credible competitive analysis for electric utility monopoly. Price to customers was above competitive energy suppliers. Loss of customer load would create the risk of not recovering the high fixed costs of generation built to serve former customers. Quantified the competitive threat, and identified the circumstances under which loss of customers was most likely.

PROJECT ENGINEERING

- Directed 40-50 engineers, technicians and building trades conducting laboratory and prototype testing of thermal and hydro plant performance problems. Responsible for daily operating management, laboratory safety, quality assurance, human resources, technology acquisition and facilities management.
- Conducted field tests and physical modeling studies on the effects of thermal generating plants on rivers and reservoirs. Contributed to preparation of several environmental statements impacting authorizations for plant operations and discharge.

MEMBERSHIPS

Board of Examiners, Tennessee Quality Award, 1997-99

PUBLICATIONS

"Baseload Generation Capital Cost Trends," Electric Power Conference, May 2007.

"Resolving Conflicts in Reservoir Operations: Some Lessons Learned at the Tennessee Valley Authority," American Fisheries Society symposium, 1996.

"Tennessee Valley Authority's Clean Water Initiative: Building Partnerships for Watershed Improvement," Journal of Environmental Planning and Management, 39(1), 1996.

"'Equal Consideration' at TVA: Changing System Operations to Meet Societal Needs," Hydro Review, July 1992.

"Reviewing the Role of Hydropower in TVA Reservoir Operations," with Douglas H. Walters, Waterpower '91, An International Conference on Hydropower, Denver, Colorado, 1991.

"TVA's Lake Improvement Plan: Reviewing the Operating Objectives of TVA's Reservoir System," National Conference on Hydraulic Engineering, Nashville, Tennessee, July 1991.

"Tennessee River and Reservoir System Operation and Planning Review, Final Environmental Impact Statement," with TVA staff, December 1990.

"Field and Model Results for Multiport Diffuser Plume," with Charles W. Almquist and William R. Waldrop, American Society of Civil Engineers Specialty Conference on Verification of Mathematical and Physical Models, University of Maryland, August 1978.

"Mixing of Submerged Turbulent Jets at Low Reynolds Number," with Gerhard Jirka and Donald R. F. Harleman, M.I.T. Ralph M. Parsons Laboratory, Report No. 197, February 1975.

EXHIBIT CDU-2

Capital Costs – Hypothetical Combined Cycle Plant based on NERA/S&L Demand Curve Report vs. AEII

Case / Source	2 x 2 x 1 GE 7FA.05 CC plant based on NERA/S&L Demand Curve Report approach	2 x 2 x 1 GE 7FA.05 CC plant based on NERA/S&L Demand Curve Report approach	Astoria Energy II
	J - NYC	J - NYC	
Commercial Operation Date / Price Level	**2010 $**	**2011 $**	**2011 $**
EPC Cost Components			
Equipment			[redacted]
Equipment	274,747,000	281,341,000	
Spare Parts	1,061,000	1,086,000	
Subtotal	275,808,000	282,427,000	
Construction			
Construction Labor & Materials	374,747,000	383,741,000	
Electrical Connection & Substation	6,968,000	7,135,000	
Electrical Interconnect & Upgrades	27,000,000	27,648,000	
Gas Interconnect & Reinforcement	5,740,000	5,878,000	
Site Prep	14,951,000	15,310,000	
Engineering & Design	31,523,000	32,280,000	
Construction Mgmt. / Field Engr. / Indirects	11,463,000	11,738,000	
Subtotal	472,392,000	483,730,000	
Startup & Testing			
Startup & Training	5,731,000	5,869,000	
Testing	-		
Subtotal	5,731,000	5,869,000	
Contingency	71,515,000	73,231,000	
Subtotal - EPC Costs	825,446,000	845,257,000	

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

Case / Source	**2 x 2 x 1 GE 7FA.05 CC plant based on NERA/S&L Demand Curve Report approach**	**2 x 2 x 1 GE 7FA.05 CC plant based on NERA/S&L Demand Curve Report approach**	**Astoria Energy II**
	J - NYC	**J - NYC**	**Astoria II**
Commercial Operation Date / Price Level	**2010 $**	**2011 $**	**2011 $**
Non-EPC Cost Components			
Owner's Costs			
Permitting	8,254,000	8,452,000	[redacted]
Legal	16,509,000	16,905,000	[redacted]
Owner's Project Mgmt. & Misc. Engr.	16,509,000	16,905,000	[redacted]
Social Justice	3,302,000	3,381,000	[redacted]
Owner's Development Costs (total)	24,763,000	25,357,000	[redacted]
Financing Fees	16,509,000	16,905,000	[redacted]
Financial Advisory	2,064,000	2,114,000	[redacted]
Environmental Studies	2,064,000	2,114,000	[redacted]
Market Studies	2,064,000	2,114,000	[redacted]
Interconnection Studies	2,064,000	2,114,000	[redacted]
Emission Reduction Credits	0	0	[redacted]
Subtotal	94,102,000	96,361,000	[redacted]
Financing (incl. AFUDC, IDC)			
EPC Portion	83,494,000	85,498,000	[redacted]
Non-EPC Portion	9,518,000	9,747,000	[redacted]
Working Capital and Inventories	16,509,000	16,905,000	[redacted]
Subtotal - Non-EPC Costs	203,623,000	208,511,000	[redacted]
Total Capital Investment	1,029,069,000	1,053,768,000	[redacted]

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

EXHIBIT CDU-3

EPC Cost Breakdown – Hypothetical Combined Cycle Plant based on NERA/S&L Demand Curve Report vs. AEII

		2 x 2 x 1 GE 7FA.05 CC plant based on NERA/S&L Demand Curve Report approach				Astoria Energy II			
Description	Scope Definition	Total Equipment or Material Cost	Total Man-hours	Total Construction & Erection Cost	Total Projected Cost	Total Equipment or Material Cost	Total Man-hours	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	GE 7FA.05	117,200,000	78,960	11,981,390	129,181,390	[redacted]	[redacted]	[redacted]	[redacted]
HRSG's w/ Accessories	3-Press HRSG w\Reheat.	58,300,000	170,100	26,062,337	84,362,337	[redacted]	[redacted]	[redacted]	[redacted]
Steam Turbine w/ Accessories	Approx. 210 MW	46,000,000	48,020	7,286,555	53,286,555	[redacted]	[redacted]	[redacted]	[redacted]
Condenser w/ Accessories		3,875,000	8,680	1,176,140	5,051,140	[redacted]	[redacted]	[redacted]	[redacted]
Cooling Tower w/ Accessories	10 Cell In-Line, Wood, Turnkey Subcontract	4,710,000	3,080	469,269	5,179,269	[redacted]	[redacted]	[redacted]	[redacted]
Water Supply	Ground Water Production Wells	1,500,000	0	0	1,500,000	[redacted]	[redacted]	[redacted]	[redacted]
Pumps		5,473,000	13,110	2,003,016	7,476,016	[redacted]	[redacted]	[redacted]	[redacted]
Heat Exchangers	CCW Exchangers and Fuel Gas Performance Heaters	840,000	1,820	276,167	1,116,167	[redacted]	[redacted]	[redacted]	[redacted]
Auxiliary Boiler		1,500,000	8,400	1,287,132	2,787,132	[redacted]	[redacted]	[redacted]	[redacted]
Field Erected Tanks	Turnkey Subcontracts	2,330,000	0	0	2,330,000	[redacted]	[redacted]	[redacted]	[redacted]
Shop Fabricated Tanks		171,000	701	106,101	277,101	[redacted]	[redacted]	[redacted]	[redacted]
Ammonia Storage & Forwarding Equipment		400,000	1,120	169,949	569,949	[redacted]	[redacted]	[redacted]	[redacted]
Cranes & Hoists		500,000	3,080	467,727	967,727	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Gas Supply & Metering	Gas Interconnection and Metering Station Assumed by Fuel Gas Supplier	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Gas Compressors	2x100%	2,000,000	2,660	403,628	2,403,628	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Gas Conditioning		1,900,000	1,260	191,192	2,091,192	[redacted]	[redacted]	[redacted]	[redacted]
Bulk Gas Storage Provisions		45,000	630	95,596	140,596	[redacted]	[redacted]	[redacted]	[redacted]
Air Compressors & Dryers		320,000	1,232	186,944	506,944	[redacted]	[redacted]	[redacted]	[redacted]
Chemical Feed & Sample Systems		375,000	840	127,982	502,982	[redacted]	[redacted]	[redacted]	[redacted]
Water Treating	Not Included	0	0	0	0	[redacted]	[redacted]	[redacted]	[redacted]
Fire Protection	Turnkey Subcontract	1,100,000	0	0	1,100,000	[redacted]	[redacted]	[redacted]	[redacted]
B.O.P. Mechanical (Miscellaneous)		175,000	1,022	155,078	330,078	[redacted]	[redacted]	[redacted]	[redacted]
Critical Piping	P91, Shop Fab LB and Field Fab SB	5,837,900	25,697	4,057,556	9,895,456	[redacted]	[redacted]	[redacted]	[redacted]

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

		2 x 2 x 1 GE 7FA.05 CC plant based on NERA/S&L Demand Curve Report approach				Astoria Energy II			
Description	Scope Definition	Total Equipment or Material Cost	Total Man-hours	Total Construction & Erection Cost	Total Projected Cost	Total Equipment or Material Cost	Total Man-hours	Total Construction & Erection Cost	Total Projected Cost
BOP Piping	Shop Fab LB and Field Fab SB. Includes all Hangers & Insulation	6,300,180	218,628	33,042,222	39,342,402	[redacted]	[redacted]	[redacted]	[redacted]
Valves & Specialties		4,479,875	14,769	2,331,962	6,811,837				
Electrical Major Equipment		16,082,500	34,636	4,589,294	20,671,794				
Electrical BOP		6,085,648	192,633	26,480,528	32,566,175				
Instrumentation & Controls		2,900,000	18,690	2,613,049	5,513,049				
Switchyard	Allowance Based on 138kV 5-Breaker GIS	4,700,000	16,142	2,056,329	6,756,329				
Steel	Excluding Building Framing	954,335	7,700	1,287,566	2,241,901				
Buildings	Includes Buildings, HVAC, & Interior Finishes	8,854,467	104,919	16,311,815	25,166,282				
Foundations	Includes Excavation and Foundation Pile Allowance	7,612,186	106,374	14,517,463	22,129,648				
Demolition & Mods to Existing Structures	None	0	0	0	0				
Site Preparation, Drainage, & Yard Work		2,890,100	47,033	6,947,076	9,837,176				
Heavy Haul Subcontracts		0	0	1,600,000	1,600,000				
Indirect and Startup Craft Support		0	251,387	3,793,500	3,793,500				
Allowances to Attract Labor		0	120,289	34,326,218	34,326,218				
Erection Contractors G&A and Profit		0	0	45,421,796	45,421,796				
Total Equipment, Material and Labor Costs		315,411,190	1,503,612	251,822,578	567,233,768				
Consumables					1,577,100				
Freight, Duties, Taxes, Etc.	Freight Only				4,338,504				
Total Direct Project Costs					573,149,372				
Indirect Project Costs					141,997,000				
Contingency & Escalation	Contingency Only				71,515,000				
Spare Parts Cost					1,061,000				
Electrical Interconnect & Upgrades					27,000,000				
Gas Interconnect & Reinforcement					5,740,000				
Site Remediation					4,983,500				
Total EPC Project Cost					825,445,872				

EXHIBIT CDU-4

Fixed O&M – Hypothetical Combined Cycle Plant based on NERA/S&L Demand Curve Report vs. AEII

Case / Source	2 x 2 x 1 GE 7FA.05 CC plant based on NERA/S&L Demand Curve Report approach	2 x 2 x 1 GE 7FA.05 CC plant based on NERA/S&L Demand Curve Report approach	Astoria Energy II
	J - NYC	J - NYC	
Commercial Operation Date / Price Level	**2010 $**	**2011 $**	**2011 $**
Fixed O&M ($/year)			[redacted]
Labor - Routine O&M	3,345,000	3,425,000	
Materials and Contract Services - Routine	3,750,000	3,840,000	
Administrative and General	600,000	614,000	
Subtotal Fixed O&M	7,695,000	7,879,000	
$/kW-year	**14.06**	**14.40**	
Other Fixed Costs ($/year)			
Site Leasing Costs	7,200,000	7,373,000	
Subtotal Fixed O&M	14,895,000	15,252,000	
$/kW-year	**27.22**	**27.88**	
Property Taxes (AEII includes tax abatement)	47,547,000	48,688,000	
Insurance	3,040,000	3,113,000	
Total Fixed O&M	65,482,000	67,053,000	
$/kW-year	**119.68**	**122.55**	

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EXHIBIT CDU-5

Variable O&M – Hypothetical Combined Cycle Plant based on NERA/S&L Demand Curve Report vs. AEII

Case / Source	**2 x 2 x 1 GE 7FA.05 CC plant based on NERA/S&L Demand Curve Report approach**	**2 x 2 x 1 GE 7FA.05 CC plant based on NERA/S&L Demand Curve Report approach**	**Astoria Energy II**
	J - NYC	**J - NYC**	
Commercial Operation Date / Price Level	**2010 $**	**2011 $**	**2011 $**
Variable O&M ($/MWh)			[redacted]
Major Maintenance Parts	0.12	0.13	
Major Maintenance Labor	0.04	0.04	
Unscheduled Maintenance	0.10	0.10	
SCR Catalyst and Ammonia	0.15	0.15	
CO Oxidation Catalyst	0.05	0.05	
Other Chemicals and Consumables	0.18	0.18	
Water	0.05	0.05	
Total Variable O&M ($/MWh)	**0.69**	**0.71**	
Variable O&M - Cost per Start:			
Major Maintenance Parts	9,062	9,279	
Major Maintenance Labor	438	448	
Total ($/factored start, per turbine)	9,499	9,727	

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

EXHIBIT CDU-6

AEII Plant Performance Excluding Degradation

Case No.	Ambient Temp, F	No. GT operating	GT Load	Net Power, kW	Net LHV HR, Btu/kW-hr	Net HHV HR, Btu/kW-hr
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

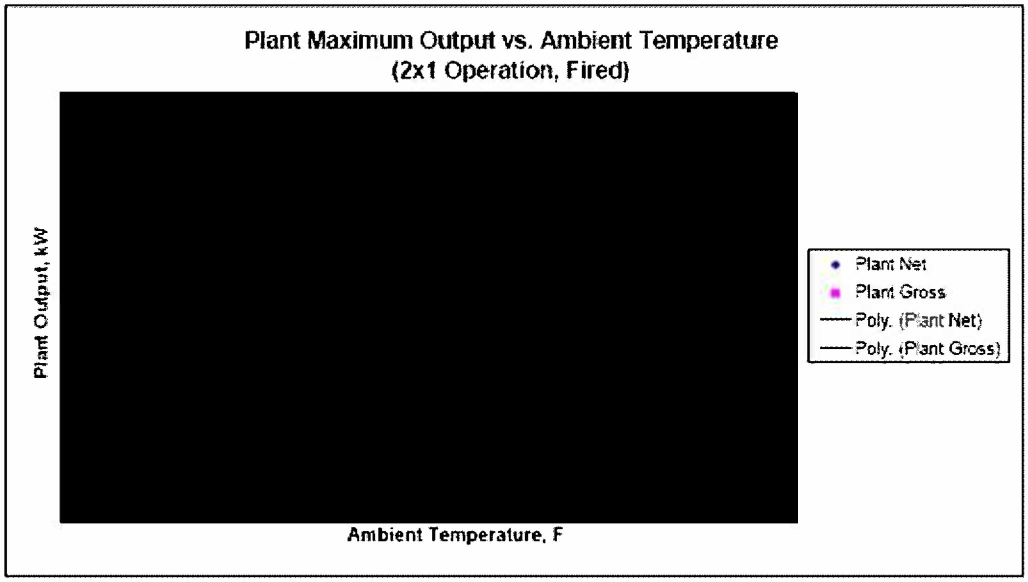
Plant Maximum Output vs. Ambient Temperature
(2x1 Operation, Fired)
Plant Output, kW
Ambient Temperature, F
Plant Net
Plant Gross
Poly. (Plant Net)
Poly. (Plant Gross)

EXHIBIT CDU-7

Real Levelized Carrying Charge Rates

Amortization Years =	10	11	12	13	14	15	16	17	18	19	20	21	22
Without Property Taxes and Insurance:													
Astoria Energy II	[redacted]												
With Property Taxes and ICIP Tax Exemption Policy; Without Insurance:													
Astoria Energy II	[redacted]												

Amortization Years =	23	24	25	26	27	28	29	30	31	32	33	34	35
Without Property Taxes and Insurance:													
Astoria Energy II	[redacted]												
With Property Taxes and ICIP Tax Exemption Policy; Without Insurance:													
Astoria Energy II	[redacted]												

APPENDIX V
AFFIDAVIT OF CHRISTOPHER D. UNGATE REGARDING BAYONNE ENERGY CENTER

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Astoria Generating Company, L.P and TC Ravenswood, LLC	)	
	)	**Docket No. EL11-50-000**
vs.	)	
	)	
New York Independent System Operator, Inc.	)	

AFFIDAVIT OF
CHRISTOPHER D. UNGATE

Mr. Christopher D. Ungate declares:

1. I have personal knowledge of the facts and opinions herein and if called to testify could and would testify competently hereto.

I. Purpose of this Affidavit

2. The purpose of my Affidavit is to present the cost and performance inputs for the Bayonne Energy Center ("BEC") project for use in determining the Cost of New Entry ("CONE") for the project.

II. Qualifications

3. I am a Senior Principal Management Consultant with Sargent & Lundy LLC ("Sargent & Lundy" or "S&L") and have over thirty years of experience in electric utility operations, planning, and consulting. Prior to joining S&L in 2006, my professional work experience included management of generation resource planning for a 30,000 megawatt ("MW") portfolio of nuclear, coal, hydro and gas generation, providing annual power supply plans, monthly cost forecast updates, and system reliability

analyses; hydro operations business planning; re-engineering and process improvement initiatives in utility planning and operations; and laboratory and prototype testing for hydro and thermal generating plants.

4. My consulting practice at Sargent & Lundy focuses on the areas of integrated resource planning, financial modeling and analysis for the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. I also perform due diligence reviews of new technology development, new projects, modification and refurbishment of existing facilities, asset transactions, and operational assessments.

5. My resume is provided in Exhibit CDU-1.

III. Process for Determining Cost and Performance Inputs to Determination of CONE

6. The New York Independent System Operator ("NYISO") contracted with NERA Economic Consulting ("NERA"), supported by Sargent & Lundy, to develop the recommended ICAP Demand Curves for the 2011/12, 2012/13, and 2013/14 Capability Periods. The ICAP Demand Curve reset report describes in detail the potential technology choice for each region, derivation of cost and performance estimates for those technologies, calculation of annual carrying charges, estimation of energy and ancillary service revenues, and development of recommended demand curves.[1] As part of that work, I managed the estimation of capital costs, fixed operations and

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[1] *See* New York Independent System Operator, Inc., Tariff Revisions to Implement ICAP Demand Curves for Capability Years 2011/2012, 2012/2013, and 2013/2014, Docket No. ER11-2224-000 (filed November 30, 2010), at Attachment 2 (Meehan Affidavit) Exhibit B "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator" ("NERA/S&L Demand Curve Report").

maintenance costs, and other costs for quantifying the CONE in New York City ("NYC"), Long Island, and for the New York Control Area ("NYCA") (with a unit located in Rest of State).

7. As a separate undertaking, the NYISO contracted with S&L to derive the cost and performance inputs used to determine the CONE for the BEC Project. The BEC project consists of eight Rolls Royce Trent 60 WLE simple-cycle gas turbine units (512 MW total nameplate capacity) located in Bayonne, New Jersey, and connected directly to the NYCA[2] grid at a Consolidated Edison Company of New York, Inc. ("Con Edison") substation in Brooklyn, New York, by a 345 kV submarine cable. The project is under development by the Hess Corporation ("Hess") with an expected commercial operation date in 2012. The CONE cost and performance inputs include the direct and indirect capital costs, owner's costs, financing costs, working capital and inventories, fixed and variable operations & maintenance ("O&M costs"), site leasing or purchase costs, property taxes, start fuel, equivalent forced outage rate, net plant capacity, and net plant heat rate.

8. Hess representatives provided detailed information on the BEC Project to S&L and responded to questions and provided clarifications. S&L determined whether or not these data were within reasonable ranges and recommended reasonable values to the NYISO. The CONE values were then used by NERA to estimate the net energy service

[2] Terms with initial capitalization not defined herein have the meaning set forth in the NYISO's Market Administration and Control Area Services Tariff.

revenues, and along with estimate ancillary services revenues provided by the NYISO, to compute BEC's Unit Net CONE.

IV. Technology Performance

9. The BEC project consists of eight Trent 60 WLE simple-cycle units. Hess provided expected performance data for the BEC project. Exhibit CDU-5 shows the expected new and clean performance as a function of ambient temperature, according to Rolls Royce. Exhibit CDU-6 shows the expected derated summer and winter performance, according to the "Independent Engineer's Report" prepared by E3 Consulting for Hess.

10. S&L's determination of the reasonableness of the CONE input values provided by Hess included a comparison to a similar plant. The BEC project information was compared to the values derived for the NERA/S&L Demand Curve Report for a hypothetical two-unit RR Trent 60 WLE installation, also located in New Jersey and connected to the NYCA by submarine cable. S&L determined it was reasonable to use the values for that hypothetical plant for purposes of comparison because the BEC project's characteristics examined by S&L to estimate the CONE are similar to the characteristics of the hypothetical plant derived for the NERA/S&L Demand Curve Report. The recommended CONE input values for performance are summarized below.

    a. The CONE input values for plant capacity are based on the average degraded summer and winter net values. The BEC values are derived from the gross output data provided by Rolls Royce, dated March 1, 2010, and the auxiliary power and degradation factors in E3 Consulting's Engineer's Report. The [redacted] per-unit net summer capacity for the BEC project is a result of a [redacted] The BEC values are based on a degradation factor of [redacted] percent, which is [redacted] percent. However, the [redacted] value is justified on the basis of [redacted] under the [redacted] In addition, the BEC values are based on [redacted] assumptions for auxiliary power loads of [redacted] percent to [redacted] percent, compared to [redacted] values of [redacted] percent to [redacted] percent. The conservatism built into the auxiliary power assumption tends to offset the optimistic degradation factor assumption.

Net Plant Capacity (Avg. Degraded Value, Per Unit)	Bayonne Energy Center; RR Trent 60 WLE (8 units)
Summer (MW)	[redacted]
Winter (MW)	[redacted]
Summer / Winter Average (MW)	[redacted]
ICAP (MW) - Summer	[redacted]

b. The CONE input values for plant heat rate are based on the average degraded summer and winter net values, expressed on a full-load, higher heating value ("HHV") basis. The BEC values are derived from the gross heat rate data provided by Rolls Royce, dated March 1, 2010, and the auxiliary power and degradation factors in E3 Consulting's Engineer's Report. As in the case of net capacity, the [redacted] net summer heat rate for the BEC project is a result of the [redacted], which can [redacted]

Net Plant Heat Rate (Avg. Degraded Value)	Bayonne Energy Center; RR Trent 60 WLE (8 units)
Summer (Btu/kWh, HHV)	[redacted]
Winter (Btu/kWh, HHV)	[redacted]
Summer / Winter Average (Btu/kWh, HHV)	[redacted]
ICAP (Btu/kWh, HHV) - Summer	[redacted]

c. The Demand Equivalent Forced Outage Rate ("EFORd") is used to reduce net profits associated with energy and ancillary services revenues. EFORd refers to the Equivalent Forced Outage Rate ("EFORd") during the period when the plant is actually dispatched. The Unforced Capacity ("UCAP") value, which is the maximum capacity a generator is able to sell in the capacity auction, is equivalent to ICAP x (1 - EFORd).

d. The EFORd in the NERA/S&L Demand Curve Report was estimated to be [redacted] percent on the basis of historical outage data from similar units. The BEC project has a projected EFORd of only [redacted] percent. Compared with typical industry data, [redacted]. However, this [redacted] outage value is justified because BEC will [redacted], which provides [redacted]. The [redacted] also contains [redacted].

e. The recommended value for the natural gas consumed during each start is estimated to be 140 mmBtu per start per unit, based on S&L analysis in relation to preparing the NERA/S&L Demand Curve Report. The recommended duration of each startup is [redacted], as identified by Rolls Royce and Hess.

f. The CONE input values for Nitrogen Oxide ("NOx") and Carbon Dioxide ("CO2") emissions are based on the summer and winter values, expressed in lb/hr per CT unit. The recommended values are based on the net output and heat rate values discussed above.

Per Unit	Bayonne Energy Center; RR Trent 60 WLE (8 units)	
	NOx	CO_2
Summer (lb/hr per CT)	[redacted]	[redacted]
Winter (lb/hr per CT)	[redacted]	[redacted]
Summer / Winter Average (lb/hr per CT)	[redacted]	[redacted]
ICAP (lb/hr per CT) – Summer	[redacted]	[redacted]

V. Capital Investment Costs

11. Capital investment costs for the BEC project were provided by Hess showing the direct costs, owner's costs, financing costs during construction, and working capital and inventories. The direct costs include project costs awarded on an Engineering, Procurement, and Construction ("EPC") contract basis. The scope of the estimate includes the gas turbines and balance of plant, a 345 kV submarine cable, and electrical and gas interconnections and upgrades.

12. The BEC cost estimate breakdown, along with explanatory notes, is presented in Exhibit CDU-2. S&L reviewed the reasonableness of this estimate on the basis of discussions with representatives from Hess and Rolls Royce, and on the basis of similar projects. The BEC project information was also compared with the values derived for the NERA/S&L Demand Curve Report for a hypothetical two-unit RR Trent 60 WLE installation, also located in New Jersey and connected to the NYCA by submarine cable. The estimates for the two-unit installation reflect plant features typically found in modern peaking facilities and are intended to reflect representative costs for new plants of their type. The estimates are conceptual and were not based on preliminary engineering activities for any specific site. The estimates were converted to 2012 price levels to match the in-service year of the BEC project and are included in Exhibit CDU-2.

13. The recommended CONE input values for BEC capital investment costs are discussed below.

    a. The EPC costs for the BEC project are based on actual fixed price contracts. In contrast, the EPC estimates derived for the NERA/S&L Demand Curve Report for Zone J were based on a hypothetical plant installation. The following assumptions for the hypothetical unit are compared and contrasted to the BEC project:

        i. The hypothetical Trent 60 peakers in Zone J are required to have selective catalytic reduction ("SCR") but not a Carbon Monoxide ("CO") catalyst. [redacted] BEC costs include [redacted]

ii. Emissions Reduction Credits ("ERCs") were included in the owner's costs for the hypothetical unit to allow for increased operating hours in accordance with economic dispatch. BEC costs [redacted].

iii. Greenfield site conditions were assumed for the hypothetical plant. In contrast, the BEC site is adjacent to an existing Hess oil terminal.

iv. Inlet air fogging was assumed for the hypothetical unit, which is [redacted]

v. Dual fuel capability was assumed for the hypothetical unit, which is also the case for BEC.

vi. Fuel gas compressors were assumed for the hypothetical unit, based on a local supply pressure of 200 psig. [redacted], the local supply pressure for BEC is [redacted] psig.

vii. A contingency of 10 percent was applied to the total of direct and indirect project costs for the hypothetical unit. [redacted], the BEC contingency is [redacted] percent of the EPC costs.

viii. All equipment and material costs for the hypothetical unit were based on S&L in-house data, vendor catalogs, or publications. Labor rates were developed based on union craft rates in 2010.[3] Costs were added to cover FICA, fringe benefits, worker's compensation insurance, small

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[3] Base pay and supplemental (fringe) benefits were obtained from the Prevailing Wage Rate Schedules – New York State Department of Labor, using the data dated as of March 2010.

tools, construction equipment, and contractor site overheads. Work was assumed to be performed on a 50-hour work week by qualified craft labor available in the plant area. Labor rates were based on New York County for Zone J. An allowance to attract and keep labor was included. A labor productivity adjustment of 1.40 was applied to Zone J.[4] Materials costs were based on data for New York City in Zone J. Certain of these costs for BEC were different, as described below in this section.

ix. Black start capability was not included for the hypothetical unit. [redacted].

x. Use of rental trailer-mounted water treating equipment was assumed for the hypothetical unit. In contrast, the BEC project has a permanent water treating system.

xi. A control/administration building was assumed for the hypothetical unit, which is also the case for BEC.

b. Some of the EPC cost differences in Exhibit CDU-2 between the hypothetical Trent 60 costs derived from the NERA/S&L Demand Curve Report and the BEC costs are a result of the differences in underlying assumptions identified above. Moreover, the BEC costs incorporate significant economies of scale of

[4] Based on ranges obtained from the 2010 Global Construction Cost Yearbook , published by Compass International, Inc.

an eight-unit plant versus a two-unit plant. The major components of the EPC costs for the BEC project are described below.

i. The Equipment and Spare Parts portion of the EPC cost for BEC is $[redacted]. This amount includes the cost of the gas turbines and balance of plant, excluding the submarine cable, under a fixed price contract with [redacted]. The amount includes the cost of an expected bonus of $[redacted] for exceeding performance guarantees, and $[redacted] for spare parts.

ii. The Construction portion of the EPC cost for BEC is $[redacted]. This amount includes $[redacted] for construction labor and materials including a fixed price contract with [redacted], $[redacted] for electrical connection and substation, $[redacted] for site preparation, $[redacted] for engineering and design, and $[redacted] for construction management and field engineering.

iii. The Startup and Testing portion of the EPC cost for BEC is $[redacted], which includes mobilization for startup and O&M, startup services, testing, and startup fuel.

iv. The contingency of $[redacted] represents approximately [redacted] percent of the EPC amount. This amount was derived from the sum total of the contingencies of the EPC component costs, recognizing that many costs are covered under fixed price contracts and require minimal contingency and accounting for the current status of the other non-fixed price components.

v. The sum total of the above EPC costs for equipment, construction, start-up and testing, and contingency is $[redacted].

14. Owner's costs include items not covered by the EPC scope such as owner's development costs, oversight, legal fees, financing fees, startup and testing, and training. The owner's costs for the BEC project are based on actual costs through August 2010 and expected remaining costs through the start of commercial operation in 2012.

15. The total owner's costs for the BEC project are [redacted] percent of the EPC costs. This percentage is [redacted] the [redacted] percent estimate for the hypothetical similar plant for the NERA/S&L Demand Curve Report. The BEC percentage is only expressed as a percentage of EPC costs and not as a percentage of the sum of the submarine cable cost and the EPC costs. The legal fees, owner's project management costs, social justice costs, owner's development costs, study costs, and ERCs for the BEC project are [redacted], measured as a percent of the EPC costs, but [redacted] The financing fees for the BEC project are [redacted] as measured as a percent of only the EPC costs, but are within the expected range of values when measured as a percent of the total of EPC and submarine cable cost, as discussed below. The aggregate total of all owner's cost categories is within the expected range for this type of installation.

16. ERCs are included in owner's costs to allow for increased operating hours in accordance with economic dispatch. The estimated operating hours for the hypothetical plant in the NERA/S&L Demand Curve Report corresponds to an estimated capacity factor of 50 percent. The recommended ERC cost provided by Hess is a reasonable estimate of the ERCs needs to assure increased operating hours for the BEC.

17. The financing fees for the hypothetical unit in the NERA/S&L Demand Curve Report include a waiver of mortgage recording taxes, which are 2.8 percent of the debt financing amount. Hess indicated that the BEC [redacted]re included in the recommended owner's cost in the following table and in Exhibit CDU-2.

18. Financing costs during construction refer to the cost of debt and equity required over the periods from each construction expenditure date through the plant in-service date. These costs were calculated from the monthly construction cash flows and the cost of project debt and equity.

19. Total financing costs for the BEC project, including the financing costs for the submarine cable, are $[redacted] or [redacted] percent of the EPC costs of $[redacted] The submarine cable cost of $[redacted] for the BEC project is shown separately from the EPC costs. Approximately $[redacted] of the submarine cable costs are estimated by S&L to be financing costs, so EPC financing costs are $[redacted] ($[redacted] minus $[redacted]) or [redacted] percent of the EPC costs. This is within the expected range of

values. By comparison, total financing costs derived for the hypothetical Trent 60 plant in the NERA/S&L Demand Curve Report are 5.6 percent of the EPC costs.

20. Working capital and inventories refer to the initial inventories of fuel, consumables, and spare parts that are normally capitalized. It also includes working capital cash for the payment of monthly operating expenses. Working capital and inventories for the BEC project are [redacted] percent of the EPC costs, whereas the NERA/S&L Demand Curve Report estimated these costs as 2 percent of EPC costs. The [redacted] value for the BEC project is justified considering [redacted].

21. S&L discussed sunk costs with the Market Monitoring Unit to the NYISO ("MMU") and the NYISO at the time of the examination. The decision to move forward with a project is not necessarily tied to a specific date, but rather a series of decision points over an extended period of time. Over time, the estimated project costs and the cost of backing out become more significant. At the direction of the NYISO, based on the recommendation of the MMU, costs incurred before the decision point described below are "sunk" and were excluded from the evaluation. S&L determined, based on project experience, that a portion of owner's costs for project development are incurred before the decision point and are sunk costs. S&L estimated the sunk portion of owner's costs as the sum of the following:

    a. One-half of permitting costs

    b. One-half of legal costs

c. Environmental studies costs

d. Market studies costs

The sum of the above sunk owner's costs is $[redacted]. S&L judged the latest expected project costs to be a reasonable estimate of Hess's expectations at the time of a decision to move forward.

22. The recommended capital cost inputs for determining the CONE for the BEC project are summarized in the following table based on the latest expected costs through the 2012 commercial operation date.

Parameter	Expected Costs (2012 COD)
EPC Costs - Plant	[redacted]
Submarine Cable	[redacted]
Owner's Costs and Other Capital Costs	[redacted]
"Sunk" Portion of Owner's Costs	[redacted]
Total Capital Investment	[redacted]
Net Degraded Summer ICAP MW	[redacted]
$/kW	[redacted]

VI. Operating Costs

23. In addition to the capital investment costs presented in the previous section, other cost inputs to the CONE calculation include fixed O&M, variable O&M, and fuel. Fixed and variable O&M costs for the BEC project were provided by Hess. The BEC O&M cost breakdowns, along with explanatory notes, are presented in Appendix A, Tables A-2 and A-3.

24. S&L reviewed the reasonableness of these estimates on the basis of discussions with representatives from Hess and Rolls Royce and on the basis of similar projects. The BEC project O&M information was compared with the values derived for the NERA/S&L Demand Curve Report for a hypothetical two unit RR Trent 60 WLE installation. The estimates were converted to 2012 price levels to match the in-service year of the BEC project and are included in Tables A-2 and A-3.

25. The recommended CONE input values for BEC fixed and variable O&M costs are discussed below.

    a. Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance). The fixed O&M costs provided by Hess for the BEC project are based on expected labor costs, contract services, leasing costs, payments in lieu of taxes, and other items. In contrast, the fixed O&M estimates derived for the NERA/S&L Demand Curve Report were based on a hypothetical plant installation.

    b. Some of the fixed O&M cost differences between the NERA/S&L Demand Curve Report and the BEC costs are a result of different underlying assumptions, splits between fixed and variable components, and site-specific factors, which are identified below. As with the capital investment costs discussed in the previous section, the BEC fixed O&M costs also incorporate economies of scale of an eight-unit plant versus a two-unit hypothetical plant.

The major components of the fixed O&M costs for the BEC project are described below and summarized in Exhibit CDU-3.

c. Routine labor costs of $[redacted] (2012 $) for the two-unit estimate were based on a staff of eight full-time equivalents and an average labor rate, including benefits, of $67/hour. The BEC budget for this category is $[redacted] which includes [redacted] to [redacted] full-time equivalents and various subcontracted services as indicated by Hess. This is a reasonable labor budget for this facility type and configuration.

d. Fixed materials and contract services of $283,000 (2012 $) for the two-unit estimate were derived from published industry data and similar projects in operation. The BEC budget of $[redacted] for this category [redacted]. These fees include $[redacted] for the [redacted], $[redacted] for [redacted], $[redacted] for fuel oil storage, $[redacted] for local gas distribution through the Transco delivery lateral, and $[redacted] for fixed fees for water and auxiliary power and annual interconnection fees for water, sewer, and power.

e. Administrative and general costs of $367,000 (2012 $) for the two-unit estimate were derived from published industry data and similar projects in operation. The BEC budget of $[redacted] includes $[redacted] for asset management fees, which is a reasonable scale-up for an eight-unit plant versus a two-unit plant, plus site-specific costs. The latter includes $[redacted] for [redacted] the Gowanus Substation property in New York and $[redacted] for the [redacted] in New Jersey.

f. The BEC site lease payment of $[redacted] is the actual annual lease payment to Hess for their 7-acre site. This equates to an annual lease rate of nearly $[redacted]/acre-year, which is [redacted] the lease rate of $240,000/acre-year assumed for the ICAP Demand Curve peaking unit located in Zone J, and considering the close proximity of the BEC site to the interconnection location at Gowanus substation. The lease rate of $22,000/acre-year assumed for New Jersey in the NERA/S&L Demand Curve Report [redacted].

g. Property taxes of $5,241,000 for the two-unit estimate are equal to an assumed property tax rate of 2.0 percent of the plant market value, multiplied by an assessment ratio of 100 percent. The BEC budget of $[redacted] includes actual negotiated payments in lieu of taxes ("PILOT") agreements of $[redacted] for New Jersey and $[redacted] for New York.

h. Insurance costs of $786,000 for the two-unit estimate are equal to 0.30 percent of the initial capital investment, escalating each year with inflation, on the basis of actual data for recent independent power projects. The BEC budget of $[redacted] is approximately [redacted] percent of the initial capital investment, which is within a reasonable range of expected values.

26. Variable costs, consisting of fuel and variable O&M, are used to develop net energy and ancillary service revenues in NERA's econometric model of NYISO market prices. The variable O&M costs for the BEC project are based on pricing information from the [redacted] for major maintenance parts and labor, along with current local pricing and material balances for ammonia, water treatment chemicals, water and sewer, auxiliary power, and NOX allowances. In contrast, the variable O&M estimates derived in the NERA/S&L Demand Curve Report were based on a hypothetical plant installation. Some of the variable O&M cost differences between the NERA/S&L Demand Curve Report and the BEC costs are a result of different underlying assumptions and splits between fixed and variable components. The major components of the variable O&M costs for the BEC project are described below and summarized in Exhibit CDU-4.

a. Over the long-term operating life of a peaking facility, the largest component of variable O&M is the allowance for major maintenance expenses. Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. For the Trent 60 WLE aeroderivative units, Rolls Royce recommends a major maintenance overhaul every 50,000 factored operating hours. Normal operating hours would be factored, that is, increased to account for severe operating conditions such as for hours of operation on fuel oil.

b. Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. The average variable O&M cost for major maintenance is thus equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored operating hours between overhauls, divided by the unit capacity in megawatts.

c. Major maintenance costs of $3.49/megawatt-hour ("MWh") (2012 $) for the ICAP Demand Curve Report estimate for the hypothetical 2-unit plant are based on parts costs of $9,332,000 and 13,000 labor hours over a 50,000-hour major maintenance interval. The BEC budget of $[redacted]/MWh (2012 $) is based on the estimated annual operating hours and reserve funding [redacted] The BEC value is [redacted] than the ICAP Demand Curve Report estimate because some of the LTSA pricing is included under the fixed O&M. The BEC budget for major maintenance is within a reasonable range.

d. Other variable O&M costs are directly proportional to plant generating output, such as unscheduled maintenance, SCR catalyst and ammonia, water, and other chemicals and consumables. SCR is required in ozone non-attainment areas, which applies to BEC. The combined estimated cost for these items is $1.89/MWh (2012 $) in the NERA/S&L Demand Curve Report compared with $[redacted]/MWh in the BEC budget.

e. As discussed in the previous section, the fixed O&M portion of the BEC budget includes some items that would typically be covered as a variable O&M cost, [redacted] The BEC budget also treats the cost of future catalyst replacement and disposal as an [redacted]. The cost of unscheduled maintenance in the NERA/S&L Demand Curve Report estimate is covered under the [redacted] in the BEC estimate. In light of these assumptions, the BEC budget for other variable O&M is within a reasonable range.

27. The recommended fixed and variable O&M cost inputs for determining the CONE for the BEC project are summarized in the following table based on the expected costs using a 2012 commercial operation date. The expected O&M costs were judged to be a reasonable estimate.

Parameter	Expected Costs (2012 $)
Fixed O&M - Plant ($/yr)	[redacted]
Other Fixed O&M (Site Leasing, Property Taxes, and Insurance)	[redacted]
Total Fixed O&M ($/yr)	[redacted]
$/kW	[redacted]
Variable O&M ($/MWh)	[redacted]

28. Fuel costs, along with variable O&M, are used to develop net energy and ancillary service revenues in NERA's econometric model of NYISO market prices. The fuel costs are derived from the delivered price of fuel, the net plant heat rate, and the plant dispatch. The net plant heat rates are presented in Section IV. The fuel price would be tied to pricing at the Transco Zone 6 trading point. Local fuel transportation charges are not significant because the BEC project is connected directly to the Transco interstate pipeline system by a delivery lateral. As previously discussed, the annual fixed fees for this connection are included in the fixed O&M costs.

VII. Carrying Charges

29. As part of the CONE derivation, capital investment costs were converted to annual capacity charges using annual carrying charge rates. The annual carrying charge rate multiplied by the original capital investment yields the annual carrying charges. Carrying charges typically include all annual costs that are a direct function of the capital investment amount: principal and interest payments on project debt, equity returns, income taxes, property taxes, and insurance. In the case of the BEC project, property taxes and insurance are included under the fixed O&M as described in Section VI, so they are excluded from the carrying charges.

30. Income tax and financing inputs were provided by Hess and are presented in the following subsections. S&L reviewed these inputs with Hess and determined they were reasonable. S&L calculated real levelized carrying charge rates.

31. Income taxes are a significant component of carrying charge rates. A portion of these charges must be grossed up to account for the income taxes due on plant revenues such that the desired return on equity is achieved. Income taxes include the federal corporate tax rate of 35.00 percent and the New Jersey state corporate tax rate of 9.00 percent. [redacted]. Hess's tax attorneys provided information that the project would be subject to [redacted], which would be [redacted] percent. The composite tax rate is the sum of these rates, reduced by the portion that is deductible from taxable income.

	Bayonne Energy Center
Federal Tax Rate	[redacted]
State Tax Rate	[redacted]
City Tax Rate	[redacted]
Composite Tax Rate *	[redacted]

* Federal tax rate + State tax rate + City tax rate – [Federal tax rate x (State tax rate + City tax rate)], to account for the deductibility of state and local taxes from federal taxable income.

32. Financing assumptions provided by Hess for the BEC are summarized in the following table. The costs of debt and equity are shown on a nominal basis and a real basis. Real rates are derived by removing the inflation component of 2.15 percent, which reflects 2.4 percent inflation net of 0.25 percent technological process. The real rates are then used to calculate the real weighted average cost of capital ("WACC") and the real levelized carrying charge rates. Note that the "pre-tax" WACC as commonly calculated uses a pre-tax cost of debt with an after-tax cost of equity. The pre-tax WACC is shown here for reference, but is not used in the CONE determination.

	Bayonne Energy Center
Equity Fraction	[redacted]
Debt Fraction	[redacted]
Cost of Equity (nominal)	[redacted]
Cost of Debt (nominal)	[redacted]
Cost of Equity (real)	[redacted]
Cost of Debt (real)	[redacted]
Weighted Average Cost of Capital *	
Pre-Tax (nominal)	[redacted]
After-Tax (nominal)	[redacted]
Pre-Tax (real)	[redacted]

After-Tax (real)	[redacted]
Tax Depreciation **	15-year MACRS
Inflation Rate	2.15%

* (Equity Fraction x Cost of Equity) + (Debt Fraction x Cost of Debt), before tax; and (Equity Fraction x Cost of Equity) + [(Debt Fraction x Cost of Debt) x (1 – Composite Tax Rate)], after tax.

** Federal tax code schedule (Modified Accelerated Cost Recovery System or MACRS) for a simple-cycle combustion turbine, adjusted for residual depreciation if the amortization period is less than 15 years.

33. For each case, the annual carrying charges were calculated over amortization periods of 10 to 35 years. Annual carrying charges are equal to the sum of the following components:

a. Principal. Based upon mortgage style amortization.

b. Interest. Equal to the cost of debt multiplied by the loan balance for the given year.

c. Target Cash Flow to Equity. Equal to the initial equity investment multiplied by an annuity factor over the amortization period, using the cost of equity as the annuity rate.

d. Income Taxes. Calculated by the formula: [t/(1-t)] x [Target Cash Flow to Equity + Principal – Annual Tax Depreciation], where t = Composite Tax Rate. Annual tax depreciation is based on 15-year Modified Accelerated Cost Recovery System ("MACRS") depreciation in accordance with the federal tax code for a simple-cycle combustion turbine.

34. The levelized carrying charge is equal to the annual carrying charges over a given amortization period converted to an annuity using the after-tax WACC. In other words, the annual carrying charges are considered to be "revenue requirements" that are discounted at the after-tax WACC. The real levelized carrying charges are expressed in reference year price levels. Nominal carrying charge rates for future years are equal to the reference year real rate escalated by the inflation rate net of technological progress of 2.15 percent/year.

35. The real levelized carrying charge rates as a function of amortization period are summarized in the following table. As previously mentioned, the rates do not include property taxes and insurance since those items are included in the fixed O&M.

	Bayonne Energy Center
10-year amortization	[redacted]
15-year amortization	[redacted]
20-year amortization	[redacted]
25-year amortization	[redacted]
30-year amortization	[redacted]
35-year amortization	[redacted]

36. The above carrying charge rates are shown for each amortization period in Exhibit CDU-7.

This concludes my Affidavit.

ATTESTATION

I am the witness identified in the foregoing affidavit. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Christopher D Ungate

Christopher D. Ungate

Subscribed and sworn to before me
this 7th day of September 2011

Tira L. Seals

Notary Public

OFFICIAL SEAL
TIRA L SEALS
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:05/04/15

My commission expires: May 4, 2015

EXHIBIT CDU-1

CHRISTOPHER D. UNGATE RESUME

CHRISTOPHER D. UNGATE
Senior Principal Management Consultant
Sargent & Lundy Consulting

Sargent & Lundy LLC

EDUCATION

University of Tennessee, Master of Business Administration, 1984
Massachusetts Institute of Technology, M.S. Civil Engineering, 1974
Massachusetts Institute of Technology, B. S. Civil Engineering, 1973

REGISTRATIONS

Professional Engineer - Tennessee

EXPERTISE

Resource Planning
Business and Strategic Planning
Process Improvement and Re-engineering
Market Analysis and Price Forecasting
Decision Analysis
Asset Valuation and Due Diligence
Generation Portfolio Analysis
Risk Analysis

RESPONSIBILITIES

Mr. Ungate is accountable for Sargent & Lundy offerings in the Utility Planning business segment. He develops and evaluates integrated resource plans and associated analyses to identify and evaluate the optimum power supply options. He reviews and evaluates power supply planning and procurement options such as generation options available in the region (potential greenfield or plant expansion options), the viability of siting and permitting new nuclear, coal, gas, wind, solar, biomass or other alternative generation, the prospects for purchase of existing assets, and the potential for partnering with other load serving entities or power generators. He also assesses the potential and/or required renewable energy resource options, the state of transmission planning and upgrade programs, recent wholesale prices in the Client's load zone, and the fuel market and transportation capacities. He assures consistency with the Client's long-term plans and objectives and Client-specific economic factors (such as standard inflation, inflation, discount, or escalation rates).

Mr. Ungate develops financial models and analyses utilized in the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. He bases the models on appropriate economic, project, operating, and client-specific inputs related to base-case scenarios, as well as associated sensitivity analyses. He also reviews existing financial models and analyses to determine if they are reasonable and appropriate, and to evaluate or develop resulting conclusions and recommendations. He also performs forward pricing analyses and evaluations, system reliability studies, load forecasting, and electric market forecasts and projections in support of power supply planning or other Client needs.

Mr. Ungate also performs due diligence reviews of new technology development, new projects, modifications and refurbishment of existing facilities, asset transactions, and operational assessments. He evaluates and develops plans to optimize the utilization of conventional hydropower plants and pumped storage plants with thermal generating units.

EXPERIENCE

Mr. Ungate has over 35 years of experience in engineering and planning for electric utilities. Since joining Sargent & Lundy in 2006, his assignments have included:

ALTERNATIVES ANALYSIS

- **San Miguel Electric Cooperative**
  - Conducted study of generation alternatives to meet federal and state requirements for justification of new coal project.

- **CPS Energy**
  - Developed cost and performance assumptions for alternative technologies for use in integrated resource planning studies. Compared published estimates of costs for new nuclear plants.

- **Entegra Power Services**
  - Conducted a planning study of adding 300 MW of natural gas-fired peaking capacity to an existing power station in the southwest US. Estimated capital costs, operating performance, and operations and maintenance (O&M) costs for three aeroderivative combustion turbine models with and without selective catalytic reduction (SCR), and two frame combustion turbine models without SCR.

- **South Mississippi Electric Power Association**
  - Reviewed renewable energy alternatives for this G&T cooperative in anticipation of future Renewable Portfolio Standard requirements. Directed the evaluation of responses to an RFP for renewable energy and capacity.

- **Department of Energy and Sandia Renewable Energy Laboratory**
  - Updated the 2003 report, “Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts” with the Dish technology.

- **Oklahoma Gas & Electric**
  - Contributed to the analysis of generating alternatives for a study of how to reduce carbon emissions from the OG&E generating portfolio.

RISK ANALYSIS

- **Various Clients**
  - Analyzing the risks associated with the cost, schedule, and performance impacts of proposed projects.

- **Globaleq**
  - Identified and quantified key drivers of increases in capital estimates for coal fired power plants.

- **American Electric Power**
  - Identified and compared key characteristics of new nuclear plant technologies. Assessed the risk of each technology relative to client objectives.

- **Allegheny Energy**
  - Developed a comprehensive risk analysis model to determine the expected outage days, generation and costs for a fleet of supercritical coal-fired units based on a high level condition assessment. The objectives were to assess the impacts of the risk issues and associated mitigation projects and to provide support the development of capital spending plans.

- **Confidential Client**
  - Let a due diligence study of a potential investment in temporary power services to countries with developing economies based on diesel engine technology.

PLANNING AND PROJECT SUPPORT

- **PSEG**
  - Developed the need for power and energy alternatives analyses to satisfy the NUREG 1555 requirements for Environmental Reports associated with an Early Site Permit Application for a new nuclear plant project.

- **Tennessee Valley Authority, PSEG**
  - Developed the need for power analysis to satisfy the NUREG 1555 requirements for Environmental Reports associated with a Combined Operating License Application for a new nuclear plant project.

- **New York Independent System Operator**
  - Estimated the cost of new entrant peaking units used in the formulation of demand curves for the NYISO capacity market. Estimated going forward costs of existing generation used in determining need for market power mitigation.

- **New England Power Generators Association**
  - Estimated the cost of new entrant peaking units in New England for a NEPGA proposal to revise the basis for capacity payments in ISO-NE.

- **Eskom**
  - Surveyed major equipment suppliers with capabilities to support a large coal-fired project in Africa to assess the potential effect of current and projected production capacity, resource availability, and transportation requirements on project schedule, quality, and costs.

- **EPB**
  - Conducted seminars on selected generation, transmission and electricity market topics to prepare senior management on current trends and issues.
- **Tennessee Valley Authority**
  - Developed the need for power and alternatives section for the 2010-11 integrated resource planning effort.
- **Confidential Client**
  - Led the preparation of a business plan for a client considering whether to develop a fleet of generating plants based on small modular nuclear reactor technology.
- **Confidential Client**
  - Estimated potential market volume for a cable manufacturer exploring entering the utility market.

Prior to joining Sargent & Lundy, Mr. Ungate had over 30 years of experience at the Tennessee Valley Authority in a variety of engineering and planning assignments. Examples of assignments include the following:

POWER SUPPLY PLANNING

- Directed supply planning for 30,000 MWs of nuclear, coal, gas, renewable, and hydro generation, and determined peak season power purchase requirements. Directed the preparation of power supply plans, and the valuation of capacity additions, major projects, product offerings, and bulk power transactions. Plans provided the basis for purchase and sale decisions; fuel purchase and inventory decisions; and hedging strategies for the commodity book.
- Led environmental controls optimization study to determine least cost approach to meeting CAIR/CAMR requirements for TVA's 15,000 MW coal generation portfolio. Alternatives included mothballing of units; increased allowance purchases; modified capital improvement programs; re-powering; and replacement with capacity and energy purchases from gas-fired units. Developed approach that resulted in reduction of projected end of period debt by more than $1 billion.
- Provided cost analysis for product pricing for industrial customers. Determined analytical approach and oversaw analyses to determine value of interruptible products, standby power, customer co-generation, long vs. short term contracts, and dispersed power products.

BUSINESS AND STRATEGIC PLANNING

- Directed business planning for portfolio of 109 conventional hydropower units at 29 sites and four pumped storage units. Portfolio supplies 10-15% of company sales with 5000 MWs of capacity. Forced outage rates, recordable injury incident rates, and reportable environmental events were increasing over the previous six years. Developed a five year business plan to increase resources to facilitate the transition to a process management maintenance strategy, and to integrate plant modernization and automation projects to change technology and workflow at the plants.

- Directed the first reassessment of the operating policies of Tennessee Valley Authority reservoirs since the system was designed in the 1930's. Stakeholders were concerned about water quality issues affecting the reservoirs and about the adverse impact of lake levels on property values and recreation-oriented businesses. Led initiative to redefine operating policies, examine environmental concerns, expand public interest and support, and more effectively meet the needs of multi-state customer base. Directed the development of an operating scheme that preserved hydropower value while improving summer lake levels for recreation and increasing minimum flows for water quality.
- Developed competitive analysis for an electric utility. Customers seeking choice of energy suppliers created need for a credible competitive analysis for electric utility monopoly. Price to customers was above competitive energy suppliers. Loss of customer load would create the risk of not recovering the high fixed costs of generation built to serve former customers. Quantified the competitive threat, and identified the circumstances under which loss of customers was most likely.

PROJECT ENGINEERING

- Directed 40-50 engineers, technicians and building trades conducting laboratory and prototype testing of thermal and hydro plant performance problems. Responsible for daily operating management, laboratory safety, quality assurance, human resources, technology acquisition and facilities management.
- Conducted field tests and physical modeling studies on the effects of thermal generating plants on rivers and reservoirs. Contributed to preparation of several environmental statements impacting authorizations for plant operations and discharge.

MEMBERSHIPS

Board of Examiners, Tennessee Quality Award, 1997-99

PUBLICATIONS

"Baseload Generation Capital Cost Trends," Electric Power Conference, May 2007.

"Resolving Conflicts in Reservoir Operations: Some Lessons Learned at the Tennessee Valley Authority," American Fisheries Society symposium, 1996.

"Tennessee Valley Authority's Clean Water Initiative: Building Partnerships for Watershed Improvement," Journal of Environmental Planning and Management, 39(1), 1996.

"'Equal Consideration' at TVA: Changing System Operations to Meet Societal Needs," Hydro Review, July 1992.

"Reviewing the Role of Hydropower in TVA Reservoir Operations," with Douglas H. Walters, Waterpower '91, An International Conference on Hydropower, Denver, Colorado, 1991.

"TVA's Lake Improvement Plan: Reviewing the Operating Objectives of TVA's Reservoir System," National Conference on Hydraulic Engineering, Nashville, Tennessee, July 1991.

"Tennessee River and Reservoir System Operation and Planning Review, Final Environmental Impact Statement," with TVA staff, December 1990.

"Field and Model Results for Multiport Diffuser Plume," with Charles W. Almquist and William R. Waldrop, American Society of Civil Engineers Specialty Conference on Verification of Mathematical and Physical Models, University of Maryland, August 1978.

"Mixing of Submerged Turbulent Jets at Low Reynolds Number," with Gerhard Jirka and Donald R. F. Harleman, M.I.T. Ralph M. Parsons Laboratory, Report No. 197, February 1975.

EXHIBIT CDU-2

Capital Costs – NERA/S&L Demand Curve Report (2 Units) vs. BEC (8 Units)

Case / Source	NERA/S&L Demand Curve Report		Bayonne Energy Center
	RR Trent 60 WLE (2 units)	RR Trent 60 WLE (2 units)	RR Trent 60 WLE (8 units)
Commercial Operation Date / Price Level	2010 $	2012 $	2012 $
EPC Cost Components			
Equipment			
Equipment	68,113,000	71,422,000	[redacted]
Spare Parts	1,061,000	1,113,000	
Subtotal - Equipment and Spare Parts	1,061,000	72,535,000	[redacted]
Construction			
Construction Labor & Materials	45,924,000	48,155,000	[redacted]
Electrical Connection & Substation	4,885,000	5,122,000	
Electrical Interconnect & Upgrades	4,800,000	5,033,000	
Gas Interconnect & Reinforcement	4,098,000	4,297,000	
Site Prep	2,994,000	3,139,000	
Engineering & Design	6,419,000	6,731,000	
Construction Mgmt. / Field Engr.	1,605,000	1,683,000	
Subtotal - Construction	70,725,000	74,160,000	[redacted]
Startup & Testing			
Startup & Training	1,070,000	1,122,000	[redacted]
Testing	0	0	
Subtotal - Startup & Testing	0	0	[redacted]
Contingency	13,001,000	13,633,000	[redacted]
Subtotal - EPC Costs	84,787,000	160,328,000	[redacted]

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

Case / Source	**NERA/S&L Demand Curve Report**		**Bayonne Energy Center**
	RR Trent 60 WLE (2 units)	**RR Trent 60 WLE (2 units)**	**RR Trent 60 WLE (8 units)**
Commercial Operation Date / Price Level	**2010 $**	**2012 $**	**2012 $**
Non-EPC Cost Components			
Owner's Costs			
Permitting	848,000	1,603,000	[redacted]
Legal	1,696,000	3,207,000	
Owner's Project Mgmt. & Misc. Engr.	1,696,000	3,207,000	
Social Justice	763,000	1,443,000	
Owner's Development Costs	2,544,000	4,810,000	
Financing Fees	1,696,000	3,207,000	
Financial Advisory	212,000	401,000	
Environmental Studies	212,000	401,000	
Market Studies	212,000	401,000	
Interconnection Studies	212,000	401,000	
Emission Reduction Credits	270,000	283,000	
Subtotal - Owner's Costs	10,361,000	19,364,000	[redacted]
Financing (incl. AFUDC, IDC)			
EPC Portion	4,248,000	8,032,000	[redacted]
Non-EPC Portion	519,000	970,000	
Working Capital and Inventories	1,696,000	3,207,000	
Subtotal - Non-EPC Costs	16,824,000	31,573,000	[redacted]
Submarine Cable Installation	68,305,000	71,623,000	
Total Capital Investment	**169,916,000**	**263,524,000**	[redacted]
Net Degraded ICAP MW	53.34	53.34	[redacted]
Total MWs	106.68	106.68	
$/kW	**1,593**	**2,470**	[redacted]

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

EXHIBIT CDU-3

Fixed O&M – NERA/S&L Demand Curve Report (2 Units) vs. BEC (8 Units)

Case / Source	**NERA/S&L Demand Curve Report**		**Bayonne Energy Center**
	RR Trent 60 WLE (2 units)	**RR Trent 60 WLE (2 units)**	**RR Trent 60 WLE (8 units)**
	NJ w/HV Cable to NYC	**NJ w/HV Cable to NYC**	**NJ w/HV Cable to NYC**
Commercial Operation Date / Price Level	**2010 $**	**2012 $**	**2012 $**
Labor - Routine O&M	1,115,000	1,169,000	[redacted]
Materials and Contract Services - Routine	270,000	283,000	[redacted]
Administrative and General	350,000	367,000	[redacted]
Subtotal	1,735,000	1,819,000	[redacted]
$/kW-year	**16.26**	**17.05**	[redacted]
Other Fixed Costs ($/year)			
Site Leasing Costs	77,000	81,000	[redacted]
Subtotal Fixed Costs	1,812,000	1,900,000	[redacted]
$/kW-year	**16.99**	**17.81**	[redacted]
Property Taxes	4,998,000	5,241,000	[redacted]
Insurance	750,000	786,000	[redacted]
Total Fixed O&M (All Units)	7,560,000	7,927,000	[redacted]
$/kW-year	**70.87**	**74.31**	[redacted]

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

EXHIBIT CDU-4

Variable O&M – NERA/S&L Demand Curve Report (2 Units) vs. BEC (8 Units)

Case / Source	**NERA/S&L Demand Curve Report**		**Bayonne Energy Center**
	RR Trent 60 WLE (2 units)	**RR Trent 60 WLE (2 units)**	**RR Trent 60 WLE (8 units)**
Commercial Operation Date / Price Level	**2010 $**	**2012 $**	**2012 $**
Variable O&M ($/MWh)			
Major Maintenance Parts	3.03	3.18	[redacted]
Major Maintenance Labor	0.30	0.31	
Unscheduled Maintenance	0.81	0.85	
SCR Catalyst and Ammonia	1.00	1.05	
CO Oxidation Catalyst	0.00	0.00	
Other Chemicals and Consumables	0.18	0.19	
Water	0.62	0.65	
Auxiliary Power - Variable	-	-	
NOx Allowances	-	-	
Total Variable O&M ($/MWh)	**5.94**	**6.23**	[redacted]

EXHIBIT CDU-5

[redacted]

PUBLIC VERSION -- HIGHLY SENSITIVE PROTECTED MATERIALS HAVE BEEN REDACTED PURSUANT TO PROTECTIVE ORDER IN FERC DOCKET NO. EL11-50-000 AND CONFIDENTIAL INFORMATION PURSUANT TO 18 C.F.R. SECTION 388.112

[redacted]

BEC Expected Performance by BEC Engineering Consultants (E3 Consulting)

[redacted]

[redacted]

Real Levelized Carrying Charge Rates

Amortization Years =	10	11	12	13	14	15	16	17	18	19	20	21	22
Bayonnne Energy Center - Real Carrying Charge Rates Without Property Taxes and Insurance	[redacted]												

Amortization Years =	23	24	25	26	27	28	29	30	31	32	33	34	35
Bayonnne Energy Center - Real Carrying Charge Rates Without Property Taxes and Insurance	[redacted]												

APPENDIX VI

AFFIDAVIT OF EUGENE T. MEEHAN

NERA
Economic Consulting

Eugene T. Meehan
Senior Vice President

National Economic Research Associates, Inc.
1255 23rd Street NW
Washington, DC 20037

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Astoria Generating Company, L.P	)	
and TC Ravenswood, LLC	)	
	)	**Docket No. EL11-50-000**
vs.	)	
	)	
New York Independent System Operator,	)	
Inc.	)	

AFFIDAVIT OF
EUGENE T. MEEHAN

Mr. Eugene T. Meehan declares:

1. I have personal knowledge of the facts and opinions herein and if called to testify could and would testify competently hereto.

I. Purpose of this Affidavit

2. The purpose of this affidavit is to describe the role of NERA Economic Consulting ("NERA") in connection with the New York Independent System Operator's ("NYISO") implementation of the Pre-Amendment Rules.[1] NERA performed work related to the NYISO's determination of Unit Net CONE and the mitigation exemption determinations

[1] Consistent with the definition in the Confidential Supplemental Answer, the "Pre-Amendment Rules" are the buyer-side capacity market power mitigation rules that existed in Attachment H to the NYISO Services Tariff prior to the effective date of the In-City Buyer-Side Capacity Mitigation Measures.

for the Astoria Energy II project ("AEII") and the Bayonne Energy Center project ("BEC"), also referred to as the Project or Projects. In describing NERA's role, I also describe certain aspects of the Unit Net CONE methodology.

II. Qualifications

3. I am a Senior Vice President with NERA and have more than thirty years experience consulting with electric and gas companies. I have testified as an expert witness before numerous state and federal regulatory agencies, and in Federal court and arbitration proceedings.

4. My consulting practice at NERA focuses on the areas of electricity tariff design, electricity procurement, wholesale power market design, electricity costing and pricing, market power analysis and mitigation, power contract analysis, and power cost risk management.

5. I have worked extensively on electric utility and electricity market issues in New York State. I have provided consulting services for New York electric companies on a continuous basis since 1980, advising the companies on production cost modeling, transmission expansion, competitive bidding and reliability, and marginal generating capacity cost quantification. In 1987, I prepared and sponsored the New York Power Pool's position paper on competitive bidding for independent power producer supplies. That paper set forth the New York Power Pool's policy position on the establishment of competitive bidding processes, power purchase contracts based on avoided cost, and the various implementation issues. Many of these positions were adopted by the New York Public Service Commission ("NYPSC"). I provided testimony on behalf of the New

York State investor-owned electric utilities concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the NYPSC and used as the basis for demand-side management evaluation in New York from 1982 through 1988.

6. I worked with the NYISO as well as the PJM Interconnection, LLC and ISO New England Inc. ("ISO-NE") in 2003 and 2004 to study the joint capacity market design proposal known as the Centralized Resource Adequacy Market or ("CRAM") and was a co-author of NERA's CRAM report.

7. I was retained by National Grid to advise the load serving entities in New England with respect to the ISO-NE forward capacity market settlement negotiations and attended many of the settlement sessions.

8. I directed NERA's efforts for the NYISO in connection with the ICAP Demand Curve reset for the three Capability Years of 2011/2012, 2012/2013, and 2013/2014, and the NYISO's previous ICAP Demand Curve reset.

9. A full statement of my qualifications is provided as Exhibit Meehan-A.

III. Overview of NERA's Role and Aspects of the Methodology

10. NERA was retained by the NYISO to determine certain components of the Unit Net CONE for AEII and BEC. NERA's role included estimating net energy revenue offsets for use in the Unit Net CONE calculations. These are referred to herein as net energy revenues or energy revenues.

11. Sargent and Lundy LLC ("Sargent & Lundy"), another consultant retained by the NYISO, provided information for the Unit Net CONE determinations. Specifically, Sargent & Lundy provided cost and performance data for AEII and BEC, including information concerning capital costs, fixed and variable operating and maintenance ("O&M") costs, property taxes and other taxes, insurance costs, real levelized carrying charges (based on inputs from NERA, as described below), heat rates and emissions, start costs, capacity levels and forced outage rates. It is my understanding that Sargent & Lundy obtained the information from the developers and other sources.

12. NERA used the information provided by Sargent & Lundy and the NYISO when estimating net energy revenues. NERA provided information to the NYISO regarding the costs of capital and the specific capital structure that Sargent & Lundy used in calculating levelized carrying charges.

13. NERA actively participated in teleconferences between and among the NYISO, Sargent & Lundy, and the independent Market Monitoring Unit for the NYISO, Potomac Economics, Ltd., (the "MMU") regarding the Unit Net CONE methodology and the data and inputs. NERA made certain recommendations as part of this collaboration.

14. At the NYISO's direction, NERA also spoke directly with Project representatives.

IV. Net Energy and Ancillary Services Estimates

15. NERA developed net energy revenues using the NERA econometric model used in the NYISO's ICAP Demand Curve reset process in 2008 and 2010 ("NERA model"). The NERA model uses the Project-specific inputs, such as heat rates and other physical characteristics, for each Project to simulate a hypothetical dispatch and calculate net energy revenues over three years.

16. As discussed in the final NERA/S&L Demand Curve Report, I did not believe in the context of the ICAP Demand Curve reset that it was necessary or desirable to adjust for the difference between actual conditions in the historical period used to develop the statistical representation of the energy market and forecast conditions over the ICAP Demand Curve reset period.[2] Such adjustments can introduce error. While adjusting for an input as basic as gas prices could be argued to improve the accuracy of the price signal, gas prices are volatile and a snapshot of gas price futures taken and used during the ICAP Demand Curve reset process may or may not better represent actual gas prices over the reset period than does the historic average. Additionally, even the gas price adjustment requires some judgments. For the ICAP Demand Curve reset, the net cost of new entry is updated every three years and, over time, net energy revenues not adjusted for gas prices will reflect actual gas prices, albeit with a lag.

17. In the context of determining Unit Net CONE pursuant to the Pre-Amendment Rules, I believe that the intent is to capture whether the entry decision is economic as of a

[2] *See* Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, Attachment 2 (Meehan Affidavit) Exhibit B at Appendix 4 pp. 41-43, 52-58, in *New York Independent System Operator, Inc., Tariff Revisions to Implement ICAP Demand Curves for Capability Years 2011/2012, 2012/2013, and 2013/2014,* Docket No. ER11-2224-000 (filed November 30, 2010).

specified time. Estimating energy prices using a snapshot of future gas prices at that specific time should reflect the economics of the entry decision over the three-year period beginning with the Starting Capability period (the "Three Year Period"). I believe, even with the judgments that are implicit in the gas price adjustment, it can be done with sufficient accuracy so that it more accurately represents the economic entry decision as of a specified time than calculating the net energy revenues without the gas price adjustment. Accordingly, for purposes of the Pre-Amendment Rules, net energy revenues should be derived using projected gas prices based on gas futures prices over the Three-Year Period. Therefore, I recommended to the NYISO that NERA, for the NYISO, adjust the gas prices using current gas futures prices in determining the net energy revenues to use in the Unit Net CONE determinations. The NYISO accepted my recommendation.

18. For the Unit Net CONE determination, the NERA model uses gas futures prices to predict energy prices and derive net energy revenues. Gas futures prices for the years generally corresponding to the Three Year Period were used. I use the term generally corresponding as the NERA econometric model used in the Demand Curve reset was estimated from November 2006 to October 2009, the most recent data available when the modeling began. Consistent with this monthly sequence, NERA used gas future prices from the November before the project was anticipated to enter service until the October three years hence.

19. For AEII, NERA used Transco-Z6 (NY) gas prices with an adder for LDC transportation charges. For BEC, NERA used Transco-Z6 (NY) gas prices without an adder for LDC transportation charges as BEC is directly connected via an owned gas lateral to the

interstate pipeline system. These prices are reasonable representations of the cost of gas delivered to the respective Projects.

20. At the direction of the NYISO based on the recommendation of the MMU, NERA added the fuel taxes generally applicable in New York City to AEII's cost of natural gas. As BEC is located in New Jersey, it would not be subject to the fuel taxes applicable in New York City and such taxes were not added to BEC's cost of natural gas.

21. The AEII unit has duct firing. The data with respect to duct firing were supplied by S&L. NERA treated AEII as two units. The first, non-duct-fired unit, used the data as supplied by S&L without duct firing. The duct-fired unit was calculated as incremental to the non-duct-fired unit. Thus, it's capacity was equal to the difference between the duct-fired capacity and non-duct-fired capacity (by season) and its (higher) heat rate was reflective of the incremental heat rate in the S&L data, i.e. calculated so that the average heat rate when both the duct-fired-unit and non-duct-fired-unit were operating is equal to the aggregate duct-fired heat rate. These two units were then both examined. The duct-fired unit was treated as having no startup cost; all startup costs were allocated to the base unit. With its higher heat rate, duct-firing was then optimal whenever prices covered the higher heat rate, variable O&M and emissions cost. Two annual revenues per MW were calculated, one for each unit, and were weighted together by unit size to give an average value per MW for the combined AEII operation.

22. On the recommendation of the MMU, gas future prices for AEII were based on prevailing gas futures in July 2008. On the recommendation of the MMU, gas future prices for BEC were based on prevailing gas futures in October 2010. It is my

understanding that the NYISO, through consultation with the MMU, identified these periods as those in which the investment decisions were made.

23. The NERA model shows that net energy revenues are sensitive to the level of excess. When calculating net energy revenues, we can develop results for a wide range of excess capacity levels. We were advised by NYISO that it would utilize net energy revenues at a 10 percent excess level for AEII and a 15 percent excess level for BEC.

24. The energy revenues in the Unit Net CONE calculation are not computed over the life of the unit but are estimates of energy revenues for the Three Year Period. It is my opinion that, in most cases, only energy revenues in the near-term period after entry, rather than energy revenues over a longer period, are germane to the decision on when to develop the unit, as the timing of development is largely discretionary. To the extent that a developer would expect future energy revenues to increase significantly in real terms, the development of the unit could be delayed. It is only energy revenues in the first few years of unit operation that offset ownership costs in those years. Forecasting net energy revenues over a 30-year period is inherently speculative and there is a wide range of plausible predictions as fuel prices and load are very uncertain over such a long period. The speculative nature and uncertainty would render an objective estimation of Unit Net CONE difficult.

25. Estimated ancillary service revenues are also a cost offset in the determination of Unit Net CONE. The NYISO provided NERA with the estimated ancillary services revenues to use for AEII and BEC, respectively. It is NERA's understanding that the NYISO used then-recent actual ancillary services revenues earned by similar plants to develop an estimate of ancillary services revenues for a Project.

26. The net energy revenues for AEII identified in the Affidavit of Joshua A. Boles regarding Astoria Energy II were determined by NERA using the NERA model. For AEII, NERA used the model developed in the Demand Curve proceeding which was estimated using data from the most recent three year historic period: November 2006 to October 2009. The AEII analyses used gas future prices serially, that is the first November price in the first November month represented in the econometric model, the second November price in the second November month represented in the model and so on. The net energy revenues were determined using gas future prices for each month from November 2010 through October 2013.

27. The net energy revenues for BEC identified in the Affidavit of Joshua A. Boles regarding Bayonne Energy Center were determined by NERA using the NERA model. For BEC, NERA used the model developed in the Demand Curve proceeding which was estimated using data from the most recent three year historic period: November 2006 to October 2009. The BEC analyses used gas future prices serially, that is the first November price in the first November month represented in the econometric model, the second November price in the second November month represented in the model and so on. The net energy revenues were determined using gas future prices for each month from November 2011 through October 2014.

28. In his most recent affidavit in this proceeding,[3] Mr. Younger criticizes the NERA econometric model as not being sufficiently sensitive to gas prices and uses as support

[3] *See Complainants' Motion for Leave to Answer and Answer*, Docket No. EL11-50-000 (filed August 19, 2011) ("Complainants' Answer") at Attachment a Supplemental Affidavit of Mark D. Younger ("Younger Supplemental Affidavit").

for this allegation the fact that average elasticity to gas prices is only 67 percent,, despite the fact that gas is on the margin in NYCA 90 percent of the time.[4] He states that when gas is on the margin, the electricity price should have close to a 100 percent correlation with the gas price. I disagree with his assessment for several reasons. First, there is no reason to believe that when gas is not on the margin that there will be a 100% elasticity relationship between gas prices and electricity prices as gas prices do not comprise all of a unit's variable costs. There are non-fuel variable O&M expenses as well as emissions expenses. These expenses would not be sensitive to gas prices and would lower the elasticity when gas is on the margin below 100%. Second, there may be costs in energy offers that reflect uncertainty and risk that are also not sensitive to gas prices. These would also lower the elasticity below 100%. Third, there is likely to be a substitution impact from changes in import and export activity. While gas may be on the margin in 90 percent of the hours, as gas prices change imports and exports from or to areas interconnected to NYCA will likely change, and the heat rate at the margin could change dampening the impact of the change in gas prices. Fourth virtual bids which may be imperfectly related to gas price may set the price. This factor may well be prominent in the Day Ahead market where I am informed by NYISO that virtual bids are often marginal. Considering these factors, I believe that an elasticity of 67% is definitely in the plausible range, and suggestions that the 67% elasticity represents a prima facie indication of a model inadequacy are unfounded. In light of these factors, I believe it is not realistic to expect an elasticity of 100 % between gas prices and electric prices. In fact, such a high elasticity would be a reason for concern.

[4] *See* Younger Supplemental Affidavit at PP 13-14.

VI. Annual Levelized Carrying Charge

29. NERA provided information and analysis used in Sargent & Lundy's determination of the annual levelized carrying charge, which is used to develop the annual levelized cost of the Project. Sargent & Lundy calculated real carrying charges for various amortization periods. Sargent & Lundy calculated the carrying charge considering the developer's capital structure and cost of capital, and debt and equity cost data.

30. NERA examined information provided to Sargent & Lundy by each developer regarding the costs of capital and the capital structure specific to each Project and developer. NERA also considered information from other sources. NERA provided its opinion with respect to the cost of capital and capital structure specific to each Project, including commenting on the reasonableness of information provided by each developer in consideration of the specific developer and Project. The NYISO, with input from the MMU, identified the cost of capital and capital structure to be used for each Project.

31. NERA recommended to the NYISO, and the NYISO agreed, that the levelized carrying charge be increased at 2.15 percent per year, which is inflation less technical progress. That carrying charge reflects an assumed long-term rate of inflation of 2.4 percent and an assumed long-term rate of inflation net of technical progress of 2.15 percent. Sargent & Lundy computed the real carrying charges accordingly.

32. In assembling the data and summarizing results, NERA used the carrying charge based on the 2.15 percent inflation rate net of technological progress, and used that rate to adjust the costs to the nominal dollars for each year of the Three Year Period.

VII. Additional NERA Analysis and Recommendations

33. NERA analyzed the information provided by Sargent & Lundy, addressed the alternatives discussed below, and made the recommendations for the calculation of Unit Net CONE as discussed herein.

34. Amortization period. Sargent & Lundy provided carrying charges for multiple amortization periods. The ICAP Demand Curve reset uses as a starting point assumption a review of cost and revenue over a full 30-year period. If no asymmetric risks were identified and modeled, the amortization period used in the ICAP Demand Curve reset would be 30 years. The actual amortization period used in the ICAP Demand Curve reset is lower to account for the preference in the NYCA towards always maintaining reliability. That preference results in capacity being expected to be long on average, and therefore requires that a shorter amortization period be used to set the ICAP Demand Curve reference point so that the ICAP Demand Curve peaking unit will recover a full return on and of capital costs over 30 years. However, in determining Unit Net CONE, there is no reason to use the shorter amortization period that adjusts for excess capacity. The Project is not being used to set the ICAP Demand Curve but only to estimate the net cost of ownership. In fact, the ICAP Demand Curve has been set to allow the ICAP Demand Curve peaking unit to recover costs based on a 30-year amortization period, recognizing that it will receive, on average, revenues less than if it were at the reference point; therefore, the ICAP Demand Curves are developed using a shorter amortization period. For the Unit Net CONE determination, accordingly, the economic life of the unit is estimated. NERA recommended an amortization period of 30 years for AEII and BEC.

35. Use of nominal levelized or real levelized carrying charge. A nominal levelized carrying charge implies an assumed annual revenue level that is constant in nominal dollars. A real carrying charge implies an assumed annual level of revenue that increases at inflation or at inflation net of technical progress. Hence, a real levelized charge is lower. Essentially a real levelized charge calculates the cost of ownership in the early years of a project's life recognizing that it will receive increasing revenues in the later years. The ICAP Demand Curve reset uses a real levelized carrying charge that increases at 2.4 percent and in the risk model assumes that revenues will decrease at 0.25 percent for technical progress. As we are not using the risk model in this analysis, NERA recommended a real levelized carrying charge that increases at 2.15 percent per year, which is inflation less technical progress.

36. With respect to NERA's recommendations provided to the NYISO regarding the cost of capital and capital structure specific to individual Projects and the developers that Sargent & Lundy used in its calculation of carrying charges, and other recommendations such as adjusting net energy revenues for actual gas future prices, NERA's role is advisory. The NYISO requested NERA to provide its advice and opinion on the issues discussed above in addition to using the econometric model to estimate net energy revenues, and computing the Unit Net CONE based on the inputs. NERA was not charged with making final decisions.

37. During the development of the methodology, and NERA's development of its analyses, recommendations, and opinions, and throughout the process, NERA collaborated with the NYISO, Sargent & Lundy and the MMU on various issues. The NYISO, with that input, made final decisions on these issues.

38. NERA was not asked to interpret or apply the NYISO tariffs. Its role was as described above. Throughout the process, NERA followed the direction provided by the NYISO.

VIII. Conclusion

39. The paragraphs above provide an accurate description of the activities undertaken by NERA in examining the Unit Net Cone for AEII and BEC. They also accurately describe aspects of the methodology that NERA applied and used to prepare the results for NYISO.

This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing Affidavit of Eugene T. Meehan dated September 7, 2011 (the "Affidavit"). I have read the Affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Eugene T. Meehan
Senior Vice President
NERA Economic Consulting
September 7, 2011

Subscribed and sworn to before me
this 7th day of September 2011

SS: District of Columbia

Rosalind Brown
My Commission Expires December 14, 2014

Rosalind Brown
Notary Public, District of Columbia
My Commission Expires 12/14/2014