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	)	

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC. REQUEST FOR LEAVE TO SUBMIT ANSWER AND ANSWER TO PLEADINGS OPPOSING EXEMPTIONS AND ANSWER TO MOTION TO LODGE

In accordance with Rule 213 of the Commission's Rules of Practice and Procedure the New York Independent System Operator, Inc. ("NYISO") respectfully requests leave to submit, and submits, this Answer[1] to the *Complainants' Answer to Supplemental Answer of the New York Independent System Operator, Inc.* ("Complainants' Answer").[2] The NYISO also seeks leave to respond to the *Comments of the NRG Companies* ("NRG Comments"), the *Answer of the Brookfield Energy Marketing LP* ("Brookfield Answer"), and the *Answer of Independent Power Producers of New York, Inc.* ("IPPNY Answer") (collectively, with the Complainants' Answer, the "Pleadings Opposing Exemptions").

[1] The NYISO also submits in support of this Answer the following Attachments: Attachment I - Supplemental Affidavit of Joshua A. Boles ("Supplemental Boles Affidavit"); Attachment II - Supplemental Affidavit of Dr. David B. Patton ("Supplemental Patton Affidavit"); Attachment III- Joint Affidavit of Eugene T. Meehan and Jonathan Falk ("Joint Meehan/Falk Affidavit"); and Attachment IV - Affidavit of Christopher D. Ungate ("Ungate Affidavit").

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

This answer refutes the challenges to the NYISO's determination that the Astoria Energy Project II ("AEII") and the Bayonne Energy Center ("BEC") are exempt from Offer Floor[3] mitigation under the Pre-Amendment Rules.[4] As reiterated throughout Section III, both determinations were reasonable, fully conformed with the then-applicable provisions of Attachment H to the Market Administration and Control Area Services Tariff ("Services Tariff"), and consistent with Commission policy and precedent. Therefore, the Commission should act expeditiously to issue an order dismissing the Complaint,[5] rejecting all the Pleadings Opposing Exemptions in their entirety, and denying all related requests for relief.

This answer also offers the NYISO's response[6] to Complainants' latest "Motion to Lodge"[7] which the NYISO received notice of filing at 4:45 PM on the final business day before this answer was due. As discussed in Section IV below, the new Motion to Lodge is a transparent attempt by Complainants to cobble together "support" for absurd allegations that the exemption analysis for AEII was improperly influenced by the New York Power Authority ("NYPA"). Accordingly, the Motion to Lodge should be denied. Further, as demonstrated through this Answer and in the NYISO's August 3 Answer, the NYISO's Answer to Comments,[8]

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[3] 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 and Request for Expedited Action of the New York Independent System Operator, Inc.* Docket No. EL11-50-000 (August 3, 2011) ("August 3 Answer").

[4] 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 November 27, 2010 effective date of the current In-City Buyer-Side Capacity Mitigation Measures.

[5] *Complaint Requesting Fast Track Processing, Emergency Interim Relief, and Shortened Comment Period,* Docket No. EL11-50-000 (July 11, 2011) ("Complaint").

[6] As is noted in Section IV, below, the NYISO reserves the right to supplement its answer to the Motion to Lodge before the expiration of the fifteen day period for answering motions.

[7] *Complainants' Motion to Lodge*, Docket No. EL11-50-000 (October 7, 2011).

[8] *Answer of the New York Independent System Operator, Inc. to Comments and Protests*, Docket No. EL11-50-000 (filed August 15, 2011) ("Answer to Comments").

and Confidential Supplemental Answer,[9] the NYISO's exemption determinations were made independently, and the Complainants have provided no evidence that the NYISO's exemption determinations were influenced by NYPA or any other entity or person.

I. REQUEST FOR LEAVE TO ANSWER

The Commission has discretion to accept answers to answers when they help to clarify complex issues or to facilitate the resolution of a proceeding.[10] There are compelling reasons for the Commission to accept this Answer given both the procedural posture of this case and the substantive deficiencies of the Pleadings Opposing Exemptions.[11]

The Pleadings Opposing Exemptions challenge the NYISO's exemption of AEII and BEC from Offer Floor mitigation by answering the actual analyses performed by the NYISO, which were as set forth for the first time in the NYISO's Confidential Supplemental Answer.[12] The original Complaint, and related pleadings, were based on speculative assumptions about what the

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[9] *Confidential Supplemental Answer of the New York Independent System Operator, Inc.,* Docket No. EL11-50-000 (filed September 8, 2011) ("Confidential Supplemental Answer").

[10] *See e.g., New York Independent System Operator Inc.*, 133 FERC ¶ 61,178 at P 11 (2011) (allowing answers to answers and protests "because they have provided information that have assisted [the Commission] in [its] decision-making process"); *Morgan Stanley Capital Group, Inc. v. New York Independent System Operator, Inc.*, 93 FERC ¶ 61,017 at 61,036 (2000) (accepting an answer that was "helpful in the development of the record . . . .").

[11] To the extent that the Commission considers this Answer to have been subject to a fifteen day response period that is commonly applied to Answers, the NYISO respectfully requests leave to submit this Answer one day out of time. The NYISO was unable to complete its preliminary review of the Motion to Lodge, and prepare redacted public versions of this Answer, by the Commission's 5 PM filing deadline on October 11. The NYISO filed and served this Answer as soon as possible after that deadline. No party's interests will be harmed by this slight delay.

[12] *See* Confidential Supplemental Answer at: Appendix I Confidential Affidavit of Joshua A. Boles Regarding Astoria Energy II ("Boles AEII Affidavit"); Appendix II Confidential Affidavit of Joshua A. Boles Regarding Bayonne Energy Center ("Boles BEC Affidavit"); Appendix III Affidavit of Dr. David B. Patton ("Initial Patton Affidavit"); Appendix IV Affidavit of Christopher D. Ungate Regarding Astoria Energy II ("Ungate AEII Affidavit"); Appendix V Affidavit of Christopher D. Ungate Regarding Bayonne Energy Center ("Ungate BEC Affidavit"); and Appendix VI Affidavit of Eugene T. Meehan ("Meehan Affidavit").

NYISO might have done. They made different arguments that were, in many respects, irrelevant, to the actual determinations. In some instances the prior arguments contradict the ones that Complainants are offering now, which only serves to demonstrate the opportunistic nature of their challenges. Although the Pleadings Opposing Exemptions are styled as "answers" and "comments," they are the functional equivalent of amendments to the Complaint and other pleadings. If the Complainants' Answer were styled an amendment to the Complaint there would be no question that the NYISO would be entitled to answer it as a matter of right.[13] The other Pleadings Opposing Exemptions are tantamount to comments in support of an amended complaint, which the NYISO would also be permitted to answer as of right.[14]

Beyond the mechanics of the Commission's procedural rules, the fact is that the NYISO, and those parties that support the AEII and BEC exemption determinations, prior to their receipt of the Pleadings Opposing Exemptions, did not yet have an opportunity to address the hundreds of pages of arguments and testimony addressing the AEII and BEC analyses that are included in them. Denying the NYISO, and others, the chance to respond would be inconsistent with basic due process and would result in an incomplete record. The need to permit answers is even greater considering that, as noted throughout Section III, the Pleadings Opposing Exemptions contain many misstatements, mischaracterizations, and other erroneous or unreasonable assertions that require correction. The NYISO has focused on addressing the most significant of these defects. To the extent that it has not addressed an allegation or argument found in Complainants' Answer, or the Motion to Lodge, the NYISO' silence should not be construed as agreement.

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[13] 18 C.F.R. § 385.215(b) (2011).

[14] 18 C.F.R. § 385.213(a)(3). The NYISO is permitted to answer the NRG Comments and the Complainants' Motion to Lodge as a matter of right.

II. EXECUTIVE SUMMARY

All of the Pleadings Opposing Exemptions are attempts by incumbent suppliers to subject their competitors to Offer Floor mitigation. The incumbent suppliers stand to benefit substantially in the near term if they can avoid competition from AEII and BEC, and in the longer term, by discouraging future potential entrants. They seek to overturn exemption determinations that were made independently by the NYISO with the assistance of its two expert ICAP Consultants,[15] and with input from and review by the independent Market Monitoring Unit for the NYISO, Potomac Economics LLC ("MMU"). The Pleadings Opposing Exemptions focus on a small fraction of the numerous inputs in the determinations. This Answer responds in detail to the Pleadings Opposing Exemptions and demonstrates that the NYISO's determinations for AEII and BEC were both reasonable and entirely consistent with the Pre-Amendment Rules. The NYISO's Confidential Supplemental Answer already established that fact and this Answer further does so by disposing of the Pleadings Opposing Exemptions. In summary, this Answer establishes that:

- There is no basis for Complainants' and NRG's argument that the AEII and BEC determinations were "*per se* invalid" because they were made prior to the close of each project's Class Year cost allocation process. Among other things, Complainants' and NRG's radical re-interpretation of the tariff would subject economic projects to mitigation for months (or even years) after their entry and potentially place incumbents in a position to prolong that mitigation. (*See* Section III.A).

- There is no basis for Complainants' and IPPNY's argument that the NYISO is prohibited by the tariff, or by any Commission policy, from using information available at the time of a new entrant's investment decision in its exemption analyses. Complainants' and IPPNY's theory that the NYISO must instead use the information that existed at the time that an entrant executed its Interconnection Facilities Study Agreement ("IFSA") would arbitrarily elevate form over substance and would be

[15] The NYISO's ICAP Consultants are NERA Economic Consulting and Sargent & Lundy.

inconsistent with Commission precedent that buyer-side mitigation analyses should focus on the time that investment decisions are made. (*See* Section III.B).

- There is no basis in the Pre-Amendment Rules, economic theory, or Commission precedent for Complainants' suggestion that the NYISO should "err on the side of over-mitigation" in its implementation of Commission-approved buyer-side market power mitigation measures. Adopting such a bias would be unprecedented and wholly incompatible with the Commission's recent reaffirmation that "[t]he whole purpose of the NYC mitigation program is to deter uneconomic entry, not economic entry."[16] (*See* Section III.C).

- It was reasonable and consistent with both the Pre-Amendment Rules and Commission policy and precedent for the NYISO to follow the MMU's recommendation that it exclude "sunk costs" from the exemption analyses. (*See* Section III.D).

- The NYISO's use of actual financing information and its use of financing assumptions was reasonable and consistent with both the Pre-Amendment Rules and Commission policy and precedent. (*See* Section III.E).

- The NYISO calculated reasonable energy and ancillary services ("E&AS") revenues in its AEII and BEC exemption determinations. (*See* Section III.F).

- The interconnection cost assumptions used in the AEII and BEC exemption determinations were reasonable. (*See* Section III.G).

- The NYISO and its Consultants took reasonable steps to verify facts and assumptions utilized in the exemption analyses. (*See* Section III.H).

- The NYISO has accounted for reasonably anticipated capacity additions in its ICAP forecasts. (*See* Section III.I).

In every instance, the Pleadings Opposing Exemptions urge the Commission to adopt positions that would exclude projects that made economic entry decisions. Their positions would have unreasonably discouraged new entry under the Pre-Amendment Rules, and would have equally pernicious effects under the currently effective In-City Buyer-Side Mitigation Measures.[17]

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[16] *New York Independent System Operator, Inc.*, 136 FERC ¶ 61,077 at P 28 (2011) ("*August 2 Order*").

[17] For example, the arguments that would prevent the NYISO from excluding sunk costs from Unit Net CONE, using information available at the time of the investment decision, using a project's actual

The Pleadings Opposing Exemptions are also biased, and are highly selective in the inputs that they challenge, and a clear effort to exclude new competitors. These characteristics are best illustrated by the fact that Complainants and NRG contended elsewhere that they would be satisfied if exemption determinations were certified by the independent MMU.[18] In this docket, however, they attack each of the MMU's major recommendations to the NYISO, despite the MMU's expertise, independence, and the fact that the MMU was a key originator of, and a leading advocate for, effective buyer-side mitigation rules in New York and in other organized markets.[19] The Pleadings Opposing Exemptions are also silent regarding the numerous other inputs into the NYISO's determinations. They do not consider reasonable alternative inputs that the NYISO could have used which would have resulted in a lower Unit Net CONE or higher forecasted ICAP clearing price for both the AEII and BEC analysis. The Supplemental Boles Affidavit and the Supplemental Patton Affidavit each identify examples of the kinds of such alternative inputs.[20] Dr. Patton goes so far as to express his independent opinion by characterizing some of the NYISO's assumptions as conservative.[21] The sponsors of the Pleadings Opposing Exemptions continue to seek to be *de facto* market monitors.[22] It should

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financing information would implicate and affect the exemption analysis under the In-City Buyer Side Mitigation Measures.

[18] *See Complaint Requesting Fast Track Processing* at 6, 46 Docket No. EL11-42-000 (filed June 3, 2011) (arguing that the Commission should require the MMU to issue a written report verifying the NYISO's exemption determinations).

[19] Supplemental Patton Affidavit at P 5; *see also*. *Motion to Intervene Out of Time and Comments of the Midwest ISO's Independent Market Monitor* at Section V, Docket No. ER11-4081-000 (filed September 19, 2011).

[20] *See* Supplemental Boles Affidavit at Section II; Supplemental Patton Affidavit at PP 9-14.

[21] Supplemental Patton Affidavit at PP 9-14.

[22] *See, e.g. Complainants' Answer to Supplemental Answer of the New York Independent System Operator, Inc.*, Docket No. EL11-50-000 (filed September 23, 2011) ("Complainants' Answer"); *Answer of Independent Power Producers of New York, Inc. to NYISO Supplemental Information Describing Buyer Side Mitigation Exemption Determinations*, Docket No. EL11-50-000 (filed September 23, 2011)

now be abundantly clear that the concerns the NYISO previously expressed about having market participants to play such a role were valid.[23] Here, Complainants seek to substitute their desired outcome for AEII and BEC, and the result-oriented inputs that would achieve it, for determinations the NYISO made with support from the Consultants and the MMU. While it might be in the Complainants' and other incumbent suppliers' interest to litigate every exemption determination, the Commission should consider the broader implications. Avoiding "complex and lengthy litigation" over individual exemption determinations is a principal reason for having ISOs/RTOs and market monitors make exemption determinations in the first place.[24] Complainants' approach would defeat this purpose and effectively convert the entry of each proposed new In-City supplier into something very much like a traditional cost of service rate case. The NYISO has previously explained that establishing a regime under which every new entry decision is subject to "complex and lengthy" litigation would only serve to discourage otherwise economic entry.[25] The MMU has the same concerns.[26]

The Commission could reduce these dangers by taking the same approach that it does in many other settings and reviewing the disputed elements of the NYISO's exemption analyses using a test similar to the familiar "just and reasonable" standard of review. Like many

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("IPPNY Answer");*Comments of the NRG Companies Opposing the New York Independent System Operator's Decision to Exempt Uneconomic Entry from Buyer Side Market Mitigation*, Docket No. EL11-50-000 (filed September 23, 2011) ("NRG Comments"); *Answer of Brookfield Energy Marketing*, Docket No. EL11-50-000 (filed September 23, 2011) ("Brookfield Answer").

[23] *Answer of the New York Independent System Operator, Inc.* at 6, 65, Docket No. EL11-42-000 (filed July 6, 2011), as corrected July 7, 2011 ("EL11-42 Answer").

[24] *PJM Interconnection, LLC*, 135 FERC ¶ 61,022 at P 118 (2011) ("*PJM MOPR Order*")

[25] August 3 Answer at 26.

[26] *Motion to Intervene Out of Time and Request for Leave to Answer of the New York ISO's Market Monitoring Unit* at 7-8, Docket No. EL11-50-000 (filed August 11, 2011) ("MMU Intervention and Answer"); Supplemental Patton Affidavit at P 15.

questions that the Commission considers, the issues surrounding exemption determinations are complex. The analyses turn based on inputs, methodologies, and assumptions (individually and collectively referred to herein as "inputs," unless the context provides otherwise). The "Part B Test" requires a comparison of forecasted capacity prices to a potential entrant's "reasonably anticipated" Unit Net CONE. It is inevitable that there will be instances where there will be no single identifiable "correct" input, and more than one reasonable alternative may be chosen. Deciding which input to use will often require the kind of "reasoned judgment" that the Commission recognized was necessary in its most recent ICAP Demand Curve reset order.[27] The Commission's analysis should therefore focus, as it does in other areas,[28] on whether the NYISO's determinations were reasonable, not on whether other potentially reasonable alternatives might have been adopted instead.

Taking this approach would diminish the incentive for market participants to try to use litigation as a tool to impede new economic entry. Just as importantly, it would allow potential entrants to have confidence in mitigation determinations, by signaling that reasonable decisions would be likely to be upheld without "complex and lengthy" litigation. The Supplemental Patton Affidavit emphasizes the impact that the Commission's handling of exemption challenges is likely to have on potential future entrants.[29]

Regardless of how the Commission frames its analysis, the NYISO respectfully requests that it expeditiously issue an order on the AEII and BEC determinations. Assuming that this

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[27] *New York Independent System Operator, Inc.* 136 FERC ¶ 61,192 at P 60 (2011).

[28] *See, e.g., New York Independent System Operator, Inc.*, 136 FERC ¶ 61,193 at P 54 (2011) (holding that the Commission expects "each RTO and ISO to exercise its reasonable discretion" in implementing its tariff)*; see also, PPL Energy Plus v. PJM*, 136 FERC ¶ 61,060 at P 21 (2010) (finding that an RTO "may exercise its judgment and discretion" in making determinations pursuant to tariff provisions").

[29] Supplemental Patton Affidavit at P 15.

Answer is accepted, there will be an extensive record regarding the NYISO's exemption determinations, the objections to them, and the responses to those objections. There is more than enough information for the Commission to conclude that Complainants have not shown that the AEII and BEC exemption determinations were unreasonable or unlawful, to conclude that Complainants have therefore failed once again to carry their burden of proof under Section 206 of the Federal Power Act, and to dismiss the Complaint. If the Commission requires more information on any issue, it should direct the parties to submit additional pleadings on an expedited basis so that it may issue an order.[30]

III. ANSWER

A. Granting an Exemption Determination to AEII and BEC Before the Conclusion of their Respective Class Year Processes Was Permitted Under the Pre-Amendment Rules

Complainants' Answer adopts a theory that was proffered by NRG in its July 27 *Motion to Intervene and Comments*, *i.e.*, that the Pre-Amendment Rules precluded the NYISO from granting exemption determinations under the "Part B Test" until after "a given project's interconnection cost allocation process was concluded."[31] Complainants' belated conversion is, at a minimum, difficult to explain given that their own August 18 filing in this proceeding advanced an argument that was inconsistent with their adoption of NRG's theory.[32]

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[30] If the Commission determines that additional procedures are necessary before ruling on the Complaint, the NYISO submits that a paper hearing would be sufficient to address any issues that the Commission may identify, consistent with the process in Section IV. Also, if, the Commission were to conclude that one or both of AEII and BEC should not have been exempt from an Offer Floor, it should seek input at that time on how to proceed given the complexity of the questions that would then arise. *See* August 3 Answer at n. 59.

[31] Complainants' Answer at 10.

[32] *Complainants' Motion for Leave to Answer and Answer* at 24-25, Docket No. EL11-50-000 (filed August 19, 2011) ("Complainants Initial Answer") (arguing that the exemption determination should have been made at the time of the execution of the Interconnection Facilities Study Agreement).

Complainants' excuse that they could not possibly have made their "per se violation" claim until after they reviewed the NYISO's Confidential Supplemental Answer is not accurate.[33] NRG offered the argument in its pleading before the NYISO filed its Confidential Supplemental Answer.[34] It should have been clear even at that time that the NYISO could only have acted under the Pre-Amendment Rules.[35] It was not necessary to know that AEII and BEC had been exempted under the Part B Test because the language Complainants are pointing to now was equally applicable to the Part A Test. Even if a project was determined to pass the Part A Test, under the Complainants' and NRG's construct of the Pre-Amendment Rules, that determination could not be final because the NYISO would need to revise the forecast ICAP Spot Market Auction Price and the Mitigation Net CONE based upon information available at the time the Class Year closed.

NRG has repeated the argument in its own most recent filing[36] notwithstanding the fact that it separately stated in a October 2010 letter to the NYISO that it was permissible for the NYISO to issue final buyer-side mitigation determination for a project under the Pre-Amendment Rules before the project's Class Year was closed. Specifically, and as is confirmed by the Supplemental Boles Affidavit,[37] NRG correctly stated that the Pre–Amendment Rules'

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[33] Complainants' Answer at 9-10.

[34] The NYISO answered NRG's theory in the NYISO's Answer to Comments filed August 11, 2011.

[35] *Answer and Request for Expedited Action of the New York Independent System Operator, Inc.* at 17, Docket No. EL11-50-000 (filed August 3, 2011) (stating that "the NYISO has repeatedly stated, both to its stakeholders, and on the record in Commission proceedings, that, in accordance with Attachment H, it would not make final determinations under the In-City Buyer-Side Mitigation Measures until after the Class Year Facilities Study process was complete, including all projects posting security, in accordance with OATT Attachment S").

[36] NRG Comments at Section II.B.

[37] *See* Supplemental Boles Affidavit at Section V. NRG's letter includes confidential information that is not relevant to this proceeding. Accordingly, the NYISO has not attached a copy of the letter to

"multiple references" to "reasonably anticipated Unit Net CONE" reflect "the fact" that the Part B Test was "an ex ante test that may be conducted at the early stages of project development, before the project's developer has accepted its interconnection costs or has made significant financial commitments to move forward."[38] Most importantly, NRG stated that the availability of estimated costs, including estimated interconnection costs, provided a sufficient basis for the NYISO to issue a final determination under the Pre-Amendment Rules. Specifically, NRG recognized that that "actual costs may vary," from estimates but that in cases where an estimate "accurately represents the costs that the project is likely to face" that should be sufficient for purposes of Section 23.4.5.7.2 and its "reasonably anticipated Unit Net CONE" language.[39]

The NYISO cannot conceive of a principled basis that would justify the difference between the position NRG has taken in its letter to the NYISO and the position that it has taken in this proceeding.

The Complainants' and NRG's radical re-interpretation of Section 23.4.5.7.2 is inconsistent with its plain meaning and with the conventional understanding of the provision. It is also at odds with the *August 2 Order* in ER10-3043-002 and -004 and with the overall structure of the buyer-side mitigation measures, which focus on determining whether entry decisions were reasonable at the time that they were made. Retroactive adoption by the Commission of a different interpretation would be contrary to the reasonable expectations of

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this Answer. Instead the NYISO has limited itself to quoting the letter's statements articulating NRG's interpretation of Section 23.4.5.7.2 of the Pre-Amendment Rules, which is not confidential. Mr. Boles was the recipient of NRG's letter and the Supplemental Boles Affidavit confirms that this Answer accurately quotes the letter. If NRG wishes to dispute the accuracy of the quotations, or if the Commission wishes to review a copy of the letter, the NYISO would submit it in response to the Commission's directive.

[38] *Id.*

[39] *Id.*

AEII and BEC which certainly were not on notice that they might be subjected to such a strained reading of the tariff.

The Pre-Amendment Rules clearly provided that an entity could request that an exemption determination be made "upon execution of all necessary Interconnection Facilities Study Agreements for the Installed Capacity Supplier."[40] Additionally, the Pre-Amendment Rules established that entities could obtain information by dates "not later than" certain milestones in the Class Year Facilities Study process. That language did not restrict or eliminate an entity's right under the tariff to request and receive an exemption determination before the Class Year Facilities Study cost allocation process is complete. The language that Complainants now read to restrict the NYISO's ability to make such a determination prior to the Class Year Facilities Study cost allocation only imposed a requirement on the NYISO to issue a determination in a set amount of time if the developer submitted a request with all necessary information by a specified date; *i.e.*, "not later than 60 days prior to the commencement of the Initial Decision Period." If the developer did not submit the request by the specified date, that time limit had no application. That time limitation provided an opportunity if the developer so desired, to have the information at the time it was required to accept or reject the NYISO's project cost allocations.

Complainants and NRG both try to get around the plain language of the tariff by inventing new requirements.[41] Despite their assertions to the contrary, there is not an "express" reference to "provisional" determination procedures in the tariff. Complainants' interpretation would have

[40] This rule originally appeared at Section 4.5g(ii) of Attachment H to the Services Tariff. Section 4.5g(ii) was re-numbered as part of the e-tariff conversion and became Section 23.4.5.7.2.

[41] NRG Comments at 7-10.

an absurd result as it would in essence nullify certain words in the tariff.[42] Similarly, NRG has constructed an elaborate alternative version of Section 23.4.5.7.2[43] which cannot be squared with its actual language or with NRG's request to the NYISO. Complainants' and NRG's arguments that determinations cannot properly be made, and that interconnection costs cannot be estimated for a final Unit Net CONE determination, is belied by NRG's own position, which the NYISO shares, that Section 23.4.5.7.2's references to "reasonably anticipated" Unit Net CONE demonstrate the *ex ante* nature of the Part B Test. There is thus no merit to the contention that the inclusion of "interconnection costs" in the definition of "Unit Net CONE" required the NYISO to wait until the Class Year process closed to finalize exemption determinations. Under the Pre-Amendment Rules, a calculation of reasonably anticipated Unit Net CONE necessarily accommodates the inclusion of reasonably anticipated costs.

The Commission's *August 2 Order* confirms the conventional understanding of the Pre-Amendment Rules. It affirms that "Commission precedent and the November 26, 2010 Order intended to allow a mitigation exemption determination before the developer decided whether to move forward with a project, but also to allow an exemption determination after the project was constructed."[44] The *August 2 Order* clearly found that the tariff required the exemption determination to be made "prior to when the project accepts its cost allocation and enters the

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[42] For example, NRG's interpretation would nullify the provisions requiring the NYISO to provide the requester with the NYISO's determination. *See, e.g., Southern. Natural Gas Co. v. FERC,* 780 F.2d 1552, 1558 (11th Cir. 1986) (holding that "[i]n construing a tariff, it is appropriate to look at the four corners of the tariff and consider the instrument as a whole"), *Northwest Pipeline Corp. v FERC,* 61 F.3d 1479, 1486 (10th Cir. 1995). (holding that "[i]n construing what a tariff means, certain general principles apply. One looks first to the four corners of the entire tariff, considers the entire instrument as a whole, giving effect as far as possible to every word, clause and sentence, and attributes to the words the meaning which is generally used, understood, and accepted.").

[43] NRG Comments at 7-10.

[44] *August 2 Order* at P 20.

capacity market."[45] The "Commission precedent" that the *August 2 Order* examined and explained are Commission orders accepting the Pre-Amendment Rules. Arguments that the Pre-Amendment Rules do not permit exemption determinations prior to the end of the relevant Class Year Facilities Study process are thus contradicted by the *August 2 Order*.

Furthermore, the entire debate in Docket EL10-3043 regarding the change from the "Reasonably Anticipated Entry Date Rule" under the Pre-Amendment Rules to the "Three Year Rule"[46] centered on concerns regarding a new entrant's ability to decide when it would request a determination. The flexibility allowed under the Pre-Amendment Rules in turn created the possibility that a new entrant could influence the anticipated entry date used in the determination.[47] In the Pre-Amendment Rules, final mitigation determinations were not tied to Class Year process milestones. Claiming that they were tied to the Class Year process is inconsistent with the fact that the tariff revision identifies that there were projects in closed Class Years for which determinations had not yet been made. Specifically, the In-City Buyer-Side Mitigation Measures state that the NYISO is to perform an exemption test for all proposed new projects "in a Class Year [that was closed by the effective date of the amendments], and has not commenced commercial operation or been canceled, and for which the ISO has not made an

[45] *Id.* at P 27.

[46] *Initial Compliance Filing and Request for Expedited Action No Later than December 14, 2010* at 2, Docket No. ER10-3043-001 (filed December 7, 2011) (explaining that under the "Reasonably Anticipated Entry Date Rule" the exemption analysis used price data starting with the Capability Period in which an ICAP Supplier "is reasonably anticipated to offer to supply UCAP" and that under the "Three-Year Rule" the exemption analysis used ICAP Spot Market Auction prices for future Capability Periods beginning with the Summer Capability Period that begins three years from the start of the proposed facility's Class Year).

[47] *Id.* at 4.

exemption or Unit Net CONE determination."[48] The need for that tariff clause in the revisions confirms that the Pre-Amendment Rules did not require that a buyer-side mitigation determination be made at the time their Class Year was closed.

Complainants and NRG are also wrong to claim[49] that the NYISO's exemption determination and interconnection cost allocation processes were tightly integrated prior to the implementation of the In-City Buyer-Side Mitigation Measures. As explained in the NYISO's September 27, 2010 Filing, which resulted in the acceptance of the In-City Buyer-Side Mitigation Measures, a principal objective of the changes to the Pre-Amendment Rules was to more closely align the mitigation exemption test and the Class Year cost allocation processes and to establish that exemption determinations would be made in tandem with the latter.[50] That filing clearly stated the tariff's new "directive" that the NYISO must make exemption and Offer Floor determinations for all Examined Facilities 'prior to the commencement of the Initial Decision Period for the Class Year . . . .' should not be construed as requiring the NYISO to re-evaluate a project for which it has previously made an exemption or Offer Floor determination under the currently effective (pre-amendment) version of Attachment H." The NYISO also clearly stated that "any exemption or Offer Floor determinations that the NYISO made under the currently

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[48] *See* Services Tariff Attachment H §23.4.5.7.3. No party in Docket No. EL10-3043 ever questioned that the NYISO was required to issue a determination for projects tied to the close of the Class Year Facilities Study process. If that were the case, then, for example, the NYISO would have been required to issue a determination for Class Year 2008 projects that received Capacity Resource Interconnect Service ("CRIS") tied to the Class Year Facilities Study cost allocation process. The Commission's Orders in that docket, and the NRG Companies' (along with the Complainants in this docket) own pleadings, by explicitly addressing that provision, recognized that determinations under the Pre-Amendment Rules were not required to be "tied" to the Class Year Facilities Study process.

[49] Complainants' Answer at 10-11; NRG Comments at 7-10.

[50] *See Proposed Enhancements to In-City Buyer-Side Capacity Mitigation Measures, Request for Expedited Commission Action, and Contingent Request for Waiver of Prior Notice Requirement* at 9-10-13-14, Docket No. ER10-3043-000 (filed September 27, 2010) ("September 27, 2010 Filing").

effective version of Attachment H would not be altered or affected by the amendments proposed in this filing."[51] Had the Pre-Amendment Rules required that exemption determination be tied to the Class Year process as NRG and the Complainants now claim, there would be no need for the modifications.

NRG's only counter to all of the information set forth above is to suggest that the NYISO and MMU previously made statements that were consistent with NRG's public interpretation of the tariff. The NYISO has already addressed these past statements.[52] It would re-emphasize here that even if the NYISO or MMU's prior statements were interpreted as being consistent with NRG's or Complainants' re-interpretation, such an interpretation would not override clear language in the current Section 23.4.5.7.2, which cannot plausibly be reconciled with it. The reality, however, is that the NYISO and MMU did not make statements endorsing NRG's and Complainants' interpretation. The NYISO's statements reflect the fact that it anticipated at the time that developers might want certain information before accepting or rejecting project cost allocations. They do not indicate that the NYISO intended to prevent, or believed that the tariff precluded, developers from voluntarily making investment decisions earlier. Likewise, the Supplemental Patton Affidavit confirms that the MMU never understood Section 23.4.5.7.2 to have the meaning suggested by NRG and Complainants.[53] Indeed, the MMU agrees with the NYISO that such a re-interpretation would have the harmful consequences described below.

Finally, the results of adopting Complainants' and NRG's interpretation of the Pre-Amendment Rules would be absurd and contrary to the *August 2 Order*. Imposing an Offer

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[51] *See* September 27, 2010 Filing at 14. *See also, Request for Leave to Answer and Answer of the New York Independent System Operator, Inc.*, filed November 1, 2010 ("November Answer") at 14, n. 39, Docket No. ER10-3043-000.

[53] Supplemental Patton Affidavit at n. 12.

Floor on all new entrants until the completion of their Class Year project cost allocation process would impose an Offer Floor on economic entrants for reasons beyond their control, and give their competitors an undue economic advantage by affecting the price at which the new entrant may offer. It would also subject them to the influence of their competitors that could take actions in an effort to delay the Class Year project cost allocation process. In addition, subjecting operational economic entrants to mitigation would discourage competitive entry in violation of the Commission's directive that buyer-side mitigation rules should not impede economic entrants.[54] It also would have the potential to artificially inflate capacity prices which is harmful to consumers and the capacity market.

B. Using Information from the Time of the Investment Decision in the AEII Analysis Was Reasonable and Consistent with Commission Precedent

1. The NYISO Correctly and Lawfully Examined the Time that AEII Made its Investment Decision

Complainants argue that the NYISO erred by considering information that existed as of the date the developer made a decision to move forward, in its analysis of AEII.[55] Proposing another sweeping re-interpretation of the Pre-Amendment Rules, Complainants contend that the NYISO was required to use in its analysis information available at the time a developer executed its IFSA, rather than information that existed at the time it actually made its investment decision. Their argument would link the exemption analysis to NYISO interconnection process milestones in ways that were not contemplated by the Pre-Amendment Rules, are inconsistent with Commission precedent, and are not reasonable.

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[54] *See August 2 Order* at P 28 (stating that "[t]he whole purpose of the NYC mitigation program is to deter uneconomic entry, not economic entry").

[55] *See* Complainants' Answer at 13-20.

Complainants point to no tariff language that supports their interpretation, and cannot because it does not exist. The version of Section 23.4.5.7.2 that was in effect under the Pre-Amendment Rules specified that a "Developer or Interconnection Customer may request the NYISO to make [an exemption determination] upon execution of all necessary Interconnection Facilities Study Agreements . . . ." Complainants selectively quote a fragment of this language and try to use it to substantiate their claim that the NYISO must make exemption determinations using the data available at the time that the IFSA is executed. Their reading is clearly implausible.

In the absence of tariff language expressly stating what time period the NYISO should look to when making exemption determinations, the tariff must be read in a manner that is reasonable and consistent with Commission policy.[56] Given the Commission precedent establishing that new entrants should only be mitigated if their entry was reasonably anticipated to be uneconomic at the time that they make their investment decision,[57] the NYISO's application of the tariff in the AEII and BEC determinations was reasonable. Complainants have it backwards when they argue[58] that the absence of language in the Pre-Amendment Rules expressly reflecting the Commission's precedent somehow prevents the NYISO from following it.

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[56] *See supra* n. 42.

[57] *New York Independent System Operator, Inc.*, 133 FERC ¶ 61,178 at P 71 (2010) (finding that "[i]t is reasonable for NYISO to provide an exemption test before a supplier begins construction of a new resource, as NYISO's tariff current[ly] provides, and to apply such a test to all new entrants. 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"); *reh'g*, 136 FERC ¶ 61,077 at P 20 (2011) (affirming that "Commission precedent … intended to allow a mitigation exemption determination before the developer decided whether to move forward with a project").

[58] *See* Complainants' Answer at 14.

Complainants argue that the tariff must be read as they say it should, because the MMU and NYISO supposedly previously said that it would be read in that manner. In each instance they chose to quote, however, the language relates to when the NYISO may make exemption determinations.[59] None of the quotes they proffer speak to the question of what time period the NYISO should be looking to when it examines the project.

Complainants' contention that the Pre-Amendment Rules impermissibly gave the NYISO "unfettered discretion" over exemption determinations is also a distortion. Commission precedent is clear that entrants should be exempt from Offer Floor mitigation if their entry was reasonably anticipated to be economic at the time that they made their investment decisions. The fact that there may not be a single, indisputable, date when a particular entrant made its decision to proceed with its investment does not mean that the NYISO had "unfettered discretion" under the Pre-Amendment Rules. The NYISO's application of its tariff, consistent with Commission orders, necessitates that it identify a reasonable date for the developer's investment decision. Complainants have not argued that the Pre-Amendment Rules' requirement that the NYISO compute the "reasonably anticipated" Unit Net Cone left it with excessive discretion. The NYISO's determination of a reasonable investment decision date is no different.

Moreover, the case cited by Complainants to support their interpretation involved the rejection of a PJM tariff proposal that the Commission concluded would have inappropriately given PJM's market monitor "unfettered discretion."[60] By contrast, the Pre-Amendment Rules

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[59] Complainants' Answer at 10, NRG Comments at 9.

[60] Complainants' Answer at n. 57. All FERC orders that address unfettered discretion by the RTO or MMU relate to proposed tariff language not the application of accepted language. *See, e.g., California Independent System Operator, Corp.*, 119 FERC ¶ 61,076, at PP 105-118 (2007); *PJM Interconnection, LLC*, 135 FERC ¶ 61,022, at PP 109-123 (Apr. 12, 2011); *PJM Interconnection, LLC*, 126 FERC ¶ 61,275, at P 190 (2009); *California Independent System Operator, Corp.*, 106 FERC ¶ 61,179, at PP 72-78 (2004); *ISO New England, Inc.*, 109 FERC ¶ 61,147 (2004).

were fully litigated and had been accepted by the Commission years before the NYISO implemented them. Moreover, during the proceedings resulting in the Commission's acceptance of the Pre-Amendment Rules, no party expressed concern that the rules would give the NYISO an impermissible level of discretion.

Certainly, there is no basis or justification for Complainants' attempt to read an "objectively established starting point"[61] into the tariff where none exists. Indeed, it would be irrational to presume that investment decisions would always be made at the time that a developer executed an IFSA. Further, any such presumption is contrary to the facts regarding AEII.[62]

There also is not any cause for concern that the NYISO, an independent entity with no stake in market outcomes, would abuse its discretion to "select the date most likely to result in an exemption for favored projects."[63] Although Complainants continue to insinuate that the NYISO is somehow biased towards providing exemptions, either as a general rule or in the case of particular "favored projects," they have presented no evidence for their assertion. The reality is that the NYISO has no favored projects and does not favor any outcome. Any lingering doubts regarding the NYISO's ability to make reasonable entry date determinations for AEII or BEC should be eliminated by the MMU's involvement and support for the dates that were chosen.[64]

2. The NYISO's Use of July 2008 as the Investment Decision Date for AEII Was Reasonable

[61] Complainants' Answer at 16.

[62] Supplemental Patton Affidavit at PP 17-29.

[63] Complainants Answer at 18.

[64] Initial Patton Affidavit at Section IV; Supplemental Patton Affidavit at PP 17-29.

Complainants go on to argue that if the NYISO were authorized to conduct exemption analyses using information available at the time of the investment decision, it nevertheless chose the wrong date for AEII.[65] IPPNY makes similar assertions.[66] The NYISO is not contending that there is only one possible go-forward investment decision date that might have reasonably been chosen. In the Confidential Supplemental Answer, Christopher Ungate testified that "[t]he 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."[67] Complainants and IPPNY appear to not dispute, and in some places seem to accept that multiple alternative investment decision dates could be reasonable.[68] The NYISO is contending, however, that its selection of the investment decision date for both AEII and BEC was reasonable and was likely the most reasonable possible choice.

First, Complainants and IPPNY are wrong to claim that the earliest reasonable investment decision date that could have been chosen for AEII would have been in 2009.[69] As Initial Patton,[70] and Supplemental Patton Affidavit, discuss in detail, the NYISO appropriately identified July 2008 as AEII's "initial decision point" because that was when "AEII signed a contract with NYPA, ordered major pieces of equipment, such as turbines and heat recovery steam generators, and began to incur significant engineering expenses."[71] AEII would have also incurred significant contractual penalties if it had decided not to proceed with the project after

[65] *See* Complainants' Answer at 19-20; IPPNY Answer at 8.

[66] *See* IPPNY Answer at 6-7.

[67] Ungate AEII Affidavit at P18.

[68] *See* Complainants' Answer at 19-20; IPPNY Answer at 6-8.

[69] *See* Complainants' Answer at 19-20; IPPNY Answer at 8

[70] Initial Patton Affidavit at PP 23-25.

[71] Initial Patton Affidavit at P 23; Supplemental Patton Affidavit at P 18.

signing the PPA. The fact that AEII incurred additional expenses or closed on financing at a later date does not mean that it had not made an investment decision by July 2008. Dr. Patton goes on to explain that the fact AEII did not have its final financing in place, or know with certainty that its request for an *Amended Certificate of Environmental Compatibility and Public Need* would be granted, should not alter this conclusion. AEII could anticipate what its final financing would be with reasonable accuracy, and be confident that it would receive an amended certificate, by July 2008.[72] The argument that market conditions worsened significantly after July 2008 amounts to an argument that the NYISO should have evaluated the likelihood that AEII would walk away from its investment after deciding to make it. Dr. Patton explains why conducting such an additional analysis would be inappropriate.[73]

Complainants and IPPNY are also mistaken when they assert that the NYISO should have looked to the NYISO's 2009 Load and Capacity Data report ("Gold Book") instead of the 2008 Gold Book, to determine the load forecast that was reasonably anticipated to exist as of July 2008.[74] As the Supplemental Boles Affidavit recounts, the load forecast in the 2008 Gold Book was not "outdated" in mid-2008.[75] The stakeholder discussion materials and revised state-wide load forecasts that Complainants reference do not show that the NYISO's use of the load forecast in the 2008 Gold Book data was unreasonable. None of that material represented an alternative to the 2008 Gold Book or signified that the Gold Book was incorrect.[76]

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[72] Supplemental Patton Affidavit at P 23.

[73] *Id.* at PP 25-29.

[74] *See* Second Supplemental Younger Affidavit at PP 75-77.

[75] Supplemental Boles Affidavit at PP 20-23.

[76] *Id.* at PP 22-23.

C. There Is No Basis in the Pre-Amendment Rules, Economic Theory, or Commission Precedent for Complainants' Suggestion that the NYISO Should Err on the Side of Over-Mitigation in its Implementation of Commission-Approved Buyer-Side Market Power Mitigation Measures

Complainants not only ignore the potential impact of their suggestion that over-mitigation of new entry is appropriate, they expressly argue that the Commission should not take a "balanced" approach, as recommended by the MMU, but should instead err on the side of over-mitigating new entry.[77] The NYISO does not believe that any market power mitigation measure should be applied in a way that favors under- or over-mitigation as a general matter or with respect to any single project or Market Participant.

There is no basis for "erring on the side of mitigation" in the provisions of the Services Tariff, in economic theory, or in Commission policy.[78] The Commission recently confirmed that "[t]he whole purpose of the NYC mitigation program is to deter uneconomic entry, not economic entry."[79] Complainants' proposal also contradicts the MMU's understanding that buyer-side mitigation "exists to deter uneconomic entry that would otherwise reduce capacity prices below competitive levels, while not erecting inefficient barriers to economic entry."[80]

There is no basis for Complainants' hypothesis that the entrance of AEII establish that "under-mitigation" has in fact caused "artificial price suppression" in New York City that will "crash" capacity prices, and cause supplier bankruptcies "for many years, all else being

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[77] Complainants' Answer at 7; Hieronymus Affidavit at P 37.

[78] Indeed, the Hieronymus Affidavit effectively proposes that the Pre-Amendment Rules be retroactively revised to make it harder for new entrants to obtain exemptions from Offer Floor mitigation. It is therefore seeking both to impose an illegal retroactive rate change and to make an impermissible end-run around the NYISO's shared governance system.

[79] *August 2 Order* at P 28.

[80] Supplemental Patton Affidavit at P 4.

equal . . . ."[81] One flaw in that assertion lies in its assumption that "all else" will remain "equal" for years. The facts, however, demonstrate that In-City capacity pricing is less static than Complainants predicted. Capacity prices have already risen in the relatively short time since the Complaint was filed, both because of the NYISO's timely implementation of revised ICAP Demand Curves and for other reasons.[82]

As explained in the Supplemental Boles Affidavit, the price fluctuations in the NYC ICAP Spot Market Auction Clearing Price from May 2011 to October 2011 are consistent with Commission precedent on the NYISO's ICAP Demand Curves acknowledging the lumpiness of capacity additions after the entry of new capacity.[83] It is also consistent with effects on the change in prices, such as the change in Special Case Resources, the quantity of MW offered and unsold, among other reasons.[84] Thus, the Complainants' assertions that they will be denied a reasonable opportunity to recover their costs unless the AEII and BEC exemptions are reversed ignores the operation and outcomes of the capacity markets in the NYISO. Moreover, statements reported on October 6, 2011 made by NRG's Senior Vice President and Regional President for

[81] Complainants' Answer at 7.

[82] ICAP clearing prices can also be affected by the number of MWs of capacity available in the market, which for example, can be the result of (1) units that mothball, retire or take inactive status. For example, TC Ravenswood Unit 3-4 was mothballed <http://www.nyiso.com/public/webdocs/services/planning/planned_gen_retirements/083011_TC_Ravenswood_Unit_3-4_Mothball_Notification.pdf>; (2) Installed Capacity Suppliers that do not offer their capacity; (3) changes in SCR registration; and (4) suppliers that increase the price at which they offer their capacity. For example, Installed Capacity Suppliers in NYC that are Pivotal Suppliers can offer the higher of their Going Forward Costs or a price based on the Demand Curve (the UCAP Offer Reference Level).

[83] Supplemental Boles Affidavit at Section IV.

[84] *Id.* at Section IV, Exhibit JAB Supplemental.

the Northeast, Lee Davis, confirmed that it was still possible for incumbent generators to be profitable even after the entry of AEII.[85]

Dr. Patton strongly agrees with Mr. Boles. He affirms that "it would be absurd for the NYISO to intentionally bias its MET evaluations towards over-mitigation as Complainant proposes."[86] Dr. Patton emphasizes that Complainants' argument implicitly, and unreasonably, assumes that economic units will still be built even when developers know that they would unjustifiably be "over-mitigated."[87] Over the long term, the prospect of over-mitigation would "slow the entry of economic resources, leading to lower average capacity margins and higher prices."[88] Dr. Patton observes further that Complainants overstate the potential harm of "under mitigation." Although it would "likely lead to periods of higher capacity margins and lower prices" such period "are not likely to persist for nearly as long as the complainants have suggested in past pleadings because the lower prices lead to accelerated retirements (or mothballing) of older, high-cost generating resources."[89] Indeed, the "sharp recovery in the October 2011 capacity prices for New York City is evidence of this type of natural market reaction to periods of low prices."[90]

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[85] Gruen, Abby, *Push to replace Indian Point may provide opportunity, NRG's Lee Davis*, SNL Energy October 6, 2011 (stating that "[b]oth facilities [in Queens and in Arthur Kill, Staten Island] are making money, but they are making a heck of a lot less than they used to because of the new entry into the market. They are continuing to operate profitably, but I will tell you that both facilities are very dependent on capacity prices in the market").

[86] Supplemental Patton Affidavit at P 16.

[87] *Id.*

[88] *Id.*

[89] *Id.*

[90] *Id.*

The Commission should therefore not accept strained tariff interpretations, or allow Complainants to re-write tariff provisions.[91] The Commission has stated that economic entry will cause prices to fall,[92] even to an extent that may put pressure on previously economic units, but such price impacts are not evidence that buyer-side market power mitigation rules have not been implemented correctly or are flawed.[93]

D. Excluding the Sunk Costs Identified by the Independent MMU from the Exemption Analyses Was Reasonable and Consistent the Pre-Amendment Rules

Complainants[94] and IPPNY[95] allege that the NYISO's exemption determinations for AEII, and to a lesser extent BEC, were distorted by the NYISO's exclusion, of certain costs incurred prior to the time of each entrant's investment decision ("sunk costs"). As the NYISO has stated, Dr. Patton recommended, and the NYISO concurred, that this exclusion was consistent with the purpose of buyer-side mitigation.[96] Complainants' suggest that the exclusion of sunk costs was somehow inconsistent with the definition of "Unit Net CONE" under the Pre-

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[91] *New York Independent System Operator, Inc.*, 136 FERC ¶ 61,077 at PP 27, 40 (2011) (rejecting attempts to read deadlines into the exemption determination provisions that were not supported by prior precedent or pleadings).

[92] *See Compliance Filing and Request for Flexible Implementation Dates*, Attachment VII Affidavit of Dr. David B. Patton at P 20, Docket No. ER11-2224-003 (filed March 29, 2011).

[93] *See Initial Answer of the New York Independent System Operator, Inc. in Opposition to Request for Shortened Answer Period and Emergency "Interim" Relief* at 6, Docket No. EL11-50-000 (filed July 12, 2011) ("Initial Answer"); Answer at 11-16. In addition, contrary to what the Affidavit of Ms. Elizabeth Ann Moler suggests, the mere fact that new entry may cause some existing generators to consider bankruptcy, or the fact that the issues in this case are important to generators and many other market participants, in no way indicates that the NYISO has failed to follow its tariff properly. Complainants' Answer, Attachment D Affidavit of Elizabeth Anne Moler at P 12. Given Ms. Moler's candid acknowledgement that she is not an expert on the tariff provisions at issue in this proceeding, her testimony should not be afforded any evidentiary weight. *Id.* at P 13.

[94] Complainants' Answer at 20-26.

[95] IPPNY Answer at 5-6.

[96] *See* Initial Patton Affidavit at P 24; Boles AEII Affidavit at P 24; Boles BEC Affidavit at P 24.

Amendment Rules.[97] Their claim that literally all costs that could possibly be associated with the entry of a new project must be included within the ambit of the "localized levelized embedded costs" for that project is grossly overstated. As the Patton Affidavit re-emphasizes, "a reasonable evaluation of whether an investment is economic must exclude costs that are sunk because such costs would not rationally be considered by a competitive firm in its decision to invest."[98]

There is nothing in the Unit Net CONE definition that requires the attribution of sunk costs such as the "shared facilities" costs associated with AEII, in the exemption analysis for the new entrant. There is likewise no reason to read such a requirement into the tariff in situations where, as Dr. Patton explains, it would be contrary to the purpose of the exemption analysis to do so.

Complainants' argument that the NYISO and MMU have ignored the textbook definition of "sunk cost" is equally misplaced. The NYISO does not dispute the Marciano Affidavit's recitation of a textbook definition of "sunk cost." Nor does the MMU. Complainants' are wrong to claim, however, that the costs that the MMU recommended be excluded were outside the scope of that definition.

The Supplemental Patton Affidavit addresses each of the Pleadings Opposition Exemptions' arguments against classifying AEII's costs for the existing facilities shared with Astoria Energy I ("AEI") as sunk costs. First, Dr. Patton explains that it is wrong to contend that the fact that AEII would not have had to pay AEI for shared facilities if the AEII unit had not been built indicates that those costs were not sunk. The Complainants' argument is an oversimplification and is not even consistent with the definition of "sunk cost" put forward by

[97] *See* Complainants' Answer at 20-21.

[98] Supplemental Patton Affidavit at P 30.

Dr. Marciano. For the reasons specified by Dr. Patton, the payment from AEII to AEI for existing joint facilities cannot be considered the market value of those facilities and thus should be treated as a sunk cost.[99]

Second, Dr. Patton refutes the claim that existing facility costs were not sunk because some portion of them could have been recovered if other investors would pay to build a generator on the site in the same timeframe.[100] Because the combined cycle technology is the most efficient resource that can be built, the market value of the existing joint facilities is bounded by its profitability. Accordingly, if AEII were uneconomic then the market value of the existing joint facilities must, by definition, fall to zero. By contrast, if AEII were economic then the existing facilities' positive market value could not be large enough to cause AEII to be considered uneconomic. Because AEII is the lowest cost resource, then the existing value of the joint facilities must be "bounded by the AEII's excess profits."[101] It is therefore "inappropriate to assume a positive market value for the joint facilities in the MET evaluation."[102]

Third, Dr. Patton addresses the theory that even if the AEI and AEII site had little value to support the entry of a new unit at this time, it could have substantial value to a future entrant and thus that existing facility costs should not be treated as sunk.[103] According to Dr. Patton, at the time that AEII entered there would have been little basis for believing that future entry would be more economic.[104]

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[99] *Id.* at PP 32, 33-39.

[100] *See* Supplemental Patton Affidavit at PP 41-46.

[101] *Id.* at P 45.

[102] *Id.* at PP 33.

[103] *See* Second Supplemental Younger Affidavit at P 84; NRG Comments, Attachment A Affidavit of Johannes P. Pfeifenberger at P 17.

[104] Supplemental Patton Affidavit at PP 47-52.

IPPNY argues that the value of the deliverability rights that NYPA provided to AEII should have been included in AEII's exemption analysis. Dr. Patton states that this would be true if the deliverability rights that AEII would require in order to sell capacity had a positive market value. Importantly, however, it does not appear that the rights that were transferred to AEII would have any material value to another entrant. This is because the rights were previously associated with the former Poletti I plant, and only projects that were operational within three years of its removal from service were eligible to receive the transfer.[105] Dr. Patton observes that if AEII is the most economic resource that could enter in time to acquire the rights then their value is based solely on AEII's profitability. He also explains that rights could only have a positive market value if AEII were economic, and that there does not appear to be any potential lower cost entrant that could have actually been eligible to receive the transferred deliverability rights.[106] Therefore "any attribution of market value to the deliverability rights on the basis that they could have been sold to a competing entrant is highly speculative and would be inappropriate to include in the MET evaluation."[107]

Several of the Pleadings Opposing Exemptions criticize Dr. Patton's recommendation to exclude sunk costs on the ground that it will create opportunities for gaming. It is at best ironic for self-interested market participants to accuse an independent MMU of being insufficiently concerned about the dangers of market manipulation. At a minimum, it is yet another indicator of the extent to which the sponsors of those pleadings intend to function as *de facto* market monitors themselves. Dr. Patton confirms that the sunk cost gaming concerns raised in the

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[105] *See* OATT Attachment S Section 25.9.3.

[106] Supplemental Patton Affidavit at PP 53-56; *see also* OATT Attachment S §§ 25.9.4 (addressing the transfer of CRIS rights at the same location), 23.9.5 (addressing the transfer of CRIS rights at a different location).

[107] *Id.* at P 56.

Pleadings Opposing Exceptions "has no bearing on what the economically correct assumptions are for the MET evaluations of the AEII and Bayonne projects. One cannot reasonably argue that the that the Astoria Energy partners developed the joint existing facilities at the time that AEI was built in order to influence the MET evaluation for AEII."[108]

Finally, the Ungate Affidavit confirms the reasonableness of Dr. Patton's recommendation that the NYISO treat a portion of preliminary permitting and legal development costs as sunk.[109]

E. The NYISO's Use of Actual Financing Information and its Choice of Financing Assumptions Were Reasonable

The Pleadings Opposing Exemptions argue that Dr. Patton's recommendation that the NYISO use the actual financing terms for AEII was inappropriate.[110] The Patton Affidavit refutes their claims. It is Dr. Patton's expert opinion that because financing costs vary from project to project it is "imperative for NYISO to consider the financing terms of a specific project when performing a MET evaluation." Otherwise legitimate financing advantages that ought to be considered in allocating market risks would be improperly ignored.

Various pieces of testimony accompanying the Pleadings Opposing Exemptions assert that the underlying purpose of the BSM rules is to prevent state entities from sponsoring uneconomic entry in order to drive down capacity market prices. In AEII's case, it obtained financing terms through arms-length negotiations with lenders that may have been attracted by the existence of a power purchase agreement with a creditworthy counterparty. But those lenders themselves had no interest in suppressing capacity prices. AEII's situation is thus no different from what it

[108] *Id.*

[109] Ungate Affidavit at Section VI.

[110] Complainants' Answer at 26-28.

would have been if it contracted with a large, credit-worthy, non-governmental customer or customers.

Dr. Patton also points out that Dr. Shanker's argument that the NYISO should have applied the peaking unit financing assumptions used in the most recent ICAP Demand Curve reset to AEII, would have been unduly discriminatory. The Unit Net CONE determination requires that the NYISO use the project's costs. Thus there is no basis under the Pre-Amendment Rules to implement Dr. Shanker's suggestion. The Pre-Amendment Rules did not empower the NYISO to substitute the estimated peaking unit financing costs for actual financing assumptions because an entrant has a long-term PPA or for any other reason.[111] That approach cannot be reconciled with the tariff's mandate that the NYISO determine a particular entrant's "reasonably anticipated Unit Net CONE." Dr. Shanker's suggestion therefore could only be adopted prospectively and then only to the extent that the tariff were revised through appropriate means.

Complainants and NRG also question the financing assumptions that the NYISO used to calculate the carrying charge rates for BEC's investment costs.[112] The Ungate Affidavit demonstrates that their arguments are not valid. Mr. Ungate explains that Sargent & Lundy has observed that "projects with nearly identical risk characteristics have a broad range of target equity returns."[113] These variations are driven by the particular circumstance and priorities of individual projects and developers. In AEII's specific case it was Sargent & Lundy's judgment

[111] The NYISO is also not empowered to substitute the Demand Curve peaking plant's data for that of the project under the In-City Buyer Side Market Mitigation Rules.

[112] *See* NRG Comments at 4 and Pfeifenberger Affidavit at PP 34-36; Complainants' Answer, Younger Affidavit at PP 107-108.

[113] Ungate Affidavit at P 21.

that the composite after-tax cost of equity that AEII estimated for the project owners was reasonable.[114]

F. The NYISO Calculated Reasonable Energy and Ancillary Services ("E&AS") Revenues in its AEII and BEC Exemption Determinations

Complainants allege that the NYISO made two errors in calculating energy and ancillary services revenues that were supposedly inconsistent with tariff language requiring it to determine AEII's and BEC's "reasonably anticipated" Unit Net CONE. In both cases, Complainants' challenges are fatally flawed.

First, Complainants claim that the NYISO failed to account for the fact that AEII and BEC interconnect at the 345 kV level and imply that this was a serious mistake.[115] Complainants have completely mischaracterized the perfectly clear explanation of the "345 kV adjustment" that the NYISO offered in its Confidential Supplemental Answer. As clearly stated in the Boles AEII and BEC Affidavits, the NYISO used the same NERA Model that was employed in the most recent ICAP Demand Curve reset process (with certain adjustments) to produce the net energy revenue estimates for the AEII and BEC exemption analyses.[116] The NERA model estimates net energy revenues relative to the load-weighted average Zone J price. The NYISO concluded that using the NERA model was reasonable. The NYISO responded to comments questioning whether adjusting the net energy revenue estimates produced by the NERA model to account for prices at the 345 kV level would have had a material impact. Mr. Boles' prior affidavits in this proceeding confirmed that it would not.[117] Thus, contrary to what Complainants imply, the

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[114] *Id.*

[115] *See* Complainants' Answer at 28-30.

[116] Boles AEII Affidavit at PP 32-35, Boles BEC Affidavit at PP-32-25.

[117] Boles AEII Affidavit at PP 37, 42-44;Boles BEC Affidavit at PP 37, 40-42.

NYISO has neither expressly nor implicitly acknowledged an error in its calculation of net energy and ancillary services revenues.[118] Nor has it tried to "correct" a supposed error.

Complainants' assorted allegations that the NYISO underestimated the price impact of making a 345 kV adjustment[119] are also incorrect, as shown in the Supplemental Boles Affidavit. Complainants' attempts to argue that the price impact was underestimated by proposing alternative methodologies does not change the fact that it was reasonable for the NYISO to use the NERA model with the adjustments described in the Confidential Boles Affidavits and the Meehan Affidavit.[120] Further, Complainants' newly proposed adjustments to their original methodology do not alter the outcome of the determination, as even with those adjustments the outcome of the mitigation exemption determination would remain the same.[121]

Second, Complainants argue that using gas futures prices rather than historic gas prices, as was done in the 2010 ICAP Demand Curve reset, to calculate net energy revenues caused the NERA Model to produce unreasonable results.[122] Just as they did with respect to the 345 kV adjustment, Complainants inaccurately imply that Mr. Meehan and Mr. Falk, believed that the use of future gas prices was likely to introduce error, due to the decision to not utilize gas futures in the Demand Curve reset.[123] In reality, as is explained in the Joint Meehan/Falk Affidavit, the decision to utilize the gas price adjustment in the mitigation exemption determinations is not invalidated by the decision in the NERA/S&L Demand Curve Report.[124] Gas futures are

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[118] Complainants' Answer at 29.

[119] *Id.* at 28-30, Second Supplemental Younger Affidavit at PP 25-30.

[120] Supplemental Boles Affidavit at PP 25-26.

[121] *Id.* at P 34.

[122] Complainants' Answer at 30-32.

[123] Complainants' Answer at 30.

[124] Joint Meehan/Falk Affidavit at P 17.

appropriate for estimating net energy revenues for the Unit Net CONE calculations, and "that regression equation and gas price coefficients are a reasonable way to reflect future electricity prices."[125] Mr. Falk and Mr. Meehan have thoroughly explained why the factors identified by Complainants' do not indicate that a gas price adjustment is inappropriate in this context and have not shown that the use of gas futures produced an unreasonable result.[126]

Complainants and NRG also claim that the gas price input adjustments introduced various other errors that supposedly had an unreasonable impact on the BEC exemption analysis. As explained in the Joint Meehan/Falk Affidavit, it was reasonable to use the NERA model used in the Demand Curve reset for the net energy revenues estimation with the gas futures adjustment.[127] The "model is soundly specified, has strong statistical properties including those associated with the gas price coefficients and was designed for the exact purpose of estimating net energy revenues for various unit types at various reserve margins" and was thus appropriately utilized for these purposes.[128]

Complainants and NRG also argue that the adjustments reflect an assumption that BEC "would operate 6,237 hours per year" and that this figure is unreasonably high compared to the approximately 1,500 hours per year that other studies suggest the BEC units would run.[129] Complainants argue that this variation is evidence of a flaw in the NERA model.

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[125] *Id.*

[126] *Id.*

[127] *Id.* at P 18.

[128] *Id.*

[129] Complainants' Answer at 31, Second Supplemental Younger Affidavit at P 45. *See also* NRG Comments at 6, Pfeifenberger Affidavit at P 7(d).

The Joint Meehan/Falk Affidavit explains that estimate of BEC's operating hours is reasonable and is not a sign of a flaw in the NERA model.[130] Although an estimate of 1,500 hours could be reasonable for a peaking unit it would be unrealistically low for BEC because it would have a significantly lower effective heat rate than an LMS100 located in New York City.[131] Complainants' various comparisons of the dispatch results for the LMS100, a generic combined cycle unit, and BEC are all inapt for similar reasons, *i.e.*, their failure to account for BEC's fuel costs advantage, low variable O&M costs, and operational flexibility.[132] As the Joint Meehan/Falk Affidavit explains in detail, an analysis of cases that are actually comparable demonstrates that the BEC run-time estimates were reasonable and that there is no problem with the NERA Model.[133] The Commission should therefore reject Complainants' claim[134] that BEC's exemption determination must be overturned because of the supposed flaws in the model.

G. The Interconnection Cost Assumptions Used in the AEII and BEC Exemption Analyses Were Reasonable

Complainants and NRG claim that the NYISO underestimated interconnection costs in its exemption analyses for AEII and BEC.[135] Their theory that the NYISO could not use reasonably anticipated interconnection costs computed prior to the close of the relevant Class Year cost allocation process to make exemption determinations has already been addressed.[136] Their notion that the costs used by the NYISO themselves were unreasonably low is disposed of by the

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[130] Joint Meehan/Falk Affidavit at Section IV.

[131] *Id.* at P 19.

[132] *Id.* at PP 20, 24-25.

[133] *Id.* at PP 26-29.

[134] Complainants' Answer at 32.

[135] *See* Complainants' Answer at 32-33; s*ee also* NRG Comments at 11-12.

[136] *See* Section III.

Ungate Affidavit. Mr. Ungate explains that Sargent & Lundy reasonably used capital cost information, including interconnection cost information, that was a combination of costs that were known at the time as well as estimates of future costs for items not yet purchased or work not yet performed. Sargent & Lundy took a number of steps to assure itself that the capital cost information utilized in the CONE estimate was reasonable.[137] Mr. Ungate also explains that it is misleading for Complainants and NRG to select a single variance between Sargent & Lundy's estimates, and a wholly separate study being undertaken by the NYISO planning staff for a different purpose, and try to use it to impugn the entire exemption analysis.[138] Mr. Ungate's affidavit confirms that the existence of the NYISO planning study should not call the reasonableness of Sargent & Lundy's assessment into question.

H. The NYISO and its Consultants Took Reasonable Steps to Verify the Facts and Assumptions Used in the AEII and BEC Exemption Analyses

Complainants assert that there are "unanswered questions" regarding the extent to which the NYISO verified information provided by project sponsors.[139] They offer two examples of such alleged failures. The first, regarding Dr. Patton's references to the Hess Corporation's cost of capital[140] was addressed in the Ungate Affidavit. Complainants attempt to criticize the verification of key inputs to Unit Net CONE by pointing to a statement by Dr. Patton[141] that the NYISO used Hess' cost of capital in determining BEC's cost of capital. As the Confidential Boles BEC Affidavit explained, at the direction of the MMU, the NYISO used BEC's project

[137] Ungate Affidavit at Sections IV, V.

[138] *Id.* at P 12.

[139] Complainants' Answer at 33.

[140] *Id.* at 33-34.

[141] Younger Second Supplemental Affidavit at P105, *citing* Initial Patton Affidavit at P 42.

specific financing to calculate BEC's carrying charge.[142] The NYISO's use of BEC's actual financing is also clear from the Ungate Affidavit,[143] which specifies that the BEC project is structured as an LLC and Hess estimated the composite after-tax cost of equity for the BEC project partners to be 10%. BEC has two project partners, and Dr. Patton's affidavit only mentioned one of them. However, it is clear from Dr. Patton's recommendation, and the affidavits of Mr. Boles and Mr. Ungate, that the NYISO's consideration of BEC recognized the project partners.

The second, allegation is that the NYISO failed to verify certain income tax information provided by AEII. This is not true. The Ungate Affidavit explains that Sargent & Lundy reviewed the tax information provided by AEII and concluded that the NYISO's use of it was reasonable.[144] Neither AEII nor the Complainants know, or in Sargent & Lundy's estimation reasonably could know, the actual tax status of AEII's individual owners. Mr. Todd acknowledges that his assessment of AEII's potential tax liabilities was based on his assumptions regarding the tax status of AEII's various owners. He derived his information from AEII's September 2008 filing with the New York State Public Service Commission, which was not the only source of information on the subject.

Mr. Ungate affirms that it was reasonable for the NYISO to rely on the tax estimates approved by Sargent & Lundy, instead of those estimated by Mr. Todd on behalf of Complainants.

As a general matter, Complainants seem to suggest that the NYISO must determine the actual cost of new entry rather than, as required by the tariff, the "reasonably anticipated Unit

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[142] Boles BEC Affidavit at PP 28 – 29.

[143] Ungate Affidavit at P26.

[144] *Id.* at P 21.

Net CONE."[145] The NYISO cannot practicability "verify" beyond all shadow of a doubt the accuracy of every input relevant to its analyses and is not legally obligated to do so.

Requiring the NYISO to prove after-the-fact that all of the inputs used in forward-looking exemption analyses were correct would clearly go far beyond what is necessary to determine "reasonably anticipated" values. Nor should the NYISO be expected to study the potential implications of every regulatory filing, or other statement, made by a developer in order to defend exemption determinations against challenges. The NYISO must instead be permitted to reasonably rely on the careful work of its own staff, the diligence and judgment of its expert consultants, and the recommendations of its MMU. It is difficult to see how the NYISO could possibly go further and perform the kinds of "verifications" that Complainants envision without seriously prolonging the exemption determination process. Making that process excessively protracted and burdensome would only serve to discourage new entry.

In this case, the NYISO utilized its two expert ICAP Consultants to assist it in its evaluation of the Unit Net CONE for AEII and BEC, and reflected the input of the MMU. The NYISO took reasonable steps to examine, or reasonably relied on its Consultants' examination of, all of the inputs to those exemption analyses, including the handful of inputs referenced by Complainants. This level of "verification" is all that is required under the tariff and all that is necessary to enable market power mitigation measures to effectively ensure that prices remain just and reasonable.

I. The NYISO Accounted for Reasonably Anticipated Capacity Additions in its ICAP Forecasts

[145] Services Tariff Attachment H § 23.4.5.7.2.

The Complainants and NRG claim that the NYISO was wrong to exclude certain projects from the ICAP forecasts used in its exemption analyses. The arguments have focused on the NYISO's decision to not include the Hudson Transmission Project ("HTP") in the ICAP forecasts for both AEII and BEC.[146] The NRG Comments question the NYISO's decision not to include other proposed capacity additions that were identified in the Gold Book.[147] The Boles Confidential Affidavits describe in detail the methodical approach used to identify which proposed generator additions and proposed controllable transmission facilities to include in the ICAP forecasts.[148] As reiterated in the Supplemental Boles Affidavit, the NYISO includes all proposed projects "except those that were not reasonably anticipated to be online during the three-year period following the entry of the project being examined."[149] Using this methodology the NYISO determined that it would not have been reasonable for AEII or BEC to expect that HTP would be online during the first three years of the project's operation. Supporting evidence and rationales are provided in the Supplemental Boles Affidavit.

The same methodology was employed to determine that several other proposed projects would not be reasonably anticipated to be online during the first three years of operation. NRG witness Dr. Johannes Pfeifenberger questions the NYISO's exclusion of other proposed projects listed in the Gold Book. As explained in the Supplemental Boles Affidavit, the Pfeifenberger Affidavit merely makes a blanket statement as to the inclusion of proposed projects; it presents no substantive arguments and does not even address the evidence previously provided in the

[146] Younger Second Supplemental Affidavit at P 79, n. 48; NRG Comments at n. 7; Pfeifenberger Affidavit at P 33.

[147] NRG Comments at P 4; Affidavit of Dr. Johannes Pfeifenberger ("Pfeifenberger Affidavit") at PP 23, 33.

[148] Boles AEII Affidavit PP 58-60; Boles BEC Affidavit PP 56-69.

[149] Supplemental Boles Affidavit at P 8.

Boles Confidential Affidavits. Indeed, price impact calculations presented in the Pfeifenberger Affidavit were all incorrectly calculated, which should certainly call the validity of the underlying claims into question.[150]

Dr. Patton states that he agrees with the NYISO's methodology and that, if anything, the NYISO was conservative in its selection of which proposed projects to include in the ICAP forecast. In addition to supporting the exclusion of the projects cited in the Boles Affidavit, Dr. Patton identifies several specific projects, and other capacity, that the NYISO could have excluded from its forecast.[151]

IV. RENEWED REQUEST FOR EXPEDITED COMMISSION ACTION

The NYISO again respectfully renews its request that the Commission expeditiously issue an order disposing of this proceeding. There is more than sufficient evidence in the record for the Commission to decide whether the AEII and BEC determinations were reasonable and lawful without initiating additional procedures. The core issues in this case concern matters of tariff interpretation, the purpose and nature of the Commission's buyer-side mitigation policy, and questions of economic theory[152] that do not constitute "disputed issues of material fact."[153] A

[150] *Id.* at n. 13.

[151] Supplemental Patton Affidavit at PP 9-13.

[152] For example, Complainants' and NRG's theories that final exemption determinations could not be made under the Pre-Amendment Rules until the conclusion of the Class Year process, that the NYISO could not consider information that existed at the time that AEII made its investment decision, that the NYISO should "err on the side of mitigation" when implementing buyer-side mitigation measures, and the claim that it is somehow inappropriate to exclude sunk costs from Unit Net CONE analyses.

[153] *See, e.g, Louisiana Ass'n of Independent Producers & Royalty Owners v. FERC*, 958 F.2d 1101, 1113 (1992) (finding that a trial-type evidentiary hearing was unnecessary where the instant dispute was over "whether additional pipeline capacity [was] needed to meet future demand, a 'purely technical issue' capable of being resolved not on the basis of a witness's motive or memory, but rather upon an 'analysis of the conflicting data and a reasoned judgment as to what the data shows'"); *ANR Pipeline Co.*, 55 FERC ¶ 61,481, at 62,591 (1991) (denying request for a trial-type hearing on the environmental issues that would be presented by siting the proposed compressor station in a rural, residential area—an issue

limited number of secondary issues have factual dimensions but none of them raise questions involving the credibility or intent of witnesses that would necessitate a hearing.[154]

To the extent that the Commission needs additional information on particular issues, it could initiate paper hearing proceedings and direct interested parties to file briefs addressing them in order to allow for expedited action. The Commission has recently turned to paper hearings to address complex capacity market issues, including buyer-side market power mitigation issues, arising in the ISO New England, Inc. and PJM regions. In the PJM MOPR proceeding, the Commission concluded that because there was "sufficient information to resolve the issues without the need for suspension or a hearing; we are not persuaded that the existing record is deficient on any of the issues presented. . . ." and thus that there was no need for hearings.[155] The same is true in this case. Complainants have conceded that a paper hearing would be the most efficient way to move forward if additional procedures are needed in this docket.[156]

An expedited ruling based on the paper record would be far more reasonable than the Complainants' three month old request for "interim" relief. It also likely would result in a more expeditious resolution of the proceeding, which is an objective the Complainants also seek. As the NYISO previously noted, that request improperly presumes the very things that it is

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involving technical information and not a witness's motive, intent, or credibility); *Iroquois Gas Transmission System, L.P.*, 54 FERC ¶ 61,103, at 61,346-47 (1991) (rejecting assertions that a trial-type hearing was needed to resolve a "purely technical issue," which could be "resolved through the presentation of additional documentary evidence, including affidavits, letters, contracts and technical data").

[154] *See Ameren Services Co. and Northern Indiana Public Service Co. v. Midwest Independent Transmission System, Inc.* 131 FERC ¶ 61,214 at PP 10-11 (2011) (stating that "[a] paper hearing procedure is appropriate where witness motive, intent, and credibility are not at issue and issues of material fact can be adequately addressed on the written record").

[155] *PJM MOPR Order* at PP 25-26.

[156] Complainants' Initial Answer at 31.

Complainants' statutory burden to prove.[157] There is no basis in the record or the law for the Commission to make a preliminary determination that all new entrants should be subject to Offer Floor mitigation and continuing that mitigation until the conclusion of a hearing.

Expedited action will benefit all stakeholders, including potential future entrants, by ending the uncertainty engendered by the Complaint and by demonstrating that disputes over mitigation determinations can be resolved promptly. Such disputes may be inevitable, given the financial stakes for many market participants. If the Commission brings this case to a clear and timely conclusion it will help to prevent investor concerns about "lengthy and complex" litigation over new capacity investments from discouraging new entry into the In-City capacity market.

V. ANSWER OPPOSING MOTION TO LODGE

At 4:45 PM on the last business day before the end of the fifteen day period for submitting this answer, Complainants served notice that they had filed the 348 page "Motion to Lodge."[158] The Motion attached documents culled from the "voluminous" amount of documentation that they obtained from NYPA pursuant to New York State's Freedom of Information Law.[159] The Motion to Lodge uses carefully selected excerpts from this material to try to lend credibility to the Complainants' fiction that NYPA influenced the NYISO's buyer-side mitigation exemption determination for AEII.

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[157] August 3 Answer at 20-22.

[158] The Motion to Lodge referred to in the Answer responds to the motion filed on October 7, 2011. References in this section are not to previous motions to lodge filed by Complainants earlier in the proceeding.

[159] N.Y. PUB. OFF. LAW §§ 84-90 (McKinney 2008).

The NYISO once again unequivocally denies all allegations that its analyses of, actions regarding, and mitigation exemption determination of AEII were influenced by NYPA. The NYISO also reiterates its unequivocal denial of all allegations that it was biased in favor of AEII or any other potential new entrant.[160] The NYISO expects that the Commission will immediately recognize that the Motion to Lodge, including its attachments, has no probative value, and that Complainants' assertions are hollow. The NYISO respectfully requests that the Commission deny the motion.[161]

Based on the NYISO's preliminary review, it is readily apparent that the Motion to Lodge is critically flawed. The following are some significant examples:

- The Motion to Lodge makes repeated assertions about AEII's and NYPA's perception that AEII was likely to be subject to Offer Floor mitigation.[162] Their perceptions, however, are irrelevant to issues before the Commission. The NYISO, not AEII or NYPA, was independently responsible for conducting the buyer-side mitigation analysis of AEII and making the determination. The NYISO carried out its obligation with input from the MMU. AEII and NYPA did not participate in that process directly or indirectly and were not privy to the MMU's independent recommendations to the NYISO regarding the proper treatment of sunk costs and other matters. In short, NYPA's and AEII's views concerning the potential outcome of the buyer-side mitigation analysis has absolutely no probative value in this proceeding.

- The Motion to Lodge suggests that the NYISO deceived its stakeholders by adhering to its tariff and moving ahead with exemption determinations under the Pre-Amendment Rules. Complainants' accusations are erroneous and disingenuous. Complainants distorted the content of the NYISO's presentation to the stakeholder Management Committee.[163] The presentation materials are clear

[160] *See* August 3 Answer at 11.

[161] The NYISO is submitting this answer well within the fifteen day period normally allowed for answers to motions, including motions to lodge. The NYISO reserves the right to supplement its answer to the Motion to Lodge if the Commission has not denied it prior to the deadline for answers. However, there is no reason to delay the issuance of an order dismissing the Complaint simply to await answers to the Motion to Lodge.

[162] Motion to Lodge at 12-13.

[163] Those presentation materials, were wholly consistent with the NYISO's earlier presentations to the Business Issues Committee and the ICAP Working Group.[163]

that the clause "provided an appeal has not been taken" referred to an appeal of a Management Committee vote approving the proposed tariff revisions. Those materials are wholly consistent with the entire statement in the Management Committee Meeting, rather than the misleading snippet in the Motion to Lodge.[164] Moreover, pursuant to the ISO Agreement and Management Committee By-Laws, appeals to the Board can only be taken from Management Committee decisions or actions.[165] It is clear from the Management Committee motions that the only items from which an appeal could be taken would be the Management Committee's action on the motions regarding the proposed tariff revisions.[166] It is thus absurd for the Motion to Lodge to imply that the NYISO was bound to seek a waiver because "the waiver issue" was not appealed.[167] The notion that stakeholders would have inferred that the NYISO had suspended the implementation of its buyer-side mitigation rules is also implausible. Complainants, who are represented by experienced FERC counsel, are well aware that the NYISO cannot suspend its tariff requirements without a Commission order. There was no such order. Any suggestion that stakeholders were misled or that they "fairly inferred"[168] that determinations under the Pre-Amendment Rules had been suspended is utterly without merit and has no basis in law or fact.

- The Motion to Lodge makes much of a snippet of language in an internal NYPA email that expresses the writer's view that NYISO was "anxious to say the least."[169] From this excerpt they concoct a theory that implies the NYISO attempted to circumvent obligations under rules that had not yet become effective. Complainants' notion that NYISO was compelled to complete the AEII exemption determination before October 28, 2010 is contradicted by the record in the In-City Buyer-Side Mitigation Measures proceeding (Docket No. ER10-3043-

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[164] *See* Motion to Lodge at 10, n. 37. Complainants deceptively omit the introductory clause of the sentence. The minutes state: "**If *this* is approved at today's MC meeting,** they will file a request for waiver of the current exemption determination provisions promptly after the period for appeal of the MC approval of tariff revisions has expired, provided an appeal has not been filed." (emphasis added). The only item for approval that day were the proposed tariff revisions. *See* NYISO Management Committee Meeting Minutes (August 25, 2010), available at <http://www.nyiso.com/public/webdocs/committees/mc/meeting_materials/2010-08-25/MC_minutes_08252010_FINAL.pdf>.

[165] *See* ISO Agreement, Sections 7.02, 7.03 *available at* <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/nyiso_agreement/iso_agreement.pdf>; By-Laws of the Management Committee, Section 13.01, available at <http://www.nyiso.com/public/webdocs/committees/general_information/mc_by_laws.pdf>.

[166] *See* Management Committee Final Motions, Motions #5, #5a, and #5b, available at <http://www.nyiso.com/public/webdocs/committees/mc/meeting_materials/2010-08-25/082510_final_Motions.pdf>.

[167] Motion to Lodge at n. 37.

[168] *Id.*

[169] Motion to Lodge at 10.

000.) The NYISO's September 27, 2010 tariff filing introducing the In-City Buyer-Side Mitigation Measures initially proposed an October 28 effective date. That date was chosen because it allowed enough time for the NYISO to perform its obligations under the new rules. Based on a change in the stakeholder Operating Committee's schedule for considering proposed Class Year project cost allocations, on October 1 the NYISO informed the Commission that it no longer needed an October 28 effective date.[170] Also on October 1, the Commission set an October 22 deadline for filing comments and protests.[171] The NYISO therefore had no reason to expect that the In-City Buyer-Side Mitigation Measures would become effective as early as October 28 at the time that it was finalizing its analysis of AEII.

- The Motion to Lodge grossly distorts the nature of the NYISO's communications with NYPA. Complainants imply that it was inappropriate or preferential for the NYISO to discuss the application of the Pre-Amendment Rules to AEII before the project was eligible to obtain an exemption. As with most mitigation examinations and determinations, whether they involve an offer cap or going forward costs for pivotal suppliers, or buyer-side mitigation analysis as in this case, the NYISO generally has on-going communications with the affected participants. These communications permit the NYISO to gather all relevant information prior to making an independent determination on whether, and if so, how to apply mitigation. Indeed, Complainants filed a complaint in Docket No. EL11-42-000 which argued that the NYISO was not being responsive enough to Astoria Generating Company's concerning the application of the In-City Buyer-Side Mitigation Measures to their own projects, which were substantially similar to NYPA's. It is not reasonable to infer that those communications had some nefarious intent. The NYISO's communications with participants that may be subjected to either supplier-side or buyer-side mitigation are entirely appropriate and necessary. The Commission should reject the negative inferences Complainants' attempt to cast around the NYISO's communications with the affected participants in this proceeding.

- The Motion to Lodge is equally disingenuous when it depicts NYPA's suggestion that it might contact NYISO senior management to discuss concerns with NYISO staff inaction as somehow applying improper pressure on the NYISO.[172] Complainants frequently reach out to NYISO senior management themselves when they have issues under the supplier-side or buyer-side mitigation rules.

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[170] *See Answer to Motion for Extension of Time and Motion to Amend Request for Expedited Action of the New York Independent System Operator, Inc*., Docket No. ER10-3043-000 (October 1, 2010).

[171] *See Notice of Extension of Time,* Docket No. ER10-3043-000 (October 1, 2010).

[172] Motion to Lodge at 10.

- The Motion to Lodge suggests that the NYISO would not be as responsive to requests from suppliers as it would be to requests from NYPA.[173] Complainants' premise is simply false. To cite only one example, the NYISO has spent an extraordinary amount of time working directly with one of the Complainants in connection with its request regarding offer caps and potential penalty issues. Yet those efforts to fully and fairly consider that Complainant's requests for relief go unmentioned in the Motion to Lodge. Complainants' accusations of bias by the NYISO have no factual basis and should be summarily rejected by the Commission.

The points outlined above demonstrate that the Commission should deny the Motion to Lodge because it will not assist the Commission's decision-making process, because the information it provides is irrelevant, [174] and because it makes arguments that are not based on newly uncovered information[175] but simply rehash points made in Complainants' Answer.[176]

[173] Motion to Lodge at 12-13.

[174] *See, e.g. Louisiana Public Service Commission*, 117 FERC ¶ 61,203 at P 10 (2006) (denying a motion to lodge testimony filed in a proceeding before the Arkansas Public Service Commission because "it is irrelevant what ... witness may have stated in a separate proceeding"); *ISO New England Inc.*, 123 FERC ¶ 61,290 at P 12 (2008) (denying a motion to lodge because it "does not provide information that has assisted us in our decision-making process").

[175] *See, e.g., Pittsfield Generating Co., LP*, 115 FERC ¶ 61,059 at P 23 (2006) (denying motion to lodge because it "serves as an untimely supplement to … answers and protests in [the] proceeding, and offers no new evidence that the Commission should consider in its review"); *Southern Company Servs, Inc.*, 95 FERC ¶ 61,307 at 62,049, (2001) (denying motion to lodge because it provided no new information that could assist the Commission in resolving the instant case).

[176] For example, the Motion to Lodge simply repeats Complainants' earlier claims that the Pre-Amendment Rules did not allow exemption determinations to be finalized before the close of the Class Year process and that AEII supposedly would not have made an investment decision before having confirmed its final financing terms. Moreover, the "new" information included in the Motion to Lodge does nothing to support these restated arguments.

VI. CONCLUSION

For the reasons set forth above, and in the attached supporting affidavits, the NYISO respectfully requests that the Commission dismiss the Complaint, and all subsequent pleadings challenging the NYISO's exemption determinations for AEII and BEC in their entirety.

Respectfully submitted,

/s/ Gloria Kavanah

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 11th day of October, 2011.

/s/ Vanessa A. Colón

Vanessa A. Colón
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
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ATTACHMENT I

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.	)	

SUPPLEMENTAL AFFIDAVIT OF JOSHUA A. BOLES

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") *Request for Leave to Submit Answer and Answer to Pleadings Opposing Exemptions and Answer to Motion to Lodge* to which this affidavit is appended.

3. I prepared two confidential affidavits in support of the NYISO's September 8, 2011 *Confidential Supplemental Answer*,[1] the "Confidential Affidavit Regarding Astoria Energy II" ("AEII"), and the "Confidential Affidavit Regarding Bayonne Energy Center"

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[1] *Confidential Supplemental Answer of the New York Independent System Operator, Inc.*, Appendix I Confidential Affidavit of Joshua A. Boles Regarding Astoria Energy II ("Boles AEII Affidavit") and Appendix II Confidential Affidavit of Joshua A. Boles Regarding Bayonne Energy Center ("Boles BEC Affidavit"), Docket No. EL11-50-000 (filed September 8, 2011) ("Confidential Supplemental Answer").

("BEC") (collectively, the "Confidential Affidavits"). In the Confidential Affidavits I provided a detailed description of the Unit Net CONE analyses and mitigation exemption tests that the NYISO performed for AEII and BEC. I identified the differences between the NYISO's assumptions and analyses and those in the two affidavits of Mark D. Younger filed by the Complainants at that time.[2] I also demonstrated that the Younger Affidavits' incorrect conclusions are attributable to his use of cost data, methodologies, and assumptions that differed from those actually used by the NYISO. With the support of the Affidavits of Christopher Ungate of Sargent & Lundy, LLC ("Sargent & Lundy"),[3] Eugene Meehan of NERA Economic Consulting ("NERA"),[4] and Dr. David Patton of Potomac Economics Ltd., the Market Monitoring Unit ("MMU") to the NYISO,[5] I demonstrated that the methodology and assumptions used by the NYISO conformed to the Pre-Amendment Rules and Federal Energy Regulatory Commission (the "Commission") orders.

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[2] *See Complaint Requesting Fast Track Processing, Emergency, Interim Relief and Shortened Comment Period*, Attachment A Affidavit of Mark D. Younger, Docket No. EL11-50-000 (filed July 11, 2011) ("Initial Younger Affidavit"); *Complainants Motion for Leave to Answer and Answer* ("Complainants Answer"), Attachment A Supplemental Affidavit of Mark D. Younger, Docket No. EL11-50-000 (filed August 19, 2011) ("Supplemental Younger Affidavit").

[3] Confidential Supplemental Answer at Appendix IV Affidavit of Christopher D. Ungate Regarding Bayonne Energy Center ("Ungate AEII Affidavit") and Appendix V Affidavit of Christopher D. Ungate Regarding Bayonne Energy Center ("Ungate BEC Affidavit")

[4] Confidential Supplemental Answer at Appendix VI Affidavit of Eugene T. Meehan ("Meehan Affidavit").

[5] Confidential Answer at Appendix III Affidavit of Dr. David P. Patton ("Initial Patton Affidavit").

4. Now that parties have had an opportunity to review all of the cost data, methodologies, and assumptions used by the NYISO in its analyses, the Pleadings Opposing Exemptions carefully select a handful of the numerous inputs into the NYISO's Unit Net CONE determination in an attempt to argue that the new entrants, with which they would compete, should be subject to an Offer Floor.

5. The Pleadings Opposing Exemptions identify a number of issues they believe would cause the NYISO's exemption determinations for AEII and BEC to have been different. In addition to demonstrating that the NYISO's methodology, analyses, and inputs were reasonable and resulted in an appropriate determination of AEII's and BEC's "reasonably anticipated Unit Net CONE,"[6] I demonstrate that the Pleadings Opposing Exemptions carefully select assumptions that would militate towards mitigation. They ignore the alternative assumptions that would have resulted in a lower Unit Net CONE for each of AEII and BEC, or a higher forecast for use in the Part B Test, which would demonstrate a greater degree of eligibility for an Offer Floor exemption.

6. In this affidavit, with the support of the Supplemental Ungate, Meehan/Falk and Supplemental Patton Affidavits, I address the specific issues raised by the Pleadings Opposing Exemptions and demonstrate that the NYISO's application of the Pre-Amendment Rules was in fact reasonable and in conformance with the Services Tariff.

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[6] See Pre-Amendment Rules at §23.4.5.7.2.

II. Unit Net CONE and ICAP Forecast Inputs

A. Supply Additions

7. An example of the bias of the Pleadings Opposing Exemptions is that they do not even acknowledge the possibility of alternative reasonable assumptions regarding the supply additions selected which would have resulted in an even higher forecast against which to compare the Unit Net CONE.

8. I described in my Confidential Affidavits the methodical approach used by the NYISO to identify the capacity resource additions to assume in its ICAP forecasts. Under this methodology, the NYISO included proposed generator additions and proposed controllable transmission facilities, except those that were not reasonably anticipated to be online during the three-year period following the entry of the project being examined. Alternative reasonable assumptions regarding the supply additions which the Complainants selectively do not identify, are described in this section.

(i) AEII ICAP Forecast

9. In the AEII ICAP forecasts, that methodology resulted in the NYISO including four proposed projects (in addition to AEII) and excluding two others, as shown in Exhibit JAB AEII-1 of the Boles AEII Affidavit. Of the four projects that the NYISO included, none of the Pleadings Opposing Exemptions presented arguments for including three of the four: NYC Energy LLC, Fortistar VP, and Fortistar VAN, totaling 239.7 MW ICAP in both the summer and winter. The only one of the Pleadings Opposing Exemptions to

include the fourth project included by the NYISO, the Linden VFT, was the Complainants.[7]

10. The two Fortistar projects were not in the 2010 Gold Book at the time the NYISO performed its analysis for AEII and made its determination. In addition, both of these proposed projects were simple cycle combustion turbines which would not have been expected to have a lower Unit Net CONE than AEII. Therefore, it would have been reasonable for AEII to have expected that these projects would not enter the market or that if they did enter, they would be subject to an Offer Floor in the capacity market.

11. The NYC Energy LLC project was removed from the Interconnection Queue on September 20, 2010. This project was a Class Year 2002 project that was inactive in the Interconnection Queue for a very long time. Therefore, it would have been reasonable for AEII to have expected that this project would not enter the market or that if it did enter the market, it would be subject to an Offer Floor in the capacity market.

12. The affidavit of Dr. Patton provides rationales that support excluding these three projects from the assumed supply additions. First, AEII's entry would reduce net energy revenues and capacity revenues for other capacity suppliers, which would make entry less enticing to the developers of these projects.[8] Second, if the projects entered despite the effect of

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[7] *Complainant's Answer to Supplemental Answer of the New York Independent System Operator, Inc.*, ("Complainants Answer") at Attachment A Second Supplemental Affidavit of Mark D. Younger at P 79, n. 47, Docket No. EL11-50-000 (filed September 23, 2011) ("Younger Affidavit"). The NYISO disposed of Mr. Younger's suggestion in his earlier affidavit that HTP should be included in the AEII ICAP forecast. Boles AEII Affidavit at PP 40, 60, Boles BEC Affidavit at PP 39, 58. No other party has raised that suggestion in the Pleadings Opposing Exemptions.

[8] Supplemental Patton Affidavit at n. 30.

AEII's capacity on the market, AEII could expect these entrants to be mitigated. Dr. Patton concludes that at the time AEII made its investment decision, its expectations for the market conditions in New York City at the time of its entrance would not have included these three projects.[9]

13. Excluding these three projects from AEII's ICAP forecast would increase the ICAP forecast used in the Part B Test by $26.71/kW-year, from $78.06/kW-year determined by the NYISO, to $104.77/kW-year. If this change were made, then AEII would have passed the Part B test by $ [redacted] /kW-year, rather than $ [redacted] /kW-year as determined by the NYISO. AEII's Unit Net CONE of $ [redacted] /kW-year would have been $ [redacted] /kW-year [redacted] than the ICAP forecast of $104.77/kW-year. If the 345 kV adjustment was made, AEII's Unit Net CONE of $ [redacted] /kW-year would have been $ [redacted] /kW-year lower than the ICAP forecast.

14. The affidavit of Mr. Pfeifenberger ("Pfeifenberger Affidavit")[10] questions the NYISO's exclusion of the TransGas Energy project and the CPN 3rd Turbine, Inc. JFK project from the AEII ICAP forecast.[11] Mr. Pfeifenberger questions the NYISO's judgment, yet does not pose any specific arguments or proffer a rationale as to why these two projects should be included in the ICAP forecast. He also does not refute or even comment on the

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[9] *Id.*

[10] *Comments of the NRG Companies Opposing the New York Independent System Operator's Decision to Exempt Uneconomic Entry from Buyer Side Market Mitigation*, Attachment A Affidavit of Johannes P. Pfeifenberger, Docket No. EL11-50-000 (filed September 23, 2011) ("Pfeifenberger Affidavit").

[11] Pfeifenberger Affidavit at P 23.

evidence I provided that demonstrates that the projects were properly excluded.[12] Mr. Pfeifenberger merely aggregates the MW of potential capacity additions and then claims that there is some non-zero probability of the projects coming online, and therefore some non-zero MW value should be assumed.[13] His position is not tenable.

15. In addition to the evidence cited above, TransGas Energy project and the CPN 3rd Turbine, Inc. JFK project would not have been reasonably anticipated to come online after the entry of AEII. The reduced net energy revenues and capacity revenues, and correspondingly higher likelihood of being mitigated, would discourage their entry.

(ii) BEC ICAP Forecast

16. NRG argues that the Hudson Transmission Project ("HTP") should have been included in the BEC forecast because HTP's Class Year, 2008, was closed and then leaps to the conclusion that HTP was committed to move forward.[14] The closing of the Class Year is a NYISO action pursuant to the OATT. HTP did not commit to incur significant costs in the Class Year process.[15] There was significant uncertainty as to the future prospects of the HTP project at the time of the BEC analysis. For example, on May 19, 2010, HTP

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[12] Boles AEII Affidavit at P 60.

[13] It is important to note that all of Mr. Pfeifenberger's calculations of price impact for AEII and BEC were calculated incorrectly. He has used an incorrect slope for the NYC Demand Curve, expressing the slope in terms of dollars per kilowatt-year instead of dollars per kilowatt-month. *See* Pfeifenberger Affidavit at PP 23, 33, n. 4, 5, 12.

[14] NRG Comments at 4, n.7.

[15] HTP's commitment in the Class Year project was $ 17,621,880. *See* <http://www.nyiso.com/public/webdocs/services/planning/notices_to_market_participants/Class_2008_Notice_of_Security_Posting_Default_Round_3_Cost_Allocation_01_20_2010.pdf >

filed a waiver with FERC, seeking to extend by more than 6 months PJM Interconnection's tariff deadline for posting a $172 million deferred security payment. The Commission granted the waiver and extended HTP's deadline for posting the security payment to October 31, 2010.[16] Had the deadline not been extended, PJM would have removed HTP from its interconnection queue.

(iii) AEII and BEC Forecast: Linden VFT

17. Consistent with the NYISO's methodology for identifying generation to include in the ICAP forecast, the NYISO included MW of ICAP for the Linden VFT controllable line. In its analysis of AEII, the NYISO attributed [redacted] MW of ICAP for the Linden VFT. The [redacted] MW ICAP value used in the AEII analysis is [redacted] UDR value of [redacted] MW of UCAP; [redacted] MW of UCAP was consistent with data sources available at the time of the analysis. In its analysis of BEC, the NYISO attributed [redacted] MW of ICAP for the Linden VFT based on data available at that time.

18. The NYISO did not adjust the Linden VFT ICAP MW to account for periods in which the PJM Capacity Market Clearing Price would have been forecast to be higher than the NYC ICAP Market Clearing Price. In those scenarios, it would decrease the likelihood that the entire amount of Linden VFT capacity would have sold into the In-City capacity market. An alternative assumption would be to include the portion of the Linden VFT ICAP MW for which the In-City capacity market is reasonably forecast to fall below the

[16] *Hudson Transmission Partners, LLC*, 131 FERC ¶ 61,157 (2010).

PJM forward capacity market over the annual period. An example of the application of this second assumption for the period being examined in the BEC analysis results in the majority of capacity imports over the Linden VFT not being sold into the In-City Capacity Market. The effect on the ICAP forecast used in the BEC determination would thus have been to exclude all of Linden VFT MW from BEC's ICAP forecasts, which would increase the ICAP clearing price by $23.17/kW-year, from $35.67/kW-year to $58.84/kW-year. In the case of AEII or BEC, applying either adjustment methodology would have demonstrated to an even greater amount that AEII and BEC are exempt from the Offer Floor.

B. Supply Reductions

19. The NYISO did not reduce the level of existing capacity when it prepared the forecast, even though new economic entry can be expected to result in units that exit the market. The removal of capacity, *e.g.*, through a mothball or retirement, would contribute to higher forecasted ICAP prices and a lower excess level being used in the net energy revenue forecast. Thus, a new economic entrant may have forecast a reduction in the level of excess shortly after entry.

C. Load Forecasts

20. Mr. Younger criticizes the NYISO's use of the load forecast from the NYISO's 2008 Load and Capacity Data ("Gold Book") as being outdated, and misleadingly cites to the NYISO's presentations to stakeholders in an attempt to support his erroneous argument.[17]

21. The NYISO used the 2008 Gold Book for the AEII load forecast because the Gold Book is a reliable, definitive source of information that the NYISO updates annually and publishes publicly. The load forecasts in each Gold Book are reviewed and approved by the Vice President of System and Resource Planning, vetted in the Load Forecasting Task Force, and reviewed with the ICAP Working Group, Business Issues Committee, and the Management Committee before publication. Therefore, using the load forecast in the Gold Book is reasonable and results in a reasonably anticipated Unit Net CONE.

22. Mr. Younger referenced three presentations before NYISO stakeholder groups – two by NYISO staff and one by Consolidated Edison Company of New York, Inc.[18] The presentations Mr. Younger attempts to rely to load forecasts broadly and, more specifically, the impacts of energy conservation initiatives. The presentations could not be used to establish a reasonable NYC load forecast. Moreover, the presentations were never intended to establish or propose a forecast. Thus, that data does not alter the fact that the NYISO's use of the Gold Book forecast was reasonable.

23. The Complainants, through the Younger affidavits, cite these general presentations to suggest that a lower load forecast should have been used. Mr. Younger argues that using

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[17] Second Supplemental Younger Affidavit at PP 75-77.

[18] *Id.*at P 76.

the lower load forecast would result in a higher Unit Net CONE and a lower ICAP price forecast in the Part B Test. However, the data do not constitute a load forecast and, thus, it would not have been reasonable to use it in the Unit Net CONE determinations. Further, the data do not provide evidence in the case in relation to a reasonably anticipated Unit Net CONE determination; instead, the Complainant's use of the information provides evidence that Complainants have carefully selected data to achieve the outcome they are seeking.

D. Estimated Net Energy Revenues

24. As explained in my Confidential Affidavits, the NYISO used the NERA model to estimate the net energy revenues. That methodology was a reasonable manner in which to estimate net energy revenues. The NYISO did not make an adjustment for the fact that the AEII and BEC facilities are being interconnected to the 345 kV system. Mr. Younger attempts to rely on the phrase in the Pre-Amendment Rules that states "likely projected annual Energy and Ancillary Services revenues" language to say that not making such an adjustment is a violation of that language.[19] Mr. Younger also interprets my Confidential Affidavits in this proceeding as conceding to making an error.[20] His assertions are wrong.

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[19] *Id.* at P 21; *Answer of Independent Power Producers of New York, Inc. to NYISO Supplemental Information Describing Buyer Side Mitigation Exemption Determinations* at 9-11, Docket No. EL11-50-000 (filed September 23, 2011) ("IPPNY Answer").

[20] Boles AEII Affidavit at PP 42-44; Boles BEC Affidavit at PP 40-42.

25. The NYISO's calculation of net energy revenues was reasonable and resulted in a reasonably anticipated Unit Net CONE for each of AEII and BEC. The NERA model used for the calculations was the same NERA model used in the 2010 Demand Curve reset, with adjustments for gas futures, a specified level of excess for each unit, and unit-specific operating characteristics, as described by Mr. Meehan in his initial affidavit[21] and as further described in the Meehan/Falk Affidavit.[22] Although it may also have been reasonable to use an alternate method to establish the "likely projected annual Energy and Ancillary Services revenues," that does not alter the fact that it was reasonable for the NYISO to use the NERA model, and that the NERA model estimated likely projected annual energy revenues.

26. As Mr. Meehan and Mr. Falk describe, the NERA model was well vetted with stakeholders and was developed for a similar purpose as the Unit Net CONE determinations under the Pre-Amendment Rules.[23] The modifications made to the model to determine the AEII and BEC net energy revenues were enhancements. Mr. Meehan and Mr. Falk describe in detail the NERA model, the manner in which it was utilized, and the estimated revenues it produced.

27. Mr. Younger argues that it is improper to use the NERA model with the gas pricing adjustment because it was not an approved use of the NERA model.[24] That

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[21] Meehan Affidavit at PP 18, 15, 23.

[22] Joint Meehan/Falk Affidavit at PP 5-18.

[23] *Id.* at P 18.

[24] Second Supplemental Younger Affidavit at P 43.

characterization is misplaced. I described in my AEII and BEC Affidavits[25] that the net revenues were derived using the NERA model used to estimate net energy revenues in the Demand Curve reset, with certain adjustments as discussed in the Meehan Affidavit. In the Demand Curve reset, the Commission accepted the forecasted net energy revenues developed using the NERA model. NERA revised the gas pricing input in its net energy model in order to provide a more accurate determination of anticipated net energy revenues. NERA vetted the use of the model and each of the adjustments to the model with the NYISO. The NYISO agreed with NERA's recommendation that the use of the NERA model with the adjustments was appropriate to determine the likely net energy revenues to use to determine the reasonably anticipated Unit Net CONE values for AEII and BEC. As described in the Meehan/Falk Affidavit, the results were both predictable and reliable.

28. I identified in my initial AEII and BEC Affidavits that an adjustment to reflect the 345 kV location was possible solely to respond to the Complainants and demonstrate that even if there were an adjustment for the specific location, it would not have altered the exemption determinations.

29. Mr. Younger attempts to overturn the exemption determinations by proposing three different alternatives for making such an adjustment. In his initial affidavit, Mr. Younger uses a methodology very similar to the one I discussed in my Confidential Affidavits. However, Mr. Younger attempts to argue that the energy revenues for AEII and BEC

[25] Boles AEII Affidavit at P 35; Boles BEC Affidavit at P 35.

should be reduced by 10 percent from the net energy revenues estimated by the NERA model.[26] In making his adjustment, Mr. Younger originally used the same $1.70/MWh all-hours price delta between the 345 kV location and the zonal LBMP as I did for purposes of my Confidential Affidavits. Also, in Mr. Younger's initial affidavit, he acknowledges that "[i]deally, the adjustment from the Zone J LBMPs to Poletti LBMPs would be done with a much more comprehensive process of adjusting the hourly LBMP in the NERA net energy model."[27] The NYISO does not disagree that there may be a reasonable alternative to the reasonable manner in which the NYISO determined the likely net energy revenues. However, there is no need to evaluate Mr. Younger's suggested alternatives because they do nothing to undermine the well-documented fact the use of the NERA model with the specific adjustments was reasonable and conformed to the Pre-Amendment Rules.

30. Tellingly, now that Mr. Younger sees the outcome of the adjustment he proposed in his initial affidavit, he proposes to change his methodology to only use the hours in which prices are greater than $50/MWh to make the adjustment.[28] As I have described in the Supply Additions section above, even with an adjustment AEII passes the Part B exemption test.

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[26] Second Supplemental Younger Affidavit at PP 67-68.

[27] Initial Younger Affidavit at n. 18.

[28] Second Supplemental Younger Affidavit at P 27.

E. Estimated Ancillary Services Revenues

31. The NYISO's estimate of Ancillary Services revenues used in its analysis of AEII was [redacted]/kW-year, which is $[redacted] kW-year [redacted] than the $7.00/kW-year estimate used by Mr. Younger in his initial affidavit.[29] If the NYISO used Mr. Younger's [redacted] Ancillary Services revenue estimate, it would [redacted] the dollar amount of Mr. Younger's most recent 345 kV adjustment proposed in his latest affidavit. Thus, contrary to Mr. Younger's assertion, using his Ancillary Services revenue estimate would not change the NYISO's determination that AEII is exempt.

32. The NYISO's estimate of Ancillary Services revenues used in its determination of BEC's Unit Net CONE was $[redacted]/kW-year, and is [redacted] to the number used by Mr. Younger in his initial affidavit.[30] However, this number only reflects historic revenue streams associated with supplying 30-minute non-synchronous reserves and voltage support service. The NYISO did not reflect the additional capabilities of the BEC unit – regulation revenues and 10-minute non-synchronous reserves – in its estimate of Ancillary Services revenues. The ability to supply these additional Ancillary Services would make the project more attractive to the dispatch systems. The resulting increase in revenues would serve as an offset to the $[redacted] kW-year 345 kV adjustment that Mr. Younger implies was an error.

33. Complainants also attempt to argue that by not making a comparison to the State of the Market Report for BEC that my AEII and BEC Affidavits somehow demonstrate that the

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[29] Initial Younger Affidavit at P 74.

[30] Initial Younger Affidavit at P 83.

NERA estimates of net energy revenues are not consistent with those of the MMU. It was wholly appropriate to not make that comparison. The State of the Market report does not provide an estimate for a unit with the characteristics of BEC. As fully described in the Meehan/Falk Affidavit, there are several reasons why a comparison of BEC to the LMS100 in the State of the Market report is flawed.[31]

III. Over-Mitigation

34. The Commission should reject Complainants' arguments based on Dr. Hieronymus' suggestion that the buyer-side mitigation examinations should favor over-mitigation.[32] First, his suggestions are wholly inconsistent with the Pre-Amendment Rules and Commission Orders.[33] Second, and of critical importance, his proposal is flawed.

35. Dr. Hieronymus ignores the consequences of over-mitigation and simply postulates that the consequences of under-mitigation are much worse than those of over-mitigation. He

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[31] Joint Meehan/Falk Affidavit at PP 32-34.

[32] Complainants Answer, Attachment B Affidavit of William Hieronymus at PP 13, 36-41 ("Hieronymus Affidavit").

[33] *See New York Independent System Operator, Inc.*, 122 FERC ¶ 61,211 at PP 113-115 (2008) (accepting the initial buyer side mitigation rules to mitigate uneconomic new entry); *see also, See, e.g. Midwest Independent Transmission System Operator, Inc.*, 122 FERC ¶ 61,172 at P 121 (2010) (accepting a proposal that "both protects consumers from market power, while also avoiding over-mitigation that can cause reliability problems to the extent that it keeps capacity out of the market over the longer term"); *Midwest Independent Transmission System Operator, Inc.*, 123 FERC ¶61,297 at P 63 (2008) (finding that the conduct threshold proposed "strikes an appropriate balance between the need to protect consumers from the exercise of market power and the goal of avoiding over-mitigation that may keep capacity out of the market"); *Southwest Power Pool, Inc.*, 117 FERC ¶61,110 at P 21 (2006) (affirming the prior order's interpretation of the mitigation proposal because "it strikes the appropriate balance between over-mitigation (mitigation of competitive market results) and under-mitigation (some exercise of market power that is not mitigated)"). Dr. Hieronymus' proposal is also inconsistent with the In-City Buyer-Side Mitigation Measures.

writes, "units that are in fact economic are not likely to be materially harmed if their offers are erroneously mitigated."[34]

36. If the NYISO rules provided for over-mitigation, an otherwise economic investment decision may be postponed or not undertaken because of the effects of over-mitigation, and prices would be artificially high. With artificially high prices, incumbent generators that might have otherwise retired upon the entry of new economic suppliers would remain in the market, and the over-mitigated new economic unit may not clear.

37. With the market design suggested by Dr. Hieronymus, a project may be subject to an Offer Floor despite making an economic entry decision. Thus, investors would be dissuaded from developing In-City capacity resources if the rules are changed as he proposes. Thus, over-mitigation would effectively create a barrier to new economic entry. It also would risk attracting needed capacity.

38. The Pre-Amendment Rules were designed for the balanced application of the mitigation exemption test. The Complainants' suggested unbalanced application of the Pre-Amendment Rules would be inconsistent with them. Were the NYISO to do as Dr. Hieronymus suggested in its buyer-side mitigation examination of AEII and BEC, the NYISO would have wrongly implemented its tariff. As Dr. Patton previously testified, the intent of these rules is to apply a balanced approach that "deter[s] uneconomic entry that would otherwise reduce capacity prices below competitive levels, while not erecting

[34] Hieronymus Affidavit at P11.

inefficient barriers to economic entry."[35] The NYISO's application of its rules in the AEII and BEC examinations carried out that intent.

IV. Capacity Clearing Prices

39. The Complaint, Complainants' Answer, and again in the Complainants' response to the Supplemental Confidential Answer, Complainants' Motions to Lodge filed on July 29, 2011 and August 31, 2011, Complainants assert that ICAP Spot Market Auction Clearing Prices are too low and leap to the conclusion that the NYISO's determination of AEII must be overturned. Their arguments are predicated upon a view of Summer 2011 market outcomes that ignores the history and robustness of the NYC Installed Capacity market. In this section, I describe recent developments in the NYC ICAP market that have resulted in ICAP Spot Market Auction Clearing Prices that depict a reality that is different than the dire one the Complainants insisted would occur absent their desired outcome. The discussion in this section and table in Exhibit JAB Supplemental cover the Summer 2011 Capability Period, which coincides with the timeframe that formed the basis for Complainants' request for urgent relief. Explanations for and price impacts of such changes are discussed generally.

40. The increase in the NYC ICAP Spot Market Auction Clearing Price for October 2011 from the July, August, and September 2011 Clearing Prices provides evidence of and support for the information and findings in the Supply Additions and Supply Reductions sections above. In accordance with the Commission's September 15, 2011 Order on

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[35] Supplemental Patton Affidavit at P 4.

ICAP Demand Curves,[36] the NYISO implemented revised demand curves for the October 2011 ICAP Spot Market Auction. Absent the change in the Demand Curves, i.e., had the NYC Demand Curve in effect for the September Spot Market been in effect in October, the Spot Market Clearing Price would have been $7.50/kW-month. Notwithstanding changes to the Demand Curve reference point, price variation within a Capability Period is caused by changes in the number of MW of capacity available and the price at which that capacity is offered (or not offered) in the ICAP Spot Market Auction.

41. The MW of capacity available can be impacted by a limited set of factors. For the NYC Locality, the chief factors are units that mothball, retire, or take inactive status; Installed Capacity Suppliers that previously offered capacity that do not offer it; and changes in SCR registration.[37] The table in Exhibit JAB Supplemental shows the monthly changes in factors between all of the Summer 2011 NYC Spot Market Auctions and their effects on prices.

42. The price at which capacity can be offered is subject to rules set forth in Services Tariff Attachment H. An ICAP Supplier that is a Pivotal Supplier can offer capacity in the Spot Market at a price that impacts the Clearing Price if it requests a Going Forward Cost reference price.[38] In general, a generator's Going Forward Cost is comprised of the costs

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[36] *See New York Independent System Operator, Inc.*, 136 FERC ¶ 61,192 (2011).

[37] The NYISO rules provide for Units to offer UCAP, which applies an EFORd so that a unit's outage is introduced in the market over a period of months, rather than having a sudden impact in one month.

[38] Absent receiving a Going Forward Cost determination, a Pivotal Supplier must offer UCAP at or below the UCAP Offer Reference Level, which is the price point on the demand curve that corresponds with all available UCAP.

the generator could avoid if a unit were to mothball or retire, net of energy and ancillary services revenues.[39]

43. The October ICAP Spot Market Auction Clearing Price was $3.30/kW-month higher than the preceding September ICAP Spot Market Auction Clearing Price. The clearing prices were $9.01/kW-month and $5.71/kW-month, respectively. As depicted in row A of the October 2011 columns of Exhibit JAB Supplemental, $1.51/kW-month of the increase can be attributed to the implementation of the newly-approved NYC Demand Curve. The remaining $1.79/kW-month is explained by a 169.3 MW reduction in available UCAP from September to October.[40] As depicted in Exhibit JAB Supplemental, the 169.3 MW reduction is equal to the sum of the 19.7 MW generator MW decrease, the 15.7 MW SCR decrease, the 149.0 MW unsold MW increase, less the 15.1 MW unoffered decrease.

44. In October, there was 47.5 MW of UCAP that was not offered, which increased the price by $0.61/kW-month.[41] Units that retire, mothball, or are on Inactive Reserve are not qualified to participate in the NYISO Installed Capacity Market.[42] The reduction due to a change of generators' active state to one of the three states resulted in a reduction of 26.7 MW of UCAP, which increased the price by $0.34/kW-month. This change is reflected

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[39] Costs can only be included in a Going Forward Cost determination if the ICAP Supplier "actually plans to mothball or retire it if the Installed Capacity revenues it receives are not sufficient to cover those costs." See Services Tariff Attachment H Section 23.4.5.3.

[40] Exhibit JAB Supplemental shows $1.80/kW-month as the price impact due to changes in UCAP sales in row Q, rather than $1.79/kW-month as provided in the text. The price difference of $0.01/kW-month in this instance and others is attributable to approximating the impact by multiplying the demand curve slope times MW rather than simulating the auction.

[41] In the September Spot Market Auction 62.6 MW was not offered.

[42] *See* Installed Capacity Manual §4.4.12.

in the 19.7 MW reduction of generator MW from September to October, shown in Exhibit JAB Supplemental. The 26.7 MW reduction was partially offset by a 7.0 MW generator increase.

45. The fluctuations in the NYC ICAP Spot Market Auction Clearing Prices concurrent from May 2011 through October 2011 are entirely consistent with past Commission Orders on the NYISO's ICAP Demand Curves related to the lumpiness of capacity additions after the entry of new capacity. As Dr. Patton has previously recognized, investments are lumpy and the addition of a large new entrant would be expected to result in a temporary capacity surplus.[43] This surplus tends to cause a short term decline in capacity prices until such time that it is either consumed by load growth or other suppliers are removed from service. The latter would occur when the capacity market revenues were not sufficient to allow a generator to recover its Going Forward Costs.

46. Thus, contrary to the Complainants' conclusion, the recent NYC ICAP Spot Market Auctions are not indicative of an improper mitigation exemption determination of AEII, and are operating as intended.

V. NRG's Interpretation of Section 23.4.5.7.2 of the Pre-Amendment Rules

47. Finally, Section III.A of the Answer to which this affidavit is attached states that NRG sent me a letter in October 2010 that made a number of statements articulating NRG's interpretation of Section 23.4.5.7.2 of the Pre-Amendment Rules. The letter was signed

[43] *See Compliance Filing and Request for Flexible Implementation Dates*, Attachment VII Affidavit of Dr. David B. Patton at P 20, Docket No. ER11-2224-003 (filed March 29, 2011).

by NRG's Director for Regulatory Affairs. The list of persons the sender copied included two NRG attorneys who appear on the signature page of the NRG Comments. I hereby confirm that I received the letter and that the Answer accurately quotes NRG. I read NRG's statements to mean that it shares the NYISO's view that final exemption determinations could be made under the Pre-Amendment Rules before the close of a project's Class Year. I further confirm that the letter contains other information that is confidential to NRG. In my opinion, NRG's confidential information is not pertinent to this proceeding at this time.

This concludes my affidavit.

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 Supplemental
Capacity Prices and Inputs

		May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Oct-11 *Prior Curve* (Note 1)	Calculations
	Spot Market Clearing Price Summary								
A	NYC Spot Market Clearing Price	$11.97	$11.76	$5.76	$5.83	$5.71	$9.01	$7.50	
B	Month to month change	-	($0.21)	($6.00)	$0.07	($0.12)	$3.30	$1.79	
C	Percent excess cleared	5.24%	5.46%	11.85%	11.78%	11.91%	10.00%	10.00%	
D	Demand Curve Slope ($/kW-mo per MW)	(0.010618)	(0.010618)	(0.010618)	(0.010618)	(0.010618)	(0.012744)	(0.010618)	
	Supply Summary								
E	Generator	8,658.6	8,658.7	9,192.3	9,192.3	9,200.7	9,181.0	9,181.0	
F	UDR	291.6	292.0	292.0	292.0	292.0	292.0	292.0	
G	SCR	370.8	386.6	420.3	423.8	454.2	438.5	438.5	
H	Total UCAP available	9,321.0	9,337.3	9,904.6	9,908.1	9,946.9	9,911.5	9,911.5	= E + F + G
	Unoffered and Unsold Capacity Summary								
I	Unoffered	26.6	23.0	25.4	35.3	62.6	47.5	47.5	
J	Unsold (offered but not sold)	0.0	0.0	0.3	0.0	0.0	149.0	149.0	
K	Total UCAP not sold	26.6	23.0	25.7	35.3	62.6	196.5	196.5	= I + J
L	Price impact of unoffered and unsold	$0.28	$0.24	$0.27	$0.37	$0.66	$2.50	$2.09	= K * D * (-1)
M	UCAP Offer Reference Level	$11.69	$11.51	$5.49	$5.45	$5.04	$6.50	$5.42	
N	Difference from Spot Market Price	$0.28	$0.25	$0.27	$0.38	$0.67	$2.51	$2.08	= A - M. (Note 2)
O	Total UCAP sold	9,294.4	9,314.3	9,878.9	9,872.8	9,884.3	9,715.0	9,715.0	= H - K
P	Month to month change	-	19.9	564.6	(6.1)	11.5	(169.3)	(169.3)	
Q	Price impact of changes in UCAP sales	-	($0.21)	($5.99)	$0.06	($0.12)	$2.16	$1.80	= P * D. (Note 3)

Notes

1. *Prior Curve* column shows expected values if the demand curve in effect prior to 9/15/11 was used. For illustrative purposes only.
2. The values in row N are approximately equal to those in row L. $0.01/kW-month differences are attributable to multiplying the demand curve slope times MW rather than simulating the auction.
3. The values in row Q are approximately equal to those in row B for the same reason provided in Note 2.

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

ATTESTATION

I am the witness identified in the foregoing Supplemental Affidavit of Joshua A. Boles. 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.
October 11, 2011

Subscribed and sworn to before me
this 11th day of October 2011.

DIANE L. EGAN
Notary Public, State of New York
Qualified in Schenectady County
Commission Expires March 21, 2013

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

ATTACHMENT 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.	)	

SUPPLEMENTAL AFFIDAVIT OF

DAVID B. PATTON, PH.D.

October 11, 2011

I. Background and Purpose of Affidavit

1. My name is David B. Patton. I am an economist and the 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. Potomac Economics serves as the Market Monitoring Unit ("MMU") for the New York ISO ("NYISO").

2. I filed an affidavit previously in this case to describe the advice I have given to the NYISO related to three aspects of the Mitigation Exemption Test ("MET") evaluations for the Astoria Energy II ("AEII") project and the Bayonne Energy Center ("BEC" or "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.

3. The purpose of this affidavit is to respond to arguments against these recommendations by the "Complainants," the NRG Companies ("NRG"), and Brookfield Energy Marketing, in what the NYISO refers to as the "Pleadings Opposing Exemptions."

II. Context Regarding the MET Evaluations

4. In working through the myriad of specific assumptions employed by the NYISO in the MET evaluations that the complainants challenge, it is critical not to lose sight of the ultimate objective of the NYISO's buyer-side mitigation ("BSM") rules.[1] BSM exists to deter uneconomic entry that would otherwise reduce capacity prices below competitive levels, while not erecting inefficient barriers to economic entry.

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

5. I have been and continue to be one of the principal proponents of BSM measures in the NYISO's market and in other organized markets. The current BSM provisions are largely based on the initial proposal I made in 2007 to address uneconomic entry.[2] I have consistently advocated these measures and filed comments with the Commission more than once suggesting changes to the existing measures or opposing changes to the measures proposed by the NYISO that I felt would weaken the effectiveness of the BSM measures.[3] Hence, it would be at odds with my prior positions and the principles I have advocated if I were to support MET evaluations that are conducted in an unreasonable manner to exempt new resources that should be mitigated, or otherwise weaken the BSM measures. In other words, I am a strong advocate of establishing and implementing rules that effectively mitigate uneconomic entry, which is the exact opposite of what the complainants allege.

6. Before addressing some of the specific elements of the MET evaluations that have been criticized by the complainants, it is important to consider these elements in the context of the overall MET evaluation. The complainants have carefully reviewed the materials provided by the NYISO and selectively challenged specific assumptions that could appear to justify a reversal of the MET evaluation. This is particularly troubling in the case of Bayonne, a resource being built by private investors with no known regulatory subsidies or a market share as a buyer large enough to provide an incentive to enter the market uneconomically in order to lower prices.[4, 5]

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2 *See Compliance filing of New York Independent System Operator, Inc. Regarding the New York City ICAP Market Structure*, Attachment 1, Affidavit of David P. Patton filed in Docket No. EL07-39-000 (October 4, 2007).

3 *See Answer of the New York ISO's Market Monitoring Unit*, Docket No. EL11-42.

4 We are only aware of two reasons why a developer would enter a market uneconomically to lower capacity prices: 1) it is receiving a direct or indirect subsidy from a public or private entity that benefits from the lower prices; or 2) its market share as a buyer is large enough that it would have the incentive to inefficiently lower prices (i.e., the short-term suppression in prices would reduce its capacity costs sufficiently to justify the cost of the uneconomic entry).

5 Hess Corporation ("Hess"), one of the equity partners in the Bayonne project, [redacted]

7. I believe that both the AEII and Bayonne evaluations were conducted objectively and reasonably. Reversing these determinations and mitigating an entrant unjustifiably after they have entered would be particularly harmful to the market in the longer term.

8. In the case of AEII, the Unit Net Cone calculated by the NYISO (with the locational adjustment for the 345-kV location) was [redacted] than the forecasted capacity revenues by a [redacted] ($[redacted] kW-year), inviting suggestions that [redacted] change in one of many assumptions would have changed the outcome. However, any such reassessment would need to also consider whether the NYISO made any conservative assumptions that may have biased the MET evaluation toward failing the new resources (*i.e.*, increased the Unit Net Cone and/or decreased the forecasted capacity revenues).

9. Based on our review and consultation with the NYISO in the course of performing the MET evaluations, we are aware of a number of overly conservative assumptions that would tend to move the MET evaluation results toward failing AEII and Bayonne. Mr. Boles' affidavits describe several such assumptions by the NYISO that had the effect of decreasing the Unit Net Cone or increasing the forecasted capacity revenues.[6]

10. The most significant such assumption for AEII was the NYISO's assumption that three projects totaling 240 MW of merchant peaking capacity would enter the market following AEII and operate without being mitigated in the first three years of operation of AEII.[7] This assumption lowered the forecasted capacity revenues, which caused AEII to appear

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[redacted]

6 *See* Boles Astoria II Affidavit and Boles Bayonne Affidavit, dated September 8, 2011, in this docket.

7 Three simple-cycle natural gas combustion turbines of approximately 80 MW: NYC Energy LLC (Interconnection Queue position 19), and Fortistar VP and Fortistar VAN (Interconnection Queue positions 90 and 91).

much less economic in the MET. I believe that this assumption was overly conservative for at least two reasons.

11. First, one would reasonably assume that the peaking resources' Unit Net CONEs are significantly higher than AEII's based on recent information showing that the Unit Net CONE for natural gas combustion turbines are significantly higher than the Unit Net CONE for a natural gas combined cycle unit. Given their higher Unit Net CONE and the fact that AEII would be entering first, one would not reasonably expect the merchant peaking projects to enter the market. Even if they did enter, one would reasonably expect them to be mitigated based on a higher Unit Net CONE than AEII's so that the entry of these projects cannot cause the forecasted capacity price to fall below AEII's Unit Net CONE. Nonetheless, the NYISO chose to include these projects in the MET evaluation.

12. Second, assuming that 240 MW of peaking resources enter the market after AEII would lower the forecasted capacity revenues by almost $[redacted] kW-year. Therefore, the difference between the forecasted capacity revenues and AEII's Unit Net Cone is reduced by approximately $[redacted] kW-year in the NYISO MET evaluation of AEII. In other words, AEII would have passed the MET evaluation by [redacted] kW-year ([redacted] kW-year) had the NYISO employed a less conservative assumption regarding the subsequent entry of these two projects.

13. The most significant conservative assumption for Bayonne was the assumption that the Linden VFT project would sell the full amount of capacity over the evaluation period. The Linden VFT Scheduled Line can import [redacted] MW of capacity from PJM's PS-North Locational Deliverability Area. However, PJM's Reliability Pricing Model prices at that location over the three planning periods from June 2012 to May 2015 were $68, $89, and $82 per kW-year. Hence, it seems extremely unlikely that the Linden VFT would have been used to import its full capability of [redacted] MW. A reduction in sales from Linden VFT of just 100 MW in one year would have increased the estimated Installed Capacity price by

more than $8 per kW-year. Nonetheless, the application of this conservative assumption was not significant enough to cause Bayonne to appear to be uneconomic and reverse the conclusion of the MET evaluation.

14. It is unreasonable to selectively reconsider only those assumptions that may move the MET evaluation results toward failure. The BSM rules require the NYISO to perform an assessment that involves a large number of assumptions and projections related to future outcomes in a short period of time as prescribed by the Tariff. I remain confident that the MET determinations made by the NYISO were reasonable and consistent with the Pre-Amendment BSM rules.[8]

15. Furthermore, subjecting the mitigation exemptions granted to AEII and Bayonne to reevaluation and potential reversal would have adverse consequences. The limited scope of the New York City capacity market causes each new investment to have a significant effect on near-term capacity prices. Hence, market participants on both the demand side and supply side have a strong incentive to litigate any exemption determination that would adversely affect their costs or revenues. Such litigation would not only consume the NYISO's and the Commission's resources, it also would raise the costs and uncertainty for the potential new entrant that would likely be compelled to defend the cost estimates it provided to the NYISO. Additionally, they would be at risk that their MET evaluation could be reversed for reasons totally beyond their control. Entrants would include those expected additional costs in their determination of whether to invest, thereby increasing the cost of new entry.

16. Witness Hieronymus supports the use of conservative assumptions that would tend to err on the side of over-mitigation.[9] In particular, he responds to an assertion in my prior

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[8] This opinion assumes that the Commission agrees with the NYISO that the net revenues estimated by NERA are likely projected energy revenues, which I did not have an opportunity to review in detail.

[9] Hieronymus Affidavit at PP 36-41.

affidavit that the NYISO's MET evaluation balance the risks of over- and under-mitigation by arguing that the costs of over-mitigation are far less than the costs of under-mitigation. However, his argument is plagued by a number of logical errors. First, he argues that "failure to grant exemption to an economic unit will typically be negligible and benign", primarily based on an assumption that subjecting an economic unit to an offer floor will only affect the developer when the market price is below the offer floor.[10] This argument is based on an implicit assumption that the economic unit was actually built. Dr. Hieronymus fails to recognize that failing to grant the exemption (*i.e.*, imposing an offer floor on an economic unit) will impose additional risk on the developer that could cause it to not proceed with the investment. In the long-term, over mitigation would slow the entry of economic resources, leading to lower average capacity margins and higher prices. Conversely, under-mitigation would likely lead to periods of higher capacity margins and lower prices. These periods are not likely to persist for nearly as long as the complainants have suggested in past pleadings because the lower prices lead to accelerated retirements (or mothballing) of older, high-cost generating resources. The sharp recovery in the October 2011 capacity prices for New York City is evidence of this type of natural market reaction to periods of low prices. Therefore, I believe it would be absurd for the NYISO to intentionally bias its MET evaluations toward over-mitigation as Dr. Hieronymus proposes.

III. Timing of the Investment Decision

17. In order to conduct the MET evaluation, the NYISO must determine when an entrant actually makes the decision to enter. Under the currently effective BSM rules,[11] this is accomplished by performing the MET evaluations in the same timeframe as the transmission interconnection analysis before the supplier has entered. However, the MET evaluations in this case were conducted under the Pre-Amendment Rules and after the

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10 *Id.* at P 37.

11 The NYISO refers to the currently effective rules as the In-City Buyer-Side Mitigation Measures; *i.e.* those rules accepted by the Commission in a series of Orders in Docket No. ER10-3043.

projects were underway, which was consistent with the Pre-Amendment Rules.[12] Therefore, the NYISO had to establish an initial decision point corresponding to when the developers made the decision to proceed with the investment so that it could appropriately utilize the market information from that timeframe to evaluate whether the developer was knowingly entering uneconomically.

18. In my previous affidavit, I explained that it was appropriate for the NYISO to use July 2008 as the initial decision point when performing the price projections for AEII's MET because:

- AEII committed contractually to the project by entering into the PPA with NYPA at that time; and
- AEII began to make significant financial commitments to the project that would not be sensible unless it had already decided to move forward.

19. Mr. Younger disagrees, asserting that the facts do not support the use of July 2008 because the financing and a substantial number of permits were not obtained until much later.[13] Although it is true that several project milestones and the majority of the project expenses occurred after July 2008, I will explain further why it was appropriate to use July 2008 as the initial decision point for the purpose of performing price projections for AEII's MET evaluation.

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12 I have also reviewed Complainants' and NRG's argument that the Pre-Amendment Rules did not allow the NYISO to issue an exemption determination before the conclusion of a new project's Class Year. This was never my understanding of the Pre-Amendment Rules and I do not believe that it is a reasonable interpretation. Among other things, that interpretation would have the potential to unnecessarily subject economic entrants to mitigation for extended periods of time solely based on the timing of the NYISO stakeholder Operating Committee decisions and the interconnection process that are beyond an entrant's control.

13 Younger Affidavit at PP 65-77.

20. The Pre-Amendment Rules specified the point in time when a developer might request a MET evaluation, but did not specify how price projections were to be developed when the decision to move forward had been made well in advance of the request. These rules were subsequently amended in part to clarify how the MET evaluations would be performed and how their timing would be coordinated with the interconnection process. However, given the rules that were in place at the time AEII requested a MET evaluation, the NYISO made the reasonable decision to perform its price projections based on market information that would have been known at the time when the developer began to make significant financial commitments toward the project.

21. July 2008 was a reasonable choice and, in my opinion, the most reasonable choice for the initial decision point because that is when AEII signed a contract with NYPA, ordered major pieces of equipment such as turbines and heat-recovery steam generators, and began to incur significant engineering expenses. If AEII had subsequently abandoned the project, it would have been liable for liquidated damages. Hence, AEII's financial losses would have been significant if it had abandoned the project, and it would be difficult to conclude that its intention to enter was not well established when it signed the PPA in July 2008.

22. The rest of this section responds to several other specific objections raised by the Pleadings Opposing Exemptions. First, Mr. Younger has argued that AEII could not have decided to invest before it knew its financing terms, which were not finalized until July 2009.[14] However, it would be unreasonable to assume that AEII could not anticipate with reasonable accuracy in July 2008 the financing terms it would ultimately secure. As some Pleadings Opposing Exemptions have indicated, AEII's contract with a credit-worthy buyer (NYPA) was key in allowing it to obtain financing at a lower cost than used in the Demand Curve for the default demand curve unit. There is no evidence that the financing terms were the subject of substantial uncertainty, but AEII would have to have formed an

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[14] Younger Affidavit at P 69.

expectation regarding its financing terms. We believe that the financing terms they were actually able to secure are consistent with the terms that AEII would have expected. Yields on industrial bonds at the time AEII secured its financing were comparable to those prevailing in July 2008.[15] In the context of the MET evaluation for AEII, therefore, the weighted average cost of capital ("WACC") that resulted from the financing that AEII secured in July 2009 provides a reasonable estimate of the WACC that a competitive investor would have anticipated in July 2008.

23. Second, Mr. Younger has argued that AEII could not have decided to invest before it received its Amended Certificate of Environmental Compatibility and Public Need from the Siting Board in April 2009.[16] There is no evidence that the receipt of the amended certificate was in jeopardy at any point in the process between July 2008 and April 2009. Therefore, it is reasonable to assume that AEII could predict this outcome with relative accuracy in July 2008.

24. Third, Mr. Younger has said that market conditions worsened significantly before AEII's expenditures ramped-up and has suggested that this justifies using a later date such as July 2009 when the project secured financing.[17] It seems undeniable that AEII's intention to build was clear when it began incurring significant financial liabilities in July 2008, so Mr. Younger is effectively advocating for the NYISO to evaluate whether AEII should have been expected to walk away from the investment at some time well after the initial decision to invest.

25. To my knowledge, the NYISO did not perform an assessment of whether a competitive investor would have walked away from the project well after the initial decision to invest

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15 The average Aaa-rated industrial bond rate, as published by the Federal Reserve, was 5.67 in July 2008 and 5.41 in July 2009.

16 Younger Affidavit at P 71.

17 *Id.* at P 70.

due to the deterioration in market conditions, nor is it obligated to perform such an assessment under the tariff. It is my understanding that the NYISO had no obligation to conduct such an evaluation under the Pre-Amendment Rules or the currently effective rules.

26. Mr. Younger implies this should be done by simply performing the MET evaluation based on a later point in time (*i.e.*, after the deterioration in market conditions) rather than on the initial decision point.[18] However, using what Mr. Younger refers to as the "final decision point" would not be appropriate because it is not consistent with how a competitive investor, having made an initial decision to enter, would decide whether to postpone or abandon the investment.

27. In order to decide whether to postpone or abandon the investment after the long-term contract has been signed and the investment has begun, the investor would have to consider:

- Any project expenditures that could not be recovered if the investor walked away from the project; and
- The lost option value of entering the market if the decision to postpone would allow other new suppliers to enter that would otherwise not have entered.

28. This decision is complicated in the case of AEII by the fact that the deliverability rights AEII was to use as a result of a transfer from the Poletti I unit that retired in January 2010 would have expired in January 2013, so AEII could only be delayed approximately 18 months before these rights would expire.

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[18] Younger calls this later point in time the "final investment decision" instead of the initial decision point. Younger Affidavit at P 69.

29. In addition, having signed the PPA with NYPA, AEII would not likely have an incentive to abandon or postpone the project except to the extent that the change in market conditions affected the revenues forecasted under the PPA. This is reinforced by the substantial contractual damages that AEII would have to pay if it abandoned the project.

IV. Sunk Costs Excluded from the MET Evaluations

30. In my initial affidavit, I explained that a reasonable evaluation of whether an investment is economic must exclude costs that are sunk because such costs would not rationally be considered by a competitive firm in its decision to invest.[19] This principle was applied to exclude two categories of costs:

- Preliminary legal and regulatory costs for both AEII and BEC that are generally incurred by an investor to evaluate and determine whether to proceed with an investment; and
- The costs to purchase existing shared facilities shared with Astoria Energy I ("AEI") that support the development of a new resource on the site used by AEII.

31. Some of the Pleadings Opposing Exemptions argue that I employ a different definition of sunk costs than traditionally used in economic theory. For example, Dr. Marciano defines sunk costs as "any past expense that is not recoverable."[20] I agree with this definition and do not believe there are significant disagreements regarding the definition of sunk costs used by any of the parties in this case.

32. Rather, the disagreement surrounds the question as to whether the costs associated with the existing facilities are, in fact, sunk. The complainants' argue that the costs of the existing

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19 Patton Affidavit at PP 26-27.

20 Marciano Affidavit at P 7.

facilities are not sunk and should, therefore, be included in AEII's Unit Net CONE in the MET evaluation. The primary arguments by those supporting this view are:

- The costs are not sunk because AEII would not have had to make the $120 million payment to AEI for the facilities if it did not build the unit;[21]
- Some of the costs of the joint facilities could have been recovered if other investors would pay to build a generator on the site instead of AEII in the same timeframe;[22] and
- Even if the site has little value to support entry of a new unit at this time, it would have substantial value to a future entrant that is foregone when AEII enters.[23]

33. In this section of my affidavit, I will explain why these arguments do not support the inclusion of the existing facilities costs in the MET evaluation. First, I explain why the payment by AEII to AEI does not represent real costs that could be avoided by not building AEII or the opportunity costs of AEII's use of the joint existing facilities. Second, I explain that because the market value of the existing joint facilities (the opportunity cost of AEII's use of the facilities) is directly related to the profitability of AEII, it is inappropriate to assume a positive market value for the joint facilities in the MET evaluation. Finally, I explain why the value of the deliverability rights transferred to AEII should be assumed to have no market value for purposes of the MET evaluation for the same reason.

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21 *See, e.g.*, Younger Affidavit at P 85: "…AE II would not have incurred the costs if it had not gone forward .." *See also* Shanker Affidavit at P 12: "In terms of the decision making of AEII to undertake and proceed with the project, they had to consider the incremental expense of the $120 million."

22 *See, e.g.*, Shanker Affidavit at P 10: "Presumably AE would have sold access to the common facilities for a comparable price to any third party."

23 *See, e.g.*, Pfeifenberger Affidavit at PP 8, 17: "Even if market conditions or other factors justified the abandonment of the AEII project and even if no new generating capacity were needed in New York City for a number of years, a fully developed site on which a new generating plant can be built in New York City will be valuable."

A. The Existing Facilities Costs Actually Paid by AEII

34. The first argument described above is that the existing facilities costs actually paid by AEII cannot reasonably be considered sunk because they would not have been incurred if the unit had not been built.

35. This argument over-simplifies the nature of the existing facilities costs and is not consistent with the economic definition of a sunk cost described above. A review of the "Report on the Existing Shared Facilities" indicates that AEII's payment for the existing facilities was deemed to be an equitable means to share the costs, and does not reflect the portion of the costs that may not be sunk (*i.e.*, the market value of the facilities if they were sold to a different entrant as I explain below).[24] This payment cannot be considered a legitimate marginal entry cost of AEII for the following reasons.

36. First, when AEII agreed to purchase the facilities in July 2008, both units were largely owned by the same group of investors, and the Report on the Existing Shared Facilities represented the transaction as a transfer payment that provides a fair way to divide the original capital costs rather than as an arms-length transaction reflecting the value of the shared facilities. When one appropriately treats this payment as a transfer payment, what becomes relevant is the market value of the existing facilities that can be recovered by selling the use of the facilities rather than AEII using them.

37. Second, the existing joint facilities were constructed for the purpose of supporting two units at the current site, AEI and AEII, and the payment formula was based on approximately half of the original costs of the joint facilities escalated at 10 percent per year until AEII signed a PPA with NYPA and then escalated at 15 percent annually thereafter. However, there is no reason to believe that the market value of such facilities is based on their original construction costs or that the value would escalate so rapidly over

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[24] Younger Affidavit Exhibit SS-9 at p. 5-5.

time. Rather, the high escalation rate reflected the capital costs that had been expended years earlier for which AEI expected to be "reimbursed" by its partners.[25]

38. Third, the price of the facilities included the costs of items that AEII did not intend to use. These include the "Electrical Interconnection (Part Outside EPC)" and "ISO System Upgrade" costs, which were priced and escalated along with all of the other shared facilities.[26] It would make little sense to incorporate these "costs" if AEI and AE II viewed the transaction as reflecting the value of the facilities to another potential entrant.

39. Fourth, no attempt was made to appraise the market value of the joint facilities and charge AEII an amount that would reflect the amount the owners could recover by selling the facilities to another new supplier. There was only a statement that the sale price was likely to be less than or equal to the costs of building new facilities.[27] However, the cost of building new facilities could only be relevant as an upper limit on the market value of the shared facilities.

40. For these reasons, the $120 million payment cannot be considered the market value of the existing joint facilities and I advised the NYISO not to assume the $120 million payment was a cost that should be attributed to the AEII project. The only costs that should not be deemed sunk are costs that correspond to the market value that could be recovered by selling the rights to another entrant, which are addressed in the following two sub-sections.

B. Recoverable Joint Existing Facilities Costs Assuming Entry in 2011

41. The prior subsection demonstrates that including the payments by AEII to AEI for existing joint facilities in the MET evaluation would not be appropriate. The relevant issue, as argued in a number of the Pleadings Opposing Exemptions, is whether the existing joint

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25 *Id.* at p. 5-1, 5-4.
26 *Id.* at p. 5-5.
27 *Id.* at p. 5-5.

facilities had a positive market value that could be recovered from a competing entrant. This subsection evaluates whether a positive market value (*i.e.*, opportunity cost) should be assumed for the joint existing facilities based on the conditions at the time of AEII's decision to enter. The possible value of the existing facilities based on the potential future use of the site is addressed in the next subsection.

42. The market value associated with the current use of the site (and the joint existing facilities) is determined by the return available to an investor using the site to build a new electric resource or using the site for another purpose. As I addressed in my prior affidavit, the site has limited value for uses other than supporting the entry of a new electric resource. However, some of the testimony submitted in the Pleadings Opposing Exemptions argues that the site has a significant positive market value based on the potential to build an economic generating resource on it.[28]

43. Therefore, in determining an appropriate assumption regarding the costs of the existing joint facilities, one must evaluate whether competing investments would likely be more economic than AEII. Confining ourselves to the current market conditions at the time of AEII's decision to enter, this is highly unlikely. Based on prior cost estimates produced by Sargent & Lundy, a natural gas combined-cycle generating resource is the lowest-cost resource that can be built in New York City currently.[29] There is no evidence that a lower-cost alternative investment to AEII exists.

44. If this is true, the joint existing facilities could only have a positive market value if AEII was in fact economic, and that market value would be directly correlated with AEII's profitability. For example, if the most economic investment produces a margin of $10 per

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[28] *See, e.g.,* Younger Affidavit at PP 28, 84: "Indeed, given the oft-cited fact that there are very few viable generating facility sites within New York City, they have great value to an electrical generator."

[29] *See Compliance Filing and Request for Flexible Effective and Implementation Dates*, Docket No. ER11-2224, dated March 29, 2011, Attachment IV. These estimated cost differences are consistent with the fact that combined cycle units have been the most common supply investment in NYISO in recent years.

kW-year (the difference between its capacity revenues and its Unit Net CONE), the market value of the existing site would have to be less than $10 per kW-year. It would be irrational for such an investor to be willing to pay more than $10 per kW-year for the existing joint facilities because that would make the investment uneconomic.

45. Therefore, if AEII is the lowest-cost type of resource that can be built, the market value of the existing joint facilities would be bounded by AEII's excess profits. If one posits that AEII is uneconomic, as argued by the complainants, then the market value of the existing joint facilities under current conditions would fall to zero. Therefore, in conducting the MET evaluation to determine whether AEII is uneconomic, one can only reasonably assume a zero value for the existing joint facilities (*i.e.*, that they are completely sunk). If AEII is found to be economic in this evaluation, one could argue that the existing joint facilities have a positive market value so they are not completely sunk, but that market value cannot be large enough to cause AEII to be considered uneconomic.

46. Therefore, I reiterate my previously-stated opinion that it is appropriate to exclude the costs of the joint existing facilities when conducting the MET evaluation to determine whether AEII is economic.

C. Future Use of the Joint Existing Facilities

47. The discussion in the prior subsection considers only potential entry under the conditions that prevailed when AEII entered the market and ignores the fact that the market value of the facilities may be influenced by the future use of the site for a new electric resource. This subsection addresses this issue by examining the likelihood that the site would be significantly more valuable for an entrant in the future than it was at the time that AEII entered.

48. Rather than speculating on the future value of the site, one should examine the expectations AEII would have had at the time it decided to enter and consider whether the expected conditions would have been more favorable at a future point in time.

49. We begin by determining the amount of surplus capacity that AEII would expect at the time of its planned entry in the Summer 2011 Capability Period. Based on the forecasted capacity requirements and resource additions/retirements expected when AEII decided to enter, a reasonable estimate of the surplus capacity would have been 6.2 percent in the Summer 2011 Capability Period following the entry of AEII.[30] Excluding AEII's entry, therefore, the expected surplus capacity margin would have fallen to just 0.4 percent. Given that the expected surplus capacity level was close to zero, there is little basis for believing that entry would be more economic in the future for two reasons.

50. First, if the surplus capacity margin fell to a level of just 0.4 percent, there is a substantial probability that another unit, such as one of the three aforementioned peaking units, might have entered. In this case, AEII would have been no less economic than if it waited an additional year to enter, since the entry of just one of the peaking units would largely offset one year of additional load growth. Furthermore, by waiting to enter, AEII would risk the possibility that another similar unit (e.g., a combined cycle generator) might enter, and that AEII would lose entirely the opportunity to enter. Second, NYISO's Comprehensive Reliability Planning Process is designed to prevent capacity shortages through regulatory solutions if necessary, so it is not reasonable for a developer to expect the surplus capacity to fall below zero.

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30 This excludes the entry of three peaking projects totaling 240 MW that I explained (in Section II) could reasonably be expected not to enter if AEII was built for several reasons. First, AEII's entry creates a surplus that would significantly reduce both the net energy revenues and capacity revenues that the peaking projects would expect. Second, the peaking projects are comprised of gas turbines whose costs are likely significantly higher than AEII's. Finally, even if these peaking units were to enter, AEII could reasonably expect that they would fail the MET evaluation and be mitigated. These expectations were validated in reality because neither of these projects proceeded to enter the New York City market.

51. Hence, given that the expected surplus capacity level was close to zero for the Summer 2011 Capability Period, there would have been little basis for AEII to believe that its entry would be more economic in the future. For this reason, the analysis in the preceding subsection holds and speculating on the value of the joint existing facilities based on their ability to support entry at some point in the future is not reasonable.

52. In conclusion, based on the economic rationale articulated above, I continue to believe that it would be inappropriate to include the costs of the joint existing facilities in the MET evaluation for AEII.

D. Deliverability Rights

53. IPPNY argues that the value of the deliverability rights that NYPA provided to AEII should be included in the MET evaluation.[31] This issue is analogous to the costs of the joint existing facilities discussed in the prior subsections. If the deliverability rights that AEII would require in order to sell capacity had a positive market value, I would agree that those costs should have been considered in the MET evaluation.

54. However, it is unclear whether the deliverability rights transferred to AEII would have had any material value to another entrant. The rights that were transferred to AEII were previously associated with the Poletti I plant that retired in January 2010. Under the NYISO tariff, these rights must be transferred within three years, and the project receiving the transfer must be operational within the same three-year period. One must determine, therefore, whether there would be any demand for such rights other than by AEII. If AEII is the most economic resource that could enter in time to acquire the deliverability rights, then the value of the deliverability rights is based solely on the profitability of AEII. Therefore, as I discussed in subsection B above regarding the joint existing facilities, the

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31 *Answer of Independent Power Producers of New York, Inc. to NYISO Supplemental Information Describing Buyer Side Mitigation Exemption Determinations*, Docket No. EL11-50 at pp. 4-6.

deliverability rights could only have a positive market value if AEII was economic. It cannot reasonably be argued that AEII is uneconomic because of the forgone market value of the rights when the rights only have a positive market value if AEII is economic.

55. One must consider, therefore, whether a lower-cost entrant could have used the deliverability rights. I do not believe this was the case. The only resources in the queue that were scheduled to enter before the expiration of the deliverability rights were three 79.9-MW simple-cycle natural gas combustion turbines: NYC Energy LLC[32] in Kings County, and Fortistar VP[33] and Fortistar VAN,[34] both in Richmond County. Each of these projects likely had costs significantly higher than AEII. As discussed previously, publicly-available cost information suggests that natural gas combined-cycle resources are the most economic technology type to build. Furthermore, AEII was presumably the most attractive new resource offered through the NYPA RFP process.

56. Moreover, those three projects were at a different location than the Poletti I project, which was located at the Astoria Annex in Queens County. Accordingly, pursuant to NYISO OATT Attachment S, the transfer would need to be evaluated. The Poletti I CRIS may or may not have been transferable to a different location. Also, certain locations in NYC have been determined to be deliverable (without a transfer), so projects in those locations would likely not pursue a transfer. Therefore, any attribution of market value to the deliverability rights on the basis that they could have been sold to a competing entrant is highly speculative and would be inappropriate to include in the MET evaluation.

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32 Interconnection Queue position 19.

33 Interconnection Queue position 90.

34 Interconnection Queue position 91.

E. Sunk Costs and Manipulation

57. Furthermore, several of the Pleadings Opposing Exemptions argue that the exclusion of all sunk costs in the MET is "rife for gaming"[35] as it creates incentives for participants to overstate their sunk costs (for example, by exclusion of the resale value of a plant site). Mr. Pfeifenberger, for example, argues that this determination may "create a 'loophole' that could allow many projects to pass the test if a large enough portion of an investment's total cost has been 'sunk' by the time the test is applied."[36] In the case of AEII, he argues, the exclusion of the resale value of the plant site would result in the resource "fail[ing] the NYISO's Part B test by a wide margin."[37]

58. Similar arguments are raised by Dr. Shanker and Mr. Younger. Dr. Shanker argues that "the potential for manipulation here is and should be a major concern, as an otherwise uneconomic investment should not be deemed or seen to be economic simply by making a large amount of expenditures and presenting a virtually complete facility as "sunk," with very low marginal costs for completion."[38] Mr. Younger submits that "this loophole must be closed for all future MET decisions."[39]

59. These witnesses are quite right that allowing developers to expend a significant share of the investment in advance of the MET evaluation in order to circumvent the BSM rules should not be allowed. This "loophole" is substantially reduced under the current BSM rules, which specify the deadline for a project's submission of data and the timing of the MET evaluation for a new resource. Further, the NYISO could develop benchmarks for the cost typically incurred prior to the decision of the developer to move forward with a new

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35 Younger Affidavit at PP 29, 87.

36 Pfeifenberger Affidavit at PP 7, 15.

37 *Id.* at PP 9, 19.

38 Shanker Affidavit at P 7.

39 Younger Affidavit at PP 29, 87.

resource. The decision to treat any other investment costs as sunk should be made on a case-specific basis, and could exclude capital costs directly related to the new resource. Regardless of how the current BSM rules or methods may be revised to address this potential concern in the future, however, this concern has no bearing on what the economically correct assumptions are for the MET evaluations of the AEII and Bayonne projects. One cannot reasonably argue that the Astoria Energy partners developed the joint existing facilities at the time that AEI was built in order to influence the MET evaluation for AEII.

V. Use of Project-Specific Financing Terms

60. As I indicated in my previous affidavit, financing costs vary from project to project, so it is imperative for NYISO to consider the financing terms of a specific project when performing a MET evaluation. Otherwise, a particularly credit-worthy supplier with a financing cost advantage that can enter the market profitably would be uneconomically impeded. Likewise, an investor with a long-term contract with a credit-worthy LSE, which is a typical arrangement for new investment in generating resources, will likely realize lower financing costs. Because these arrangements are likely an efficient means to allocate the market risk associated with the project, such financing cost advantages should not be ignored.

61. Drs. Hieronymus and Shanker, and Mr. Younger object asserting that because the purpose of the BSM rules is to prevent entities such as NYPA from sponsoring uneconomic capacity, financing terms that were likely affected by the presence of AEII's contract with NYPA should not be used.[40, 41, 42] Dr. Hieronymus goes further, arguing that this

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40 Hieronymus Affidavit at PP 39, 71.

41 Shanker Affidavit at PP 16-17.

42 Younger Affidavit at PP 33, 99.

constitutes a "collateral attack" on the BSM rules.[43] Mr. Younger also argues that it is inappropriate to use the financing terms in this case partly because AEII obtained the PPA through a discriminatory contracting process by NYPA.[44]

62. However, these witnesses fail to properly distinguish the aspects of the PPA that may constitute a subsidy from the aspects that legitimately reduce the cost of the project. A PPA that motivates a developer to invest in an uneconomic generating resource by providing subsidies (resulting in above-market revenues) is fundamentally different than the indirect financing benefits that may convey from the PPA. Any subsidy effects of the PPA are appropriately excluded from the MET evaluation by utilizing the actual costs to build the unit and the forecasted market revenues, rather than the revenues and net costs that would result under the terms of the PPA.

63. AEII was able to obtain arms-length financing on advantageous terms as a result of its PPA with NYPA. AEII's lenders were arms-length in the sense that they had no equity interest in AEII, and they were not entities with an interest in depressing capacity prices by building uneconomic capacity. Therefore, we can assume that the lenders were attracted by the fact that AEII had a long-term contract with a credit-worthy entity. This is also what we would expect if a developer signs long-term contracts with a number of large credit-worthy industrial or commercial customers (whose market shares are too small to create an incentive to build uneconomically). In that hypothetical case, the developer would benefit from the credit-worthiness of the buyers. I believe it would be unduly discriminatory to use the actual financing terms in this hypothetical case, but apply the demand curve financing assumptions for AEII when the only difference between the two cases is the identity of the counterparty.

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43 Hieronymus Affidavit at PP 39, 72.

44 Younger Affidavit at PP 7, 15.

64. Dr. Shanker identifies similarities between NYPA's contract with AEII and the type of anticompetitive conduct that the Commission addressed in its recent PJM Minimum Offer Price Rule ("MOPR") order.[45] In the order, the Commission eliminated the exemption provisions that had previously existed for state-sponsored uneconomic entry, so that such projects would be subject to the MOPR rules in the same manner as other projects. This is entirely consistent with the NYISO's application of the BSM rules, which evaluate merchant projects and projects that may have some form of state-sponsorship comparably. Contrary to Dr. Shanker's assertion, FERC's order in the MOPR provides a precedent that would require NYISO to use less favorable financing terms that a developer was actually able to secure.

65. This concludes my affidavit.

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[45] *PJM Interconnection, LLC,* 135 FERC ¶ 61,022 at PP 139-143 (2011). Shanker Affidavit at P 15.

ATTESTATION

I am the witness identified in the foregoing Affidavit of David B. Patton, Ph.D. dated October 11, 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
October 11, 2011

Subscribed and sworn to before me
this 11th day of October 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, 2011

ATTACHMENT III

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.	)	

Joint Affidavit of Eugene T. Meehan and Jonathan Falk

Mr. Eugene T. Meehan and Jonathan Falk each declare:

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 respond to Astoria Generating Company, L.P. ("AGC") and TC Ravenswood, LLC (collectively, "Complainants") and the NRG Companies' pleadings, in particular the Second Supplemental Affidavit of Mark D. Younger[1] and the Affidavit of Johannes P. Pfeifenberger,[2] regarding NERA's energy revenue modeling for

[1] *Complainant's Answer to Supplemental Answer of the New York Independent System Operator, Inc.*, Attachment A Second Supplemental Affidavit of Mark D. Younger, Docket No. EL11-50-000 (filed September 23, 2011) ("Second Supplemental Younger Affidavit")

[2] *Comments of the NRG Companies Opposing the New York Independent System Operator's Decision to Exempt Uneconomic Entry from Buyer Side Market Mitigation*, Attachment A Affidavit of Johannes P. Pfeifenberger, Docket No. EL11-50-000 (filed September 23, 2011) ("Pfeifenberger Affidavit").

the Astoria Energy II (AEII") and Bayonne Energy Center ("BEC") Unit Net CONE[3] determinations by the New York Independent System Operator ("NYISO").

II. Qualifications

A. Eugene T. Meehan

3. I am a Senior Vice President with NERA. I submitted an Affidavit in this proceeding which was Appendix VI to the NYISO's *Confidential Supplemental Answer* filed with the Commission on September 8, 2011.[4] My qualifications were provided as Exhibit Meehan-A to my initial Affidavit.

B. Jonathan Falk

4. I am a Vice President at NERA where I have been continuously employed since 1984. In that time, I have carried out numerous analyses of electric markets and numerous statistical and econometric analyses, both in electricity markets and outside them. I have testified before many tribunals and regulatory bodies, including the Federal Energy Regulatory Commission (the "Commission"). Most relevantly, I am NERA's primary researcher for the econometric analyses and simulation work relating to the estimation of Energy and Ancillary Services revenues in the NYISO's ICAP market. The chapter of the NERA/S&L Report for the 2010 Demand Curve reset regarding this estimation was substantially my own, and I carried out similar work for the NYISO in the 2007 ICAP

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[3] 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 and Request for Expedited Action of the New York Independent System Operator, Inc.* Docket No. EL11-50-000 (August 3, 2011) ("August 3 Answer").

[4] *Confidential Supplemental Answer of the New York Independent System Operator, Inc.*, Appendix VI Affidavit of Eugene T. Meehan, Docket No. EL11-50-000 (filed September 8, 2011) ("Confidential Supplemental Answer").

Demand Curve reset process. A complete copy of my *curriculum vitae* is appended as Exhibit EM/JF-1.

III. Summary of Critiques and Description of Methodology and Elasticities

5. The Complainants, through the affidavit of Mr. Younger, and the NRG Companies through the Affidavit of Dr. Pfeifenberger, attempt to critique NERA's energy revenue model in two main ways. First, they feel that energy prices and gas prices should be more proportionately linked for the determination of the Unit Net Cone for AEII and BEC, than they were estimated to be linked in the regression used to estimate net energy revenues for the NERA/S&L Demand Curve Report.[5] Mr. Younger also asserts that the regression model should not be used with gas prices that reflect a forecast, and rather should be used with the actual gas prices that prevailed over the 2006 to 2009 period for which the model estimated net energy revenues.[6] Second, Mr. Younger and Mr. Pfeifenberger feel that the run time of the BEC units is [redacted] that it constitutes an obvious error.[7]

6. In order to fully respond to their first complaint, we will explain how gas prices are represented in the NERA econometric model ("NERA model"). In the Demand Curve reset, the NERA model was used to estimate separate gas price elasticity for every hour of the day, for every month of the year, which created 24x12=288 separate coefficients. For the Demand Curve reset and the analysis for AEII and BEC, and explained below, these coefficients are reasonably estimated. In calculating the change in any particular hour's expected energy price from a change in gas prices, the logarithm of the change in gas prices (which vary daily) are multiplied by the relevant coefficient, and this change is then applied to the price on the relevant day. Since the model is measured in the logarithm of LBMP, the exponential of the new quantity is the new prediction.

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[5] Second Supplemental Younger Affidavit at PP 33, 40-42; Pfeifenberger Affidavit at P 7.

[6] Second Supplemental Younger Affidavit at P 33, 53-64.

[7] Second Supplemental Younger Affidavit at PP 45-49; Pfeifenberger Affidavit at PP 26-31.

Equivalently, we can say that the price as observed is multiplied by exp([log(new gas)-log(old gas)] x GasCoefficient).

7. This very common specification implies that the percentage increase in price is greater than or less than the percentage increase in gas price depending on whether the coefficient is greater than or less than 1. There are months and hours where the coefficient is quite close to 1, indicating that the increase (or decrease) would be proportional. But many hours are less than one, such that the average is 0.67. That relationship and average were reported in the Affidavit of Mr. Meehan filed by the NYISO in its Answer in Docket No. EL11-42-000 ("Exhibit EM/JF-2").[8] Because information contained therein is pertinent to this response, and it responds to and disposes of issues raised by Mr. Younger and Mr. Pfeifenberger, we incorporate that affidavit as Exhibit EM/JF-2 to this Affidavit.

8. That relationship between gas prices and LBMP means that in many hours a gas price increase will increase LBMP less than proportionately, and a gas price decrease will decrease LBMP less than proportionately. It also means that there will be situations in which profits are higher for some gas-fired generators at lower gas prices and lower for some gas-fired generators at higher gas prices as gas costs may decrease by a greater amount than energy prices. The direction of the change in profits will depend on the heat rate of the unit, the percentage of the unit's variable cost that is gas driven, and the level of gas and electricity prices before the change and the elasticity. As a general rule, it is more likely that a higher heat rate unit will experience higher profits with a lower gas price than will a lower heat rate unit.

9. Mr. Younger apparently believes that the coefficients on gas prices should be closer to 1 than to 0.67.[9] The regression analysis demonstrates that his belief is untenable. Of the

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[8] *See Request for Leave to Submit Supplemental Answer and Supplemental Answer of the New York Independent System Operator, Inc.*, Supplemental Affidavit of Eugene T. Meehan, Docket No. EL11-42-000 (filed July 6, 2011) ("EL11-42 Meehan Affidavit"), as corrected July 7, 2011.

[9] We infer this from Mr. Younger's categorical statement in P 40 that as natural gas prices decline the net energy revenues of both combined cycle and simple cycle units also decline. Second Supplemental Younger Affidavit at P 40. However, that statement is only true absolutely if elasticities

288 gas price coefficients, 10 are roughly 1 at a 95% confidence level, 278 are less than 1 at a 95% confidence level, and roughly half are less than 0.8 at a 95% confidence level. These outcomes are more intuitive than Mr. Younger's apparent view that all coefficients be equal, particularly when one considers that gas is only a portion of each gas unit's variable cost and when one considers the economic substitution effect. The economic substitution effect in this scenario is that as gas prices rise, other sources of energy including imports will become more competitive.

10. Exhibit EM/JF-2 explains why gas and electric prices although correlated would not be expected to change proportionally with an elasticity of 1.0, but would have a lower elasticity. As explained in Exhibit EM/JF-2, there is nothing odd about gas price coefficients less than one.[10] In winter, for example, when gas prices are high, alternative uses for the gas may divert gas to other uses, lowering the utilization of gas on the margin. Local Distribution Company ("LDC") gas transport charges, variable operations and maintenance ("O&M") costs, and emissions costs are not variable with respect to gas prices. Therefore, the impact of a change in gas prices on the all-in cost to gas-fired generators that pay LDC charges, and/or have variable O&M or emissions costs, will be lower in percentage terms than the change in gas prices. In other words, these other costs components lower the elasticity of electric prices with respect to gas prices.

11. Also explaining why gas price coefficients reasonably can be less than 1 is the fact that there are hours when gas is not on the margin. In these hours, price would be expected to be insensitive to variations in gas prices. While most of the time we would expect prices to be relatively low in these hours and this would make gas generation uneconomic, it is not always true. Gas units with lower heat rates may be dispatched infra-marginally, especially if they have costs advantages as does BEC. We discuss these advantages below.

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are 1. We also infer it from his references to the "tight" correlations between gas prices and electric prices. *Id.*

[10] EL11-42 Meehan Affidavit at PP 9-20.

12. Imports and exports from and to adjoining markets and within the NYCA but outside of New York City ("NYC"), and their associated prices, can also change with many factors including gas price levels and affect which unit is on the margin. It is not realistic to expect that gas prices will change but that the dispatch will remain the same and the change in each unit's marginal cost will be exactly proportional to the change in gas price. As gas prices change, economic substitution can occur.

13. It is a basic tenet of economics that as prices rise for an input, substitution occurs. This substitution has a downward effect on elasticity. The fact that the equations are reasonably specified, include the variables which should logically impact price, that explanatory power of the equation as measured by its R squared of over .88 is strong, and that the coefficients measured are highly statistically significant, gives us confidence that the estimated gas price coefficients, and hence gas price elasticities, are reasonable.

14. The estimated net energy revenues for BEC[11] are the result of an objective process by which NERA applied the regression analysis done for the 2010 Demand Curve reset, to estimate net energy revenues for BEC. The NERA model used for the BEC regression analysis was the same as that used to establish the net energy revenues accepted by the Commission in the Demand Curve reset.[12] The NERA model was specifically designed to estimate net energy revenue at various reserve margins, which was the exact task required for the NYISO's determination of BEC's Unit Net CONE.

15. At the time the NERA model was being used by the NYISO in the 2010 Demand Curve reset, the Complainants and NRG, through Dr. Richard Carlson, were advocating an alternative model specification ("Complainants/NRG Model").[13] Interestingly, the model the Complainants argued should be used in that case showed that net energy revenue

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[11] We believe that the same applies to estimates for AE II, but frame this discussion with respect to BEC as the estimates for AE II have not been challenged to the same degree.

[12] *New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 at P 136 (2011).

[13] *Protest of the New York City Suppliers*, Attachment B The Carlson Affidavit ("ER11-2224 Carlson Affidavit").

estimates were insensitive to the reserve margin.[14] Both the Complainants/NRG's model specification and the NERA model were presented to the Commission.[15] The Commission determined in its January 28, 2011 order, which was more than three months after NYISO had made its Unit Net Cone determination for AEII and BEC that the NERA model of net energy revenues for the Demand Curve reset was reasonable and appropriate to use to estimate net energy revenues for the 2010 Demand Curve reset.[16] Estimating net energy revenues for the Demand Curve reset and for AEII and BEC are similar exercises

16. Mr. Younger appears to object to the use of net energy revenue estimates developed using the NERA model for four reasons. The first is that the 2010 Demand Curve reset did not make an adjustment for gas price futures and, in the context of the Demand Curve reset, NERA stated that it recommended against such an adjustment.[17] Second, Mr. Younger makes several comparisons of the hours of dispatch for the BEC unit, to a generic combined cycle plant and to a generic LMS100 combustion turbine, and concludes that these comparisons demonstrate on their face that the NERA model produced unreasonable results.[18] He attempts to buttress his position with cites to a study done for BEC showing much lower hours of operation.[19] Third, he believes that the results produced by the NERA model are contradicted by the findings of the independent Market Monitoring Unit for the NYISO (the "MMU") stated in the State of the Market

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[14] *See* ER11-2224 Carlson Affidavit at Figures 3 and 16, *see also Request for Leave to Answer and Answer of the New York Independent System Operator, Inc.*, Attachment 4 Affidavit of Jonathan Falk at PP 6, 9, Docket No. ER11-2224-000 (filed January 6, 2011) ("ER11-2224 Falk Affidavit").

[15] ER11-42 Carlson Affidavit; *Answer to Motion, Motion for Leave to Answer and Limited Answer of the New York City Suppliers*, Attachment B The Supplemental Carlson Affidavit, Docket No. ER11-2224-000 (filed January 14, 2011).

[16] *New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 at P 136 (2011).

[17] Second Supplemental Younger Affidavit at P 43.

[18] *Id.* at PP 45-49.

[19] *Id.* at P 46, n. 22.

reports.[20] Fourth, Mr. Younger does not believe that there is adequate pricing data available to use gas futures.[21] We disagree with all four of his assertions.

17. In the NERA/S&L Demand Curve Report, NERA recommended, in the context of the Demand Curve reset, against all adjustments from actual to forecast of independent variables including gas prices.[22] The NERA/S&L Demand Curve Report noted four issues with respect to adjusting gas prices. Mr. Younger misinterprets that report. As explained in Exhibit EM/JF-2, the discussion of the gas price adjustment in the NERA/S&L Demand Curve Report does not invalidate a gas price adjustment. It also does not question the statistical validity of the estimated gas price coefficients. We believed in October of 2010, and continue to believe, that in the context of estimating net energy revenues for use in Unit Net Cone calculations, that it is appropriate to use gas futures, and that regression equation and gas price coefficients are a reasonable way to reflect future electricity prices. Exhibit EM/JF-2 discusses and disposes of the issues Mr. Younger raises in the context of Unit Net CONE calculations based on the NERA/S&L Demand Curve Report. That exhibit thoroughly explains why these factors do not indicate that a gas price adjustment is inappropriate in the context of estimating net energy revenues in the determination of Unit Net Cone. Because those explanations are already incorporated herein through that exhibit, we will not reiterate them.

18. As with any statistical modeling, however, we cannot say that the coefficients estimated are necessarily perfect. All regressions estimate their effects from the range of inputs and outputs they have been given, and none explain 100% of the impact of the independent variables. There is always a risk that extrapolation outside the range of observed data creates inaccuracies. But there is no obvious way to adjust for that within a regression context. In the Demand Curve reset process, Dr. Carlson argued that one way to make

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[20] *Id.* at P 42.

[21] *Id.* at PP 61-63.

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

such an adjustment is to add more data to the regression. We responded to Dr. Carlson's suggestion, and FERC agreed, such solutions often cause more problems than they solve.[23] Mr. Younger points out that the FERC approval of the regression analysis underlying the 2010 Demand Curve reset did not focus on the gas price coefficients. However, what Mr. Younger does not mention is that the coefficients are all interrelated: any change in the gas price coefficients could change the reasonably-sized reserve margin coefficient. In any case, our view is that it was and is reasonable to use the NERA regression model developed for and used in the Demand Curve reset to estimate net energy revenues for BEC and AEII, and to use gas futures. Our opinion is that the model is soundly specified, has strong statistical properties including those associated with the gas price coefficients and was designed for the exact purpose of estimating net energy revenues for various unit types at various reserve margins. Further, the NERA model was vetted and redeveloped with input in an open stakeholder process over the months directly preceding its use for the AEII and BEC determinations.

IV. Hours of Operation and the BEC [redacted]

19. Mr. Younger claims that other studies showed the BEC units would operate roughly [redacted] hours while the NERA model shows operation [redacted] hours.[24] The NERA model does estimate that given gas futures the BEC units will operate [redacted] hours. While this number of operating hours may be [redacted], we do not agree that it is evidence of an obvious error in the NERA model. We can and do show by a comparison to actual historical prices that an estimate of [redacted] hours would not be realistic. The BEC units [redacted]. The BEC units have a [redacted] an LMS100 unit located in NYC. This comes about for two reasons.

[23] ER11-2224 Falk Affidavit at Section IV.

[24] Second Supplemental Younger Affidavit at P 46, n.22.

20. First, BEC is directly connected to an interstate pipeline and [redacted]. The LDC charge estimated in the 2010 Demand Curve reset for the NYC peaking plant is 20.4 cents per MMBTU. At a $ 5 per MMBTU gas price level, this equates to a [redacted], which is the equivalent of [redacted].

21. Second, gas generators in NYC are subject to fuel use and gross receipt taxes of 6.99%. BEC is located in New Jersey [redacted]. This could also be viewed as [redacted]. Hence BEC's effective heat rate for purposes of dispatch in the NYC energy market can be viewed [redacted].

22. We estimate that BEC's effective heat rate for dispatch purposes, that is its heat rate in comparable terms to a unit in NYC, is likely [redacted] BTU per kWh, which is [redacted] an LMS100 in NYC. Therefore, BEC's effective heat rate is [redacted] a combined cycle unit and the most efficient peaking unit in NYC. After adjusting for the heat rate [redacted], we estimate that the BEC units have [redacted] at the level of gas futures that was used to develop BEC net energy revenue estimates and [redacted] the average level of gas prices in the November 2006 to October 2009 model [redacted] the Demand Curve Reset model was estimated. The percentage [redacted] at lower gas prices. Exhibit JF/EM-3 shows [redacted] for the BEC units relative to the LMS100 Demand Curve peaking plant.

23. Understanding the [redacted] of the BEC units relative to the LMS100 is very important as both Mr. Younger's and Mr. Pfeifenberger's comparisons of BEC to other units are predicated on the assumption that BEC [redacted] than an LMS100 in NYC.[25] The facts are the opposite. BEC has [redacted] net energy revenues than would an LMS100 in NYC.

[25] Second Supplemental Younger Affidavit at PP 45-49, Pfeifenberger Affidavit at PP 27-30.

24. Additionally, the BEC units have [redacted] emission characteristics, [redacted] start-up costs, and [redacted] units in NYC. Contrary to Mr. Younger's assertions, the fact that the BEC units are estimated to operate [redacted] hours is not evidence that there is a problem with the model.[26]

25. Mr. Younger also compares the dispatch of the LMS100 and a generic combined cycle unit to BEC for various scenarios using data that is contained in the NERA model posted on the NYISO's web site in connection with the 2010 Demand Curve reset.[27] The comparisons made by Mr. Younger are inapt as they do not account for BEC's [redacted] variable O&M costs.

26. To put the run time issue asserted by Mr. Younger in context, we have made several parametric analyses. First, we use actual prices from a three-year historical period and determine the estimated run hours of BEC, the NYC LMS100 used in the Demand Curve reset, and a generic Frame 7 combined cycle in NYC. BEC when compared to a LMS100 unit in NYC has a variable cost [redacted] the LMS100 as its higher heat rate is [redacted]. To develop the results below, each unit was dispatched using the daily gas price corresponding to each day of energy prices.

Unit	Hours
LMS100	3972
BEC	[redacted]
Generic CCGT	6445

Note that BEC runs almost [redacted] hours when dispatched against actual energy price data from the historic period of 2006 through 2009. The gas price and regression issues Mr. Younger raises are irrelevant to this result, since the prices used are not adjusted for gas

[26] Second Supplemental Younger Affidavit at PP 45-49.

[27] *Id.* at PP 48-49.

prices and are not estimated by the NERA model. These results conclusively refute any inference that the operating hour results should be on the order of [redacted] hours.

27. Next, we model the dispatch of these units against the revised prices developed using gas futures from October 2010, but adjusting for no other variables from actual values. The results are:

Unit	Hours
LMS100	5889
BEC	[redacted]
Generic CCGT	7605

28. The lower gas prices do, as expected, lead to an increase in the utilization of all gas units including the BEC units. However, the BEC units' operating hours [redacted] when the regression estimated energy prices are used with an adjustment for only gas prices, which decline by an average of 27 %. The LMS100 units increase utilization by almost 50%. The Second Supplemental Younger Affidavit infers that the NERA model and use of gas futures was the cause of a large anomaly.[28] The facts show that such an inference is simply untrue. In our opinion, this increase is well within what could be considered the normal range of expectation. It is economic substitution: As gas prices drop, gas units operate more hours.

29. To demonstrate further that Mr. Younger 's comparisons are misleading, we model the dispatch of these units against the revised prices developed using gas futures and also adjusting to a 15% reserve margin. These results, which form the inputs to the NYISO's Unit Net CONE determination, are:

Unit	Hours
LMS100	5482

[28] *Id.*at PP 53-56.

BEC	[redacted]
Generic CCGT	7434

The substitution of the higher reserve margins makes the [redacted] in BEC operating hours [redacted] over the historic period. This percentage change is, as expected, [redacted] than the percentage change in the operating hours of in the proxy LMS100 unit and [redacted] than the change in the operating hours of a generic CCGT. There are a number of reasons for this result, mostly arising from the fact that infra-marginal units will not have operating hours greatly restricted by modest drops in prices, and by substitution of real-time hours for day-ahead hours.

30. The impression Mr. Younger attempts to create that the NERA model is inconsistently dispatching unit types,[29] is refuted by all three cases in the parametric analysis. The false impression created by Mr. Younger is only because the cases he compares are not truly comparable, and because he ignores BEC's [redacted]. BEC's variable costs are [redacted] that of an LMS100 and a combined cycle unit, and in all cases its dispatch is [redacted] those values.

31. The tables above show quite clearly two facts. First, for actual gas and energy prices, all units operate in a consistent and expected manner given heat rates and fuel costs. Second, all units respond similarly and with reasonable magnitudes to changes in fuel prices.

V. Net Energy Revenue Calculations

32. Mr. Younger questions the net energy revenue estimate's developed for BEC by comparing these estimate's to those in the 2010 Demand Curve reset for the LMS100.[30] He compares the NERA model estimate of LMS100 net energy revenues at a 15% reserve level of $ 49.89/kW-year to the estimate we developed for BEC of $[redacted] and suggests that it would be reasonable to substitute the LMS100 estimate for BEC. That is

[29] *Id.* at PP 53-56.

[30] *Id.* at P 59.

wrong. BEC has an operating cost [redacted] during the hours that both units operate and [redacted] net energy revenue [redacted]. Mr. Pfeifenberger makes a similar comparison[31] and also compares the BEC estimated net energy revenue to the estimate for the LMS100 unit in the State of the Market Report by the MMU. As with Mr. Younger's comparison, these are flawed in they do not recognize the variable cost [redacted] of BEC [redacted] the LMS 100 located in NYC.

33. Again, to put these attempted assertions by Mr. Younger and Mr. Pfeifenberger in context, we performed a parametric analysis. First, we report net energy revenue estimates for the LMS100 and BEC using the historical LBMP data and making no adjustments. These values are $ 57.12 for the LMS100 and $ [redacted] for BEC. Next, we develop net energy revenues adjusting only for gas futures. These values are $ 100.17 for the LMS100 and $ [redacted][32] for BEC. This represents a 77% profit increase for the LMS100 unit and [redacted] for the BEC unit.[33] This analysis shows consistent results for the LMS100 and the BEC units. BEC is [redacted] in the energy market [redacted] at the lower gas prices. This is a function of the gas price elasticities estimated by the NERA model used in the Demand Curve reset and as we have stated before, we believe that those elasticities are reasonable and have been estimated objectively. There is no justification as Mr. Younger and Mr. Pfeifenberger suggest to base BEC's net energy revenues on the net energy revenues estimated for an LMS100 unit in NYC.

34. Mr. Younger references the State of the Market Reports by the MMU, and claims that these reports show that, he "know[s] from Dr. Patton's analysis for the state of the market reports that simple cycle units' revenues decline as gas prices decline."[34] What he fails to

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[31] Pfeifenberger Affidavit at PP 29-31.

[32] The difference in this value from the $ [redacted] value in the Confidential Affidavit of Joshua A. Boles Regarding Bayonne Energy Center at P 35 is because it has not been adjusted for the 15% level of excess capacity, the EFORd rate, or shaped for Winter/Summer.

[33] These values are the result of the parametric analyses before adjustment for seasonal ratings and forced outage rates to present results that are most consistent over all unit types.

[34] Second Supplemental Younger Affidavit at P 57.

mention is that the analysis in those reports is not intended to isolate the impact of just gas prices. In fact, the 2010 State of the Market Report states that "[t]he considerable increase in load levels also contributed to the increase in electricity prices. From 2009 to 2010, average load increased by more than 3 percent and peak load rose 9 percent, which led to more frequent dispatch of high-cost peaking resources."[35] Further, that report states, "[r]egardless, the dual-fuel capability of many units in New York moderates the effects on energy prices of transitory spikes in natural gas prices that can occur during the winter months."[36] In addition, that Report states that "[w]hen the natural gas price get close to the coal price (e.g., April to November 2010), gas-fired combined cycle units become more cost-competitive with coal-fired steam units, reducing the use of coal-fired generation."[37] We do not deny it is true that the State of the Market Reports have observed a positive correlation between gas prices and net energy revenues for simple cycle combustion turbines. However, it is also true that these were observed in the context of many factors changing, including load and are not designed to and do not isolate the impact of any single variable. The NERA model on the other hand is developed to estimate the individual impact of specific variables including gas prices and installed capacity levels. We were charged with estimating net energy revenues at a 15% level of capacity excess and gas futures at a specific point in time. In our opinion, that estimate is best done using a well specified model that estimates coefficients for gas prices and excess capacity levels and we have described above that is just what we did by applying to the net energy revenue estimates for AE II and BEC, a model that had been under development in an open forum for many months and that was provided and discussed in the stakeholder process for the Demand Curve reset.

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[35] Potomac Economics, *2010 State of the Market Report for the New York ISO Markets* at 23 (July 2011) *available at* <http://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2010_Final.pdf>.

[36] *Id.* at 31

[37] *Id.* at 32.

VI. The Use of Gas Futures Prices

35 Mr. Younger also criticizes the use of gas futures on the rationale that the market is thin in future years[38] and discusses the June 2008 United States Department of Energy Information Administration ("DOE EIA") gas price forecast which was predicting that gas prices would decline through 2016.[39] He concludes that NYISO should have made the net energy revenue estimates using historic gas prices as there was a lack of available data to provide sufficiently robust analysis and there were wide variations in projections.[40] These arguments appear to be intended to be directed at the AEII net energy revenue estimates, not to the BEC estimates,[41] as he references the 2008 Annual Energy Outlook.[42] We disagree with Mr. Younger on several bases. First, the natural gas futures market is and has been well established and there is open interest at least six years out in Henry Hub futures. Second, the market changes each trading day and reflects the most recent expectations. The DOE EIA forecast is generally updated once a year. Third, when futures markets exist, traders mark their positions to market data not forecasts, and base margin requirements on market data not forecasts. We are familiar with numerous electricity supply contracts and they often rely on market data to determine margin requirements even for periods more than three years out. In our opinion, the use of market data from traded gas futures is superior to a forecast for the time period in question. We do not see any support for the claim that the gas futures market data cannot be reasonably relied upon to provide a robust estimate of future gas prices or any reason why it would be reasonable to ignore actual market data and instead use a forecast.

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[38] Second Supplemental Younger Affidavit at P 62.

[39] *Id.* at P 63.

[40] *Id.* at P 64.

[41] There is no evidence that gas future prices and DOE EAI AEO forecasts were not aligned in October 2010. Additionally, the October 2010 date does not require the use of gas future prices for BEC six years out.

[42] Second Supplemental Younger Affidavit at P 63, n. 29.

36. Mr. Younger's attempt to use a Brattle Group report to support his argument is also misplaced.[43] The Brattle Group report that Mr. Younger cites[44] does discuss illiquidity, but does not state that the prices are not reflective of the market. The discussion in the Brattle report is framed with respect to the impact that illiquidity has on hedging, not on the reliability of the prices as market indicators.[45] The only discussion of price and liquidity is the observation that bid/ask spreads may be higher due to the lower liquidity.

VII. Conclusions

37. Supported by the above we reach the following conclusions.

- The use of the NERA model to estimate net energy revenues for BEC and AEII was and is reasonable as this model had just been developed to estimate the net energy revenues for a variety of generating units at various excess capacity levels. The model was and is designed for this task.

- The use of the NERA model used to estimate net energy revenues for the 2010 Demand Curve reset, to estimate net energy revenues for BEC and for AE II is reasonable as it is statistically sound on and overall basis and specified to include as independent variables the key variables that would affect energy prices.

- The NERA model has estimated gas price coefficients that are statistically significant and can be used to estimate energy prices and hence net energy revenues given gas futures prices. Mr. Younger does not accurately describe the NERA/S&L Demand Curve Report in this regard. Exhibit EM/JF-2 further explains why we believe that it is appropriate to use the NERA model to develop net energy revenues for future gas prices that differ from historical gas prices.

- The appropriateness of this model is further supported by the fact that it was developed for NYISO for a very similar purpose over the nine months before the net energy revenues for BEC and AE II were estimated, and was developed in a transparent process with stakeholder input.

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[43] *Id.* at P 62.

[44] *Id.* at n. 28.

[45] *See* Brattle Group, Managing Natural Gas Price Volatility: Principles and Practices Across the Industry at 37-38 (November 2010) *available at* <http://www.brattle.com/_documents/UploadLibrary/Upload931.pdf>.

- The gas price elasticities in the NERA model are sound statistical estimates and also sensible given that gas is only a portion, albeit a large portion, of variable operating costs and given the economic substitution effect that will occur in response to gas price changes.

- When comparing operating hours from various analyses and net energy revenue estimates from various analyses (including the MMU's State of the Market Reports) both Mr. Younger and Mr. Pfeifenberger make a critical error by ignoring the variable costs [redacted] of the BEC units [redacted]

- The parametric analyses we performed of BEC operating hours and net energy revenues show that the NERA model consistently dispatches various unit types and consistently develops net energy revenue estimates.

- The NERA model does show that lower gas prices [redacted] BEC operating hours and net energy revenues. This is the case because the elasticity of energy prices with respect to gas are less than 1 (on average 0.67) while the elasticity of BEC's variable costs with respect to gas would be between [redacted] at the range of gas prices examined. [redacted] the results of the State of the Market Reports for a LMS100 unit, the State of the Market Reports do not attempt to isolate the impact of gas price alone.

- The use of gas futures is reasonable and, in general, where future gas prices that reflect actual market activity are available, we believe that future prices are preferable to forecast prices as an indication of what gas prices are likely to be.

This concludes our affidavit.

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 EM/JF 1

Curriculum Vitae of Mr. Jonathan Falk Exhibit

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JONATHAN FALK
VICE PRESIDENT

Mr. Falk is a Vice President in NERA's Energy Practice. He received his B.A., *cum laude*, and M.A. in Economics from Yale University. While completing Ph.D. examination requirements at Yale, he taught courses in microeconomic theory and the history of economic thought.

At NERA, Mr. Falk has testified and consulted on a broad range of issues. He has testified in several cases on contract damages and has extensive experience in the estimation of damages arising from contract disputes.

In NERA's electricity practice, Mr. Falk has consulted with a wide variety of electricity industry participants on a number of issues involving the statistical modeling of investment, industry structure, and both short- and long-run pricing questions. He has substantial experience in dispatch modeling for complex electric systems, especially the development of software for large linear programming-based marginal cost models, including the modeling of both run-of-river and storage hydro systems. He has been involved in the creation of novel insurance products to transfer price risk in electric markets. He was a participant in the design process for the New England Forward Capacity Market. Mr. Falk has also statistically estimated the value of reliability in restructured electric markets. In addition, he has studied market power questions in emerging electricity markets and has estimated the social benefits of real-time pricing options for electricity. His work has also addressed questions of valuation, optimization, and the financial risks associated with restructured electric markets. He has advised on the structure of market rules, including the benchmarking of contracts between affiliated entities. Finally, he has created a number of models to value flexibility in utility planning, including hydro-based uncertainty. Mr. Falk has lectured and written as well on game-theoretic strategies in electric market bidding for both energy and capacity. Mr. Falk has appeared before both state commissions, Canadian provincial commissions and the Federal Energy Regulatory Commission.

As a statistical expert, Mr. Falk has specialized in statistical estimation for both liability and damages and the creation of models to simulate economic processes. He has testified as an expert witness on both general statistical issues and industry-specific studies in electricity and telecommunications.

In NERA's Communications Practice, Mr. Falk has participated in studies on residential access demand to the telephone system, choice of service among telephone company offerings, optimal pricing structures, and estimation of the short- and long-run marginal costs of telephone service.

In environmental economics, Mr. Falk has estimated benefits in recreational activity and increased property values resulting from tighter discharge standards for paper mills and for nuclear power plants.

Mr. Falk has worked on several cases involving credit discrimination in automobile and housing markets. He has also performed statistical analyses to predict credit decisions.

Finally, in labor economics, Mr. Falk has testified both on statistical estimations of liability in termination and promotion processes and in calculations of lost earnings in both wrongful termination and wrongful death cases.

Education

Yale University
M.Phil., Economics, 1982
M.A., Economics, 1980
B.A., Economics, 1978

Professional Experience

NERA Economic Consulting
1984- Vice President (current position)

Independent Consultant
1981-1983 Worked for various firms including PM Industrial Economics and MRR Associates on the development of econometric models in energy and financial analysis. Also consulted on installation of microcomputer systems.

Yale University
1980-1981 Teaching Assistant
Taught introductory micro-economics and history of economic thought.

US Department of Transportation
1980 Summer Research Assistant, Energy Policy Division
Analyzed energy related transportation issues, including diesel automobiles, coal slurry pipelines, fuel allocation regulations, and coal export policies.

Professional Activities

Faculty, Practising Law Institute, Employment Law Seminar

Member, American Statistical Association

Publications

"Paying for Demand-Side Response at the Wholesale Level," *The Electricity Journal*, Volume 23, Issue 9, pp. 13-18, November 2010.

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Testimony

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Testimony on behalf of the MTA in *George Derienzo v. Metropolitan Transit Authority and Metro North Commuter Railroad*, Southern District of New York, Case No 01 Civ 8138 (JGK) regarding the estimation of salary-based damages to an allegedly injured Metro North policeman, May 23, 2011.

Affidavit on behalf of New York Independent System Operator, Inc. before the Federal Energy Regulatory Commission regarding econometric specification of the model underlying Energy and Ancillary Service Revenue calculations for the Installed Capacity Market, FERC Docket No. ER11-2224-000, January 5, 2011.

Declaration on behalf of Merrill Lynch and Advest, In the U.S. District Court for the District of Connecticut in *William Fenwick, et al. v. Merrill Lynch & Co., Inc., Advest Group, Inc., et al.* regarding the "top hat" status of a deferred compensation plan at Advest, January 20, 2009.

Affidavit on behalf of Public Service Enterprise Group (PSEG) before the Federal Energy Regulatory Commission regarding application of the Hobbs model to proposed changes in the RPM capacity market in *PJM Interconnection, L.L.C.*, FERC Docket Nos. ER05-1410-010 and EL05-148-010, and Docket No. ER09-412-000, January 9, 2009.

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Testimony on behalf of WE Energies in re: Application of Wisconsin Electric Power Company for Authority to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment for Control of Sulfur Dioxide and Nitrogen Oxide Emission at its Oak Creek Power Plant Units 5, 6, 7 and 8, Docket NO. 6630-CE-299, regarding cost-benefit analysis of the decision to install equipment. Prefiled Rebuttal Testimony, January 17, 2008. Live Sur-surrebuttal testimony and Cross Examination, February 5, 2008, Madison, WI.

Affidavit on behalf of Pike Electric regarding admission of expert testimony in Pike Electric Corporation & Pike Electric, Inc., Plaintiffs, v. T&D Solutions, Ltd., T&D Solution Managers, L.L.C., Cory Close & Chad Dubea, Defendants (Civil Action No. M-05-410), September 5, 2007.

Testimony on behalf of Gould Publications in Matthew Bender and Co. v. Gould Publications, *et al.* (AAA No. 13 489 Y 02155 05) regarding interpretations of results of a telephone survey and damage estimates prepared by Matthew Bender witnesses, August 29-30, 2007, New York, NY.

Testimony on behalf of the IESO regarding cost-benefit test of rule changes in the Ontario Electric market in Ontario Energy Board Docket EB-2007-0040. Prefiled testimony: March 9, 2007. Live Testimony: Toronto, Ontario, March 30, 2007.

Deposition on behalf of Pike Electric in *Pike Electric, et al. v. T&D Solutions, et. al.*, US District Court for the Southern District of Texas, McAllen Division, Civil Action No. M-05-410, regarding lost profits from the violation of a noncompete agreement, New York City, November 13, 2006.

Reply Affidavit on behalf of PSEG Parties and PP&L Companies regarding modification to the Hobbs model in FERC Dockets ER05-1410-000, ER05-1410-001, EL05-148-000, and EL05-148-001, November 8, 2006.

Affidavit on behalf of PSEG Parties and PP&L Companies regarding modification to the Hobbs model in FERC Dockets ER05-1410-000, ER05-1410-001, EL05-148-000, and EL05-148-001, October 25, 2006.

Deposition on behalf of Pike Electric in *Pike Electric, et al. v. Mick Dubea*, US District Court for the District of Delaware Case No. 05-879 (SLR), regarding lost profits from the violation of a noncompete agreement, New York City, August 9, 2006.

Testimony on behalf on ENMAX regarding profit margin from retail services before the Alberta Electric Utility Board, January 14, 2005. Live cross-examination, Calgary, Alberta, September 5, 2005.

Direct Testimony on behalf of the Midwest Independent Transmission System Operator before the Kentucky Public Service Commission, in the Matter of: Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc. Case Number 2003-00266, regarding the benefits from enhanced reliability standards, December 29th, 2003. Live Cross Examination, February 26, 2004.

Appearance on behalf of PPL Corporation before the Federal Energy Regulatory Commission at Technical Conference on methods of compensating must-run generators in organized markets in PL04-2-000 and EL03-236-000, Washington, DC, February 4-5, 2004.

Testimony on behalf of Kansai in *Kansai Power International Corporation and KPIC North America Corporation, Claimants, v. Morgan Stanley Capital Group Inc., Respondents* in the Court of Arbitration, International Chamber of Commerce Case No. 12 402/JNK, regarding the Western Electricity Market in 2000-2001, risk management, and the economic structure of a joint venture agreement, December 16-17th, 2003.

Declaration on behalf of the PPL Companies before the Federal Energy Regulatory Commission regarding the PJM proposal on offer-capping to mitigate local market power in FERC Docket No. EL03-236-000, October 30, 2003.

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Declaration regarding statistical model of plaintiff's expert in *Overseas Media, Inc. v. Echostar Satellite Corporation*, Unites States District Court, Southern District of New York, 02 CV 1768 (HB), November 21, 2002.

Affidavit on statistical evidence for age differentials in a reduction in force on behalf of defendant in *Frank Pezzola v. Avon, Inc.,* United States District Court, Southern District of New York, Case No. 00 CIV 9763 (LAP), November 15, 2002.

Testimony on behalf of defendant in Doreen Smith v. Bell Atlantic, NYNEX and Robert Olson, regarding lost wages and benefits to plaintiff on May 21, 2002, Cambridge, MA.

Deposition testimony on behalf of defendant in Doreen Smith v. Bell Atlantic, NYNEX and Robert Olson, regarding post-injury damages to plaintiff, April 19, 2002.

Declaration in support of plaintiff Pacific Gas And Electric Company's motion for summary judgment on first and second claims for relief in Pacific Gas and Electric Company v. Loretta M. Lynch, Henry M. Duque, Richard A. Bilas, Carl W. Wood and Geoffrey F. Brown in their official capacities as Commissioners of the California Public Utilities Commission, United States District Court, Northern District of California, San Francisco Division, Case No.: C 01-03023 VRW, April 18, 2002.

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Deposition Testimony in *Sbarro v. Touray et. al.* on behalf of defendant Sbarro, Inc. regarding the plaintiffs' relative promotion rates, Brooklyn, NY, January 7, 2002.

Deposition testimony for defendant regarding the economic damages associated with electricity outages in Santa Cruz County, Arizona in *Sam and Sherri Chilcote; Brad Cook and Jane Doe Cook; Alfread and Frankie Donau; Dave Fenner; Hulsey Hotel Property Management, LLC, dba The Americana Hotel; Alan Anderson dba Ausi Gallery; and Desert Fire Glass Works, LLC vs. CitizensUtilities Company, et al., No. CV 98-471 (Consolidated with CV 99-081)*, September 10, 2001.

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Affidavit on behalf of Texas Utilities regarding confidentiality of information provided to Texas Public Utilities Commission, March 27, 2000.

Testimony on behalf of plaintiff regarding statistical estimation of the effect of age-related factors in a reduction in force in *Thomas Hale v. American Telephone & Telegraph Company, AT&T Global Business Communications Systems and Ismael Velez, Jr., Superior Court of New Jersey Law Division: Bergen County Docket No. BER-L-12619-96*, February 3, 2000.

Deposition testimony for defendant regarding damages arising from alleged wrongful termination in *Adel A. Mallemat v. Coopers & Lybrand, LLP*, 97-CV-3871 (JBW), May 20, 1999.

Deposition testimony for plaintiff regarding statistical estimation of the effect of age-related factors in a reduction in force on behalf of plaintiff in *Thomas Hale v. American Telephone & Telegraph Company, AT&T Global Business Communications Systems and Ismael Velez, Jr., Superior Court of New Jersey Law Division: Bergen County Docket No. BER-L-12619-96*, April 5, 1999.

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Testimony before the Maryland Public Service Commission regarding the calculation of future market prices for electricity on behalf of Baltimore Gas and Electric Company, case Number 8794, July 1, 1998.

Deposition testimony for defendant regarding a statistical model of quit decisions in *Brenda Kay Stoll Madrid, et al vs Oklahoma Gas and Electric Company*, District Court of Oklahoma County State of Oklahoma C.J-91-9695-32, March 17, 1998.

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In the Matter of the Arbitration Between Donna Karan Studio and Erwin Pearl Inc. Rebuttal testimony for Erwin Pearl rebutting criticisms of previous analysis, September 16, 1992. Testimony for Erwin Pearl regarding lost profits from the termination of the DKNY Jewelry license, April 6, 1992.

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Before the State of Maine Public Utilities Commission, Docket No. 88-111, Volume 1. Supplemental testimony, with John H. Wile, evaluating issues about the relative economics of the proposed Hydro-Quebec purchase, a potential New Brunswick purchase and cogeneration, on behalf of Central Maine Power, June 24, 1988.

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with Eugene Meehan, Anthony Schmitz and Sargent & Lundy, Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, September 7, 2010.

Second Supplemental Expert Report on behalf of Gould Publications, August 15, 2007.

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Supplemental Expert Report on behalf of Gould Publications commenting on Guideline and Vanderboom Reports, November 10, 2006.

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"Critique of the SIC Draft Report," prepared for Texas Utilities, September 3, 1998.

with Mark Berkman, "Economic Impacts of GHI Employment," December 6, 1996.

"Analysis of Damage Sustained by Isao Kato," prepared for law firm of Harold Woolfalk, November 4, 1996.

with Lewis J. Perl and Mark Berkman, "Estimating Employment Effects of Electric Price Increases in US Manufacturing Industries," June 28, 1996.

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with Lewis J. Perl and John H. Wile, "Benefits and Costs from the Reduction of Color Effluent From the Champion Mill into the Pigeon River," prepared for Champion International Corporation, April 1988.

with Lewis J. Perl and Timothy J. Tardiff, "Residential Demand for Telephone Service in California," prepared for Pacific Bell, March 23, 1988.

Presentations

"The Price is Right: Compensating Price-Based Demand Response," presented at the EnergySMART Conference 2011, EnerNOC, Boston, MA, September 28, 2011.

"State of the Industry: A Wall Street Perspective," presented at the Utilities Services Alliance Conference, Squaw Valley, CA, June 15, 2005.

"Is Nuclear Power Compatible with a Deregulated Electricity Market," presented at IFRI-CFE Conference on the Future of Nuclear Power in the US, Paris, France, May 25, 2004.

"Prospects for Recovery: When Will We Put More Iron in the Ground?" Presented at NACBE Annual Conference, Naples, FL, February 24, 2004.

"Impacts of Fuel Cost Trends on the Relative Economics of Nuclear vs. Conventional Power," Presented at Infocast Conference: Building New Nuclear Power Plants – Assessing the Possibilities, Washington, DC, October 16, 2003.

"Economic Impacts of Indian Point Shutdown," presented before joint session of Hudson Valley Technical Societies and Westchester Section of the American Institute of Chemical Engineers, Pleasantville, NY, September 24, 2003.

"The Crisis in Financing Independent Power, With Implications for Nuclear Power," Utilities Services Alliance Conference, Santa Fe, New Mexico, June 17, 2003.

"Electricity Regulation: The Mess We're In, How We Got There, And The Road Out," presented at a Foundation for American Communications Seminar, Washington, DC, January 27, 2003.

"A Contrarian View of Enron," Marsh, Inc. Power Group Conference, Palm Harbor, FL, February 20, 2002.

"Competitive Markets for Power 2001: An Electrical Odyssey," presented at the USA annual meeting, Key Largo, Florida, June 13, 2001.

"Electricity Restructuring: The (Pretty) Good, The (Pretty) Bad, and the (Extremely) Ugly," Marsh, Inc. Power Group Conference, Palm Harbor, FL, February 14, 2001.

"Competitive Nuclear Power", presented at the USA Nuclear Annual Meeting, Lake Tahoe, NV, June 14, 2000.

"Applying Congestion Pricing in a Decentralized Electricity System," presented at InfoCast Transmission Pricing Conference, Chicago IL, May 2, 2000.

"Electric Price Volatility: Causes, Prospects and Solutions," presented at PURMA Annual Conference, Sturbridge, MA, October 12, 1999.

"Ensuring Accurate Price Forecasting: A Building Block for Asset Valuation," presented at IIR Conference: Buying and Selling Utility Generation Assets, Atlanta, GA, October 1, 1999.

Price-Cost Modeling of Electricity Markets at "New Directions in the Economic Analysis of Market Power," sponsored by National Economic Research Associates, presented at the Four Seasons Hotel, Washington, D.C., June 24, 1998.

Panelist, "Litigating Employment Discrimination," sponsored by the Practising Law Institute, presented at the NYC-Sheraton, June 9, 1998.

Panelist, "Examination Of Defendant's Economics Expert In A Discrimination Case," presented at the New York State Bar Association Annual Meeting of the Commercial and Federal Litigation Section and Corporate Counsel Section, January 28, 1998.

"Calculating Economic Damages," presented at the Second Annual Employment Law Litigation Institute, sponsored by the Labor & Employment Law Section of the New York State Bar Association and St. John's University School of Law, Queens, New York, May 16, 1997.

"How to Minimize the Impact of Stranded Costs on Credit Valuation," CBI Conference on Credit Ratings for U.S. Utilities and Power Projects, New York, New York, November 22, 1996.

"Statistics for Labor Lawyers: Using Math to Tell a Story," sponsored by National Employment Lawyers Association, New York, New York, October 29, 1996.

Seminar Participant. "How to Hire and Fire," Practicing Law Institute Conference on Employment Law, New York, New York, October 2, 1996.

"Modeling Who Gets RIFed: What's Age Got To Do With It?," luncheon seminar sponsored by National Economic Research Associates, New York, New York, May 1, 1996.

"Econometrics and Marginal Cost," presented at Symposium on Marginal Cost Techniques for Telephone Services, sponsored by The National Regulatory Research Institute, in Seattle, Washington, July 18-19, 1990, and in Columbus, Ohio, August 15-16, 1990.

with Mark Berkman, "Valuing Flexibility in Utility Planning Using Dynamic Programming," presented at Decision Support Methods for the Electric Power Industry Conference, sponsored by Electric Power Research Institute, Cambridge, Massachusetts, May 29-31, 1990.

with Lewis J. Perl, "The Use of Econometric Analysis in Estimating Marginal Cost: The Choice of Functional Form," presented at the International Telecommunications Society, North American Regional Conference, Ottawa, Canada, June 19, 1989.

"Investment in Equipment Modernization: The Question of Prudence," presented at Telecommunications Policy in a Competitive Environment, sponsored by NERA, Scottsdale, Arizona, April 12-15, 1989.

with Lewis J. Perl, "The Use of Econometric Analysis in Estimating Marginal Cost," presented at the Bellcore and Bell Canada Industry Forum, San Diego, California, April 6, 1989.

September 2011

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

EM/JF - 2

Affidavit of Eugene T. Meehan filed in Docket No. EL11-42-000

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

New York Independent System Operator, Inc. **Docket No. EL11- 42-000**

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 current version of the buyer-side mitigation measures. These measures are set forth in Attachment H of the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff"). As the NYISO does in its Answer, I refer to these measures as the "In City Buyer Side Mitigation Measures". NERA is performing work related to the NYISO's determination of Unit Net CONE[1] that is part of

[1] Terms with initial capitalization that are not otherwise defined herein shall have the meaning specified in the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff") and if not defined therein, they shall have the meaning specified in the NYISO's Open Access Transmission Tariff ("OATT").

the In-City Buyer-Side Mitigation Measures[2] for proposed new capacity projects in New York City ("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

[2] As the NYISO does in the Answer, I use the term "In-City Buyer Side Mitigation Measures" to refer to the currently-effective buyer-side capacity market mitigation provisions in Attachment H to its Services Tariff, including those that were accepted by the Commission in its series of orders in Docket ER10-3043.

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 PJM Interconnection, LLC ("PJM") 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 individual Projects. NERA's role included estimating energy and ancillary services revenue offsets for use in the Unit Net CONE calculations.

11. Sargent and Lundy LLC (Sargent & Lundy), another consultant retained by the NYISO, provides information for the Unit Net Cone determinations. Specifically, Sargent & Lundy provides cost and performance data for individual Projects, including information concerning capital costs, fixed and variable operating and maintenance ("O&M") costs, property 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 obtains the information from the developers and other sources.

12. NERA used the information provided by Sargent & Lundy and the NYISO when estimating net energy and ancillary service revenues. NERA provided information and analysis to NYISO regarding the costs of capital and the capital structure specific to individual Projects and the developers 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 (MMU) for the NYISO, Potomac Economics, Ltd., 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 and ancillary services revenues using the econometric model used in the NYISO's Demand Curve reset process. The econometric 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 Demand Curve report, I did not believe in the context of the 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.[3] 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 In-City Buyer-Side Mitigation Measures, I believe that the intent is to capture whether the entry decision is

[3] *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).

economic as of a 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 Mitigation Study 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 energy net revenues without the gas price adjustment. Accordingly, for purposes of the In-City Buyer Side Mitigation Measures, energy revenues should be derived using projected gas prices based on gas futures prices over the Mitigation Study Period. Therefore, I recommended to the NYISO that we adjust the gas prices using current gas futures prices in determining the net energy revenues to use in the Unit Net CONE determinations.

18. For the Unit Net CONE determination, the econometric model uses gas futures prices to predict energy prices and derive net energy revenues. Gas futures prices for the years corresponding to the years of the Mitigation Study Period are used.

19. NERA used Transco-Z6 (NY) gas prices with an adder for LDC transportation charges. These prices are reasonable representations of the cost of gas delivered to the Projects.

20. The NERA econometric model shows that net energy revenues are sensitive to the level of excess. When calculating net energy revenues, we develop results for a wide range of excess capacity levels.

21. I understand that the methodology used by NYISO provides for revising net energy revenues and the Unit Net CONE values in relation to changes in the expected excess capacity level based on the Class Year Facilities Study process. The expected levels would change if a Project for which a determination is being made concurrently with

other Projects is no longer being considered for Capacity Resource Interconnection Service ("CRIS") in the NYISO's Class Year process. In that instance, that Project is removed from the expected excess capacity level but will remain in the energy forecast. Energy revenues are also adjusted if a Project ceases to move forward in the Class Year process, and thus it is also no longer in the energy forecast. It is for this reason that we provide the NYISO the Unit Net CONE results for a wide range of excess capacity levels.

22. 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 starting with initial entry. 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.

23. Estimated ancillary service revenues are also a cost offset in the determination of Unit Net CONE. The NYISO provides NERA estimates of ancillary services revenues. It is NERA's understanding that the NYISO uses recent actual ancillary services revenues

earned by similar plants that would qualify for the same ancillary services, to develop an estimate of ancillary services revenues for a Project.

V. Unit Net CONE Determination

24. NERA also prepares the Unit Net CONE for a wide range of excess capacity levels so that the NYISO can apply the results to scenarios in which other Projects being examined do not proceed in the Class Year process for CRIS but proceed as an energy-only resource, or if other Projects reject their allocations and thus will not enter the market for capacity or energy. In this step of the calculation, NERA multiplies the Project's total investment cost by the carrying charge, adds annual fixed O&M costs, and subtracts annual net energy and ancillary services revenues to determine the annual Unit Net CONE for each of the three years of the Project's Mitigation Study Period. The Project's Unit Net CONE is equal to the average of the three annual values. In calculating net energy revenues over the three years, NERA uses an average of the gas futures price for the three year period to calculate a single net revenue value that is used for each of the three years.

VI. Annual Levelized Carrying Charge

25. 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.

26. NERA examined information provided to Sargent & Lundy by each developer regarding the costs of capital and the capital structure specific to the Project and the 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 the 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.

27. 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.

28. 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 Mitigation Study Period.

VII. Additional NERA Analysis and Recommendations

29. 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.

30. Amortization period. Sargent & Lundy provided carrying charges for multiple amortization periods. The 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 Demand Curve reset would be 30 years. The actual amortization period used in the 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 Demand Curve reference point so that the 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 Demand Curve but only to estimate the net cost of ownership. In fact, the Demand Curve has been set to allow the 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 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 recommends an amortization period appropriate for each Project.

31. 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 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 recommends a real levelized carrying charge that increases at 2.15 percent per year, which is inflation less technical progress.

32. 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.

33. 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 independent Market Monitoring Unit on various issues. The NYISO, with that input, made final decisions on these issues.

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

VIII. Conclusion

35. The paragraphs above provide an accurate description of the activities undertaken by NERA in examining the Unit Net Cone for Projects pursuant to the Buyer-Side Mitigation Measures. 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 July 6, 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
July 6, 2011

Subscribed and sworn to before me
this 6th day of July.

NARI TROTTER
NOTARY PUBLIC-STATE OF UTAH
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EUGENE T. MEEHAN
SENIOR VICE PRESIDENT

Mr. Meehan is a Senior Vice President at NERA. He has over thirty years of experience consulting with electric and gas utilities and has testified as an expert witness before numerous state and federal regulatory agencies, as well as appeared in federal court and arbitration proceedings.

At NERA, Mr. Meehan's practice concentrates on serving energy industry clients, with a focus on helping clients manage the transition from regulatory to more competitive environments. He has performed consulting assignments for over fifty large electric, gas, and combination utilities in the areas of retail access, regulatory strategy, strategic planning, financial and economic analysis, merger and acquisition advisory services, power contract analysis, market power and market definition, stranded cost analysis, power pooling, power markets and risk management, ISO and PX development, and costing and pricing. In addition, he has advised numerous utilities on power procurement issues and administered power procurements on behalf of utilities and regulators.

Mr. Meehan has experience leading NERA's advisory work on several major restructuring and unbundling assignments. These assignments were multi-year projects that involved integration of regulatory and business strategy, as well as development of regulatory filings associated with the recovery of stranded cost and rate unbundling.

Education

Boston College, BA, Economics, *cum laude*
New York University (NYU), Graduate School of Business, completed core courses for the doctoral program.

Professional Experience

	NERA Economic Consulting
1999-	Senior Vice President
1996-1999	Vice President
1973-1980	Senior Economic Analyst; Research Assistant
	Deloitte & Touche Consulting Group
1994-1996	Principal
	Energy Management Associates, Inc.
1980-1994	Vice President

Areas of Expertise

Restructuring/Stranded Cost Recovery

Mr. Meehan has directed several multi-year projects associated with restructuring and stranded cost recovery. These projects involved facilitating the development of an integrated regulatory and business strategy and formulating regulatory filings to accomplish strategy. As part of these assignments, Mr. Meehan facilitated sessions with senior management to set and track filing strategy. Clients include Public Service Gas & Electric and Baltimore Gas and Electric.

Unbundling/Generation Pricing

Mr. Meehan has formulated unbundling strategies, with a specialization in generation pricing. He has advised several utilities in standard offer pricing and has testified on shopping credits on behalf of First Energy and Baltimore Gas and Electric.

Power Procurement

Mr. Meehan has been involved in power procurement activities for a variety of utilities and regulatory agencies. He has advised utilities in developing and implementing evaluation processes for new generation, with the objective of achieving the best portfolio evaluation. He has helped regulators in Ireland and Canada design and implement portfolio evaluation processes. He has testified before FERC and state regulatory agencies on competitive power procurement. In addition, Mr. Meehan helped to design and implement the New Jersey BGS auction process.

Power Contracts

Mr. Meehan has extensive experience with power contracts and power contract issues. He has reviewed and testified on the three principal types of power contracts: integrated utility to integrated utility contracts, IPP to utility contract, and integrated or wholesale utility to distribution utility contracts. He has testified in power contracts disputes on behalf of Carolina Power and Light, Duke Power Company, Southern Company, Orange and Rockland Utilities, and Tucson Electric Power. He has also advised Oglethorpe Power Corporation in the reform of its wholesale contracts with its distributor cooperative members.

Retail and Wholesale Settlements

In addition to his expertise on power pooling issues, Mr. Meehan has significant experience with assignments related to the settlement process. He has focused on the issues of credit management as new entrants appear in retail and wholesale markets and has designed efficient specifications for retail settlement systems, including the use of load profiling, and examined the risk and cost allocation issues of alternative settlement systems.

Risk Management

Mr. Meehan has advised several large utilities on price risk management. These assignments have included evaluation of price management service offers solicited from power marketers in association with management of assets and entitlements, as well as provision of price managed service for various terms.

Marginal Costs

Mr. Meehan has provided comprehensive marginal cost analyses for over 25 North American Utilities. These assignments required detailed knowledge of utility operations and planning.

Power Supply and Transmission Planning

Mr. Meehan has advised electric utilities on economic evaluations of generation and transmission expansion. He has testified on the economics of particular investments, the prudence of planning processes, and the prudence of particular investment decisions.

Generation Strategy

Mr. Meehan has led NERA efforts on a client task force charged with developing an integrated generation asset/power marketing strategy.

Power Pooling

Mr. Meehan has in-depth working knowledge of the operating, accounting, and settlement processes of all United States power pools and representative international power pools. He has provided consulting services for New York Power Pool members on a continuous basis since

1980, advising the Pool and its members on production cost modeling, transmission expansion, competitive bidding and reliability, and marginal generating capacity cost quantification. In NEPOOL, he has quantified the benefits of continued utility membership in the Pool and the impact of the Pool settlement process on marginal cost. He has worked with a major PJM utility to explore the impact of PJM restructuring proposals upon generating asset valuation and examine the implications of alternative restructuring proposals. He has consulted for Central and Southwest Corporation, Entergy, and Southern Company on issues that involved the internal pooling arrangements of the utility operating companies of those holding companies, as well as for various utilities on the impact of pooling arrangements on strategic alternatives.

Representative Assignments

Worked with Public Service Electric & Gas Company (PSE&G) to direct a three year NERA advisory effort on restructuring. Facilitated a two-day senior management meeting to set regulatory strategy in 1997. Throughout 1997 and 1998, worked over half time at PSE&G to help implement that strategy and advised on testimony preparation, cross-examination, and briefing. Also advised PSE&G on business issues related to securitization, energy settlement and credit requirements for third party suppliers. During 1999, advised PSE&G during settlement negotiations and litigation of the settlement. PSE&G achieved a restructuring outcome that involved continued ownership of generation by an affiliate and the securitization of $2.5 billion in stranded costs.

Worked on separate assignments for a large utility in the Northeast and a large utility in the Southeast, advising on the evaluation of risk management offers from power marketers. The assignments included reviewing proposals, attending interviews with marketers and providing advice on these, and the developing analytical software to evaluate offers.

Worked with government of Ontario beginning in 2004 to help design the RFP and economic evaluation process for the solicitation of 2500 Mw of new generating capacity. Supervising NERA's portfolio-based economic evaluation on behalf of the Ontario Ministry of Energy.

Testified on behalf of Pacific Gas & Electric Company before the FERC in a case benchmarking the PSA between the distribution utility and a soon-to-be-created generating company. This effort involved developing detailed expertise in applying the Edgar standard and a detailed review of DWR procurement during the western power crisis. In addition, this effort involved the review of more than 100 power contracts in the WECC.

Directed NERA's efforts, on behalf of the electricity regulator in Ireland, to design an RFP and implementation process for the purchase of 500 Mw of new generating capacity in 2003. NERA advised on the RFP, the portfolio evaluation method, and the power contract and also conducted the economic evaluation.

Reviewed the economic evaluation conducted by Southern Company Service for affiliated operating companies in connection with an RFP for over 2000 Mw of new generating capacity. Submitted testimony before FERC on behalf of Southern Company Service.

Worked with Baltimore Gas and Electric (BG&E) to conduct a one and one-half year consulting assignment that involved providing restructuring advice. The project began in March/April 1998 with senior management discussions and workshops on plan development and filing strategy. Advised BG&E in the development of testimony, rebuttal testimony, and public information dissemination. Worked to review and coordinate testimony from all witnesses and offered testimony on shopping credits and in defense of the case settlement. BG&E achieved a restructuring outcome enabling it to retain generation ownership. As part of this assignment, advised BG&E on generation valuation and unregulated generation business strategy.

Directed the efforts of a large Southeastern utility to develop a short-term power contract portfolio and to evaluate the relative value of power options, forwards, and unit contracts to determine the optimal mix of instruments to manage price risk.

Testified for XCEL Energy on the use of competitive bids for new generation needs. Examined whether XCEL was prudent not to explore a self-build plan and the reasonableness of relying on ten-year or shorter contracts as opposed to life-of-facility contracts, in order to meet needs and facilitate a possible future transition to competition. This project addressed the comparability of fixed bids to rate base plant additions.

Advised and testified on behalf of First Energy in the Ohio restructuring proceeding on the issues of generation unbundling and stranded cost. Defended the First Energy shopping credit proposal.

Advised Consolidated Edison and Northeast Utilities on merger issues and testified in Connecticut and New Hampshire merger proceedings. Testimony focused on retail competition in gas and electric commodity markets.

Directed NERA's effort to train selected representatives of a major European power company in American power marketing and risk management practices. The project involved numerous meetings and interviews with power marketing firms.

Led NERA's effort to advise the New England ISO on the development of an RTO filing. Examined performance-based ratemaking for transmission and market operator functions.

Examined ERCOT power market conditions during the period of time from 1997 to 1999 and testified on behalf of Texas New Mexico Power Company for the prudence of its power purchase activity.

Advised a Midwestern utility on restructuring of a wholesale contract with an affiliate. Involved forecasting of the unbundled wholesale cost-of-service and market prices, as well as development of a regulatory strategy for gaining approval of contract restructuring and the transfer of generation from regulated to EWG states.

Performed market price forecasts for numerous utility clients. These forecasts have employed both traditional modeling and newly developed statistical approaches.

Examined the credit issues associated with the entry of new entities into retail and wholesale settlement market. These assignments involved a review of current Pool credit procedures, examination of commodity and security trading credit requirements, coordination with financial institutions, and recommendations concerning credit exposure monitoring, credit evaluation processes, and credit requirements.

Oversight of EMA's consulting and software team in designing and implementing the LOLP capacity payment, a portion of the UK wholesale settlement system.

Advised Oglethorpe Power Corporation in the reform of its contracts with its distribution cooperative members and the evolution of full requirement power wholesale power contracts into contracts that preserve Oglethorpe's financial integrity and are suitable for a competitive environment.

Developed long run marginal and avoided costs of natural gas service, as well as avoided cost methods and procedures. These costs have been used primarily for the analysis of gas DSM opportunities. Clients include Consolidated Edison Company, Southern California Edison Company, Niagara Mohawk Power Corporation, and Elizabethtown Gas Company.

Review of power contracts and testimony in numerous power contract disputes.

Development of long run avoided costs of electricity service and avoided cost methods and procedures. These costs have been used to assess DSM and cogeneration, as well as to develop integrated resource plans. Clients include Public Service Company of Oklahoma, Central Maine Power Company, Duquesne Light Company, and the New York investor-owned utilities.

Advised Central Maine Power Company (CMP) on the development of a competitive bidding framework. This framework was implemented in 1984 and was the first of its kind in the nation. CMP adopted the framework outlined in EMA's report and won prompt regulatory approval.

Advised a utility in the development of an incentive ratemaking plan for a new nuclear facility. This assignment involved strategic analysis of alternate proposals and quantification of the financial impact of various ratemaking alternatives. Presented strategic and financial results in order to convince senior management to initiate negotiations for the incentive plan.

Advised and testified on behalf of the New York Power Pool utilities on the methodology for measuring pool marginal capacity costs. This work included development of the methodology and implementation of the system for quantifying LOLP-based marginal capacity costs.

Provided testimony on behalf of the investor-owned electric utilities in New York State, concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the Commission and used as the basis for DSM evaluation in New York from 1982 through 1988.

Developed the functional design of a retail access settlement system and business processes for a major PJM combination utility. This design is being used to construct a software system and develop business procedures that will be used for retail settlements beginning January 1999.

Reviewed the power pool operating and interchange accounting procedure of the New York Power Pool, the Pennsylvania, New Jersey, Maryland Interconnection, Allegheny Power System, Southern Company, and the New England Power Pool as part of various consulting assignments and in connection with the development of production simulation software.

Summarized and analyzed the operational NEPOOL to examine the feasibility of incorporating NEPOOL interchange impacts with Central Maine and accounting procedure of the New England Power Pool Power Company's buy-back tariffs.

Developed and presented a two-day seminar delivered to electric industry participants in the UK (prior to privatization), outlining the structure and operation of power pools and bulk power market transactions in North America.

Benchmark analysis and FERC testimony of PGE's proposed twelve-year contract between PG&E and Electric Gen LLC (contract value in excess of $15 billion).

Responsible for NERA's overall efforts in advising New Jersey's Electric Distribution Companies on the structuring and conduct of the Basic Generation Service auctions (the 2002 auction involved $3.5 billion, and the 2003 and 2004 auctions involved over $4.0 billion).

Publications, Speeches, Presentations, and Reports

Capacity Adequacy in New Zealand's Electricity Market, published in *Asian Power*, September 18, 2003

Central Resource Adequacy Markets For PJM, NY-ISO AND NE-ISO, a report written February 2004

Ex Ante or *Ex Post*? Risk, Hedging and Prudence in the Restructured Power Business, The Electricity Journal, April 2006

Distributed Resources: Incentives, a white paper prepared for Edison Electric Institute, May 2006

Restructuring Expectations and Outcomes, a presentation presented at the Saul Ewing Annual Utility Conference: The Post Rate Cap and 2007 State Regulatory Environment, Philadelphia, PA, May 21, 2007

Making a Business of Energy Efficiency: Sustainable Business Models for Utilities, prepared for Edison Electric Institute, August 2007

Restructuring at a Crossroads, presented at Empowering Consumers Through Competitive Markets: The Choice Is Yours, Sponsored by COMPETE and the Electric Power Supply Association, Washington, DC, November 5, 2007

Competitive Electricity Markets: The Benefits for Customers and the Environment, a white paper prepared for COMPETE Collation, February 2008

The Continuing Rationale for Full and Timely Recovery of Fuel Price Levels in Fuel Adjustment Clauses, The Electricity Journal, July 2008

Impact of EU Electricity Competition Directives on Nuclear Financing presented to: SMI – Financing Nuclear Power Conference, London, UK, May 20, 2009

Testimony

Forums

Arkansas Public Service Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Maine Public Utilities Commission

Minnesota Public Service Commission

Nevada Public Service Commission

New York Public Service Commission

Nuclear Regulatory Commission – Atomic Safety and Licensing Board

Oklahoma Public Service Commission

Public Service Commission of Indiana

Public Utilities Commission of Ohio

Public Utilities Commission of Nevada

Public Utilities Commission of Texas

Public Utilities Commission of New Hampshire

United States District Court

United States Senate Committee on Energy and Natural Resources

Various arbitration proceedings

Clients

Arkansas Power & Light Company

Baltimore Gas & Electric

Carolina Power & Light Company

Central Maine Power

Consolidated Edison Company of New York, Inc.

Dayton Power and Light Company

Florida Coordinating Group

Houston Lighting & Power Company

Minnesota Power and Light Company

Nevada Power Company

Niagara Mohawk Power Corporation

Northern Indiana Public Service Company

Oglethorpe Power Corporation

Pacific Gas and Electric Company

Power Authority of the State of New York

Public Service and Electric Company

Public Service Company of Oklahoma

Sierra Pacific Power Company

Southern Company Services, Inc.

Tucson Electric Power Company

Texas-New Mexico Power Company

Recent Expert Testimony and Expert Reports

Supplemental Testimony on behalf of Texas-New Mexico Power Company, Docket No. 15660, September 5, 1996.

Direct Testimony on behalf of Long Island Lighting Company before the Federal Energy Regulatory Commission, September 29, 1997.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, SOAH Docket No. 473-97-1561, PUC Docket No. 17751, March 2, 1998.

Prepared Testimony and deposition testimony on behalf of Central Maine Power Company, United Stated District Court Southern District of New York, 98-civ-8162 (JSM), March 5, 1999.

Prepared Direct Testimony Before the Public Service Commission of Maryland on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, June 1999.

Rebuttal Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, March 22, 1999.

NORCON Power Partners LP v. Niagara Mohawk Energy Marketing, before the United States District Court, Southern District of New York, June 1999.

Prepared Supplemental Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, July 23, 1999.

Prepared Supplemental Reply Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, August 3, 1999.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0681, September 3, 1999.

Rebuttal Testimony on behalf of Niagara Mohawk, PSC Case No. 99-E-0681 Before the New York State Public Service Commission, November 10, 1999.

Arbitration deposition on behalf of Oglethorpe Power Corporation, last quarter of 1999.

Direct Testimony Before the Public Utilities Commission of Ohio on behalf of FirstEnergy Corporation, Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, Case No. 99-1212-EL-ETP re: Shopping Credits.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0990, February 25, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., State of Connecticut, Department of Public Utility Control, Docket No.: 00-01-11, April 28, 2000 and June 30, 2000.

Testimony on behalf of Texas-New Mexico Power Company, Fuel Reconciliation Proceeding before the Texas PUC, June 30, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the New Hampshire Public Service Commission, Docket No.: DE 00-009, June 30, 2000.

Rebuttal Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, November 22, 2000.

Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, January 19, 2001.

DETM Management, Inc. Duke Energy Services Canada Ltd., And DTMSI Management Ltd., Claimants vs. Mobil Natural Gas Inc., And Mobil Canada Products, Ltd., Respondents. American Arbitration Association Cause No. 50 T 198 00485 00, August 27, 2001.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) Docket No.: EX01050303, October 4, 2001.

Direct Testimony Before the Federal Energy Regulatory Commission on behalf of Pacific Gas and Electric Company, Docket No.: ER02-456-000, November 30, 2001.

Fourth Branch Associates/Mechanicville vs. Niagara Mohawk Power Corporation, January 2002 (Expert Report).

Arbitration Deposition on behalf of Oglethorpe Power Corporation, March 2002.

Direct Testimony and Deposition Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, July 16, 2002.

Rebuttal Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, August 13, 2002.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, in the matter of the Application of Nevada Power Company to Reduce Fuel and Purchased Power Rates, PUCN Docket No. 02-11021, November 8, 2002 and subsequent Deposition Testimony.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, Docket No. 03-1014, January 10, 2003.

Direct Testimony Before the Public Utility Commission Of Texas on behalf of Texas-New Mexico Power Company, Application Of Texas-New Mexico Power Company For Reconciliation Of Fuel Costs, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, PUCN Docket No. 02-11021, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company, Docket No. 03-1014, May 5, 2003.

Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the Public Service Commission of New York, Case No.: 00-E-0612, September 19, 2003.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 12, 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 12, 2004.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, May 28, 2004.

Direct Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, January 22, 2004.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, April, 2004.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 9, 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 7, 2005.

Expert Report on behalf of Oglethorpe Power Corporation, March 23, 2005.

Arbitration deposition on behalf of Oglethorpe Power Corporation, April 1, 2005.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's December 2005 Deferred Energy Case.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, January 13, 2006.

Remand Rebuttal for Public Service Company of Oklahoma before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200200038, **Confidential**, March 17, 2006

Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, April 18, 2006.

Cross-Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, May 22, 2006.

Distributed Resources: Incentives, a report prepared for Edison Electric Institute, May 2006

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, Docket No. 06-01016, June 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386, December 22, 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 05-0315, December 29, 2006.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2007 Deferred Energy Case, January 2007.

Declaration Before the State of New York Public Service Commission, on behalf of Consolidated Edison Company of New York, Inc.'s Long Island City Electric Network, Case 06-E-0894 – Proceeding on Motion of the Commission to Investigate the Electric Power Outage and Case 06-E-1158 – In the Matter of Staff's Investigation of Consolidated Edison Company of New York, Inc.'s Performance During and Following the July and September Electric Utility Outages. July 24, 2007

Direct Testimony Before The Public Utilities Commission of Colorado, In The Matter of the Application of Public Service Company of Colorado for Approval of its 2007 Colorado Resource Plan, April 2008

Answer Testimony Before the Public Utilities Commission of the State of Colorado on behalf of Trans-Elect Development Company, LLC, and The Wyoming Infrastructure Authority, Docket No. 07A-447E, April 28, 2008

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's 2008 Deferred Energy Case, February 2009.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2008 Deferred Energy Case, February 2009.

Direct Testimony Before the Public Utilities Commission of Texas, on behalf of Entergy Texas, Inc. Docket No. 33687, April 29, 2009

Direct Testimony Before The Public Utilities Commission Of Nevada On Behalf of Nevada Power Company D/B/A Nevada Energy, 2010 – 2029 Integrated Resource Plan, June 26, 2009

Before the Public Service Commission of New York, Case 09-E-0428 Consolidated Edison Company of New York, Inc. Rate Case, Rebuttal Testimony, September 2009

Direct Testimony Before the Public Utilities Commission of Nevada on Behalf of Sierra Pacific Power Company's 2009 Deferred Energy Case, February 2010.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2009 Deferred Energy Case, February 2010

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2010 – 2029 Integrated Resource Plan, Docket No. 09-07003, July 2010

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Eighth Amendment to its 2008 – 2027 Integrated Resource Plan, Docket No. 10-03023, July 2010

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Application of Nevada power Company d/b/a NV Energy Seeking Acceptance of its Triennial Integrated Resource Plan covering the period 2010-2029, including authority to proceed with the permitting and construction of the ON Line transmission project, Docket No. 10-02009

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Petition of Nevada Power Company d/b/a NV Energy requesting a determination under NRS 704.7821 that the terms and conditions of five renewable power purchase agreements are just and reasonable and allowing limited deviation from the requirements of NAC 704.8885, Docket No. 10-03022

Rebuttal Testimony Before the Public Utilities commission of Nevada, Application of Sierra pacific Power Company d/b/a/ NV Energy Seeking Acceptance of its Eight Amendment to its 2008-2007 Integrated Resource Plan, Docket No. 10-02023

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 11-03 ____ 2011 Electric Deferred Energy Proceeding, February 2011

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 11-03 ____ 2011 Electric Deferred Energy Proceeding, February 2011

February 2011

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 JF/EM-3. Cost Advantage of BEC vs. NYC LMS100

Gas Price ($/MMBTU)	LMS100 ($/MWh)	BEC	BEC Cost Advantage
5	55.13	[redacted]	[redacted]
6	64.82		
7	74.52		
8	84.22		

Average heat rates are taken as the average of the summer and winter heat rates.
The average heat rate of an LMS100 unit is 9065.5 BTU/kWh. The average heat rate of the BEC is [redacted] BTU/kWh.
The variable O&M cost of an LMS100 unit is $4.78/MWh. The variable O&M cost of the BEC is [redacted] /MWh.
The energy price of an LMS100 unit reflects a 6.99% NYC fuel use tax and 20.4 cents LDC adder.
BEC [redacted] these costs.

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

ATTESTATION

We are the witnesses identified in the foregoing Affidavit of Eugene T. Meehan and Jonathan Falk dated October 10, 2011 (the "Affidavit"). We have read the Affidavit and are familiar with its contents. The facts set forth therein are true to the best of our knowledge, information, and belief.

Subscribed and sworn to before me
this 10th day of October 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

Eugene T. Meehan
Senior Vice President
NERA Economic Consulting
October 10, 2011

Subscribed and sworn to before me
this 10th day of October 2011

SS: New York

Notary Public
My Commission Expires: Oct. 13, 2014

GRETCHEN P. POLK
Notary Public, State of New York
No. 5003066
Qualified in Westchester County
Commission Expires October 13, 2014

Jonathan Falk
Vice President
NERA Economic Consulting
October 10, 2011

ATTACHMENT IV

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 respond to statements by Complainants addressing certain topics in my September 7, 2011, Affidavit of Christopher D. Ungate Regarding Astoria Energy II ("AEII Affidavit") and Affidavit of Christopher D. Ungate Regarding Bayonne Energy Center ("BEC Affidavit") filed as Appendices IV and V, respectively, to the NYISO's *Confidential Supplemental Answer.*[1] The AEII Affidavit and BEC Affidavit presented the cost and performance inputs for the Astoria Energy II ("AEII") project and the Bayonne Energy Center ("BEC") project for use in determining the Cost

[1] *Confidential Supplemental Answer of the New York Independent System Operator, Inc.*, Appendix IV Affidavit of Christopher D. Ungate Regarding Bayonne Energy Center ("AEII Affidavit") and Appendix V Affidavit of Christopher D. Ungate Regarding Bayonne Energy Center ("BEC Affidavit"), Docket No. EL11-50-000 (filed September 8, 2011) ("Confidential Supplemental Answer").

of New Entry ("CONE") for the projects. These topics include interconnection costs, financial assumptions, income tax rates, and sunk costs.

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. My qualifications are further described in my AEII and BEC Affidavits that are Attachments IV and V to the NYISO's Confidential Supplemental Answer including my resume which is Exhibit CDU-1to those Affidavits.

III. Interconnection Costs

4. Astoria Energy, on behalf of AEII, and Hess on behalf of BEC, provided Sargent & Lundy with capital cost information for the respective projects. At the time this information was provided (August-September 2010), the developers of the respective projects were moving forward with the projects. Equipment requiring long lead procurement, such as combustion turbines, were under contract, and construction was underway. For each of the projects, the capital cost information was a combination of known costs and estimates of future costs for items not yet purchased or work not yet performed.

5. Complainants have taken issue with the reasonableness of the interconnection cost estimates utilized in the Unit Net CONE determinations.[2] Interconnection costs are just one of the many line items of cost contained in the capital cost information provided by

[2] *Complainant's Answer to Supplemental Answer of the New York Independent System Operator, Inc.*, ("Complainants Answer") at Attachment A Second Supplemental Affidavit of Mark D. Younger at PP 90-93, Docket No. EL11-50-000 (filed September 23, 2011) ("Second Supplemental Younger Affidavit").

the developers. At the time interconnection cost information was provided by the developers, I have been informed that studies were being conducted by NYISO to determine system upgrades and associated costs for the projects to be presented to the NYISO's Operating Committee for approval. Because these studies were not complete, the interconnection costs submitted by developers were estimates of what the final interconnection costs would be. The following paragraphs describe how Sargent & Lundy reviewed the reasonableness of the capital cost information, including interconnection costs, provided by the developers, and provides my perspective on the Complainant's comments now that more recent estimates for these costs are available and have been approved by the Operating Committee.

6. To determine the reasonableness of the capital cost information provided by each developer, Sargent & Lundy followed the following process.

   a. We first had the project developer categorize the costs using the same breakdown of capital costs presented for peaking plants in the NERA/S&L Demand Curve Report.[3]

   b. In the case of AEII, we compared the cost breakdown provided by Astoria Energy to a hypothetical 2 x 2 x 1 combined cycle plant based on the approach used in the NERA/S&L Demand Curve Report.

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

c. In the case of BEC, we compared the cost breakdown provided by Hess to a hypothetical two unit RR Trent 60 WLE installation, also located in New Jersey and connected to NYCA by submarine cable, as shown in the NERA/S&L Demand Curve Report.

d. Based on these comparisons and our knowledge of capital costs for similar projects, we followed up with the project developers to ask for additional information or explanations for particular cost elements.

e. We then formed our opinion about the reasonableness of the capital cost information for AEII and BEC, as outlined in the AEII Affidavit and BEC Affidavit.

A. AEII Interconnection Costs

7. Exhibit CDU -2, from my AEII Affidavit, shows the comparison of capital cost information for AEII with the hypothetical 2 x 2 x 1 combined cycle plant based on the approach used in the NERA/S&L Demand Curve Report. For convenience, this comparison is provided as Exhibit CDU Supp. – 1 to this affidavit. The comparison shows that the total for EPC costs provided by Astoria Energy is about [redacted] than the EPC cost for the hypothetical plant, which Sargent & Lundy found as not unreasonable given the size and complexity of the AEII project. AEII equipment costs were [redacted] than the hypothetical plant; construction costs were [redacted]; and Startup & Testing costs were [redacted], while estimated Contingency was [redacted]. Based on conversations with Astoria Energy, what ordinarily might seem like a [redacted] of Contingency reflects the fact that the costs of Equipment and Construction

were known with more certainty and required less Contingency at the time the capital cost information was provided to Sargent & Lundy and the NYISO -- about 10 months in advance of commercial operation. Sargent & Lundy determined this to be a reasonable allocation of Equipment, Construction, Startup & Testing, and Contingency estimates at this point in the development of the project.

8. Exhibit CDU Supp. – 1 shows [redacted] in the cost of Construction line items between the AEII information and the hypothetical plant. For example, AEII capital cost information for Electrical Connection & Substation, Site Preparation, and Construction Management/Field Engineering/Indirects was [redacted] than the hypothetical unit, while AEII capital cost information for Construction Labor & Materials, Gas Interconnect & Reinforcement, and Engineering Design was [redacted] than the hypothetical unit. After questioning Astoria Energy representatives, I concluded that it was likely that Astoria Energy categorized some costs differently than Sargent & Lundy had categorized them for the hypothetical unit. From experience I knew that this could easily happen given the number of contracts and the complexity of the project, and that resolving the differences between Astoria Energy's categorization of costs and Sargent & Lundy's categorization of costs would require an extensive review of source data. Given that the EPC cost estimate provided by Astoria Energy was [redacted] different from Sargent & Lundy's independent estimate for the hypothetical unit, we determined that the Astoria Energy estimate for the EPC cost of the AEII project was reasonable.

B. BEC Interconnection Costs

9. Exhibit CDU -2, from my BEC Affidavit, shows the comparison of capital cost information for BEC with a hypothetical two unit RR Trent 60 WLE installation, also located in New Jersey and connected to NYCA by submarine cable, as shown in the NERA/S&L Demand Curve Report. For convenience, this comparison is provided as Exhibit CDU Supp. – 2 to this affidavit.[4] The comparison is complicated because the BEC project is an 8-unit RR Trent 60 WLE plant and the hypothetical plant from the NERA/S&L Demand Curve Report is a 2-unit installation. I would expect that the comparison of the BEC capital cost information to an estimate for an 8-unit installation based on multiplying the cost of the two unit installation by a factor of four would show savings due to economies of scale. Such a comparison is provided in Exhibit CDU Supp. – 3.[5]

10. The comparison in Exhibit CDU Supp. – 3 shows that the total for EPC costs provided by Hess is about [redacted] than the EPC costs for the hypothetical 8-unit plant using the approach described in the previous paragraph. Sargent & Lundy found Hess's estimate of EPC costs to be reasonable given the economies of scale. However, Sargent & Lundy's review went beyond a mere multiplication of the number of units. BEC equipment costs were [redacted] than the hypothetical 8-unit plant; construction costs were [redacted]; and Startup & Testing costs were [redacted], while estimated

[4] Note that I have corrected an addition error in the "Subtotal – Startup & Testing" line item that appears in Exhibit CDU – 2 to my BEC Affidavit. The error is not significant and does not affect my findings in that affidavit.

[5] The cost of Hypothetical 8-Unit Plant in Exhibit CDU Supp. – 3 is simply four times the cost of the two unit plant, excluding the submarine cable, as shown in Exhibit CDU Supp. – 2. It is provided for comparative purposes only. This estimate does not reflect a detailed development of the cost of a hypothetical 8-unit plant using the approach taken by Sargent & Lundy for and described in the NERA/S&L Demand Curve Report.

Contingency was [redacted]. Based on conversations with the developer, the [redacted] Equipment costs were based on its contract with the combustion turbine supplier. The [redacted] amount of Contingency reflects the number of significant cost items, such as the combustion turbines, which were under contract, and the state of construction, at the time the capital cost information was provided -- about 20 months in advance of commercial operation. Based on these findings, Sargent & Lundy found Hess's allocation of cost among Equipment, Construction, Startup & Testing, and Contingency at this point in the development of the project to be reasonable.

11. Similar to Exhibit CDU Supp. – 1 for the AEII project, Exhibit CDU Supp. – 3 shows considerable differences in the cost of Construction line items between the BEC information and the hypothetical 8-unit plant. Without considering the aforementioned effects of economies of scale, BEC capital cost information for Electrical Interconnect & Upgrades and Gas Interconnect & Reinforcement was [redacted] than the hypothetical 8-unit. BEC capital cost information for Site Preparation and Engineering Design was [redacted] than the hypothetical 8-unit installation, although this difference may [redacted]. After questioning the developer's representatives, I concluded that it was likely that BEC categorized some costs differently than Sargent & Lundy had categorized them for the hypothetical plant. I knew that this could easily happen given the number of contracts and the complexity of the project, and that resolving the differences between the developers' categorization of costs and Sargent & Lundy's categorization of costs would require an extensive review of source data. Given that the EPC cost estimate provided by Hess reflected reasonable

economies of scale from Sargent & Lundy's estimate for the hypothetical 8-unit plant, we determined that the Hess estimate for the EPC cost of the BEC project was reasonable.

C. Summary - Interconnection Costs

12. Complainants take issue with the variance between the interconnection cost estimates provided by each project in the August – September 2010 time period, as compared to estimates approved by the Operating Committee for purposes of Class Year cost allocations that are available one year later.[6] Actual costs or updated cost estimates for other cost categories are not available to determine all variances. To point out that there is a significant variance in one line item without considering the potential effect of variances in other line items is potentially misleading and does not invalidate the conclusions reached in our assessment.

13. The overall process Sargent & Lundy conducted to determine the reasonableness of AEII and BEC capital cost information was itself reasonable and based on Sargent & Lundy's approach and experience with numerous other due diligence assignments.

IV. Financial Assumptions for AEII Project

14. As part of the Unit Net CONE determination, Sargent & Lundy calculated real levelized carrying charge rates for the AEII project. The 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, and income taxes.

[6] Second Supplemental Younger Affidavit at PP 91-92.

Property taxes were included in the carrying charge calculation to account for property tax abatement under the former ICIP program.[7]

15. Astoria Energy provided Sargent & Lundy with project financing information for the AEII project. The financing information used in the Unit Net CONE calculation was:

	2010 Demand Curve Reset Study	AEII Project
Equity Fraction	0.500	[redacted]
Debt Fraction	0.500	[redacted]
Cost of Equity (after tax, nominal)	12.48%	[redacted]
Cost of Debt (pre-tax, nominal)	7.25%	[redacted]

16. Income tax rates applicable to the project, which is another component of the carrying charge rates, were also provided by Astoria Energy and are discussed below.

17. AEII achieved financial close on July 2, 2009. Consequently, the debt/equity ratio and cost of debt were already well-established at the time the information was provided to Sargent & Lundy in August-September 2010. The debt/equity ratio and cost of debt established at the financial close are the basis for funding the monthly construction draws and calculating interest during construction.

18. The financing amounts and costs of debt as provided by Astoria Energy were consistent with the published project information at the time (for example, as published in Project Finance, March 1, 2010). Sargent & Lundy thus judged this information to be reasonable and accurate.

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[7] AEII [redacted] under the former ICIP program [redacted]. The property tax exemption under ICIP has a gradual phase-out in years 12 through 15. Carrying charges were [redacted], as presented in my AEII Affidavit.

19. The AEII project is structured as an LLC. At the time the information was provided to Sargent & Lundy, AEII had four equity partners. The cost of equity for each of those partners was not available to Astoria Energy. In response to Sargent & Lundy's request, Astoria Energy estimated the composite after-tax cost of equity for the partners to be [redacted]. This is a composite rate that accounts for the estimated income tax liabilities of the partners.

20. Compared with the estimated cost of equity used in the 2010 Demand Curve Reset Study, Astoria Energy's estimate is [redacted]. This range in equity returns is within the range of variation among other independent power projects with which Sargent & Lundy is familiar.

21. Projects with nearly identical risk characteristics have a broad range of target equity returns. Sargent & Lundy has observed this, for example, in its experience in evaluating bids for independent power projects. The project-specific return on equity is related to several factors, including the amount of leverage, the terms and conditions in the various project agreements, the terms and conditions of the project debt, the tax status of the equity partners, and the developer's judgment of the project risks. The developer's judgment of the project risks, for example, is closely related to the risk of the project's projected cash flows. The projected cash flows are dependent on the developer's long-term assumptions about the power market, which can vary significantly. For these reasons, the "merchant risk" is not uniform across all merchant projects. Based on Sargent & Lundy's experience, the composite after-tax cost of equity for the LLC partners as estimated by Astoria Energy was judged to be reasonable.

V. Financial Assumptions for BEC Project

22. As part of the CONE determination, Sargent & Lundy calculated real levelized carrying charge rates for the BEC project. The 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, and income taxes. Property taxes were included in the carrying charge calculation.

23. Hess provided Sargent & Lundy with project financing information for the BEC project. The financing information for the project used in the Unit Net CONE calculation was:

	2010 Demand Curve Reset Study	BEC Project
Equity Fraction	0.500	[redacted]
Debt Fraction	0.500	[redacted]
Cost of Equity (after tax, nominal)	12.48%	[redacted]
Cost of Debt (pre-tax, nominal)	7.25%	[redacted]

24. Income tax rates applicable to the project, which is another component of the carrying charge rates, were also provided by Hess and are discussed below.

25. BEC achieved financial close on September 30, 2010, shortly after the time Hess provided the above information. Consequently, the debt/equity ratios and cost of debt were already well-established at the time the information was provided to Sargent & Lundy. The debt/equity ratio and cost of debt established at the financial close are the basis for funding the monthly construction draws and calculating interest during construction

26. The BEC project is structured as an LLC. BEC's equity partners are subsidiaries of Hess Corporation and ArcLight Capital Partners. Hess estimated the composite after-tax cost of equity for the BEC project partners to be [redacted].

27. Compared with the estimated cost of equity used in the NERA/S&L Demand Curve Reset Report, Hess's estimate is [redacted]. This range in equity returns is within the range of variation in other independent power projects with which Sargent & Lundy is familiar.

28. Projects with nearly identical risk characteristics have a broad range of target equity returns. Sargent & Lundy has observed this, for example, in its experience in evaluating bids for independent power projects. The project-specific return on equity is related to several factors, including the amount of leverage, the terms and conditions in the various project agreements, the terms and conditions of the project debt, the tax status of the equity partners, and the developer's judgment of the project risks. The developer's judgment of the project risks, for example, is closely related to the risk of the project's projected cash flows. The projected cash flows are dependent on the developer's long-term assumptions about the power market, which can vary significantly. For these reasons, the "merchant risk" is not uniform across all merchant projects. Based on Sargent & Lundy's experience, the composite after-tax cost of equity for the LLC partners as estimated by Hess was judged to be reasonable.

VI. Income Tax Rates

29. As discussed above in the section on financial assumptions, 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, and income taxes. Income taxes affect the carrying charges because 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. Astoria Energy and Hess provided Sargent & Lundy with income tax information for the AEII and BEC projects, respectively. At the time this information was provided (August-September 2010), the terms of the financing for both projects were already known. The income tax information included the following:

	2010 Demand Curve Reset Study	AEII Project	BEC Project
Federal Tax Rate	35.00%	[redacted]	[redacted]
State Tax Rate	7.10%	[redacted]	[redacted]
City Tax Rate	8.85%	[redacted]	[redacted]
Composite Tax Rate *	45.37%	[redacted]	[redacted]

* State and city taxes are deductible against federal taxes.

30. The AEII and BEC projects are both structured as LLCs, so the actual tax rates will depend on the tax status of the individual developers. Astoria Energy and Hess, as acknowledged by the Complainants in the Affidavit of Glenn Todd of KPMG,[8] indicated that the actual tax status of the individual developers is not known. Astoria Energy, Hess, and KPMG assumed that the [redacted] corporate tax rate was a reasonable estimate of federal taxes.

[8] *See* Complainants Answer at Attachment E Affidavit of Glenn Todd at P 5, Exhibit B, Docket No. EL11-50-000 (filed September 23, 2011).

31. Regarding AEII, at the time the information was provided to Sargent & Lundy, AEII had four equity partners. The tax records for each of those partners was confidential information not available to Astoria Energy. Astoria Energy estimated the composite city/state tax rate for the partners to be [redacted]. This estimate took into consideration Astoria Energy's knowledge of the LLC ownership structure and the potential tax liabilities of the individual owners. KPMG's analysis was based on its own assumptions about the LLC ownership structure derived from AEII's filing to the New York State Public Service Commission on December 15, 2008.[9] Both Astoria Energy's and KPMG's respective estimates took into account the tax rates, deductions, and credits applicable to the individual owners. Sargent & Lundy judged Astoria Energy's estimate to be a reasonable estimate.

32. BEC's equity partners are subsidiaries of Hess Corporation and ArcLight Capital Partners. Hess' tax advisors determined that BEC would be subject to the New Jersey state income tax rate of [redacted] and the New York City General Corporation Tax Rate of [redacted]. Sargent & Lundy judged this to be a reasonable estimate given the fact that the project is located in New Jersey and is interconnected directly to New York City via submarine cable.

VI. Sunk Costs

33. Complainants cite Sargent & Lundy's estimate of one half of permitting and legal costs as sunk costs as an example of the imprecision of the Unit Net CONE determinations.[10]

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[9] *Id.* at P 3.

[10] Complainants Answer at 22.

In contrast, Brookfield's witness Roy Shanker agrees with Sargent & Lundy; he states that 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 can be viewed as sunk."[11]

34. As explained in my AEII Affidavit and BEC Affidavit, the portion of owner's cost for project development depends on the timing of the decision to move forward with a project, which is not necessarily tied to a specific date, but to a series of decision points over an extended period of time. Sargent & Lundy's experience with project development shows that permitting and legal costs occur both before and after the decision to move forward. Given that the magnitude of permitting and legal costs is small relative to total project costs, I determined that it was reasonable to consider one half of legal and permitting costs as sunk and the remainder as yet to be incurred.

This concludes my Affidavit.

[11] *Answer of Brookfield Energy Marketing LP* at Affidavit of Roy J. Shanker Ph. D. on Behalf of Brookfield Energy Management LP at 13, Docket No. EL11-50-000 (filed September 23, 2011).

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 Supp. -1

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			
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	
Owner's Project Mgmt. & Misc. Engr.	16,509,000	16,905,000	
Social Justice	3,302,000	3,381,000	
Owner's Development Costs (total)	24,763,000	25,357,000	
Financing Fees	16,509,000	16,905,000	
Financial Advisory	2,064,000	2,114,000	
Environmental Studies	2,064,000	2,114,000	
Market Studies	2,064,000	2,114,000	
Interconnection Studies	2,064,000	2,114,000	
Emission Reduction Credits	0	0	
Subtotal	94,102,000	96,361,000	
Financing (incl. AFUDC, IDC)			
EPC Portion	83,494,000	85,498,000	
Non-EPC Portion	9,518,000	9,747,000	
Working Capital and Inventories	16,509,000	16,905,000	
Subtotal - Non-EPC Costs	203,623,000	208,511,000	
Total Capital Investment	1,029,069,000	1,053,768,000	

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

CLEAN VERSION - EXHIBIT CDU Supp. -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	
Spare Parts	1,061,000	1,113,000	
Subtotal - Equipment and Spare Parts	1,061,000	72,535,000	
Construction			
Construction Labor & Materials	45,924,000	48,155,000	
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	
Startup & Testing			
Startup & Training	1,070,000	1,122,000	
Testing	0	0	
Subtotal - Startup & Testing	1,070,000	1,122,000	
Contingency	13,001,000	13,633,000	
Subtotal - EPC Costs	85,857,000	161,450,000	

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	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	859,000	1,615,000	
Legal	1,717,000	3,229,000	
Owner's Project Mgmt. & Misc. Engr.	1,717,000	3,229,000	
Social Justice	773,000	1,453,000	
Owner's Development Costs	2,576,000	4,844,000	
Financing Fees	1,717,000	3,229,000	
Financial Advisory	215,000	404,000	
Environmental Studies	215,000	404,000	
Market Studies	215,000	404,000	
Interconnection Studies	215,000	404,000	
Emission Reduction Credits	270,000	283,000	
Subtotal - Owner's Costs	10,489,000	19,498,000	
Financing (incl. AFUDC, IDC)			
EPC Portion	4,301,000	8,089,000	
Non-EPC Portion	525,000	977,000	
Working Capital and Inventories	1,717,000	3,229,000	
Subtotal - Non-EPC Costs	17,032,000	31,793,000	
Submarine Cable Installation	68,305,000	71,623,000	
Total Capital Investment	**171,194,000**	**264,866,000**	

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

REDLINE VERSION - EXHIBIT CDU Supp. -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	
Spare Parts	1,061,000	1,113,000	
Subtotal - Equipment and Spare Parts	1,061,000	72,535,000	
Construction			
Construction Labor & Materials	45,924,000	48,155,000	
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	
Startup & Testing			
Startup & Training	1,070,000	1,122,000	
Testing	0	0	
Subtotal - Startup & Testing	~~1,070,000~~0	~~1,122,000~~0	
Contingency	13,001,000	13,633,000	
Subtotal - EPC Costs	84~~,575~~87,000	160,328~~450,~~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	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	84859,000	1,60315,000	
Legal	1,696717,000	3,20729,000	
Owner's Project Mgmt. & Misc. Engr.	1,696717,000	3,20729,000	
Social Justice	7673,000	1,4453,000	
Owner's Development Costs	2,54476,000	4,81044,000	
Financing Fees	1,696717,000	3,20729,000	
Financial Advisory	2125,000	4014,000	
Environmental Studies	2125,000	4014,000	
Market Studies	2125,000	4014,000	
Interconnection Studies	2125,000	4014,000	
Emission Reduction Credits	270,000	283,000	
Subtotal - Owner's Costs	10,361489,000	19,36498,000	
Financing (incl. AFUDC, IDC)			
EPC Portion	4,248301,000	8,03289,000	
Non-EPC Portion	51925,000	9707,000	
Working Capital and Inventories	1,696717,000	3,20729,000	
Subtotal - Non-EPC Costs	16,82417,032,000	31,5793,000	
Submarine Cable Installation	68,305,000	71,623,000	
Total Capital Investment	**169,916171,194,000**	**263,524,866,000**	

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

EXHIBIT CDU Supp. -3

Capital Costs – Hypothetical 8-Unit Plant vs. BEC (8 Units)

(Note: The cost of Hypothetical 8-Unit Plant is simply four times the cost of the two unit plant, excluding the submarine cable, as shown in Exhibit CDU – 2. It is provided for comparative purposes only. This estimate does not reflect a detailed development of the cost of a hypothetical 8-unit plant using the approach taken by Sargent & Lundy for and described in the NERA/S&L Demand Curve Report.)

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	272,452,000	285,687,000	[redacted]
Spare Parts	4,244,000	4,450,000	
Subtotal - Equipment and Spare Parts	4,244,000	290,137,000	
Construction			
Construction Labor & Materials	183,696,000	192,619,000	
Electrical Connection & Substation	19,540,000	20,489,000	
Electrical Interconnect & Upgrades	19,200,000	20,133,000	
Gas Interconnect & Reinforcement	16,392,000	17,188,000	
Site Prep	11,976,000	12,558,000	
Engineering & Design	25,676,000	26,923,000	
Construction Mgmt. / Field Engr.	6,420,000	6,732,000	
Subtotal - Construction	282,900,000	296,642,000	
Startup & Testing			
Startup & Training	4,280,000	4,488,000	
Testing	0	0	
Subtotal - Startup & Testing	4,280,000	4,488,000	
Contingency	52,004,000	54,530,000	
Subtotal - EPC Costs	343,428,000	645,797,000	

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	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	3,434,000	6,458,000	
Legal	6,869,000	12,916,000	
Owner's Project Mgmt. & Misc. Engr.	6,869,000	12,916,000	
Social Justice	3,091,000	5,812,000	
Owner's Development Costs	10,303,000	19,374,000	
Financing Fees	6,869,000	12,916,000	
Financial Advisory	859,000	1,614,000	
Environmental Studies	859,000	1,614,000	
Market Studies	859,000	1,614,000	
Interconnection Studies	859,000	1,614,000	
Emission Reduction Credits	1,080,000	1,132,000	
Subtotal - Owner's Costs	41,951,000	77,980,000	
Financing (incl. AFUDC, IDC)			
EPC Portion	17,206,000	32,354,000	
Non-EPC Portion	2,102,000	3,907,000	
Working Capital and Inventories	6,869,000	12,916,000	
Subtotal - Non-EPC Costs	68,128,000	127,157,000	
Submarine Cable Installation	68,305,000	71,623,000	
Total Capital Investment	**479,861,000**	**844,577,000**	

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

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

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

Notary Public

My commission expires: 12-21-2014