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October 1, 2007

VIA ELECTRONIC MAIL

Ms. Karen Antion
Chairman of the Board of Directors
c/o Robert E. Fernandez, Esq.
General Counsel
New York Independent System Operator, Inc
10 Krey Boulevard
Rensselaer, New York 12144

Re: Installed Capacity Demand Curves
Supplemental Information and Request for Oral Argument

Dear Chairman Antion:

In accordance with Sections 5.14.1(b)(ix) and (x) of the New York Independent System Operator, Inc.'s ("NYISO") Market Administration and Control Area Services Tariff and Section 5.6.6. of the NYISO's Installed Capacity Manual, enclosed please find an original and two copies of supplemental information on the NYISO Staff's proposed Installed Capacity Demand Curves for Capability Years 2008-2009, 2009-2010, and 2010-2011. This submission is made on behalf of AES Eastern Energy, L.P., Astoria Generating Company, L.P., a U.S. Power Generating Company, Dynegy Northeast Generation, Inc., Entergy Nuclear Power Marketing, LLC, the Indeck Companies, and the Mirant Parties (collectively, the "New York Suppliers").

Additionally, the New York Suppliers respectfully request the opportunity to engage in oral arguments before the NYISO Board of Directors' Market Performance Subcommittee on the issues addressed in the enclosed submission and those of other market participants.

Sincerely yours,

GREENBERG TRAURIG, LLP

Kevin M. Lang
Counsel to the New York Suppliers

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SUPPLEMENTAL INFORMATION AND COMMENTS OF THE NEW YORK SUPPLIERS ON THE NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.'S PROPOSED INSTALLED CAPACITY DEMAND CURVES FOR CAPABILITY YEARS 2008-2009, 2009-2010 AND 2010-2011

In accordance with Sections 5.14.1(b)(ix) and (x) of the New York Independent System Operator, Inc.'s ("NYISO") Market Administration and Control Area Services Tariff ("Services Tariff") and Section 5.6.6. of the NYISO's Installed Capacity ("ICAP") Manual, AES Eastern Energy, L.P., Astoria Generating Company, L.P., a U.S. Power Generating Company, Dynegy Northeast Generation, Inc., Entergy Nuclear Power Marketing, LLC, the Indeck Companies,[1] and the Mirant Parties[2] (collectively, "the New York Suppliers") hereby submit the following supplemental information and comments on the NYISO's "Proposed NYISO Installed Capacity Demand Curves For Capability Years 2008/2009, 2009/2010 and 2010/2011," dated August 31, 2007 ("NYISO Proposal"). Also in accordance with the above Services Tariff and ICAP Manual provisions, the New York Suppliers request the opportunity to present oral argument on the matters addressed by this information and by the submissions of other market participants before the NYISO Board of Directors' Market Performance Subcommittee at its October 15, 2007 meeting.

A. Overview

The ICAP Demand Curves serve a number of purposes, including: (i) determining the price of the load serving entities' unforced capacity obligations in each capacity zone; and (ii)

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1 The Indeck Companies are Indeck-Corinth, LP; Indeck-Olean, LP; Indeck-Oswego, LP; Indeck-Yerkes, LP and Indeck Energy Services of Silver Springs.

2 The Mirant Parties are Mirant Energy Trading, LLC, Mirant New York, LLC, Mirant Lovett, LLC and Mirant Bowline, LLC.

providing economic signals to encourage new entry when the available capacity approaches or equals minimum installed reserve requirements. To achieve these purposes, reference values are determined that must reflect "the current localized, levelized embedded cost of a peaking unit" designated as the proxy for a new entrant;[3] in other words, the Demand Curves must properly reflect the cost of new entry.

The "Independent Study To Establish Parameters Of The ICAP Demand Curve For The New York Independent System Operator" ("the Study") prepared by NERA Economic Consulting ("NERA") in association with Sargent & Lundy, LLC, when taken as a whole, reasonably determines the reference values and associated demand curves for the three capacity zones in New York – the New York Control Area ("NYCA"), New York City, and Long Island. The New York Suppliers therefore support its use as the basis for resetting the ICAP Demand Curves for the next three years.

The New York Suppliers disagree with certain of the changes to, and recommendations based on, the Study that are set forth in the NYISO Proposal. If allowed to remain, those changes may frustrate the second purpose of the ICAP Demand Curves because the resulting reference values will be less, and potentially substantially less, than the cost of new entry. This concern is heightened by the fact that the NYISO's own planning studies demonstrate and conclude that capacity must be built in New York over the next three years. In addition, as explained more fully below, due to the split in responsibility between NERA and NYISO Staff, the capacity revenues from the annualized, unadjusted Demand Curves recommended by NERA were not properly adjusted for the summer/winter capacity differential. As a result, the seasonally adjusted Demand Curves in the NYISO Proposal do not provide the same level of

[3] Services Tariff, Section 5.14.1(b).

revenues at the expected capacity levels in each capacity zone as calculated by NERA, an inadvertent error that should be corrected. Accordingly, the New York Suppliers respectfully request that in considering the NYISO Proposal and setting the ICAP Demand Curves for the next three years, the NYISO Board of Directors incorporate the following specific recommendations, as well as those proffered by the Independent Power Producers of New York, Inc.

B. Changes In The Supply Curve Should Be Taken Into Account When Determining Net Energy Revenues

For purposes of calculating net energy revenues for each of the three proxy units studied (*i.e.*, Frame 7FA, LM-6000 and LMS-100), NERA developed a model that estimates the net revenues at different capacity reserve margins. In general, NERA's approach, model design and inputs, and analysis are reasonable and should be adopted subject to the following consideration.

In developing the Study, NERA assumed that the shape of the supply curve in New York will remain unchanged over the 30-year life of the proxy unit that was assumed in the Study. The existing supply curve is largely based on older, relatively less efficient, dual-fueled boilers and combustion turbines with relatively higher heat rates.[4] However, that technology is no longer being constructed in New York, and modern generating units use technology with greater efficiencies and substantially lower heat rates.

Additionally, the new units may not be incremental to existing generation capacity; in some cases, they are replacing existing units. Examples of this include the New York Power Authority's new Poletti units, which are intended to allow the Power Authority to shut down the existing Poletti facility, Consolidated Edison Company of New York, Inc.'s repowering of its

[4] *See* Affidavit of Mark Younger, sworn to on October 1, 2007 ("Younger Aff."), at ¶ 15. The Younger Aff. is attached to and a part of this submission.

East River Generating Station, which replaced and expanded the capacity from its Waterside Generating Station, and Public Service Enterprise Group's repowering of the Bethlehem Energy Center, which resulted in the retirement of the Albany Steam Station. These newer, more efficient generating units produce greater output at lower costs and with substantially lower emissions. It is reasonable to assume that once the Regional Greenhouse Gas Initiative and the High Electric Demand Day programs are fully implemented, the pressure to replace older capacity with newer, more efficient capacity may increase even more. Accordingly, the shape of the supply curve is not likely to remain the same.

The implication of NERA's assumption is that it may produce an overestimate of the proxy units' net revenues and, concomitantly, an artificially suppressed net cost of new entry. Because of these units, as well as other similar projects under consideration (*e.g.*, NRG's proposal to repower some of its combustion turbines with new, more efficient units), the marginal price of electricity in many hours will fall compared to historic market data, resulting in lower net energy revenues for a new generating unit than the amounts set forth in the Study and the NYISO Proposal.

NERA explained that no adjustment to the supply curve was necessary because the proxy unit is intended to be a peaking unit, and the revenues realized during peak periods would not be materially reduced. If the NYISO Proposal recommended a true peaking unit as the proxy unit, NERA's explanation would suffice and no further consideration would be necessary. However, NERA estimated that an LMS-100 unit operating in New York City would have a capacity factor between 30% and 40%. A unit with that capacity factor would clearly operate far more than a typical peaking unit and will operate during periods when, over time, these more efficient units

will replace existing units in setting the clearing price.[5] While this is unlikely to affect the highest load hours, it will affect many of the hours that the LMS-100 unit is forecast to run. By failing to capture this impact, the Study and the NYISO Proposal overstate the net energy revenues of the proxy unit over its useful life.

The Board should direct NYISO Staff, in collaboration with NERA, to consider the impact on the net energy revenues of a change to the shape of the supply curve that reflects the above-described differences between new and older units. Other than this consideration, the Board should not make any changes to the net energy revenues.

In their comments on the Study, Department of Public Service ("DPS") Staff were critical of NERA's analysis on the basis that it understates the net revenues for the Capital Zone. As explained by Mr. Younger,[6] this criticism lacks merit and is expressly disproved by Mr. Younger's comparison of the NERA model results to the NYISO Independent Market Advisor's analysis of net revenues in 2002. If the DPS Staff's criticism was correct, the net revenues for a generating unit in the Capital Zone in 2002, when the NYISO market was near minimum capacity conditions, should have virtually equaled those of a New York City unit. They did not. Instead, the Independent Market Advisor's estimate of net revenues for a peaking unit in that year are close to those estimated by the NERA model under similar conditions. This demonstrates that no further changes to the net energy model or calculations are warranted.

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[5] While an LMS-100 unit can function as a peaking unit, its design and heat rate result in it operating as an intermediate-level generating unit in the NYISO markets.

[6] Younger Aff., ¶¶ 5-15.

C. Regulatory Risk Is Real And Must Be Reflected In The Demand Curves

In developing its recommendations for the Demand Curves, NERA determined that numerous factors can influence the cost of new entry. The choice of technology drives many of these factors, and significant determinants include associated construction and financing costs, estimated operating and maintenance costs, and expected net energy revenues. In all, NERA's model incorporates approximately 40 variables, broken down into eight categories.[7]

A significant factor, or more appropriately, group of factors, in the analysis relates to risk. There is risk in the choice of technology, changes in construction and financing costs, and predictions of expenses and revenues. There are other types of risk as well, including the likelihood that the capacity markets will remain long and the possibility and effect of regulatory intervention. On this latter risk, NERA assumed a 20% probability that the Demand Curve will produce only 50% of a developer's required revenues. The NYISO Proposal rejected this adjustment on the basis that although regulatory risk is significant, ". . . it is extremely difficult to quantify this risk based on observable information."[8]

While some may dispute the potential regulatory risk, the Board need look no further than the New York Public Service Commission's ongoing proceeding examining the need for long-term contracts for affirmation of the significance of this risk.[9] In comments submitted in

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7 Study, pp. 57-61.

8 NYISO Proposal, p. 5. At the September 12 ICAP Working Group meeting, NYISO Staff reported that the removal of this risk factor changed the reference price in each zone by $8 to $9 and was the largest individual change made to the Study's recommendations.

9 PSC Case 06-M-1017, Proceeding on Motion of the Commission as to the Policies, Practices and Procedures For Utility Commodity Supply Service to Residential and Small Commercial and Industrial Customers, Order Requiring Development Of Utility-Specific Guidelines For Electric Commodity Supply Portfolios And Instituting A Phase II To Address Longer-Term Issues (issued April 19, 2007), wherein the Public Service Commission is considering, *inter alia*, whether the regulated utilities should be required to enter into long-term contracts to facilitate the construction of new generation in New York.

that proceeding, DPS Staff stated that "entry into long-term contracts should be facilitated so that infrastructure needs are met and public policies are advanced."[10]

Given this and other regulatory proceedings, and the support these regulatory policies are receiving, the New York Suppliers respectfully urge the NYISO Board to ensure that regulatory risk is properly reflected in the ICAP Demand Curves. Under the foregoing circumstances, the wholesale removal of NERA's regulatory risk adjustment is inappropriate.

Moreover, the NYISO Proposal's stated reason for removing this risk factor does not provide a valid justification for ignoring a risk that the Proposal acknowledges is both real and significant. The Study contains many other assumptions, many of which were difficult to quantify. For example, the costs of an LMS-100 unit, which the NYISO Proposal recommends as the proxy unit for New York City and Long Island, include numerous difficult assumptions because of the lack of information and data for that unit. If assumptions can be made for these other factors, there is no reason to treat regulatory risk differently. Therefore, if NERA's assumptions are considered to be overly aggressive (and the New York Suppliers do not consider this to be the case), it may be appropriate to modify them to some degree. It is not, however, reasonable or justifiable to eliminate them entirely, especially here where the underlying risk is expressly acknowledged.

In the event the NYISO Board declines to reinsert a factor for regulatory risk, it must increase the only other capacity risk factor in the analysis. That is, the Study and the NYISO Proposal assume that the future level of capacity will be 2.8% greater than the ICAP requirements for NYCA and 4% greater for New York City. While these assumptions are meant

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[10] PSC Case 06-M-1017, supra, Staff Initial Comment (dated June 5, 2007), p. 9; *see also* Comments by City of New York (dated June 5, 2007), *passim*. Consistent with its comments in that proceeding, New York City's PlaNYC proposes to add 2,000 to 3,000 MW of new generation in New York by 2015, even though it concedes

to represent normal fluctuations in the marketplace, their asymmetry around the ICAP requirements for each capacity zone represent the reality that through a combination of the NYISO's policies and procedures (*e.g.*, the Comprehensive Reliability Planning Process) and other regulatory actions, ICAP levels will not be permitted to fall below the ICAP requirements.[11] If regulatory risk is not going to be addressed directly in the model, the expected capacity levels need to be increased so that they can capture this additional risk as well.

Although the factor for normal market fluctuations was not intended to reflect regulatory risk, it remains the only factor that measures future uncertainty about ICAP levels, and the regulatory risk is essentially another factor that would cause the markets to be long on capacity. Therefore, the NYISO Board should direct the NYISO Staff to work with NERA to determine an expected level of capacity that represents both the normal fluctuations and the potential risk of the market being long as a result of regulatory risk. The failure to make this adjustment will, in turn, result in the failure of the ICAP Demand Curves to accomplish their intended purpose of providing appropriate economic signals to encourage new entry when appropriate because the Curves will not fairly or reasonably represent the risks that a market entrant would face.

D. The Seasonal Demand Curves Must Be Adjusted To Provide The Same Annualized Revenues Upon Which NERA Based Its Demand Curve Recommendations

Because the calculation of the summer/winter adjustment was left to NYISO Staff, NERA's analysis of the expected revenues of the proxy units was based on demand curves that had not been adjusted for the extra capacity that is available in the winter capability period. The summer/winter adjustment is performed to ensure that generators receive the full payment level

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that only 900 MW of new supply are needed by that date. *See* "PLANYC: A Greener, Greater New York" (dated April 22, 2007), p. 110.

[11] For a further discussion of this point, see the Younger Aff. at ¶¶ 19-25.

at the minimum installed reserve requirements. However, when capacity levels are greater than the minimum requirements, the capacity revenues adjusted for the summer/winter differential will decline faster than the unadjusted capacity revenues, as demonstrated on Exhibit MDY-2 of the Younger Affidavit. This results in the proxy units receiving less capacity revenues at the expected capacity levels than were assumed in the NERA analysis.

Due to the split in responsibility that applied to addressing seasonal capacity differences, neither the Study nor the NYISO Proposal's summer/winter adjustment properly accounts for the impact of the summer/winter differential on the revenues at points beyond the minimum installed reserve levels. As demonstrated by Mr. Younger, failing to properly account for the impact of the summer/winter differential results in a 10% reduction in the annual revenues that actually will be received compared to the levels set forth in the Study.[12]

That is, at the expected capacity level of 102.8% of ICAP requirements, the unadjusted demand curve for NYCA would produce $21.2 million of annual ICAP revenues. When adjusted for seasonal differences, though, the same demand curve produces only $19.3 million of annual ICAP revenues. A similar difference occurs for the New York City demand curve, as shown on Exhibit MDY-2. To compensate for this unintended result and assure that the generators, which will be paid based on summer/winter adjusted Demand Curves, receive the revenues upon which the Demand Curves recommended by the Study and NYISO Proposal are based, the seasonally adjusted demand curve must be increased by 10% (*i.e.*, the minimum requirement crossing point must be increased from $9.09 to $10.00 for NYCA and from $12.65 to $13.94 for New York City), also as shown on Exhibit MDY-2.

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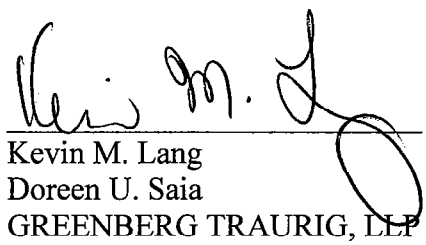
[12] *See* Younger Aff., ¶¶ 26-28 and Exhibit MDY-2.

CONCLUSION

The NYISO Board of Directors should modify the NYISO Proposal in accordance with the foregoing discussion and that contained in the comments submitted by the Independent Power Producers of New York, Inc. For the foregoing reasons, the Board should not make other changes to the net energy revenues or change the manner in which the annual net revenue requirement for the proxy units is seasonally adjusted.

Dated: October 1, 2007
Albany, New York

Respectfully submitted,



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ALB 1113137v1 10/1/2007

AFFIDAVIT OF MARK D. YOUNGER

Mark D. Younger, having been duly sworn, deposes and states as follows:

1. My name is Mark D. Younger. I am employed as Vice President of Slater Consulting. My business address is 69 Werking Road, East Greenbush, New York 12061.
2. My entire professional career has been devoted to matters relating to electric generation and the development of competitive electricity markets. For the past ten years, I have been an active participant in the working groups refining the New York Independent System Operator, Inc. ("NYISO") market structure and developing methods to improve the market design, including all aspects of its energy, ancillary services and capacity markets. My resume is attached as Exhibit MDY-1.
3. I write this affidavit in support of the Supplemental Information and Comments to the NYISO Board of Directors by the New York Suppliers[1] regarding the setting of the Installed Capacity ("ICAP") Demand Curves for the period May 2008 through April 2011.

THE RELATIONSHIP OF CAPITAL AND NEW YORK CITY NET ENERGY REVENUES IN TIGHT MARKET CONDITIONS ARE ACCURATELY REPRESENTED

4. NERA Economic Consulting ("NERA") estimated the net energy revenues of the gas turbines that were considered in setting the ICAP Demand Curves ("Proxy Units") via a computer model that determines the relationship between electricity prices and the following factors: NY load, zonal load, hour, zone, gas price, reserve margin, and temperature.[2] The model allowed NERA to calculate the expected net revenues for each Proxy Unit under different levels of capacity reserve margins.
5. Department of Public Service ("DPS") Staff claimed in written comments on the "Independent Study To Establish Parameters Of The ICAP Demand Curve For The New York Independent System Operator" ("the Study") prepared by NERA in association with Sargent & Lundy, LLC, and in the ICAP Working Group that this analysis adequately estimates the New York City ("NYC") Zone net revenues but fails to adequately estimate the

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[1] List of Signing Suppliers.

[2] *See* "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," dated August 15, 2007 ("the Study"), p. 50.

relationship between the Capital and NYC Zones. In particular, DPS Staff claims that the net revenue estimate for the Capital Zone should be much closer to net revenue estimate for the NYC Zone than the relationship indicated by the model.

6. The basis for DPS Staff's claim is that there is no congestion during peak system conditions and therefore, absent thunderstorm conditions, NYC gas turbines will set the price in the Capital Zone during those periods. They also note that in 2000, the average clearing price in the Capital Zone was much closer to the clearing price in the NYC Zone.
7. The DPS Staff criticism lacks merit for several reasons. First, the clearing prices in 2000 are not relevant because there have been changes in the NYISO-administered markets since 2000 that have resulted in higher clearing prices for NYC. In particular, in 2000 the NYISO was addressing the load pockets in NYC by dispatching units out of merit. The costs, therefore, were improperly included in uplift, leaving artificially suppressed market clearing prices.
8. Since that time, modeling changes have been implemented that allow the NYISO commitment and dispatch models to solve for the NYC load pockets. As a result, uplift costs have been reduced and the cost of running higher priced units to meet load pocket requirements are properly reflected in the clearing price. If this change had been implemented in 2000, the Capital Zone average locational-based marginal price ("LBMP") would have been unchanged but the NYC Zone LBMP would have risen significantly.
9. There have also been additions of substantial capacity to the Capital Zone since 2000 that have resulted in congestion between the Capital Zone and lower Hudson Valley Zones in many hours.
10. Second, the LMS-100 and LM-6000 units that are being considered as the Proxy Units have operating costs that are significantly less than those of the older gas turbines. For this reason, it is likely that they will run more frequently than under peak system conditions. In fact, the Study estimates that the LMS-100 and LM-6000 would operate during 38% and 33%, respectively, of the hours in a year when the electric system was just meeting its minimum capacity requirements. During much of this time, there are likely to be transmission constraints between the Capital and NYC Zones.
11. Third, as DPS Staff acknowledged, Thunderstorm Alerts ("TSAs") will have an impact. During TSAs, the NYISO operates the transmission system in the lower Hudson Valley based upon a second order contingency. Second contingency conditions create congestion

between NYC and upstate, which causes NYC prices to rise substantially above upstate prices. While TSAs occur in real-time, Day-Ahead bidding patterns result in their average effect being represented in the Day-Ahead Market. TSAs therefore substantially increase the expected net revenues of the NYC units compared to the expected net revenues of the upstate units.

12. Fourth, DPS Staff appears to disregard that the Demand Curves for the Capital and NYC Zones are based on different Proxy Units – a Frame 7FA and an LMS-100 unit, respectively. The LMS-100 unit has a heat rate that is roughly 85% of the Frame 7FA unit. Consequently, and as discussed above, the LMS-100 unit is expected to run much more and have much higher net energy revenues. Additionally, because the Frame 7FA unit is not designed for fast starts and stops as are typically experienced for a peaking unit, running it as a peaking unit substantially increases the frequency of overhauls. This results in making the Frame 7FA unit even more expensive to run and results in it running in only the highest load hours.[3]
13. To confirm that NERA's model provides a reasonable estimate of the relationship of net revenues in the Capital and NYC Zones under tight market conditions, I compared the model's results to the analysis performed by the NYISO's Independent Market Advisor, Dr. David Patton, in his State of the Market ("SOM") reports for 2003 and 2006 .[4] In 2002, the NYISO market was near minimum capacity conditions and none of the post-NYISO combined cycle additions had yet been installed.[5]
14. Dr. Patton's analysis of 2002 estimated that a combined cycle unit in the Capital Zone would have had 71% of the net revenues of the same unit connected to the 345kV system in NYC. He further estimated that a unit with a heat rate similar to an LM-6000 in the Capital Zone would have had 58% of the net revenues of the same unit connected to the 345kV system in

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[3] For example, the Study sets the charge associated with each start at $20,000.

[4] Specifically, I compared the estimated net revenues from the model to Figure 14 from the 2003 SOM Report and Figures 9-12 from the 2006 SOM Report.

[5] The combined cycle units that were added to the NYISO market after 2002 include the Athens Generating Plant (914.6 MW) and Bethlehem Energy Center (745.8 MW) in the Capital Zone, and the SCS-Astoria Energy plant (530.9 MW), Poletti Station Expansion (492.4 MW) and KeySpan Ravenswood Cogeneration Facility (231.2 MW) in the NYC Zone.

NYC. The highest of the historic annual ratios of zonal prices between the Capital and NYC Zones occurred in 2002.

15. NERA presents the net revenues for the different Proxy Units and locations in the "Energy Curve Raw" tab of its spreadsheet model. The data shows that at minimum capacity requirements, an LM-6000 in the Capital Zone would have net revenues that are 62.9% of the net revenues of the same unit located in the NYC Zone. An LMS-100 unit in the Capital Zone would have net revenues that are 71.9% of the net revenues for the same unit in the NYC Zone. This relationship compares very favorably with the actual conditions for 2002 and shows that NERA's model reasonably and properly estimates how the market would tighten with lower capacity levels.

THE STUDY OVERSTATES EXPECTED NET ENERGY REVENUES

16. The Study erroneously assumes that the supply curve for the NYISO will retain its current shape. The prices in the NYISO eastern zones have historically been set by older oil/gas fired boiler units with heat rates of approximately 10,000 Btu/kWh and combustion turbines with heat rates as high as 16,000 to 22,000 Btu/kWh. In contrast, the technology employed in new generating units results in combined cycle units with heat rates of about 7000 Btu/kWh and combustion turbines with heat rates less than 10,000 Btu/kWh.
17. Furthermore, the new units are not merely supplementing the existing resources. In some cases, they are replacing the existing resources. Examples of this include the pending shutdown of the Poletti Station due to the replacement of its capacity by much more efficient combined cycle units and the proposal by NRG to repower some of its combustion turbines with new units with much lower heat rates. The pressure to shut down older, less efficient units and replace them with newer, more efficient units will only strengthen with the implementation of the Regional Greenhouse Gas Initiative and High Electric Demand Day programs.
18. By failing to capture this technology shift, the Study likely overstates the net energy revenues that a merchant generator will receive from the market.

NYISO STAFF'S RECOMMENDED DEMAND CURVES UNDERSTATE THE CONSERVATIVENESS OF THE NYISO AND STATE PLANNING PROCESS AND THE LIKELIHOOD OF EXCESS CAPACITY

19. The NYISO has two key backstops to assure that the market will not run short of capacity for any significant period of time. First, Section 5.14.1 (c) of the NYISO's Market Services Tariff mandates that the NYISO must attempt to procure additional capacity if the NYISO fails to satisfy the minimum capacity requirements. The result is that a shortage price in any capacity zone would not be expected to last more than one month if there are any resources available that could meet the requirement or demand side resources could be developed quickly.
20. The NYISO also assesses whether it expects to meet its capacity requirements as part of the Comprehensive Reliability Planning Process ("CRPP") that is outlined in OATT Attachment Y.
21. The key focus of the CRPP is determining the need for compensatory MW. The Transmission Owners ("TOs") are directed to identify regulated backstop solutions (presumably targeted contracts or self-build projects) to meet the need for those MW. If market solutions have not shown progress before the time the TOs would need to enter into the contracts, the regulated backstop solutions may begin being implemented.
22. Since the time period for implementing a regulated backstop solution (*i.e.*, from contract to commercial operation) is generally three to four years, while it only takes around two years or so from the commencement of construction to the in-service date for a combined cycle unit and only about one year for a simple cycle unit, a market-based solution must lead the market by one to two years to avoid triggering a regulated backstop solution. Based upon recent peak load growth rates, the one to two year lead time is approximately equivalent to one to two times the standard deviation estimated by NERA. If this timing difference is not recognized in setting the Demand Curves, and the Demand Curves are not consistent with the backstop decisions made in the CRPP, the potential result will be that all new additions will be regulated backstop solutions and we will have a market failure.
23. The CRPP creates a bias towards the market being long in its treatment of resources. For example, the CRPP only recognizes imports that have long-term contracts. Historically, the NYISO has reached or been close to its maximum capacity import level of 2,755 MW during the summer period but almost none of that capacity is under long-term contract. There is no

requirement that an import have a long-term contract to participate in the NYISO's markets; it simply must secure import rights either before, or at times during, the then-current capability period. This inconsistency results in the potential that the CRPP could trigger a regulated backstop solution when ultimately there will be hundreds or even thousands of MW of capacity that will sell into the NYISO's markets from other control areas.

24. Recent actions in the NYC Zone provide other examples of the bias towards the market being long. The New York Power Authority ("NYPA") built the Poletti Station Expansion to replace the original Poletti Station. However, it brought the new facility on-line two years before Poletti Station was originally scheduled to shut down. With the delays in Poletti Station's retirement, the new facility will ultimately be on-line for four years before the old plant retires. Consolidated Edison Company of New York, Inc. entered into a contract with SCS Energy, LLC for the output of its Astoria Energy facility. A key basis for the contract was to assure that there is not a shortage of capacity in NYC. However, the result of adding these two facilities is that rather than a shortage of capacity, the market has substantially more capacity than is needed to meet the NYC Zone's minimum installed capacity requirement.

THE DEMAND CURVES MUST BE ADJUSTED TO ACCOUNT FOR THE DIFFERENT SUMMER AND WINTER RATINGS

25. While I agree with the NERA method for addressing the potential of the market being long,[6] NERA was not charged with the task of accounting for the impact of the fact that the NYISO sells capacity based on separate summer and winter ratings. In contrast, the NYISO Proposal was required to, but did not properly adjust the expected capacity revenues to account for the different summer and winter ratings. The result has been to create an inconsistency between the revenues that the NERA model estimated an ICAP provider would receive at different levels of capacity beyond the NYISO minimum requirement and the amount of revenues that the supplier will actually receive in our market.
26. Because the adjustments for the summer/winter capacity ratings are made at the minimum installed reserve requirements for each zone, revenues at a given level of excess capacity on the summer/winter adjusted curves are lower than they are on the unadjusted curves. As

[6] *See* page 60 of the Study.

shown on Exhibit MDY-2, the capacity revenues that NERA calculated at the summer capacity level of 102.8% of the minimum installed reserve requirement in the NYCA Zone would actually be achieved at a summer capacity level of 102.1% of the minimum requirement. Likewise, the capacity revenues that NERA calculated at the summer capacity level of 104% of the minimum installed reserve requirement for the NYC Zone would actually be achieved at a summer capacity level of 103% of the minimum requirement.

27. To correct for this difference between the unadjusted and summer/winter adjusted Demand Curves and provide the same revenues under the adjusted Curves as NERA determined for the unadjusted Curves, the Demand Curve levels must be increased by 10%, also as shown on Exhibit MDY-2.
28. This concludes my affidavit.

Mark D. Younger

Sworn to before me this
1st day of October, 2007.

Notary Public

AUTUMN WHITE
Notary Public, State of New York
Qualified in Saratoga County
No. 01WH6068256
Commission Expires Nov. 13, 2009

MARK D. YOUNGER

Mr. Younger is Vice President of Slater Consulting and has over twenty-five years of experience in energy analysis.

EDUCATION

MBA, Cornell University, 1983

M.E., Operations Research
Cornell University, 1983

B.S., Engineering, Major - Operations Research
Cornell University 1981

PROFESSIONAL EXPERIENCE

Vice President
Slater Consulting (1994 - Present)
Specialist on electric deregulation, market structure issues and deregulated electric energy, ancillary service and capacity market design. Specialist in electric utility system planning and simulation modeling. Specialist in New York Independent System Operator rules and operation. Extensive modeling experience of California's utilities and the New York Independent System Operator Market. Experienced with PROMOD, ELFIN and EGEAS production cost models.

Senior Project Manager
Morse, Richard, Weisenmiller & Associates, Inc. (1986-1994)
Head of MRW's New York office. Responsible for directing MRW's projects on production cost modeling. Directed MRW's analysis of East Coast utility operations. Prepared extensive analysis on avoided costs in California, New York, Pennsylvania and New Jersey. Prepared expert witness testimony on avoided costs in California and New York. Performed analyses of electric utility emissions reductions associated with cogeneration projects.

Energy Economist
Pacific Gas & Electric Company (1983-1986)
Responsible for developing models and methods for integrated supply and demand-side resource analysis. Performed least-cost utility resource planning, Developed and performed an analysis of resource planning under uncertainty using Monte Carlo techniques. Performed extensive analysis for electric peak and load shape forecasting.

Research Specialist
Duane Chapman, Professor of Resource Economics
Cornell University (1982-1983)
Formulated the financial simulation section of the University Research Group on Energy's (URGE) integrated model of the electric utility industry. Performed an analysis of the impact on New York Pollution levels and New York utilities of proposed acid rain abatement strategies.

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Exhibit MDY-2

EFFECT OF SUMMER/WINTER ADJUSTMENT ON EXPECTED SUPPLIER REVENUES WITH ADDITIONAL CAPACITY

		NYCA Demand Curve			NYC Demand Curve		
	Percent Capacity Beyond Min Requirement	Unadjusted Curve	NYISO Staff Summer/ Winter Adjusted Curve	Corrected Summer/ Winter Adjusted Curve	Unadjusted Curve	NYISO Staff Summer/ Winter Adjusted Curve	Corrected Summer/ Winter Adjusted Curve
Minimum Requirement Crossing Point		$7.68	9.09	10.00	$9.72	12.65	13.94
Curve Length (%)		12	12	12	18	18	18
Curve Slope		$0.64	$0.76	$0.83	$0.54	$0.70	$0.77
Claimed Capacity		300.3			188.7		
Summer Capacity			298.7	298.7		188.7	188.7
Winter Capacity			355.7	355.7		196.4	196.4
Additional Winter Capacity for Market (%)			5	5		9	9
Annual Revenue with additional Summer Capacity	0.0	$27,660.63	$27,607.69	$30,366.61	$21,998.65	$22,024.16	$24,266.82
	1.0	$25,355.58	$24,633.45	$27,095.14	$20,776.50	$20,400.32	$22,477.63
	2.0	$23,050.53	$21,659.20	$23,823.66	$19,554.35	$18,776.48	$20,688.44
	2.1	$22,820.02	**$21,361.77**	$23,496.52	$19,432.14	$18,614.10	$20,509.52
	2.2	$22,589.52	$21,064.35	$23,169.37	$19,309.92	$18,451.71	$20,330.60
	2.3	$22,359.01	$20,766.92	$22,842.22	$19,187.71	$18,289.33	$20,151.68
	2.4	$22,128.51	$20,469.50	$22,515.07	$19,065.49	$18,126.94	$19,972.76
	2.5	$21,898.00	$20,172.07	$22,187.93	$18,943.28	$17,964.56	$19,793.84
	2.6	$21,667.50	$19,874.65	$21,860.78	$18,821.06	$17,802.18	$19,614.92
	2.7	$21,436.99	$19,577.22	$21,533.63	$18,698.85	$17,639.79	$19,436.00
	2.8	**$21,206.49**	$19,279.80	**$21,206.49**	$18,576.63	$17,477.41	$19,257.09
	2.9	$20,975.98	$18,982.37	$20,879.34	$18,454.42	$17,315.02	$19,078.17
	3.0	$20,745.47	$18,684.95	$20,552.19	$18,332.21	**$17,152.64**	$18,899.25
	3.1	$20,514.97	$18,387.52	$20,225.04	$18,209.99	$16,990.26	$18,720.33
	3.2	$20,284.46	$18,090.10	$19,897.90	$18,087.78	$16,827.87	$18,541.41
	3.3	$20,053.96	$17,792.68	$19,570.75	$17,965.56	$16,665.49	$18,362.49
	3.4	$19,823.45	$17,495.25	$19,243.60	$17,843.35	$16,503.11	$18,183.57
	3.5	$19,592.95	$17,197.83	$18,916.45	$17,721.13	$16,340.72	$18,004.65
	3.6	$19,362.44	$16,900.40	$18,589.31	$17,598.92	$16,178.34	$17,825.73
	3.7	$19,131.94	$16,602.98	$18,262.16	$17,476.70	$16,015.95	$17,646.81
	3.8	$18,901.43	$16,305.55	$17,935.01	$17,354.49	$15,853.57	$17,467.90
	3.9	$18,670.93	$16,008.13	$17,607.86	$17,232.27	$15,691.19	$17,288.98
	4.0	$18,440.42	$15,710.70	$17,280.72	**$17,110.06**	$15,528.80	**$17,110.06**
	5.0	$16,135.37	$12,736.45	$14,009.24	$15,887.91	$13,904.96	$15,320.87
	6.0	$13,830.32	$9,762.21	$10,737.77	$14,665.76	$12,281.13	$13,531.68
	7.0	$11,525.26	$6,787.96	$7,466.30	$13,443.62	$10,657.29	$11,742.49
	8.0	$9,220.21	$3,813.71	$4,194.82	$12,221.47	$9,033.45	$9,953.30