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To: Dave Lawrence – NYISO

From: Chris LaRoe

Date: Wednesday, July 21, 2010

Re: IPPNY Comments on NERA / S&L Demand Curve Report

1. Introduction

In accordance with the NYISO's revised 2011-2014 ICAP Demand Curve Development Schedule, IPPNY offers the following initial comments on the *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator* issued by NERA Economic Consulting ("NERA", and the "NERA Report").[1] At the outset, we note that IPPNY views the NERA Report as a very professional, comprehensive and internally consistent effort to address the myriad of interdependent and interrelated factors and assumptions that must be accounted for in order to determine the net cost of new entry ("Net CONE") of the proxy peaking unit(s) and the other parameters used to establish the New York City ("NYC"), Long Island ("LI") and New York Control Area ("NYCA") ICAP Demand Curves, as required by the NYISO's Services Tariff. Following below, IPPNY addresses concerns it has with open ended elements of the report, such as deliverability costs and property taxes. As IPPNY understands it, NERA was tasked with simply providing the spectrum for both of the cost factors (i.e., with/without deliverability and with/without property tax abatement). While setting up these two cost factors in the model with effectively an on/off switch may have been appropriate, the data that NERA provided demonstrates that both of these are major cost factors that substantially impact the Net CONE calculations. Thus, NERA should provide its expert opinion in its Final Report on whether each of these costs should be included in the Net CONE calculations, which would be consistent with the NYISO's request for proposal related to this process: "The Consultant will be required to deliver a written report to the NYISO documenting the Consultant's study methodology, calculations, results and **recommendations** consistent with FERC requirements and covering the 2011-12 Capability Year [emphasis added]."

[1] The Report establishes that it was developed jointly by NERA and Sargent & Lundy.

In addition, IPPNY addresses its concerns with the assumptions made in terms of energy and ancillary service revenues and financing requirements, regulatory risk, site requirements, summer/winter adjustments, staffing levels and plant availability, fuel prices, and the shape and slope of the demand curves. Each of these elements substantially impacts the Net CONE levels that are derived.

2. Deliverability Costs

The NERA Report provides Demand Curve Values at the Reference Point for a ROS Frame 7FA unit both with and without interzonal deliverability. The Net CONE without including the deliverability costs is $89.88 ($/kW-year); the Net CONE with deliverability costs is $116.5. NERA calculated Demand Curve Values for the NYCA with and without including the impact of deliverability at the request of the NYISO. However, similar calculations are missing for Zones J and K. These calculations must be provided.

The NERA Report states, "In order to participate in the capacity market a unit must be deliverable to all zones in the Capacity Region as defined in NYISO Services Tariff Attachment S (Zone J, Zone K and all Zones other than J and K collectively as a single region). Currently new units north and west of UPNY/SENY could not deliver to Zones G to I and hence could not participate in the capacity market for ROS without obtaining deliverability. The NYISO has determined that the cost of deliverability is an investment of $178 per kW." (p.67)

The fact that a new resource must be deliverable (and, if necessary, pay for system upgrades to be considered so) to be a capacity provider and secure capacity revenues is an irrefutable requirement of the NYISO tariff. However, NERA is neutral with respect to whether deliverability costs should be included in the calculation of the Demand Curve Values. NERA states, "We have been advised by NYISO that the decision on how deliverability will be reflected in the reset Demand Curves is under consideration by NYISO." (p.67) Deliverability costs are, by definition, a form of system upgrade costs. Thus, they must be included in the calculation of the Demand Curve Values just as all other system upgrade costs for the hypothetical proxy unit have long been included in the modeling.

Under current and foreseeable system conditions, constraints exist that would require a new unit located north and west of UPNY/SENY to invest in infrastructure upgrades to allow this unit to be eligible to sell capacity. In fact, the NYISO's Class Year 2008 Facilities Studies finds that, before any new resources are taken into consideration, the interface between the Capital Zone and the Lower Hudson Valley is already overloaded by more than 1500 MW.[2] The price tag for the upgrades required of new capacity

[2] Class Year 2008 Facilities Study, *Part 2 Studies (Sections 11, 12, 13 only): Deliverability Study and System Deliverability Upgrade Facilities (SDU)*
https://www.nyiso.com/secure/webdocs/committees/oc/meeting_materials/2009-11-12/CY08_Facilities_Study_Part2_Deliverability_Study_Draft3_clean.pdf.

resources located in Zones A through F in that class year was calculated at $178/kW.[3] Absent such investment, those resources would not be permitted to sell capacity – a significant source of revenues for a new facility. The same holds true for the hypothetical proxy unit located in the Capital region.

Theoretical arguments have been made regarding what system conditions may look like under near-equilibrium conditions. Specifically, during working group meetings, some market participants have alleged that retirements would drive the system to these near equilibrium conditions, and therefore, CRIS rights would become available to new entrants, eliminating the need for transmission upgrades (correctly, such system capability assumptions that would lead to avoided System Upgrade Facilities costs for new units are not and have not been assumed). This argument is flawed in several critical respects. First, the factors that could drive the system to near-equilibrium conditions (load increase/shifting, changes in capacity resource quantity/location, etc.) are unpredictable and cannot be assumed to occur in a manner that would facilitate a new resource being sited in the Capital Zone without incurring substantial system deliverability upgrade costs.. If anything, the more likely result is to reach approximate load/capacity equilibrium via future load growth in the areas where we have seen load growth in the past.[4] This would likely exacerbate existing deliverability constraints.

Even if one assumes that system conditions in the future (such as generator retirements) will free up deliverability rights (which IPPNY does not concede), deliverability rights are owned by existing generators and, because they are transferable, they have value. It is unreasonable to assume that such rights will simply be given to new entrants. Rather than risk the expiration of valuable CRIS rights, a retiring generator is much more likely to sell those rights, take advantage of those rights themselves by repowering their facilities, or transfer these rights to others for consideration. Thus, the NERA Report must recognize that deliverability rights have value, and new generators will likely have to pay for deliverability rights or for SDUs.

Currently, it may be possible for a unit to be constructed with zero deliverability costs if it is located in the Lower Hudson Valley. However, because the Lower Hudson Valley is a non-attainment area, the proxy unit that NERA has designated for this area is an LMS 100 unit. The Net CONE for the proxy GT in the Lower Hudson Valley, even with no assumed SDU costs, is still higher than the Net CONE of the Frame 7FA unit (Proxy GT in the Capital region) plus the necessary $178/kW deliverability costs. Those pricing signals would lead a developer to locate a new facility north and west of the

[3] "The recommended system deliverability upgrade (SDU) is the installation of phase angle regulation on the Leeds – Hurley Avenue 345kV circuit consisting of two (2) 345kV 575MW (625MVA, +/- 30 degree shift) located at National Grid's Leeds 345kV station and one (1) 135MVAr switched shunt capacitor bank located at Central Hudson's Hurley Avenue 345kV station. This provides 257MW of transmission transfer capability for the CY2008 projects in ROS for their CRIS rights, and 195MW additional transfer capability for future Class Years. The preliminary SDU project cost estimate is $ 80,420,000.00 (2009$); relative to deliverable capacity the upgrade cost is approximately $177,920/CRIS-MW." Id

[4] The NYCA Demand Curves, as currently proposed, are insufficiently low to support new entry in the Lower Hudson Valley. Thus, absent development of a new zone, new construction is likely to be limited to Zones A-F resulting in even more generation coming on line that is not deliverable.

UPNY/SENY constraint and, therefore, a new ROS resource would be required to incur the costs of necessary SDUs. If the NYCA Demand Curve is based upon a Capital Zone GT without including deliverability charges, new capacity resources will not be economic anywhere in the Rest of State capacity zones. Capacity resources in the Lower Hudson valley will not come online because the Net CONE of the resource itself exceeds the revenue that it will receive from the Demand Curve. A unit north and west of the UPNY/SENY constraint will not be built because the deliverability costs that it would incur to be a capacity provider plus the Net CONE of the resource itself would exceed the revenues it would receive under the Demand Curve. If the resource did not pay its deliverability costs, it would not be eligible for any capacity revenues. In this case the resource would also not be built because it energy and ancillary service revenues are not sufficient to cover the full cost of the unit. (even assuming the very aggressive run hours estimated by NERA for this unit, which we dispute below).

The Demand Curve must include all costs that a capacity supplier would incur to sell and provide capacity in a reliable manner, as stated in Section 5.14.1(b) of the NYISO's Services Tariff, "The periodic review shall assess: (i) the current localized levelized embedded cost of a peaking unit in each NYCA Locality and the Rest of State to meet minimum capacity requirements." A new generator cannot be eligible to sell capacity without paying (among other things) all deliverability costs that are allocated to it. If the Demand Curve is set without considering these costs, the revenues that the Demand Curve will provide will not be sufficient to induce new entry. As such, a Demand Curve that does not include the deliverability costs of the proxy unit will fail to provide appropriate price signals to assure that the NYISO can meet its reliability requirements. The difference between NERA's projected net CONEs with and without deliverability costs is significant. CONE calculated without deliverability costs accounts for only 77% of the actual costs that a new unit would incur. Now that deliverability requirements and the associated cost allocation rules exist in the NYISO's tariff, ignoring deliverability costs in setting the Demand Curves would frustrate the fundamental purpose of the Demand Curves to provide the necessary signal to developers to build new resources in time to meet the State's reliability needs.

Moreover, failing to include the deliverability costs will result in a violation of the tariff. The tariff requires that the Demand Curve be based upon an economically viable GT. Given that a GT must pay deliverability costs to be a capacity provider, setting the demand curve without including the deliverability costs that the GT would incur would result in the GT not being economically viable.

3. <u>In-City Property Taxes</u>

The NYISO also instructed NERA to calculate Net Cone for a NYC LMS 100 unit with and without property tax abatement. NERA estimated a Net Cone of $144.32/kW-year with assumed abatement and $219.77 without abatement. NERA then analyzes the In-City property tax issue properly, "The ICIP program no longer applies to generation units. We use it only as a proxy of potential abatement to illustrate the impact. Our understanding is that the NYC EDC is currently considering an abatement policy that may apply to new generation and that the NYISO Board will review any policy that is developed and determine its applicability to the proxy peaking units. In the event that a policy is not developed, we would anticipate that the without abatement results would apply. In the event an abatement policy is developed that would provide a different incentive than the ICIP, we anticipate that the Model would be revised to reflect the new abatement policy."(p 67)

As NERA's estimates of Net CONE with and without property tax abatements demonstrate, property taxes constitute a substantial portion of fixed costs for a generator. Calculating Net CONE assuming a non-existent tax abatement puts the demand curves at risk of sending substantially insufficient pricing signals In-City to the tune of over $75/kW-year (i.e. deficient by approximately 33%). Such a risk is unacceptable. Tax abatement cannot be used to offset the costs of the proxy unit unless a new regulation has been promulgated that expressly makes tax abatement available to generating facility projects in the form of an "as of right" reduction. There is no evidence of any "as of right" property tax abatement programs currently available to proposed generating facility projects. In light of the repeal of the ICIP and the trend of other fees being foisted onto the shoulders of the energy sector in the recent state budgets, the possibility of securing a tax abatement has grown exceedingly unlikely.

In fact, New York City itself very recently confirmed that property tax abatements cannot be guaranteed in advance. Specifying that "NYCIDA incentives and benefits are discretionary and only may be awarded upon the successful completion of a rigorous application process that includes a public hearing and authorization by the NYCIDA Board of Directors…,"[5] New York City further established in the most recent Con Edison Steam proceeding that neither it nor the NYCIDA had any ability to circumvent these application and review procedures to offer a developer an assured package of benefits before a project proposal is submitted.[6] Given the very real possibility that a new generating project would not be able to secure a property tax abatement from the discretionary programs that are currently available in New York City, property tax abatement must not be assumed as a cost reduction for the proxy unit for Zone J. In fact, it is far more likely that an unusually high tax burden will be placed upon suppliers of capacity going forward.

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[5] See PSC Case 09-S-0029, et al., Proceeding on Motion of the Commission to Consider Steam Resources Plan and East River Re-powering Project Cost Allocation Study, and Steam Energy Efficiency Programs for Consolidated Edison Company of New York, Inc., "New York City Petition for Rehearing or Clarification" (dated January 19, 2010) at 6.

[6] Id. In the Con Edison Steam proceeding, New York City advocated that the Commission initiate a process to determine whether third parties would pursue constructing a cogeneration facility at Con Edison's Hudson Avenue site. Finding that Con Edison should proceed with its less expensive boiler replacement proposal, the Commission stated, "If New York City makes a timely proposal for IDA (or other) support of a cogeneration option, which is no more costly to customers than a boiler option, it should be considered by Con Edison." (See PSC Case 09-S-0029, et al., "Order Approving the Hudson Avenue Generating Facility" (issued December 17, 2009) at 31.) New York City sought rehearing of the Commission's order on the grounds that the Commission Order was in error, expressly stating, "In fact, the City cannot take such action." (See NYC Petition for Rehearing at 5-6.)

Failing to include the property taxes in the Demand Curve will put a pall on potential new resources in the City. The process to receive potential property tax exemptions that was described by the City would require the generator to spend millions of dollars in development costs before finding out whether it would receive the property tax exemptions that would be necessary to make the project economic. This would make investing in new generation in NYC significantly riskier. The NERA study did not include this additional risk factor.

Moving forward without assuming tax abatements is consistent with the decision in the last Demand Curve Reset process to not include potential property tax relief in the determination of the NYCA Demand Curve due to the uncertainty surrounding whether new combustion turbine generators would qualify for such tax abatement.[7] It would also be consistent with the determination that was made during the last reset process to include dual fuel capability as a component of the capital costs for the NYC proxy unit because there was no assurance that units would otherwise be able to negotiate and arrange for special, site specific exemptions from Con Edison under its gas tariffs. As a result, the past Demand Curve Reset Final Report expressly found, "Given the possibility that a new peaking unit in New York City may be required to have [dual fuel] capability, dual fuel capability has been assumed for Zone J." [8]

Concerns about "double-dipping" (not having abatement built into the curve and then having a new facility secure additional abatement) are unwarranted. New York City entities control discretionary tax abatement grants. If full property tax payments are included as a cost in setting the Net CONE for the NYC Demand Curves, New York City entities can reject an future requests submitted by a new generator for a property tax abatement.

4. <u>Energy and Ancillary (E&AS) Service Revenues</u>

Projected E&AS revenues estimates have increased dramatically since the last resent process, which themselves showed a marked increase over the levels estimated in the first reset process: [9]

	2007	**2010**	**2011**
ROS:	$7	$10.87	$30.17
NYC:	$48	$75.41	$125.48
LI:	$19	$104.56	$199.64

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7 Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, NERA, August 15, 2007, p. 37.

8 The costs associated with dual fuel capability have again been included in the Net CONE calculation for the NYC proxy unit as part of this reset process. (see Report at 23)

9.The NYCA Demand Curves always have been developed based on the Frame 7FA as the proxy unit. The NYC and LI Demand Curves were developed based on the LM-6000 as the proxy unit in the first reset process. However, they were developed based on the LMS100 as the proxy unit in the last reset process and, again, in this reset process. This difference in peaking technology accounts for some portion of the revenue estimate differential. "Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator." Levitan and Associates, August 16, 2004. Pg. 1.

The Net Energy and Ancillary Service revenues included in the NERA report are significantly higher than the values that NERA estimated for the last reset process three years ago, notwithstanding the fact that NERA has confirmed that it used the same methodology to calculate these revenues in both studies. NERA has provided no explanation for this substantial change other than that this is what results from the more recent three years of data. They have not identified what fundamentals of the market have changed over this period to result in such an increase in estimated revenues.

Comparing NERA's estimate of how many hours the proxy units would be expected to operate with similar unit actual operation shows that the NERA estimates are unreasonably high. NERA's demand curve model provides estimated operating results for three different potential proxy GTs: GE Frame 7, LMS100, and LM6000. There are no LMS100s currently operating in the NYISO. Likewise, there are no GE Frame 7 units operating in the NYISO as standalone peakers. However, comparing the NERA estimate of LM6000 operation calculated even at high levels of excess capacity to the actual operating results for the NYPA LM6000 units that are located in New York City shows that NERA inexplicably projects that the proxy LM6000 units would operate more than twice as much as the actual LM6000 units have operated over the past three years under similar excess capacity conditions. (see Appendix A).

In its Report, NERA states that it has not "controlled" for the impact of any extraordinary circumstances on the pricing data that it used. NERA further states that it has not done so because such factors will "even out" over the long run. This was fundamental error as respects the Lake Erie loop flow issue which was encountered from January-July 2008. In ten years of operation, no other issue comes near the extreme impact of this event. In addition, it clearly had a significant impact on the NYCA net energy and ancillary services revenues as a substantial portion of the revenues were attributable to that period. Nor will this issue replicate itself. Since the loop flow issues were experienced, the NYISO proactively has implemented a series of measures expressly designed to prevent its recurrence. As a result, this factor will not simply be "evened" out in the end. Thus, NERA should adjust the data in its model to adequately account for the impact that the Lake Erie loop flow factor had on pricing during this period.

5. NERA'S FINANCIAL ASSUMPTIONS CONTAIN SEVERAL FUNDAMENTAL ERRORS THAT WILL CAUSE THE DEMAND CURVES TO BE SET INSUFFICIENTLY LOW

NERA has set forth the financial parameters, capital structure and cost of capital assumptions that it has developed in Section IV.B of its Draft Report. As NERA itself recognizes, these issues have been the subject of substantial attention during this reset process; no consensus has been reached concerning how they should be addressed. (See Report at 55.) As an initial matter, all of NERA's assumptions proceed from the premise that the proxy unit cannot be project financed but rather must be balance sheet financed. This is not correct. As is evident from recent New England and PJM transactions, a new generation project can, in fact, be project financed. It is simply a matter of the cost and amount of debt that is required for a merchant project. If ultimately accepted, NERA's base assumption will artificially limit the pool of entities that can construct a new facility in New York. In short, accepting this assumption means narrowly constricting the merchant developers that could proceed with a project in New York to those with a balance sheet that is big enough to accommodate a new project and whose available resources are not otherwise being committed to other markets.

Accepting for purposes of argument that the project must be put on the balance sheet of a company that issues senior secured debt to finance the project, some of NERA's other assumptions are materially flawed. First, NERA presumes that a new generation project can be added to a company's portfolio without affecting its BB rating. In effect, it has taken a risky project and assigned a lower cost to it by essentially burying it within the company's balance sheet. However, this assumption is itself questionable. Unless other steps are taken, this buried project will adversely affect the company's overall rating.

NERA appears to acknowledge the irrefutable need to shore up the company's overall credit rating under these circumstances, noting that it also must "allow for a modicum of risk that may be unique to the peaker project." (See Report at 57.) However, NERA's attempt to do so leads to its second material flaw in this section of its Draft Report. While NERA claims that it sought to recognize the risk that this would place on the company's balance sheet, the "slightly lower" debt ratio, "slightly higher" cost of debt and "slightly higher" cost of equity ultimately proposed by NERA fall far short. For example, NERA has only increased the cost of debt from 7.04% (which is the Barclays Capital index yield for BB US corporate debt) to 7.25%. (See Report at 57-58.) However, providing for less than a 2/10th of one percent increase to the cost of debt cannot reasonably be deemed to be sufficient to offset the incremental exposure to a company's balance sheet of adding a project that is itself claimed by NERA to be so risky that it cannot secure stand-alone project financing. At a minimum, a one notch reduction and commensurate cost increase to single B debt would be a more appropriate proxy for, and more reflective of, the merchant project's risk.

IPPNY can appreciate the pressure to listen to both sides and take a mid-point view by "splitting the baby" financially. However, the ICAP Demand Curves are an administrative construct whose core purpose is to provide a reasonable proxy for actual capacity costs. If this process is to yield Demand Curves that produce sustainable markets over the long term, NERA, like Sargent & Lundy, must apply its professional judgment to issue an independently derived, viable set of financial assumptions. To do so, NERA should take the information that it receives into account but it also must contact the banks and other lending institutions that are actively engaged in these markets to obtain definitive information about the factors that are necessary to secure financing. Only then can it produce results that are sufficient to provide for new generation and to retain needed existing generation on the system.

6. Treatment of Uncertainty and Regulatory Risk

The NERA Report states "Regulatory Risks – the Demand Curve is an administered value subject to regulatory risk. We assume no percent probability that the Demand Curve will yield only 50% of the required revenue. Regulatory risks include items such as regulated rate-supported long-term contracts that may be added even when there are surpluses or to create surpluses. While regulatory risks are certainly plausible and we allow for them in the model, the NYISO Board did not believe in 2007 that such risks should be accounted for in the Demand Curve." (p.66)

NERA should approach the treatment of uncertainty and regulatory risk with a fresh look at the factors that determine the Demand Curves for the next cycle and advance its own view on what elements are appropriate for consideration. Did NERA change its view from the prior? If not, NERA should continue to propose and support the regulatory risk adjustment factors that it, in its professional judgment and expert opinion, finds are required to produce adequate Net CONE calculations. NERA should not change its opinion just because it was not accepted in the past. NERA is required to explain what it thinks should occur, not what the NYISO has done or is expected to do.

In the last Demand Curve reset process, the NYISO Staff elected to eliminate the regulatory risk factor because it said that regulatory risk should be addressed by applying appropriate mitigation to protect against suppression of market prices rather than by including a regulatory risk factor. This resulted in implementing the In-City uneconomic entry mitigation. Unfortunately, a recent FERC decision has significantly reduced the protection provided by the uneconomic entry mitigation.[10]

The NERA analysis assumes that the NYC market will be, on average, 3% long, and that the market will have a 1.5% standard deviation for the market excess. The revised FERC decision places the uneconomic entry bid floor at a price consistent with a 7.5% excess capacity level. This results in the bid floor being three standard deviations beyond NERA's assumed average excess capacity level. As such, in NERA's calculations there is a 0.13% chance that the capacity market would clear at or below the FERC floor level. This does not adequately represent the risk that, even with the uneconomic entry mitigation in place, uneconomic entry would suppress NYC capacity prices to the floor.

7. LMS100 Site Requirements - NYC

NERA states "As part of this study, we assumed that only a unit that could be practically constructed in a particular location would qualify."[11] (p.7) Earlier on in this process, S&L proposed to use a 3.5 acre site in New York City for 2 LMS100 units.

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[10] IPPNY has sought rehearing of this decision. Its rehearing request currently is pending before the FERC.

[11] Thus, for example, applying this rule, NERA selected the LMS100 unit as the peaking unit for NYC and LI because these locations require an SCR to avoid severe operating restrictions, and thus, the Frame 7FA could not practically be constructed as the peaking unit. (See Report at 8, 15-16.)

Levitan challenged this proposal on the grounds presented at the June 10, 2010 ICAPWG meeting:

> We note that each LMS100 unit is twice the size of an LM6000 unit, plus the LMS100 requires additional land for its unique intercooling design. Not only would it be extremely difficult to site a 2 x LMS100 project on 3.5 acres, doing so would incur significant additional construction costs and operating costs. Efficient construction practices require easy access by personnel and trucks to all parts of the plant, adequate laydown areas to temporarily store equipment and tools, and the ability to work on multiple plant components in parallel.
>
> A small site would not accommodate these efficient construction practices. Efficient operating practices are also affected if a small site restricts access for equipment inspections and overhauls, or requires special equipment to conduct maintenance.
>
> While there may be relatively small 3.5 acre sites in NYC close to existing substations, 6-6.5 acre sites large enough for a 2 x LMS100 plant may not be nearly as well situated with respect to access to existing substations and gas infrastructure. Locating further from an existing substation would require additional electrical interconnection costs for longer feeder lines, higher upgrade costs, or to construct a new substation. We have collected hard data on four actual LMS100 installations to support our position that a 1 x LMS100 Response to Multiple Intervenors and Transmission Owners on behalf of New York City Generators plant requires 3.5 - 4 acres, and that a 2 x LMS100 plant requires at least 6 - 6.5 acres when dry intercooling and fuel oil storage are required…"[12]

Apparently, S&L now endorses Levitan's view as it has correctly increased the site size for the NYC LMS100 proxy unit to six acres. However, there are problems with the assumption that such property is available for development, especially at the lease rate of $129,000 / acre. S&L has not provided evidence that viable six acre sites within Zone J, that are deliverable, actually exist to support the decision to use the 2-unit LMS100 scenario.

Like Levitan, IPPNY does not believe that six acre greenfield sites exist in New York City. In fact, during the July 16, 2010 ICAP Working Group meeting, S&L confirmed that it had only identified six acre brownfield sites, not six acre greenfield sites. If that is not the case, S&L should provide the details of the potential greenfield sites that they believe are available and the brownfield analysis that led them to revise their assumption from their earlier position.

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[12] "Response to Multiple Intervenors and Transmission Owners on behalf of New York City Generators." Levitan and Associates, Inc. Pgs 5-6.

In its Report, NERA rejected considering brownfield sites on the grounds that "…Although such brownfield sites exist, the number of these sites are limited." The same logic applied here with respect to the lack of six acre greenfield sites. Thus, following the practical construction in a particular location rule, t the NYISO should use the 1-unit LMS100 scenario, not the 2-unit LMS100 scenario, as the proxy unit for the NYC Demand curve.

8. Shape and Slope

We support the consultant's decision to maintain the current shape and slope of the demand curve for the reasons provided in the report. During the current surplus conditions, additional risk should not be foisted on investors by adding a kink to the Curves for opportunistic reasons. Some Market Participants have suggested the slope and shape of the curve needs to be addressed to ensure that consumers are not overpaying for capacity. We disagree; these same Market Participants have not brought forth any evidence the current slope and shape of the curve results in unreasonably high capacity prices for consumers. Moreover, doing so will only serve to significantly raise the levelized cost of new entry.

9. Summer Winter Adjustment

In this year's Demand Curve reset process, NERA incorporated the Summer Winter Adjustment into the model to set the demand curve. This is a significant improvement because the model now has been designed to account for how summer and winter capacity revenues would with excess in the market. [13]

In its Report, NERA compares the Demand Curve values for all three markets for Capability Year 2010/2011 derived in the last reset process with the values for Capability Year 2011/2012 derived in this reset process. However, it appears that the 2011/2012 values developed in this reset process already incorporate the summer/winter adjustment factor while the 2010/2011 values did not. To provide an apples to apples comparison, NERA should revise this chart by adding the summer/winter adjustment factor to the 2010/2011 values.

10. Staffing Levels

The Net Energy and Ancillary Service revenues produced by NERA are based upon assuming that each of these proxy units is available to operate any hour of the year. In an

[13] The summer/winter adjustment was incorporated into the model using the NYISO's current formula. This formula works if the demand curve is a straight line. The model should be revised to include a more flexible formula that can accommodate alternate kinked demand curve shapes so that, if anyone proposes such a shape, the model will be able to accurately account for the impact on summer and winter capacity prices.

email communication and at the July 16th ICAP meeting, S&L acknowledged that it had not assumed a manpower level for the Frame 7 unit that would allow the unit to be available 24 hours per day, 365 days per year.

Either the NERA Net Energy and Ancillary Service revenue modeling must be revised to be consistent with the assumed manpower levels or the manpower levels must be revised to enable the unit to be available every hour per year. Otherwise, the Net CONE for the proxy unit for the NYCA Demand Curve will not incorporate all the required costs, and, thus, will be set too low to adequately incentivize new entry.

11. <u>Real-time Fuel Costs</u>

The NERA analysis assumed that the proxy peak in each area would pay the same price for fuel in the real-time market as it paid in the intra-day market. This understates the real-time fuel cost because it ignores the risks of purchasing in the intra-day market. For the GTs to operate in the real-time market they will need to purchase gas with very little notice. Because the real-time operation will be uncertain they will not generally have procured any fuel in the intra-day market to cover potential real-time operation. This is particularly the case for the Frame 7 Proxy unit because its real-time operation is particularly unpredictable and sporadic. Moreover, they will need to place bids for real-time operation well before the real-time operation would occur. The manpower levels that have been assumed for the proxy units do not allow for sufficient manpower to constantly be updating real-time gas costs just in case the unit needs to run. Consequently, unless the manpower is significantly increased to account for this additional need, the unit needs to be bid into the real-time market with a significant adder over day-ahead fuel costs to account for the risk that the intraday gas costs would understate real-time gas costs.

Imbalance costs associated with real-time operation have also been ignored. For the GTs, real-time operation will, by definition, result in imbalances against the intra-day gas obligations because real-time operation is too sporadic for the generation owner to be able to predict when the unit will run in real-time. The difficulty of predicting real-time operations is that real-time operation arises from conditions that are sufficiently unexpected that they did not result in the unit already being picked up in the day-ahead market.

Imbalance charges are a matter of record. They must be accounted for as a cost of real-time operation or the NERA modeling will overstate the real-time net energy revenues for the unit.

Appendix A

Comparison of Actual and NERA Forecast Capacity Factor for LM6000 Units

	2007	2008	2009
New York City Summer Average Monthly Excess Capacity Percent	3.10%	10.50%	8.54%
NERA Estimated Capacity Factor	52.79%	40.86%	43.93%
Actual LM6000 Capacity Factors in NYC			
Gowanus 5	24.51%	20.96%	14.81%
Gowanus 6	22.99%	18.12%	8.76%
Harlem River 1	9.65%	8.74%	1.91%
Harlem River 2	15.52%	13.37%	2.19%
Hellgate 1	14.05%	14.87%	1.98%
Hellgate 2	13.80%	14.47%	2.51%
Kent	28.32%	19.06%	3.24%
Pouch	35.90%	28.74%	14.87%
Vernon Blvd 2	17.24%	18.13%	2.53%
Vernon Blvd 3	14.57%	14.13%	2.60%
Average Actual	19.65%	17.06%	5.54%