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To: Dave Lawrence – NYISO

From: Chris LaRoe

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Re: IPPNY Comments on the NYISO Staff Draft Recommendations for the NYISO Installed Capacity Demand Curves

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1. Introduction

In accordance with the NYISO's revised 2011-2014 ICAP Demand Curve Development Schedule, IPPNY offers the following comments on the *New York Independent System Operator, Inc. Proposed NYISO Installed Capacity Demand Curves For Capability Years 2011/2012, 2012/2013 and 2013/2014 ("*NYISO Staff Draft Recommendations"). IPPNY's positions on several key elements of the parameters of the curves remain unchanged from the comments we submitted on the consultants' draft *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] Regarding two of the most important parameters of this Demand Curve reset process, deliverability and In-City property taxes, the NERA Report provided calculations of Net CONE both with and without the costs of those variables built into the model. Therefore, market participants had the opportunity to weigh in on those issues prior to the issuance of these Draft Recommendations. IPPNY maintains its position that costs associated with each of those elements must be fully captured in the Net CONE for the proxy unit, and we submit the following additional comments on those issues and others.

2. Deliverability Costs

Similar to the NERA Report, the NYISO proposal does an adequate job explaining what the NYISO tariff requires of capacity providers. Despite the fact that the tariff requires a capacity provider to be fully deliverable throughout its capacity zone (as fully acknowledged by NYISO Staff), NYISO Staff continues to maintain its position that any

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

System Deliverability Upgrade (SDU) costs associated with being deliverable should not be included in the proxy unit's Net CONE. It is logically indefensible, as well as counter to the tariff provisions that require the updated curves to reflect Net CONE, to take a position denying a legitimate (and potentially substantial) cost that the proxy unit would encounter upon entry to the market as a capacity provider.

Our earlier comments pointed to the significant cost associated with SDUs – the price tag for the upgrades required of new capacity resources located in Zones A through F was calculated by the NYISO at $178/kW.[2] There is no other mechanism in the NYISO's market for a generator to collect such costs. It begs the question to the NYISO of what developer of resources would be willing, or is even capable, to absorb such a cost if it is not otherwise recoverable. As the name implies, the entire purpose of the Demand Curve reset exercise is to set Net CONE – i.e., the costs incurred for a new unit to enter each of the NYISO capacity zones – and the reference price at levels so as to properly provide for new investment. 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 – in this instance, deficient by $26.71/kW-yr (NERA determined Net CONE with deliverability costs at $116.5; NYISO is recommending $89.79).

Moreover, the NYISO Staff's Draft Recommendations result in no proxy unit being economically viable anywhere in the Rest-of-State region. While not presented in the Draft Demand Curve Report or in the NYISO's recommendations, the NERA Demand Curve model provides the information to estimate the Net CONE for the Central zone and the Lower Hudson Valley. The Central zone GT has slightly lower costs than the Capital Zone proxy unit but much lower Net Energy and Ancillary Service Revenues. This results in the Central zone proxy unit having a higher Net CONE than a proxy unit in the Capital Zone as the NYISO has proposed as the basis for the Demand Curve. Additionally, a new capacity provider in the Central zone (or any zone north and west of UPNY/SENY) would be required to incur the same deliverability costs as a new unit in the Capital zone to be eligible to sell capacity. Consequently, a Central zone proxy unit would not be economically viable.

A Lower Hudson Value zone proxy unit would not have deliverability costs associated with the UPNY/SENY interface. However, it would be a more expensive unit because

[2] "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." 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.

environmental restrictions require a different type of GT to be used as the proxy unit in this area. The NERA Demand Curve model determines that the Lower Hudson Valley unit's Net CONE is higher than the cost of a proxy unit in the Capital Zone even with the inclusion of deliverability costs in the Capital Zone proxy unit's cost. Consequently, a Lower Hudson Valley proxy unit also is not economically viable given the NYISO Staff's Draft Recommendations.

The NYISO mistakenly relies upon the potential future creation of new capacity zones as a way to "eliminate the impact of transmission bottlenecks in the deliverability analysis and better reflect regional costs to construct a new facility, thereby restoring the proper signals for new entry. The NYISO states that it is committed to pursuing the development of new Capacity Zones with stakeholders as a separate activity from this Demand Curve review process." Unfortunately, this statement simply affirms that transmission bottlenecks exist today and would be encountered by the recommended proxy unit located in the Capital zone. Although new capacity zones may address these conditions (IPPNY expects its members will address the new capacity zone proposal when it is released), the NYISO has yet to even present to market participants its recommended criteria for new capacity zones. Moreover, once the criteria are presented, it is not clear how quickly a new zone would be formed. The system as it stands today does not contain a Lower Hudson Valley zone and the Demand Curves must be based on the facts at hand. To comply with the requirement of its tariff, the NYISO's options are limited to determining Net CONE based on a proxy unit above the UPNY-SENY interface with deliverability costs or in the Lower Hudson Valley, which does not appear to have deliverability costs.

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

IPPNY's position on In-City property taxes remains the same – Net CONE must not assume tax abatements that are not ensured to applicants "as of right." Discretionary tax abatement programs are just that, discretionary, meaning there is significant risk that the entity in charge of granting such abatements may choose to deny a request for abatement in its entirety or otherwise limit it. This is true for the Third Amended and Restated Uniform Tax Exemption Policy recently approved by the Board of Directors of the New York City Industrial Development Authority (NYCIDA). Given the discretionary nature of all New York City programs, NYISO Staff's Draft Recommendation to assume 100% tax abatement for the NYC proxy unit Net CONE violates the NYISO's tariff.

The risk of shortfall in the NYC cost of new entry levels is significant. The NYISO's recommended reference point with assumed full property tax abatement is $165.93 (this price reflects other adjustments from the NERA report, including variables related to site cost), while the NERA report recommended a reference point of $219.77 with no property tax abatement. Again, considering that the purpose of an accurately set Demand Curve is to ensure that new generation is properly incentivized, the NYISO's proposal is deficient by approximately $55/kW-yr. The only way to reasonably ensure that the proxy unit recovers it full property tax costs is to assume no tax abatements. Since the newly created program, like any other NYC program, is discretionary, and, considering that

New York City continues to be an active participant in the Demand Curve reset process, NYCIDA would be able to point to FERC orders including such costs as sufficient support to deny abatement to a requesting generator. Discretion cuts both ways – it can protect against "double-dipping," but it also has the potential to deny full property tax cost recovery if the NYISO does not build the appropriate costs in its Demand Curves. The NYISO must come down on the side of ensuring costs are recovered in its Demand Curves.

The Services Tariff requires the NYISO to "assess: (i) the current localized levelized embedded cost of a peaking unit …" (5.14.1.2). During the last reset process, the Industrial and Commercial Incentive Program (ICIP) included provisions that granted new generation projects an as-of-right exemption from NYC real property taxes for eleven years, phasing out such exemption at 20% per year through year sixteen. Finding that full property tax abatement can be presumed in this reset process is fundamentally flawed for a number of reasons.

The ICIP exemption described above no longer exists for new generation projects. Recently, the NYC IDA has promulgated a new discretionary program, the Third Amended and Restated Uniform Tax Exemption Policy (the "Policy"), which includes criteria for generation projects that seek tax exemptions. Notably, the Policy defines a "PlaNYC Energy Program Project" as a generation addition which resembles the choice of Peaking Unit to be used for CONE. Unlike ICIP, however, the Policy does not automatically grant a property tax exemption to effectively all new generation projects. Instead, it grants the IDA the right to grant partial or full tax exemptions to projects which meet both objective and subjective criteria. The objective criteria resemble the physical and operating characteristics of a GE LMS100, which is the presumed Peaking Unit for the 2011-2014 reset period. The subjective criteria provide the IDA with substantial flexibility to make determinations as it chooses. For example, the subjective criteria include the requirement that "the proposed Peaking Unit will satisfy either (aa) a future reliability need as identified by any one of NYISO, the transmission owner, or the City or (bb) an environmental need identified by the City." There is, however, no definition as to how such reliability or environmental needs would be "identified" by NYC.

Likewise, requirement (aa) could be read to eliminate merchant entry as a candidate for exemptions. That is, only a project identified to satisfy a future reliability need, not one sponsored by an entrant on a merchant basis, would appear to qualify. Similarly, requirement (bb) is completely amorphous, subjective and not subject to question or independent analysis. Lastly, it must be noted that the very entity that would be deprived of property tax revenue (NYC) has exclusive authority to determine whether an exemption would be granted.

For all of the aforementioned reasons, the NYISO Staff recommended Net CONE for the NYC proxy unit and the associated NYC Demand Curve that it will produce do not represent "the current localized levelized embedded cost of a peaking unit." The current cost of a peaking unit includes property taxes. NYISO and the representative for NYC have both admitted, without qualification, that the Policy is not an as-of-right exemption for new entry of a peaking unit. Neither the NYISO nor NYC has proffered any evidence that the Policy has been utilized nor have they offered details on definitively demonstrating how the subjective criteria outlined above would be applied. A purely discretionary program that has never been utilized, is not based on objective criteria – in fact, is subject to an inherent conflict of interest – cannot be construed as a guaranteed tax exemption. Finding otherwise is fundamentally counter to the requirements of the tariff and common sense.

4. <u>Excess Capacity</u>

IPPNY agrees with the NYISO that the existing reliability processes in New York State make it extremely unlikely that the levels of capacity will be permitted to drop below the minimum requirement for any sustained period of time. In the NERA Report, the following levels of excess were recommended: NYCA average excess of 1.5%, NYC average excess of 3.0%, and LI average excess of 7.0%. However, in the NYISO Staff Draft Recommendations, those levels of excess were arbitrarily trimmed down, with the NYISO now supporting NYCA at 1% excess, or 101% of the Installed Reserve Margin; NYC at 2% excess, and Long Island at 104.67% excess.

The NYISO has not provided justification for its assumption that there will be lower levels of excess capacity in the market and, therefore, less risk that warrants longer amortization periods than those recommended by NERA. NERA had recommended amortization at 20.5 years for NYCA, 17.5 years for NYC, and 15.5 years for LI. Due directly to the excess capacity assumptions that it incorporated into the model, the NYISO Staff is recommending longer amortization periods, "The results, as explained in the NERA/S&L Report, are amortization periods of 28.5, 22.5, and 18.5 years for NYC, ROS, and LI, respectively."[3]

Such a recommendation does not sufficiently address risk. Indeed, these newly recommended levels are well below the risk levels that are embedded in the current Demand Curves. Yet the NYISO has not identified any major changes in the market justifying that such risk has abated significantly. The ICAP Demand Curves were implemented in New York, in part, to promote stability in the capacity market. Changing such a significant parameter without identifying changes to justify such reductions will substantially undercut such stability. Thus, absent being able to do so, the excess capacity levels should remain unchanged.

In addition to not sufficiently addressing risk, the NYISO recommendation is a significant step backwards in the methodology and assumptions employed in this process. In the 2004 Demand Curve Reset Process, a 20-year amortization period was used for all regions. In 2007, NERA recognized that merchant risk was not adequately captured in the previous process and introduced a new methodology to address this shortfall. The methodology that was suggested, which the NYISO ultimately agreed with and adopted, was to shorten the amortization periods to reflect the merchant risk

[3] NYISO Proposal, Pg 3

appropriate for each region. For NYC, for example, this led to a 17.5 year amortization period which NERA stated was a "move toward reflecting a degree of merchant risk for NYC as it is lower than the 20 years used in the prior update." In the current 2010 process, NERA utilized similar assumptions that included amortization periods for each region. As stated in the draft NERA report, "A single assumption is not suitable for the NYISO as the NYISO is commonly acknowledged by stakeholders to have a bias toward excess. An implied capital cost based on an amortization period of 20 years in ROS is consistent with relatively low risk…The somewhat lower amortization periods in NYC and LI are appropriate given the greater risk of smaller markets."

The NYISO recommendation of a 28.5 year amortization period for NYC is unreasonable. Given that the 20 year amortization in the ROS represents "relatively low risk," assuming a 28.5 year amortization in the NYC market effectively assumes no risk. Comparatively, other markets, including PJM and MISO, use a 20-year amortization period. As mentioned previously, New York started with a similar assumption and then improved the methodology by introducing merchant risk and shorter amortization periods (e.g. 17.5 years for NYC). Moving to a 28.5 year amortization period effectively eliminates merchant risk, is inconsistent with methodologies employed in other markets and in New York during previous processes, and is indefensible given the higher risk profile of the NYC market as outlined in the NERA report. For all the aforementioned reasons, an amortization period of under 20 years, as reflected in the NERA draft proposal, provides a reasonable approximation of project risk.

5. <u>Shape and Slope</u>

We support the NYISO's and consultant's decision to maintain the current shape and slope of the Demand Curves 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 need 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 result in unreasonably high capacity prices for consumers. Moreover, doing so will only serve to significantly raise the levelized cost of new entry.

6. <u>Proxy Unit To Set the NYCA Demand Curve</u>

The NYISO has recommended that the NYCA Demand Curve be based on the Net CONE (without, as noted above, including deliverability costs) of a Capital zone proxy unit. As demonstrated above, IPPNY supports setting the demand curve based upon either a Capital zone proxy unit including the cost of making the unit deliverable to the Rest of State Region or a Lower Hudson Valley proxy unit which presumably does not have significant deliverability costs.

Some market participants have suggested that the NYCA Demand Curve should be based upon the estimated Net CONE for Long Island. Such an approach, however, would be flawed. Initially, it should be noted that there has been little attention paid to the Long Island demand curves because Long Island Power Authority ("LIPA") procures most of its capacity by contract and because LIPA has procured so much capacity that the spot market for Long Island based resources is expected to clear against the NYCA Demand Curve.

It is not appropriate to set the NYCA curve based upon NERA's estimated Net CONE for Long Island. The reason the Net CONE for Long Island is lower than the Net CONE of the Capital Region proxy unit is because, while the capital costs are higher, the NERA Net Energy and Ancillary Service revenue model provided very high estimates for the net revenues of a new unit on Long Island. The demand curve model estimated that the Net Energy and Ancillary Service Revenues of an LMS100 unit on Long Island were more than 65% above the level for the same type of unit in New York City.

While Long Island LBMPs might have been significantly higher than NYC LBMPs during most of the historic period used for the Net Energy modeling, this is no longer the case. Towards the end of the historic period, roughly 1000 MW of new efficient capacity was added to Long Island that has significantly altered the resource base on the Island and, correspondingly, the energy prices on the Island. However, this change in the Long Island resource mix, which translated to the addition of efficient resources at a level equal to roughly 1/5 of the Long Island peak load, was not adjusted for in any manner in the net energy modeling.

A review of recent President's reports and CEO/COO reports to the Management Committee shows the impact of the resource change on Long Island. Long Island no longer has LBMP's that are substantially above, or even significantly above, the LBMPs for NYC. If the Long Island Curve had been estimated based upon the NYC Net Energy and Ancillary Service revenues, the Long Island Net CONE would have been significantly above the Capital Region Net CONE, even with deliverability costs included for the Capital Region.

The Long Island proxy unit should not be used to set the NYCA Demand Curve without first adjusting the Net Energy and Ancillary Service revenues for the substantial changes in the Long Island resource mix. Making this change at this point would most likely require significant analysis. The net result of such analysis would likely reveal that the Long Island proxy unit Net CONE was higher than that of the Capital Zone proxy unit, and thus, the Long Island proxy unit should not, in fact, be used to set the NYCA Demand Curve.

7. **Additional Issues - Modeling**

Several significant errors have been identified in the Demand Curve modeling that must be corrected before NYISO Staff's final recommendations are produced and the NERA Final Report is issued. These are addressed below.

Real-Time Gas Prices
Currently the Net Energy and Ancillary Service model assumes that a generator can obtain gas in the intra-day market at the same price that it pays for gas in the day-ahead market. Shell has produced an analysis that shows that purchasing gas in the intra-day market results in the generator paying a premium over prices in the day-ahead market. While this analysis was based on Transco Zone 5 prices, it confirms the fact that there is a premium that must be taken into consideration. The Net Energy and Ancillary Services estimates should be re-run accounting for this additional intra-day gas cost. This is likely to be most significant for the NYCA proxy unit's revenues since this unit is assumed to achieve a significant amount of its revenues from the real-time market.

NYC LBMP for the Net Energy and Ancillary Service Revenue Calculation
In estimating the Net Energy and Ancillary Service Revenues for the NYC unit, NERA has performed the analysis based on the Zone J LBMP. However, the new unit is assumed to be connected at the 345 kV system to avoid the likelihood that connecting the proxy unit into a 138 kV load pocket would cause the price to collapse to the 345kV price. Using the Zone J LBMP does not provide a good estimate for the 345 kV system prices, or for the 138kV load pocket prices. In particular, the Zone J price overstates the 345 kV price during the high priced hours when the proxy unit would be expected to run and equals the 345kV price during the low priced hours when the unit would not be expected to run. Thus, this error overstates the Net Energy revenues that the NYC proxy unit would receive.

LMS100 Residual Value
The NERA Draft Report states that the NERA analysis assumes that the LMS100 unit would have a residual value equal to 5% of its initial investment cost. However, in the Demand Curve model that NERA used to perform its analysis, the residual value has been treated at its current year level, not the value at the end of its life in the 30th year. This overstates the benefit of the unit's residual value at the end of its life. This should be corrected by applying the same discount rate to the residual value as is applied to other revenues from the last year of the unit's economic life.

Out-of-Market Resources
In their effort to forecast future revenues in the wholesale energy market, NERA failed to include the impact of out-of-market resources, such as those brought online via the RPS, on LBMP's over the next 3 years. In a report prepared by KEMA for NYSERDA called "New York Renewable Portfolio Standard Program Evaluation Report - 2009 Review" under the section "Program Progress and Key Evaluation Findings" on page 6 it states:

- "Main Tier renewable resources are suppressing wholesale electricity prices and, more modestly, natural gas prices. A regression analysis estimated electricity price suppression statewide in 2010 at $2/MWh."

This matter has been raised both in direct communication with the NYISO as well as open discussions within the ICAPWG. To date a reason for excluding the impact has not been given, just simply a statement by NERA that they have not considered the impact.

The fact that a consultant for NYSERDA was able to model the impact suggests that it can be done. There is no indication given current public policy and the 6,868 MW's of wind in the NYISO Interconnection Queue (as of 7/2/2010), that such price suppression won't continue and become more pronounced. As such, to ensure the integrity of the wholesale markets in NYCA the impact of the price suppression needs to be taken into account when evaluating energy revenues to existing resources going forward.