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Memorandum

To: **Mr. David J. Lawrence**

From: **Chris LaRoe**

Date: **2-9-10**

Re: IPPNY Response to NYISO Demand Curve Questionnaire

NYISO Questions to Stakeholders – Demand Curve Reset Issues

The questions below were discussed at the January 25th ICAPWG meeting. NYISO staff is interested in stakeholder views on these issues. Please e-mail comments to Peter Lemme (plemme@nyiso.com) by COB February 8th. Please identify in the document whether you want the comments to be kept confidential or want them to be posted.

Demand Response as Peaking Unit

1. How does the use of Demand Response comport with the tariff? Please specify if your answer is different if the Demand Response is provided by a generating unit(s),or load reduction.

   ANSWER:

   The use of Demand Response as the Proxy Unit, simply put, does not comport with the tariff. Nor does it comport with the foundational elements of reliability planning in New York, as outlined and administered by the NYSRC. The provisions of setting the "Installed" Reserve Margin or "IRM" that have a long and successful history in New York State at maintaining reliability, are in essence thrown in the trash once the underlying resource to support IRM is accepted as being – on the margin – demand instead of physical supply. If accepted, this would be a very serious departure in long-standing reliability planning processes. Due to their inherent characteristics, all Demand Response resources (curtailment as well as distributed generation) are ill-suited to act as the proxy "unit" to set any of the Demand Curves for New York State for a significant number of both practical and public policy reasons. On its face, the use of a load reduction Demand Response resource as the proxy unit to set the Demand Curves also would not be permitted under the provisions of the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff"). Section 5.14.1(b) provides that the Demand Curves shall be set based upon the current localized, levelized embedded cost of a peaking unit in each NYCA Locality less the likely projected annual Energy and Ancillary Services revenues to be secured by such unit. (See Superseding Sixth Revised Sheet No. 157.) This section then defines the term “peaking unit” as “the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable.” (Id.) The term “Generator” is defined in the Services Tariff as a facility. (See Fourth Revised Sheet No. 39A) Although not separately defined in the Tariff, the term “unit” must be accorded its commonly accepted meaning as a standalone facility or “generating” unit. (Note: for example, the use throughout the Tariff of the term “Security Constrained Unit Commitment.”) In contrast, Demand Response resources that take the form of load curtailment are neither facilities, nor can they reasonably otherwise be characterized as units. Thus, these resources cannot meet the tariff requirement that they must be a unit whose costs can be measured.

2. Should load reduction Demand Response be considered?

ANSWER:

No. The limited amount of Demand Response that is participating in the Capacity Market at present is technically not comparable at all to generation capacity. The notice provisions, dispatch limitations and penalties applied to Demand Response versus generation do not match and if they are to be relied upon as the marginal resource, they must. Put another way, at present the Demand Curve and IRM provisions of the tariff inherently assume a Value Of Lost Load (VOLL) that is very high, much higher than the Proxy Unit costs on the Demand Curve. This notion is inherent in the Demand Curve pricing structure. It is only that load or Demand Response that can accept being dispatched down on the same basis as generation may be dispatched up that should be able to participate in pricing derived from the Demand Curve. Since this is not the case and unmet load will occur after accounting for available Demand Response, the load must be met with physical supply. The approach to pricing this physical supply is the Proxy Unit and the price points on the Demand Curve (rather than using VOLL proxies). This approach is the foundation of the Demand Curve and would be fundamentally disrupted if Demand Response is used as the proxy for physical supply. It simply is not sensible.

Additionally, the primary driver underlying the cost for load reduction Demand Response is the opportunity cost to the load associated with forgoing its normal levels of electricity usage. This can be manifested through, e.g., increasing facility temperatures, changing or eliminating manufacturing cycles, or the financial impacts of taking whatever other steps the customer can to reduce its loads. In contrast to “steel in the ground” equipment costs, these costs cannot be measured with any degree of specificity or accuracy. In fact, the limited information we do have indicates that the opportunity costs are significant and that they increase the more the resource is called upon to perform.

For example, Con Edison has implemented a load reduction program, entitled the Commercial System Relief Program (“CSRP”) that is designed to secure load reductions during the four peak summer months. After reviewing comments on the cost of Demand Response in Con Edison's CSRP – many of which were submitted by Demand Response resources themselves – the PSC structured the compensation for this program as follows: i) the load reduction participant is paid the NYISO spot market clearing price on the NYC Curve; ii) the load reduction participant is paid a base premium of $5/kW-month for each of the four months; and iii) if the program is called more than five times in any year, the load reduction participant receives an additional $5/kW-month premium for each of the four months. In addition, the maximum number of times that the resource may be called is capped at 10 calls per year.[1]

[1] The CSRP pays program participants a base premium of $5/kW-month over and the NYISO spot market clearing price for the NYC Curveand then increases the premium another $5/kW-month if there are more than five calls in a given year.

The recent analysis to set the IRM for 2010 estimated that there would be 18.4 SCR calls per year under conditions where the NYISO just meets its reliability requirement.[2] This is significantly greater than the maximum of ten calls that was established as the outside limit for Demand Response providers for the CSRP program. In years where reserves just met the minimum requirement and there was hotter than normal weather, the number of calls reasonably could be expected to be even higher, perhaps significantly so.

While RIP representatives have stated that they could put together a portfolio of demand response resources to respond to a higher number of calls, they further have noted that it would require signing up multiple MWs to support each MW of "capacity" sold. This factor alone raises two issues. Initially, it will be difficult to determine with any degree of accuracy the sufficient number of "pledged" Demand Response provider MWs, i.e., should Demand Response provider MWs be sold on a 2:1, 3:1, 4:1, etc basis as compared to peaking unit MWs. In essence, more "nameplate" capacity would be required to be the equivalent of the desired peaker proxy size. Moreover, once a ratio is determined, procuring these redundant supplies would also significantly increase the cost of using Demand Response resources as compared to using a peaking unit as the proxy to set the Demand Curves in New York. Thus, given all of these factors and the degree of uncertainty inherent in each of them, calculating the value of Demand Response as the proxy "unit" with any demonstrable degree of accuracy would, at a minimum, be very complicated and, in fact, may be impossible.

Third, another consideration is that Demand Response resources cannot be relied upon as the basis to set the proxy "unit" costs if these resources continue to have the current limitations on when the resources can be called. If utilizing Demand Response to set the values of the Demand Curve resulted in lowering the price points on the Demand Curve, it would also lower the likelihood of entry by peaking units and other traditional generation because their costs would not be recovered from the market. This would create a greater need to rely upon Demand Response for many of the reliability functions that we currently rely upon peaking units to perform. Consequently, if Demand Response resources are to be used as the basis for the Demand Curve, a comprehensive review will be required to identify the changes that need to be made to the Demand Response rules to eliminate special exceptions and ensure that these resources can be called and will respond whenever needed to meet system reliability needs.

Finally, given that Demand Response cannot (and is not required to) respond to NYISO dispatch commands on the same basis as a generation Peaking Unit that can indeed be used to meet the energy needs of (other) load, Demand Response lacks the physical attributes to be considered as a proxy for the Demand Curve Reset process.

Any Market Participant that proposes to use Demand Response resources as the proxy "unit" to set any of the Demand Curves for New York State must be required to provide a methodology for estimating with an acceptable degree of accuracy the cost of the Demand Response resource that addresses all of the above issues.

3. Should Demand Response using behind-the-fence generation be considered?

ANSWER:

[2] *NYCA Installed Capacity Requirement for the Period May 2010 through April 2011, New York State Reliability Council, LLC, Installed Capacity Subcommittee, December 4, 2009, p. 68.*

Behind-the-fence generation may be a viable as the proxy unit to set the Demand Curves in New York if there are no significant limitations on when the generation can be called (or in the lead time for the call) and there are no significant limitations on the total number of hours that the resource can be called. It must be noted in this regard that the NYISO's Services Tariff requires that a viable technology must be chosen as the proxy unit. (See Superseding Sixth Revised Sheet No. 157.) A unit that would be prevented by environmental restrictions from operating when or as often as is needed does not meet this requirement.

4. If behind-the-fence generation is considered, should there be a distinction between emergency generation, baseload generation, and cogeneration?

   ANSWER:

   As noted above, the Services Tariff expressly requires that the Demand Curves in New York be set based on a peaking unit. (See Superseding Sixth Revised Sheet No. 157.) The Services Tariff then expressly defines peaking unit to mean the "technology that results in the lowest fixed costs and highest variable costs." Id. This applies whether the proxy unit is a grid connected unit or a behind-the-fence unit. Consequently, the Demand Curves cannot be set based on behind-the-fence generation that is baseload generation or cogeneration (which, presumably, is merely baseload generation that also produces usable heat) as neither of these facility types meets the express definition that is set forth in the Services Tariff. Emergency generation also cannot be used as the basis for the proxy unit unless the "emergency generation" does not have limitations on the total number of hours or the time periods it is allowed to operate and it otherwise meets the express definition of peaking unit that is set forth in the Services Tariff.

5. Significance of run hours - can Demand Response meet expected annual deployments, as determined in the IRM study, if the duration of those deployments is significantly greater than past experience?

   ANSWER:

   This is a legitimate concern, as the NYISO can ill-afford to rely on Demand Response to solve actual reliability problems with the hope that these resources will meet expected annual deployments; the NYISO needs to know the answer to this before allowing Demand Response technology to be considered for this process. It is our contention that, while demand response resources play an important role in other respects, the answer to whether they can be relied upon to solve actual reliability problems is no.

   As noted above, the 2010 IRM study analysis estimated 18.4 SCR calls per year with the New York system at the minimum requirement. If Demand Response cannot meet the expected annual deployments as determined in the IRM study, we need to look at whether the total amount of Demand Response that we will rely upon must be limited in some manner. This is somewhat separate from the question of whether Demand Response should be used to set any of the Demand Curves. On that specific question, as noted above, Demand Response resources cannot be used as the proxy unit to set the Demand Curves if they will not be able to respond when and as often as required to meet system reliability needs. Moreover, were Demand Response resources chosen as the peaking unit because it was believed to be the lowest cost, viable resource notwithstanding the issues noted herein, the lower price points on the Demand Curve would increase the reliance on these resources because it would decrease the price signal to traditional resource entry. This would exacerbate the concern raised in the question.

Regardless of whether Demand Response can be expected to meet the 18.4 calls per year estimated in the IRM study, we cannot set the Demand Curve based upon a resource that has severely restricted operating hours. The past Demand Curve Reset Final Report[3] rejected using a Frame 7 unit as the basis for the Demand Curve in NYC and Long Island because environmental restrictions would have forced it to be limited to too few hours of operation. The study considered availability for 678 hours of operation as being too limiting. This level of required availability is well beyond the amount of response that we can expect from demand side resources. For RIPs to attempt to compile a portfolio of Demand Side Resources that was able to operate more than 678 hours would require the RIPs to procure several MWs of Demand Response resources for each "peak grid" MW that was sold. This would clearly raise the price significantly.

6. Are there other types of Demand Response that should be considered?

   ANSWER:

   No

7. If Demand Response technology(ies) were to be used as the peaking unit, what process should the NYISO use to determine which technology(ies) to use?

   ANSWER:

   For the reasons provided above, Demand Response resources cannot and should not be used as the proxy "unit". If the NYISO chooses to analyze Demand Response technologies in the form of load curtailment, it is critical that the NYISO accurately capture the lost opportunity costs that are associated with providing this Demand Response given that this consideration has been documented by the Demand Response community as a driving factor on the costs that they face to participate in such a program. Moreover, the NYISO must accurately capture the increase in costs associated with relying upon these resources for more than a de minimus number of events. This latter effect results from both the need to pay individual responders higher capacity payments as the number of calls increases and the need for RIPs to procure multiple MWs of capacity for each MW sold so that they can manage the frequency of calls.

   As noted above, any Market Participant that proposes using any form of Demand Response technology(ies) as the proxy "unit" must be required to propose a comprehensive methodology to identify all of its costs.

8. Should a group of different technologies be considered? If so, what is the process for determining the mix of such technologies?

   ANSWER:

   No. GTs are the most economic peaking capacity technology. As others become economic, they should be evaluated (e.g. large scale energy storage facilities).

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[3] Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, NERA, August 15, 2007, p. 29.

NYC Tax Abatement

1. Name the types of taxes imposed on generators for which there is an opportunity to receive an abatement.

2. How should the opportunity for new generation to receive some form of tax abatement be quantified? If the answer to the foregoing question varies depending on the type of tax, identify the specific tax in the answer.

   ANSWER:

   As a preliminary matter, it must be noted that property taxes are a very significant fixed cost for a new generator as was evidenced in the last reset process.[4] Tax abatement should only be used to offset the costs of the proxy unit if such abatement is available to generating facility projects in the form of an "as of" right reduction. This is consistent with the decision in the last Demand Curve Reset process to not include potential property tax relief in the determination of the Rest of State Demand Curve due to the uncertainty surrounding whether new combustion turbine generators would qualify for such tax abatement.[5]

   IPPNY is not aware of any disagreement that there are no "as of" right property tax abatement programs currently available to proposed generating facility projects. In fact, New York City itself very recently acknowledged 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 …"[6] New York City further established that neither it nor the NYCIDA had any ability to circumvent these application and review procedures to offer a developer a package of benefits before a project proposal is submitted.[7] Given the very real possibility that a new generating project also 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 likewise must not be assumed as a cost reduction for the proxy unit for Zone J. Indeed, in light of the repeal of the ICIP and 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, it is far more likely that an unusually high tax burden will be placed upon suppliers of capacity in the NYCA going forward.[8]

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[4] In the last Demand Curve Reset Final Report, NERA's modeling included a binomial variable to measure the impact of including property taxes as a cost component for the NYC proxy unit. In that reset process, the property tax component translated into costs of $47.74/kW-year for the proxy unit for the 2008-2009 NYC Demand Curves.

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

[6] 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.

[7] Id.

[8] As expressly stated by Con Edison in support of the settlement agreement in its electric rate case currently pending before the New York Public Service Commission which proposes to increase rates by $420 million per year for the next three years, "…substantial expenditures must continue to be made in order for [Con Edison] to continue to perform the complex task of utility operations in what is truly [a] unique but undeniably high-cost service area." See PSC Case 09-E-0428, Proceeding on Motion of

If the estimation of the Net CONE for the proxy peaking unit were to assume property tax abatement and the entrants were not able to obtain the assumed property tax abatement level, the resulting Demand Curves would fall far short of providing appropriate price signals to assure new entry or investment in existing facilities was induced to meet reliability requirements. For example, when the ICIP real property tax statute was repealed, the 2008-2009 NYC Demand Curve was understated by nearly 40%. As FERC repeatedly has held, it is critical that the capacity market be structured properly to ensure the long term reliability of the system.[9] The price points set for the Demand Curves are a key determinant of inducing new entry and ensuring needed units remain operational to maintain the long term reliability of the system.[10] Costs cannot be omitted when, as here with respect to property taxes, doing so will directly result in under-compensating generators.

3. For tax abatements that are discretionary, what process does the governmental entity use to prioritize requests for tax abatements?

4. Could an historical average tax abatement approach work?
    a. Requires tax abatement information on new NYC projects.
    b. Should historical average consider just CTs or all technologies?

    ANSWER:

    For the reasons discussed above, no property tax abatement should be assumed in developing the Demand Curves because no "as of" right programs are available for generating facility projects. If, however, an historical average approach were used, it must consider just the treatment of property tax abatement applications by CTs to be consistent with the basis that is used to identify the costs of the proxy unit. If an assumed property tax abatement level were based on non CTs and the CT would not be expected to receive the abatement, the resulting Demand Curves would not otherwise provide appropriate price signals to assure new entry was induced to meet reliability requirements. Moreover, given that the ICIP real property tax exemption statute was in place for more than two decades and has only recently been repealed and replaced by the ICAP statute, it is unlikely that a sufficient number of CT property tax abatement applications have been submitted and acted upon to produce a statistically relevant and reliable review set.

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the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, "Con Edison Statement in Support of Joint Proposal" (dated December 17, 2009). Con Edison further emphasized that the proposed settlement agreement "recognizes the limited ability for the Company to avoid costs." (Id.) To give an order magnitude, of the $420 million in rate increases sought by Con Edison for the first rate year covered by the settlement, Con Edison established that more than 40% were attributable to property tax increases and pension costs. (Id. at 6.) Property taxes are indisputably a significant cost driver in New York City. There is no basis to assume that proposed generating facilities, as a whole, will be substantially more successful than Con Edison in avoiding such assessments.

[9] See New York Independent System Operator, Inc. 118 FERC ¶ 61,182 (2007) at P7 (establishing that rules must provide a level of compensation that will attract and retain needed infrastructure and thus promote long-term reliability while neither over-compensating nor under-compensating generators).

[10] See New York Independent System Operator, Inc., 103 FERC ¶ 61,201 at P22, 31 (Demand Curves were approved with the goal, inter alia, of stabilizing prices and sending better price signals to encourage the construction of new generation and thus enhance reliability).

5. If Demand Response is considered, what forms of tax abatement, if any, exist? Specify the name of the tax in the response. If for a load reduction Demand Response proxy "unit", should all forms of tax abatement be considered or just those that might be uniquely applicable to the load reduction?

   ANSWER:

   As addressed above, Demand Response resources should not be considered as the proxy "unit" to set any of the Demand Curves for New York State for many reasons – one of which is the significant uncertainty surrounding assumptions. There is insufficient data concerning applications and awards for Demand Response to make such data statistically supportable. In any event, allowing property tax abatement to be incorporated into the calculation would result in making the Demand Curves even more distorted and would result in relying more on mandatory Demand Response to meet system reliability needs. This would be particularly problematic if Demand Response in the form of load reduction was able to secure property tax abatements that were not otherwise available to generating facility projects. For the reasons provided above, Demand Response programs should not be the proxy unit used to determine Net CONE nor should it be viewed as a resource that can meet New York's reliability needs. Demand Response is a behind-the-meter load modifier and is not a dispatchable capacity resource. It needs to be treated as such in the market or be required to provide the same reliability services that traditional resources provide.

Impact of Deliverability

1. If considered, how would System Deliverability Upgrades identified within a Class Year be used to quantify the impact of deliverability?

   ANSWER:

   First, the question is not if but how deliverability will be quantified. System Deliverability Upgrades (SDUs) must be considered. All capacity suppliers must comply with the NYISO deliverability requirements by either holding existing deliverability rights or paying any attendant upgrade costs to assure deliverability and secure such deliverability rights – deliverability is a prerequisite to being permitted to sell capacity in the New York markets. As part of its Class Year interconnection process, the NYISO recently performed an analysis where it identified the deliverability costs associated with adding new generation upstream of the UPNY/SENY interface. The analysis was the basis for allocating costs to resources through the NYISO CRIS process and is certainly sufficiently recent and robust to serve as a basis for the upgrade costs for units that are constructed above this interface. New peaking units located below the UPNY/SENY zone would not be subject to the deliverability costs associated with upgrading the UPNY/SENY interface. However, any potential location in the Lower Hudson Valley that is considered as the basis for the Demand Curve must be analyzed to assure that the location does not require other deliverability upgrade costs to be incurred to secure CRIS rights. This can be accomplished by using the recently completed Class Year 2008 deliverability study to measure the delivery impacts and cost for the potential location.

   Ex: For the statewide or rest-of-state (ROS) region, if the capacity cost is simulating a proxy unit installed North or West of Leeds-PV, the SDU upgrade cost from the Class Year 2008 should be utilized. Specifically for the 251 MW of UCAP, an upgrade of Leed-PV of 258 MW was required; i.e. greater than 1 MW for 1 MW. For any 1 MW of capacity North or West of Leeds-PV, an upgrade of Leeds-Hurley Phase Angle Regulating Transformer (2-575MW) 452 MW at a cost of $80,420,000 is required. This translates to a cost of $177.9/kW.

To ensure that costs are adequately captured, to determine the peaking unit that should be used as the proxy unit for the NYCA Demand Curve, the Net CONE of the Capital Region Zone sited unit that has traditionally been the basis for the Demand Curve plus that unit's deliverability costs must be compared against a Hudson Valley based proxy peaking unit plus that unit's deliverability costs (if any) to determine which proxy unit has the lowest Net CONE.

2. Given that existing Deliverability rules were developed based on developers (suppliers) paying for upgrades in return for the ability to offer capacity, what is the rationale for additional cost recovery based on deliverability charges?

   ANSWER:

   Deliverability is part of the cost of new entry. Every cost component associated with developing a new capacity resource is required in order be a capacity supplier. Going back to first principles, the Demand Curve needs to include all costs that a capacity supplier must incur to sell and provide capacity in a reliable manner. 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. Now that deliverability requirements and the associated cost allocation rules exist in the tariff, eliminating deliverability costs would be an indirect attack on capacity markets (and the reliability they provide) in general.

3. What would be the impact of a Lower Hudson Valley Zone?

   ANSWER:

   In his past State of the Market Reports, Dr. David Patton has recommended that the addition of a new capacity zone in Eastern New York (i.e., the Lower Hudson Valley) be considered.[11] Likewise, one of the components of the Consensus Deliverability Plan that was filed with the Federal Energy Regulatory Commission ("FERC") on October 5, 2007 was the commitment for NYISO Staff to work with market participants to develop, over the next three years, criteria for the potential formation of additional locational capacity zones.[12] This commitment was reaffirmed by the FERC in its June 30, 2009 decision in the FERC Deliverability Docket. In that decision, FERC established an expectation that the NYISO would continue with this process and directed the NYISO to make a filing by October 5, 2010.[13] Lastly, as part of the last Demand Curve Reset Process, NERA was directed to develop the costs of a peaking

[11] See, e.g., Dr. David B. Patton, 2008 State of the Market Report -- New York ISO Electricity Markets (dated May, 2009).

[12] See, e.g., FERC Docket No. ER04-449-003, et al, New York Independent System Operator, Inc., "Consensus Deliverability Plan of the New York Independent System Operator, Inc. and the New York Transmission Owners" (filed October 5, 2007).

[13] See New York Independent System Operator, Inc., 127 FERC ¶ 61,318 (2009) at P 53.

unit in the Lower Hudson Valley which were incorporated into the last Demand Curve Reset Final Report.[14]

Addressing the Lower Hudson Valley zone issue, inter alia, provides an alternative mechanism to address the deliverability costs that must be addressed for the proxy unit within such a zone. By virtue of creating an additional zone and continuing the requirement that a new generator must only demonstrate that it is deliverable throughout the zone in which it seeks to locate to secure its CRIS rights, creation of a Lower Hudson Valley Zone limits the costs statewide resources would incur to be deliverable in the new Lower Hudson Valley Zone. There would still be a deliverability analysis associated with the Proxy Peaking Unit in the Lower Hudson Valley and statewide zone. The deliverability cost would depend upon the location of the unit and the value of existing deliverability rights.

[14] Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, NERA, August 15, 2007, pp. 76, 78.