NYISO Installed Capacity Working Group

Response to Multiple Intervenors and Transmission Owners on behalf of New York City Generators

Levitan & Associates, Inc. (LAI) presents this response to the Demand Curve Reset Straw Proposal by the Multiple Intervenors (MI) of May 21, 2010 and the Comments submitted by the Transmission Owners (TOs) of May 20, 2010. This response is presented on behalf of US Power Generating Co., TransCanada Power, and NRG Energy, Inc., owners and operators of power plants in New York City (NYC).

Multiple Intervenors: Demand Curve Reset Straw Proposal

The MI's main argument is that high reserve margins and new proposed resources demonstrate that capacity price signals are adequate or "artificially-high." The MI's second point is that consumers cannot afford unnecessary cost increases in light of the current economy. Arguing that periodic reviews are <u>mandatory</u> but that adjustments are <u>discretionary</u>, the MI's straw proposal is that the demand curve parameters should not be adjusted every three years unless a requirement for new resources is triggered. We believe that MI's straw proposal is ill-conceived for several reasons. First, the five plants listed by the MI do not provide a factual basis for their claim, since the plants are either insulated from market prices or are not in fact under construction. Second, there is no economic basis since market prices have been inadequate to finance new entry as described in various State of the Market (SOM) reports and summarized in a lengthy footnote in the white paper "A Ten Year Review", provided as Appendix A.[1] Capacity rates should be just and reasonable, and as FERC stated on in paragraph 17 of its March 6, 2007 Order Rejecting Proposed Tariff Revisions (Docket Nos. ER07-360-000, EL07-39-000), provided as Appendix B:

> The proceeding should consider the justness and reasonableness of the New York ISO's in-city ICAP market, and whether and how market rules need to be revised to provide a level of compensation that will attract and retain needed infrastructure and thus promote long-term reliability while neither overcompensating nor under-compensating generators.[2]

Third, while consumer costs are generally of concern to all market participants, they are not part of the demand curve parameter reset process. Demand curve parameters should be set to send correct capacity price signals. Having a periodic reset

[1] See footnote #108 of "A Ten Year Review" that quotes numerous SOM reports from 2003 through 2009.

[2] New York Independent System Operator, Inc., 118 FERC 61,182 @ P17 (March 6, 2007), rehearing denied, 118 FERC 61,251 (2007)

prices that is stable and certain benefits all stakeholders. Finally, the MI's proposal would heighten regulatory risk, thereby raising costs to generators and ultimately to consumers.

1. No Factual or Economic Basis

The MI claims that five power plants (listed on page 5) are evidence that "…the current demand curves are sending adequate (or artificially high) price signals to incent [*sic*] new investment even when unnecessary from a reliability perspective." This straw proposal misinterprets important facts about these plants. The reality behind Astoria Energy Block II and other recently completed projects, such as the Caithness plant on Long Island, is that they are insulated from market dynamics because of long term contracts. These contracts provide fixed revenues independent of Spot Capacity market prices. Other projects on the MI list are not even under construction. In some cases there are tactical and strategic reasons for developers to construct new projects that transcend near-term market signals. One cannot compare investment decisions made years ago with current Spot Market capacity prices. For MI to claim that the five projects are evidence that market revenues are sufficient to support new plant construction is unjustified and does not represent a factual or economic basis for their claims.

Consumer costs are not part of the demand curve parameter reset process. Demand curve parameters should be set to send correct capacity price signals. As FERC stated in its December 18, 2008 Order on Complaint in Docket No. EL09-4-000,

> The Commission must balance the need for an out-of-cycle adjustment to provide proper signals to encourage new economic capacity entry against the value of price stability, and certainty to customers in the market. The ICAP demand curve process is based on the premise that price stability and certainty are important to the market."[3]

2. Selective Readings of Documents

In the straw proposal, the MI noted that the rules governing the demand curve reset process mandate a periodic review of the demand curve parameters every three years, but do not mandate actual adjustments. To bolster this assertion, the MI provided references to the NYISO Tariff, the ICAP Manual, and FERC filings and orders. In our review of those same references, we believe that the MI made selective readings of those sources.

- On slide 9 of the MI presentation, the MI cited Section 5.14.1(b) of the NYISO Markets and Services Tariff to justify their position that adjustments are not mandated, as follows: "A periodic review of the ICAP Demand Curves shall be performed every three (3) years in accordance with the ISO Procedures…" However, the full sentence reads: "A periodic review of the ICAP Demand Curves shall be performed every three (3) years in accordance with the ISO Procedures to

[3] See paragraph 35 of the FERC Order on Complaint, provided as Appendix C.

determine the parameters of the ICAP Demand Curves for the next three Capability Years." [emphasis added] Under the Tariff, the periodic review is performed for a specified reason. NYISO cannot perform the periodic review but then not use the resulting demand curve parameters.

Section 5.14.1(b) goes on to specify that the schedule and procedures of the periodic review shall provide for: "(vii) Issuance of a draft of the ISO's recommended adjustments to the ICAP Demand Curves for stakeholder review and comment" and "(viii) Issuance of the ISO's proposed ICAP Demand Curves, taking into account the report of the independent consultant, the recommendations of the Market Monitoring Unit, and the views of the stakeholders together with the rationale for accepting or rejecting any such inputs." Upon further reading of the Tariff language, it is clear that the Tariff describes much more than a nominal review of the demand curve parameters.

- On slide 9, the MI quoted part of Section 5.6 of the ICAP Manual to suggest that the periodic review be used: "…to determine whether the parameters of the ICAP demand Curve should be adjusted…" However, the word "whether" was removed from the Tariff in a NYISO compliance filing that was accepted by FERC on December 15, 2005.[4] We note that the ICAP Manual is intended "for informational purposes," it is the Tariff that is dispositive.

- On slide 10, the MI claimed that FERC has "repeatedly" indicated that demand curve adjustments are discretionary, but again used selective reading in the FERC citations they provided. For example, in their citation of 125FERC¶61,299, the MI refer to ¶3 which states: "Section 5.14.1(b) of the Services Tariff requires NYISO to perform a triennial review to determine whether the parameters of the ICAP Demand Curve should be adjusted." [emphasis added by MI] However, FERC appears to have quoted the old section 5.14.1(b) Tariff language because at ¶37 FERC quoted the correct Tariff language: "Section 5.14.1(b) states, in part: 'A periodic review of the ICAP Demand Curves shall be performed every three (3) years to determine the parameters of the ICAP Demand Curves for the next three Capability Years…'" We note that the word "whether" does not appear in this corrected quote from the Tariff.

Demand curves may not require adjustments if the periodic review develops parameters that have not changed since the last periodic review. However, the current Tariff language indicates that reviews are performed for a reason – to determine those parameters and make any necessary adjustments. Ratepayers are protected from high prices when there is excess capacity by the inherent slope of the demand curve. *Ad hoc* adjustments based on selective readings of the Tariff and on FERC filings and orders should be proscribed.

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[4] Sixth Revised Sheet No.157 provided as Appendix D. The compliance filing in ER05-428-005 was made in response to an April 21, 2005 FERC Order to revise the Tariff in order to implement transparent and efficient procedures for setting and reviewing future ICAP Demand Curve parameters.

3. Unnecessary Change Heightens Regulatory Risk

Altering the demand curve mechanism from cycle to cycle in favor of one stakeholder group compounds regulatory risk. The process has been designed to balance the interests of all stakeholders rather than favor generators, TOs, or load. Utilities and regulatory agencies rely on market capacity prices to help gauge investment decisions in renewables, energy efficiency and other demand management programs. Debt lenders and equity investors rely on the demand curve mechanism to make decisions on power plant investments, whether to keep existing plants in operation, and recapitalizing existing assets. Making unnecessary modifications to this mechanism would heighten regulatory risk and bias those decisions, thereby leading to sub-optimal investment in both supply-side and demand-side resources.

The straw proposal states that "Consumers can ill-afford unnecessary, additional cost increases." MI ignores the fact that the sloped demand curve mechanism already protects consumer interests. Whenever the spot capacity market clears long, clearing prices fall. This was the transaction structure agreed to by stakeholders years ago. We believe it has protected consumer interests well since implementation. An example helps demonstrate the principle of consumer protection, as follows. If the spot capacity market were to clear long, say, one-half the distance between IRM (for NYCA) or the locational capacity requirements (for NYC and LI) and the zero crossing point, instead of exactly at the capacity requirement, then ratepayers would save approximately $1.2 billion during the six summer months. In the table below, the estimated ratepayer savings are shown for the summer 2010/11.[5] There would be additional ratepayer savings during the winter months.

Table 1. Summer 2010/11 Demand Curve Parameters (UCAP) and Estimated Ratepayer Savings

	ROS	NYC	LI
100% of IRM or Locational Requirement			
MW	21,288.2	8,336.0	5,021.1
Price (/kW-mo)	$ 11.01	$ 17.99	$ 9.71
Total (millions)	$ 238.8	$ 150.0	$ 48.8
Halfway to Zero-Crossing Point			
MW	22,588.8	9.086.2	5.473.0
Price (/kW-mo)	$ 5.51	$ 9.00	$ 4.86
Total (millions)	$ 124.4	$ 81.7	$ 26.6
Savings per month (millions)	$ 114.4	$ 68.2	$ 22.2

[5] ROS MW is equal to the NYCA requirement less the NYC and LI requirements. The NYCA price is applied to ROS.

In LAI's view, it is important to note that consumers cannot only "…ill-afford unnecessary, additional cost increases," they cannot afford an ill-defined, moving capacity pricing mechanism that is altered outside of the NYISO Services Tariff provisions. Artificially lowering market capacity prices in violation of the Tariff will hinder investment when needed and unfairly penalize existing plant owners. Unnecessary alterations render the demand curve mechanism unstable, making it ever more difficult for investors and other stakeholders to rely on the demand curve mechanism for capacity price signals used to base new investment. The heightened regulatory risk will increase financing costs that will ultimately be passed on to ratepayers.

Comments of Transmission Owners, NYPA and LIPA on the Data and Assumptions Being Used in the 2011-14 ICAP Demand Curve Analysis

The TOs submitted comments on six issues, five of which are addressed in full or in part below.

1. <u>Cost of Generation Development</u>

The TOs make a series of claims, without offering any evidence, that the Cost of New Entry (CONE) should be lower for various reasons. We address two CONE issues raised by the TOs regarding (a) site requirements for a 2 x LMS100 plant and (b) the granting of NYC property tax abatements.

a. <u>LMS100 Site Requirements</u>

The TOs question whether "…only one LMS100 plant could be sited on a 3.5 acre site." In the past, NYISO has assumed that a 2 x LM6000 plant requires 3.5 acres in NYC. 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 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, as explained below.[6]

<u>Basin Electric</u> – The first LMS100 installation was at the Basin Electric Power Cooperative which began commercial operation in 2006. According to the "LMS100 Installation and Operating Experience at Basin Electric" report on the GE website, the 1 x LMS100 installation is on 3.85 acres. Key pages from this report are provided as Appendix E. It is important to note the following from this report:

- "Although the unit is configured for dual fuel, the liquid fuel supply and storage systems have not been installed." Land for a fuel oil tank and catch basin is not included in the 3.85 acres.

- "The [dry] cooling tower system has a footprint of 60 x 180 feet", equivalent to 0.25 acres. A cooling system is required for the LMS100 intercoolers but not for other aeroderivative GTs.

According to a Basin Electric employee, a second LMS100 unit was added in 2008, doubling the site size to 7.7 acres. An oil tank and catch basin have not yet been installed, but would require additional acreage according to a Basin Electric employee.

<u>South Pier Improvement Project</u> – The Astoria Generating Company, a subsidiary of USPowerGen, is proposing to add a 1 x LMS100 unit at the Gowanus Generating Station's existing south pier. According to Astoria Generating Company, the pier site is approximately 150' by 750', equivalent to 2.6 acres. A site rendering is provided as Appendix F. Most documents, including the draft Environmental Impact Statement (EIS), the final EIS, and the NY PSC Order for a Certificate of Public Convenience and Necessity, use a slightly higher figure of 2.75 acres.[7]

- The pier site does not include the fuel oil tank and catch basin, which adds close to another full acre of land for a total of 3.5 acres.

- Site restrictions at the long, narrow pier site require construction barges to deliver and hoist major equipment onto the pier, adding to the project's construction cost and complexity.

- According to Figure 1.2 in the South Pier's Final EIS, the fin fan cooling system is expected to require 65' x 200', equivalent to 0.3 acres, very close to the system at Basin Electric. As mentioned above, these cooling systems require substantial

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[6] The extremely high cost of constructing the Kennedy International Airport Cogeneration plant (KIAC) in the early 1990s underscores the high premium incurred by GEI and PSEG when there is not sufficient space to construct a GT plant.

[7] The project's Final EIS uses a site value of 2.75 acres throughout; one instance in which it refers to a 2.25 acre site appears to be a typographical error.

space and are required for LMS100 installations, but not for other aeroderivative GTs.

Braintree Electric – According to Mr. William Bottiggi, General Manager of Braintree Electric Light Department (Braintree), a municipal utility in eastern Massachusetts, Braintree tried to site a 1 x LMS100 unit at the existing Thomas A. Watson Generation Station. The site rendering, provided as Appendix G, indicates that the fin fan coolers would have required a significant amount of space on the 4 acre site. Due to space limitations, Braintree decided that installing the LMS100 would be possible but tight. Braintree instead opted to install two Trent 60 units that are now operational.

Capital Power Corporation – Capital Power developed the Clover Bar Energy Centre outside of Edmonton, Alberta. The site includes 2 x LMS 100 units and 1 x LM 6000 unit that were commissioned between February 2008 and January 2010. The 2 x LMS100 units take up 6+ acres even without fuel oil storage or dry intercooling systems, each of which would require additional acreage.

b. Tax Abatement

The TOs argue that Zone J CONE should assume that NYC generators "…receive 100% of the available tax abatement…" supported by the contention "… that Brooklyn Navy Yard Cogeneration Partners (BNYCP) received full abatement under available NYC tax abatements". The TOs do not acknowledge that BNYCP's tax benefits were part of a package negotiated over 15 years ago that included many inducements from the City of New York and the State of New York to spur economic development at the Brooklyn Navy Yard, including covering the high cost of asbestos removal borne by BNYCP. BNYCP's tax abatement is not the norm and, in our opinion, is of little or no relevance in the present context. In contrast to BNYCP's tax concessions, the TransCanada Ravenswood facility paid about $41 million in property taxes in FY2009/10. US PowerGen paid property taxes of about $31 million for its NYC facilities, and may receive refunds of about $6 million.

More generally, Payments in Lieu of Taxes (PILOT) agreements and property tax abatements are negotiated on a case-by-case basis and are rarely "free money". They are typically part of a negotiated give-and-take in which the developer receives tax benefits in exchange for targeted economic development and other concessions.

The criteria for property tax abatement evolve. For example, the Industrial and Commercial Incentive Program (ICIP) was terminated in June 2008. The successor to the ICIP, the Industrial and Commercial Abatement Program, excludes "Utility Companies"; we understand that this category includes power plants. Furthermore, this new abatement program is currently authorized only through March 1, 2011. While a new replacement program may be authorized, the benefits offered and eligibility requirements of those new programs may differ significantly from the current abatement program.

Unless the TOs can demonstrate that generous property tax and/or PILOT arrangements are really the norm for plant additions in NYC, it would be unreasonable to set CONE based on property tax arrangements associated with one specific, benefited project. Therefore, we recommend that NYISO scrutinize the full set of data on property taxes paid and any associated abatements for all plants in each capacity zone. It is reasonable to expect that taxes will change over time and that absent some form of definite right to abatement or avoidance (such as previously existed under ICIP) that investors will look to understand average tax rates and the tax cost reality that will most likely prevail over the life of a project. Further, it may be important to understand and take account of the prevailing fiscal reality facing the taxing jurisdictions going forward.

2. <u>Generator Financing Assumptions</u>

LAI did not address the TO's comments on financing assumptions in detail, but we note in brief that (i) no sources are provided to support any of these data, (ii) a merchant generation company may have a credit rating higher than any single asset because of portfolio diversification benefits, (iii) the debt and equity costs for a new proxy peaker should reflect the underlying risks for that project on a stand-alone basis, including development, construction, and completion risks, without portfolio diversification support, (iv) bank loans reflect short-term interest rates, are more appropriate for project construction, and are typically replaced by long-term, fixed interest rate capital market debt, (v) the sources for the TO debt and market capitalization data appear out-dated, and (vi) the wide range of beta results may reflect different risk profiles for the merchant generator's assets, *i.e.* companies with true merchant plants that have market price risk versus companies with plants that have PPAs, tolling agreements, or commercial hedges with creditworthy counterparties, (vii) eliminating RRI from the equity beta analysis incorrectly skews results downward; if RRI is removed for being "too high", than the low beta outlier should also be removed.

3. <u>Deliverability Costs</u>

The TOs presented their three point rationale for excluding deliverability costs from CONE in Paul Gioia's memo to Dave Lawrence of April 21, 2010. In our opinion, the TOs make a number of oversimplifications and ignore certain facts. In this section we assess the reasonableness of the TOs' position on deliverability and then explain why it is reasonable to include deliverability costs in the derivation of CONE.

a. The TOs assert that CONE should be set as "…if we were at the minimum capacity requirement during the 2011-2014 time frame." This claim violates a basic tenet of the demand curve reset process: CONE is based on the costs of a proxy peaking unit added in each study year regardless of need. Only the calculation of net energy and ancillary service revenues require an explicit reserve margin assumption. The TOs go on to assert that deliverability costs are not required because "There is sufficient deliverability to serve current and projected load levels." However, the TOs confuse inter-zonal deliverability with intra-zonal deliverability, particularly in NYC. Under the NYISO deliverability standard, deliverability costs cannot be avoided if required for reliability. Finally, the TOs suggest that existing grandfathered generation should not receive capacity revenues for costs they did not incur. However, CONE reflects all types of changes regarding GT capital costs, performance, emission controls, among other things. These costs are incorporated in CONE whether or not existing units are subject to them. Capacity payments are not adjusted based on costs faced by each specific resource.

b. The TOs assert that "While new units that want to sell capacity may have to pay deliverability costs, these units are not needed for reliability," so those costs should not be reflected in CONE. Whether or not new units are required for reliability, they must pay for their share of deliverability upgrades in order to receive capacity revenues. Some reasonable level of deliverability upgrade costs must be considered, since they are no different than system upgrade costs that have always been incorporated in CONE.

c. The TOs propose that deliverability costs should not be included unless "…NYISO reliability planning studies demonstrate that a resource adequacy deficiency and transmission capability deficiency are contributing to a future reliability violation…" However, NYISO's methodology for reliability planning does not specifically address deliverability issues within a capacity zone. Based on the current reliability planning methodology, it is not accurate to say that resource adequacy negates the need for deliverability upgrades.

System Delivery Upgrade (SDU) costs must be included in CONE. SDUs are real out-of-pocket costs to assure system reliability and should not be treated differently than other interconnection costs. A project cannot receive capacity revenues if it does not fund allocated SDU costs. Whether or not there is a capacity surplus is irrelevant. Our position is summarized as follows, with a more detailed explanation included as Appendix H.

<u>The Deliverability Interconnection Standard is a Tariff Requirement</u>

New generation projects in NYCA larger than 2 MW must satisfy the FERC-approved NYISO Deliverability Interconnection Standard in order to become a qualified Installed Capacity Supplier that is deliverable within its Capacity Region.[8] To participate in the NYISO capacity market, a project is required to elect Capacity Resource Interconnection Service and undergo a deliverability test as defined in the NYISO OATT. A project must fund its share of any SDUs identified in its Class Year Deliverability Study, or else it will not be considered an Installed Capacity Supplier and not be entitled to capacity revenues. SDU costs are comparable to System Upgrade Facility (SUF) costs, which have always

[8] The three NY Capacity Regions are Zone J, Zone K, and Zones A-I (ROS).

been included in CONE. Excluding a reasonable and appropriate level of SDU costs in CONE would result in capacity revenues being too low, which may lead to insufficient new entry in the long term.

The NYISO Demand Curve RFP Specifically Included Deliverability Impacts

Page 3 of NYISO's Demand Curve RFP specifically states that the consultant's report includes costs required to address deliverability impacts: "Total installed costs as of May, 2011; the localized, levelized embedded cost of a peaking unit…., including transmission and deliverability impacts, in Zone J and in Zone K…" [emphasis added]. NYISO did not differentiate among Attachment Facilities (AFs), SUFs, and SDUs. All generator costs to address "transmission and deliverability impacts" should be included in the consultant's report. NYISO would be inconsistent with its own RFP requirements if it decides to ignore SDU costs.

SDUs are needed for Reliability

The TOs argument that SDUs are not needed for reliability is misleading and inconsistent with the OATT, which defines SDUs as: "The least costly configuration of commercially available components of electrical equipment that can be used, consistent with Good Utility Practice and Applicable Reliability Requirements, to make modifications or additions to Byways and Highways and Other Interfaces on the existing New York State Transmission System that are required for the proposed project to connect reliably to the system..."[9] [emphasis added] If an interconnecting unit rejects its SDU allocation, it will not be deliverable, will not support system reliability, and will not be able to participate in the NYISO's capacity market.[10]

SDUs have been Required and will likely be Required in the Future

The TOs present no evidence that SDUs will not be required in the future. However, the CY 2008 Deliverability Study identified a need for SDUs to create 257 MW of additional transfer capacity for ROS resources at an estimated cost of $45.7 million, equivalent to $178/kW.[11] Zone J has traditionally been considered a constrained zone and would likely require SDUs for new generation. For example, Con Edison argued at FERC that Astoria Energy II would not be deliverable at its original interconnection point, the Astoria East 138 kV substation.[12] In another FERC case, Con Edison argued that the output of the

[9] Attachment S of the OATT.

[10] System reliability here is defined within the context of Loss of Load Expectation, the capacity-based criterion used to assess Resource Adequacy.

[11] NYISO estimated an $80.4 million cost for 452 MW of transfer capability, of which $45.7 was allocated to CY 2008 developers based on the 257 MW needed to qualify as a capacity resource.

[12] In FERC Docket No. ER04-449-018, Con Edison's expert witness, Dr. Mayer Sasson, noted that "…the entire output of the AE-2 facility would not be deliverable in Zone J" at the Astoria East 138 kV s/s but would be fully deliverable if it interconnected at a proposed new 345 kV s/s.

Linden VFT project was not deliverable in Zone J beyond Staten Island.[13] While the above examples are not exhaustive and may not be representative of all potential interconnecting points in Zone J, they do show that there are deliverability constraints in Zone J which may trigger SDUs. Hence, a reasonable estimate of SDU costs should be included in the demand curve reset process.

Current Projected Surplus Does not Translate to Deliverability

The statement by TOs that "There is sufficient deliverability to serve current and projected load levels" is misleading. In the TOs' presentation at the December 8, 2009 ICAPWG meeting, they relied on the 2009 RNA to support their claim that the NYISO system may not need new resources to meet reliability requirements within the next 3-year demand curve reset period.[14] However, the RNA is based on a Loss of Load Expectation resource adequacy analysis that considers available transmission capability between zones.[15] The RNA examines inter-zonal deliverability, not intra-zonal deliverability, so the TOs claim of sufficient deliverability for CONE purposes is unsupported.

Deliverability Rights of Retiring Plants have Value

In the same December 8, 2009 presentation, the TOs also claimed that "Retirements will free up deliverability rights, which new generators can utilize after 3 years." It is not reasonable to ascribe no value to deliverability rights upon plant retirement. The retiring generator will not allow valuable rights to expire, but rather would sell those rights, take advantage of those rights themselves, or trade these rights to others for consideration. Dr David Patton, the Independent Market Advisor, made this point in his presentation on grandfathering deliverability.[16] Deliverability rights have value, and new generators may have to pay for deliverability rights or for SDUs.

SDUs, like AFs and SUFs, are all Necessary Interconnection Costs

SDUs are part of a developer's necessary interconnection costs, just like AFs and SUFs, and are necessary if the plant is to count as capacity and contribute towards system reliability. The CONE for a proxy unit is based on all costs that a developer is expected to

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[13] In the Answer and Leave to File Answer filed in the FERC Linden VFT Docket ER07-543-00, Con Edison argued that the output of the Linden VFT project was not deliverable to market areas beyond Staten Island based on an analysis that compared the supply resources attached to Staten Island with the capacity of the feeders that deliver power from those resources to load on Staten Island and Brooklyn.

[14] Demand Curve Reset Issues for Analysis, December 8, 2009.

[15] The RNA results are based on a system-wide resource adequacy study using GE MARS to quantify expected LOLE values. The transfer limits used in GE MARS are based on inter-zonal deliverability. The Deliverability Standard, on the other hand, specifically addresses intra-zonal deliverability issues.

[16] See presentation to the NYISO Interconnection Issues Task Force, January 15, 2007

incur. Interconnection costs for deliverability are legitimate costs that must be taken into account and cannot be de-coupled from other interconnection costs.

4. Excess Capacity Assumptions

The TO's suggest that NYISO should eliminate the excess capacity assumption specified in the Tariff. While actual capacity may often exceed the minimum requirement, we demonstrate that the capacity market will almost never be short. Therefore, it is reasonable to assume some level of excess capacity, a position supported by the Independent Market Advisor.

a. The Market Will Almost Never Be Short

Section 5.14(b) of the NYISO Services Tariff states that each periodic review shall assess "…the likely [net] Energy and Ancillary Services revenues…under conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement…" This Tariff language recognizes that the capacity market may often be long, with excess capacity, but will seldom, if ever, be short. A key purpose of the NYISO capacity demand curve pricing mechanism is to send correct "market signals" if new capacity is needed. Moreover, regulators and NYISO will not tolerate a power system that cannot meet minimum reliability requirements, especially after the blackouts of 1965, 1977, and 2003. NYISO's Transmission Planning process facilitates transmission backstop solutions if generation is not added where and when needed. Finally, public power authorities can step in to provide capacity to maintain reliability, if necessary.

This is a realistic view of the capacity market, one that is bolstered by NYPA's and LIPA's ability to ensure grid reliability objectives are met on a timely basis. Notably, the NYPA PowerNow! Program resulted in the addition of about 450 MW of GTs in and around NYC in 2001. LIPA's Fast Track program resulted in the addition of 412 MW of GT capacity in 2002/03 on LI. The following descriptions of these two programs were taken from the NYPA and LIPA web sites:

> NYPA PowerNow! Program
>
> PowerNow! Small, Clean Plants
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> We increased our generating capacity by about 450 megawatts during summer 2001 when we began operating small, clean natural gas-powered generating plants at six sites in New York City and one on Long Island. We had launched a crash program in late August 2000 to install these PowerNow! plants in response to warnings from officials in the public and private sectors that the New York City metropolitan area could face power shortages in the summer of 2001. Similar warnings were repeated throughout the 10 months it took to obtain, site, design and install the units—a process that normally would require more than two years.

Meeting the need for electricity

The small plants proved invaluable during an August 2001 heat wave, when temperatures—and electricity use—soared to new highs, and in the summer of 2002, when Con Edison and the Long Island Power Authority each set records for three-month electricity use. The units again proved their worth in the wake of the September 11 terrorist attacks, when the NYISO, which runs the state's transmission system, limited deliveries of electricity into the area from upstate plants. During the great northeast blackout in August 2003, the plant's helped return power to New York City while stabilizing the downstate transmission system. They have helped strengthen the power system at other times during day-to-day operations. The New York City generators—at two sites in the Bronx, two in Brooklyn, one in Queens and one on Staten Island—are the cleanest, simple-cycle plants in the city. The Long Island unit is located in Brentwood, in the Town of Islip.

LIPA Fast Track Program

During the summer of 2001, LIPA determined that due to Long Island's rapidly growing demand for electricity, there was an urgent need to add at least 400 megawatts (MW) of new electric power generation capacity on Long Island. LIPA followed a rigorous environmental review and public outreach process which successfully added six new electric generating facilities around Long Island in 2002. LIPA increased competition in the power plant business on Long Island by selecting four different developers for the six projects. Calpine built a 44 MW facility in Bethpage; Florida Power & Light built a 53 MW facility in Far Rockaway; KeySpan built 79.9 MW facilities in Glenwood Landing and Port Jefferson; and Pennsylvania Power & Light built 79.9 MW facilities in Brentwood and Shoreham. Additional facilities were built in 2003-04 to meet continuing growth in summer peak demand for electricity on Long Island: the 54 MW Hawkeye Greenport Generating Facility; the 55 MW Jamaica Bay Energy Center built by Florida Power & Light in Far Rockaway; and twin 46 MW facilities built by Equus Power in the Village of Freeport.[17]

b. A 1.5% Level Of Excess Capacity Is Reasonable

This realistic view of the capacity market and the likelihood of never falling below the minimum Installed Capacity requirement are explained on page 15 of NYISO's ICAP Demand Curve filing to FERC on November 30, 2007. After considering a low level of excess (100 MW) and a moderate level of excess (1,000 MW) for NYCA, NYISO chose 1.5% as "…a reasonable indication of the average level of excess (600 MW) that should be expected in NYCA if the [required reserve] margin is never to fall below the 100% target."

[17] In actuality, Freeport Electric built one unit and Equus Power built a second unit at that site for LIPA.

NYISO also approved a 4% excess capacity level for NYC and LI as consistent with the NYCA value.

Dr. Patton, the NYISO Independent Market Advisor, explained that "…there is no single correct assumption for this parameter, only a reasonable range of assumptions." He concluded that "…a 1.5% level of excess capacity for NYCA is within a reasonable range….although he believes it is toward the low end of such a range." We agree with Dr. Patton that a 1.5% level of is already at the low end of a reasonable range and recommend that NYISO adopt this value, along with 4% values for NYC and LI.

5. Seasonality Adjustments

NYISO sets the demand curve reference point based on Net CONE plus an adjustment based on the ratio of winter / summer capacity in each capacity region. The ICAP Manual currently requires the winter / summer ratio to be established using data from the Gold Book based on all units in a given region.[18] The TO's propose to set the winter / summer ratio based only on capacity that is actually sold. However, doing so would require NYISO's demand curve consultant to develop a projection of how much capacity will be sold into the market and set the winter / summer ratio accordingly. This proposal should not be accepted because it unnecessarily introduces regulatory market risk, makes the reset process more complex and contentious, and it fails to account for the fact that small changes to the winter / summer ratio could have large price consequences. Each reason is discussed in detail below.

The Proposal Introduces Market Uncertainty

The ultimate purpose of the ICAP market is to create a reliable market mechanism that encourages investment in generation assets when and where needed in order to assure long-term reliability. Stability of the demand curve mechanism and low regulatory risk are key concerns. Arbitrary changes to the market rules erode confidence in the market's stability, increase participants' perception of regulatory risk, and ultimately make it more difficult (and more expensive) to invest in generation assets.

The Proposal Adds Significant Complexity to the Reset Process

Setting the demand curve requires certain projections and forecasts, all of which are subject to forecast error as well as debate among stakeholders. At present, it is necessary to project what resources will exist throughout NYCA and to calculate winter / summer ratios for the three planning years. The TO proposal would require an additional step of projecting how much of the existing capacity will clear in the spot market auctions and sell into the capacity market. These calculations will be subject to forecast error; by using a two-step process, the TO proposal has the potential to compound that error.

[18] Page 5-7 of NYISO 2007 Gold Book.

Moreover, the proposal does not indicate how a ratio based on a forecast of capacity sold would be more accurate than the current method. The TOs did not demonstrate that the total winter and summer revenues a generator would receive in equilibrium would be equal to the annual revenue target (Net CONE) that NYISO verifies for every planning year.

Small Changes to the Winter / Summer Ratio Could Have Large Consequences

In their proposal, the TOs point out that the winter / summer ratios of capacity sold into the ICAP markets ranged from 1.006 to 1.022 in the last seven years in NYCA, 1.044 to 1.100 for NYC, and 1.029 to 1.051 for LI after discarding an "anomalous" capacity year. These values are presented as indication that the margin for error in forecasting the winter / summer ratios based on sold capacity will be acceptably small.

In our view, this argument is weak. First, the TOs offer no evidence that the ranges they provide represent conditions that are likely to persist into the future. Second, "anomalous" outcomes cannot be simply discarded as if they never happened, especially for a small sample size. Third, and most importantly, the range of outcomes presented is not, in fact, small as very small changes to the winter / summer ratio can have significant effects on the placement of the demand curve along the y-axis.

In order to quantify this effect, we have recalculated the 2010/11 NYC reference point based on a range of winter / summer ratios. The formula for calculation of the reference point is in the NYISO Installed Capacity Manual and is repeated below:[19]

$$RP_i = \frac{ARV_i \cdot \dfrac{AssmdCap}{SDMNC}}{6 \cdot \left[1 + \dfrac{WDMNC}{SDMNC} \cdot \left(1 - \dfrac{WSR_i - 1}{ZCPR_i - 1}\right)\right]}$$

Where:

RP_i = reference point

$ZCPR_i$ = the ratio of demand curve zero crossing points to the minimum requirement for each location

WSR_i = the ratio of the sum of winter DMNCs to all ICAP providers to the sum of summer DMNC of all ICAP providers in a given location

ARV_i = the Annual Reference Value for location i, otherwise known as Net CONE

AssumdCap = the capacity assumed for the peaking unit when calculating reference values

SDMNC = Summer DMNC

WDMNC = Winter DMNC

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[19] See page 5-7 of the ICAP Manual.

Input parameters for the calculation of the 2010/11 NYC demand curve are shown below in Table 2. The values are from the NYISO proposed demand curves for capability years 2008/09-2010/11, which were accepted by FERC.

Table 2. Inputs for Calculation of 2010/11 NYC Reference Price

ARV ($/kW-year)	143.15
AssumdCap (MW)	188.7
SDMNC (MW)	188.7
WDMNC (MW)	196.4
WSR-1	0.095
ZCPR-1	0.18

The resulting 2010/11 NYC reference price was $15.99/kW-month. Using these values and the equations listed above, we can calculate the reference price for any given winter / summer ratio. Table 3, below, shows the NYC reference point for a range of winter / summer ratio values.

Table 3. 2010/11 NYC Reference Points at Various Winter / Summer Ratios

Winter / Summer Ratio	Reference Point ($/kW-mo)
1.01	12.03
1.02	12.39
1.03	12.78
1.04	13.18
1.05	13.62
1.06	14.09
1.07	14.58
1.08	15.12
1.09	15.69
*1.095	*15.99
1.10	16.31
1.11	16.98

** Actual 2010/11 values for NYC*

As these results indicate, the 10% change of moving from a winter / summer ratio of 1.11 (highest value in table) to 1.01 (lowest value) reduces the reference point by nearly 30%, a much larger result. Reducing the winter / summer ratio and thus the reference point could mean that new generators would be unable to meet their revenue requirements and would discourage investment throughout NYCA.

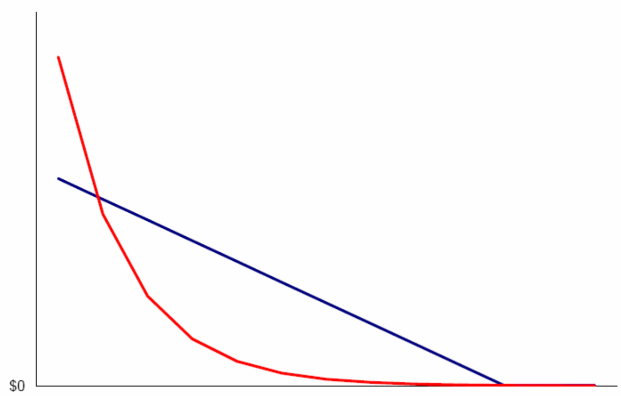
6. <u>Shape and Slope of ICAP Demand Curves</u>

The TOs contend that the shape and slope of the demand curves should be reset based on "…the marginal value that additional capacity beyond the Minimum ICAP Requirement provides to end-users in terms of reliability." The curve the TOs proposed would result in ratepayers buying less excess capacity. However, these proposed measures are impractical and would weaken the capacity markets by increasing price volatility, introducing opportunities for the exercise of market power, and increasing regulatory risk. Further, since the proposed changes would universally cut revenues from a key portion of the demand curve, *i.e.* at or above the reliability criterion, it would further exacerbate the revenue insufficiency concerns previously noted that have been identified in the SOM reports. Lastly, if plant owners and other market participants believe that significant changes to the demand curve mechanism like this are possible in the future, the New York capacity market will be a riskier environment to invest in and own generation assets, which may ultimately increase ratepayer costs.

a. Demand Curve Shape

The TOs propose a non-linear demand curve that is steeply sloped initially and flattens as it approaches the zero-crossing point. The TOs representation of the proposed curve is shown in Figure 1, below. LAI identified several key flaws in the proposed demand curve that are discussed below:

Figure 1 – TOs' Proposed Demand Curve



A Non-Linear Curve Is Impractical and Makes the Reset Process More Contentious

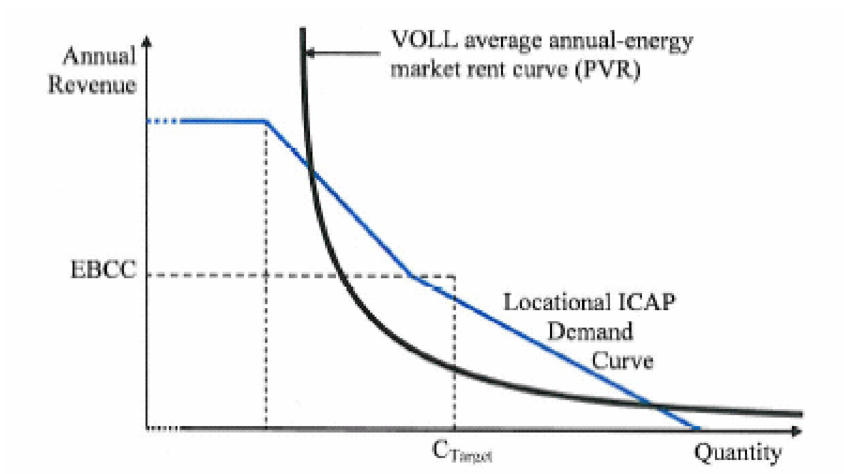
A key advantage of the current demand curve mechanism is its simplicity and its certainty. A straight line that intersects the x-axis at the zero-crossing point and flattens at another defined point is easy to understand and reproduce, which makes planning and analysis simpler. The simpler and more consistent the planning process, the easier it is for market participants to have confidence in the process and in the price signals. A non-linear curve would be mathematically more complicated, more difficult to use, and would ultimately make the NYISO spot capacity market both opaque and contentious. Of paramount importance, we believe that these changes would undermine a primary goal of the ICAP market, namely the encouragement of new investment where and when needed. .

Even with the simple demand curve mechanism currently in place, the periodic stakeholder process to update the curve parameters is contentious. Switching to a more complicated non-linear curve that is harder to understand and requires more inputs will make an already difficult and politicized stakeholder process even more of an administrative burden. Arguably, the marginal value of additional capacity is in the eye of the beholder and is difficult to accurately estimate. Establishing and reaching consensus on curve slopes, zero-crossing points, maximum values, reference points, seasonal adjustments, and other curve inputs would be much more difficult if a non-linear curve were adopted.

The Proposed Curve Increases Opportunities For The Exercise Of Market Power

The steep section of the proposed curve will provide greater opportunities for suppliers to exercise market power compared to the current flat demand curve. Testifying before FERC in the proceeding that established the ISO-NE forward capacity market, Dr. Steven E. Stoft, an expert witness for ISO-NE, discussed a Value of Lost Load (VOLL) curve, shown in Figure 2, similar to the one proposed by the TOs.[20] Dr. Stoft found that "VOLL pricing creates too much market power." Small changes in cleared capacity would produce large price changes in the steeply sloped portion of the proposed curve, which offers greater opportunities for market suppliers to withhold capacity to influence prices.

Figure 2 – VOLL Curve



The TOs have noted that there are mitigation measures in place currently that could prevent the exercise of market power. However, many of those measures only apply to NYC, and monitoring after the fact is not as good as a proven mechanism that by design minimizes market power opportunities. The TOs have not demonstrated that the mitigation measures currently in place will be effective in countering the exercise of market power.

[20] Direct testimony of Steven E. Stoft in ER03-563-030

The Proposed Curve Would Increase Price Volatility

The left-most portion of the TOs' proposed curve is very steep, which results in highly volatile prices as small changes in cleared supply can yield large changes in price. In his testimony in ER03-563-030, Dr. Stoft noted that the VOLL curve could yield "…occasionally extremely high payments by load to generation [that] may well lead to political intervention."[21]

b. Zero-Crossing Point

The TOs contend that the zero-crossing point should be shifted left to "…the point at which capacity has no significant value." This issue has already been addressed many times, and NYISO's consultants have consistently found the zero-crossing points to be reasonable. Shifting the curve left would make it steeper and provide more opportunities for market power, and any significant change after seven years would increase regulatory and costs for ratepayers.

The Current Zero-Crossing Points Are Reasonable

The zero crossing points of 118% and 112% have been in use since the initial formulation of the demand curve mechanism and have been reviewed during each demand curve reset. In all cases the NYISO's consultants found no basis for changing the zero-crossing point.

- In their August 16, 2004 report, LAI concluded that: "At this point we have no recommendation to change the zero crossing point; any recommendation should be based on analyzing the final 2005 reference values and actual supply bid data"

- In its August 3, 2007 report, NERA did "….not recommend increasing the slope [of the demand curve] by moving the zero crossing point closer to the origin."

FERC directly addressed this issue in 2005, when it approved the proposed demand curves for the 2005/06-2007/08 capability years.[22] In its April 21, 2005 order accepting those demand curve, FERC rejected a proposal put forth by a group of load-side participants, finding that the demand curves utilizing the current zero-crossing points "…will result in lower incentives to exercise market power as well as lower price volatility that will tend to lower risk and investment financing costs."[23] The current zero-crossing points were upheld again in 2007, when FERC approved demand curves for capability years 2008/09-2010/11.

[21] *Ibid.* p. 5

[22] See dockets ER05-428-000 and ER05-428-001.

[23] p. 25

Shifting The Zero-Crossing Points Would Increase Price Volatility, Market Power Opportunities, And Regulatory Risk

Shifting the zero-crossing points to the left would steepen the demand curve, increase price volatility, and increase opportunities for the exercise of market power. Paying generators a reduced price for capacity, even if there is a market surplus, recognizes the value of increased reliability – a key aspect of the spot market mechanism. When functioning properly, keeping the mechanism intact reduces regulatory risk, promotes an environment more conducive to new investment, and helps reduce financing costs. To encourage investment and preserve reliability objectives, the spot capacity market mechanism should be stable, not subject to occasional changes in response to stakeholder whim. In the final analysis, market participants have demonstrated their overall satisfaction with the existing mechanism and by periodically updating the demand curve parameters.

APPENDICES