New York Independent System Operator, Inc.

Proposed NYISO Installed Capacity Demand Curves

For

Capability Years 2011/2012, 2012/2013 and 2013/2014

Final

Issued: **9/3/2010**
Revised: **9/7/2010**
10/30/2010

This final report was prepared based on NERA/S&L's September 7, 2010 revised final study report.

Revision No.	Date	Description
1	9/7/2010	NERA correction to NYC demand curve to eliminate double-counting of insurance costs.
2	10/30/2010	Updated NYC and LI demand curves to reflect addition of oxidation catalyst to LMS100

1. Introduction

The Installed Capacity (ICAP) obligation for New York Load Serving Entities and the market prices for the associated ICAP are determined according to the results of monthly ICAP Spot Market Auctions using separately-established downward sloping ICAP Demand Curves for New York City (NYC), Long Island (LI) and the New York Control Area (NYCA).[1] [2] Section 5.14.1.2 of the Services Tariff requires the New York Independent System Operator, Inc. (NYISO) to perform a review of the ICAP Demand Curves every three years in accordance with the ISO Procedures to determine the parameters of the ICAP Demand Curves for the next three Capability Years. As part of this review, the NYISO must determine the cost of a peaking unit in the NYCA and each Locality, the projected net Energy and Ancillary Services revenues, and the appropriate shape and slope of the ICAP Demand Curves. "For purposes of this review, a peaking unit is defined 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."[3]

In accordance with the Services Tariff, in the third quarter of 2009, the NYISO solicited proposals from qualified consultants to identify appropriate methodologies and to develop the ICAP Demand Curve parameters for the three Capability Years beginning in May 2011. The NYISO selected the team of NERA (National Economic Research Associates, Inc.), with Sargent and Lundy (S&L) as a subcontractor to NERA (collectively identified as the Consultants). The Consultants began their analysis in December 2009. Through thirteen Installed Capacity Working Group meetings between December 2009 and August 2010, NYISO market participants and other stakeholders provided feedback to the Consultants on the Consultant's assumptions, methodology, analysis, estimates, and preliminary results. On July 1, 2010, the Consultants released the first draft of their report for stakeholder review and comment ("NERA/S&L Report")[4]

[1] Capitalized terms that are not otherwise defined herein shall have the meaning specified in the Market Administration and Control Area Services Tariff (Services Tariff), and if not defined therein, then in the Open Access Transmission Tariff (OATT).

[2] The term Rest of State (ROS) is used when referring to supply in the part of the New York Control Area that does not include the NYC and LI Localities.

[3] Services Tariff Section 5.14.1.2.

[4] "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, July 1, 2010, prepared by NERA Economic Consulting, available at *http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2010-07-16/Demand_Curve_Study_Report_DRAFTV1_07_16_2010.pdf*

and on August 29, 2010, a revised draft report was issued to stakeholders.[5] The final version of the NERA/S&L Report was released on September 3, 2010, with a revision as noted above on September 7, 2010; both versions ~~will be~~were posted on the NYISO website under the ICAP Working Group materials.

In October 2010, S&L informed the NYISO that a revision was necessary to the CO emissions rate for the LMS100 combustion turbine, based on discussions with the manufacturer in which the manufacturer indicated it will be updating the software the manufacturer provides for calculating CO emissions. The NYISO's recommendations have been updated to reflect the addition of oxidation catalysts to the NYC and LI LMS100 peaking units.

This proposal contains the NYISO's recommended ICAP Demand Curves for the three Capability Years beginning May 1, 2011 through April 30, 2014. In preparing this proposal, NYISO has taken into account the NERA/S&L Report, comments from the Market Monitoring Unit, and comments provided by stakeholders. The NYISO's preparation included consideration of all of the written and oral comments from stakeholders throughout the process and on papers by NERA/S&L and the draft NERA/S&L Report.

The Consultants considered many risks that a developer would consider when making a decision on whether to invest in New York. For example, the Consultants considered the risk that the level of supply will exceed the minimum required in each Locality and in the NYCA. They also considered the impact of the slope of the Demand Curves and their zero crossing points. The Consultants determined, and the NYISO agrees, that the probability is quite low that the reliability processes in place for the New York will allow the level of capacity in either Locality or in the NYCA to fall below the minimum requirement. Because of these processes, there is a risk that a developer will not earn revenues above the cost of new entry (CONE), which are necessary to offset the times in which it earns revenues below the CONE, because it could only earn those revenues if there is insufficient capacity to meet the minimum requirements. (The Demand Curves set reference values at 100 percent of the minimum ICAP requirement.[6]) The Consultants' methodology reflects this risk by allowing the amortization period to vary. The results, as explained in the NERA/S&L Report, are amortization periods of 15.5, 19.5, and 15.5 years for NYC, ROS, and LI, respectively.

This report sets forth the NYISO staff's set of recommendations for adjusting the current ICAP Demand Curve parameters and the underlying assumptions leading to those recommendations. The Market Monitoring Unit has been involved in reviewing the Consultant's work product and in the development of the NYISO's ICAP Demand Curve

[5] Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, August 27, 2010, prepared by NERA Economic Consulting, available at http://www.nyiso.com/public/markets_operations/committees/meeting_materials/index.jsp?com=bic_icapwg

[6] The Services Tariff sets forth the manner in which Locational Minimum Installed Capacity Requirements and the NYCA Minimum Installed Capacity Requirement is set annually.

update recommendations. The schedule shown in Appendix B identifies the remaining steps in the Demand Curve update process, culminating in the NYISO's filing with the Federal Energy Regulatory Commission on or before November 30, 2010 the results of the NYISO's review and the updated Demand Curves approved by the Board of Directors.

In choosing the appropriate peaking unit, the NYISO's Services Tariff does not explicitly indicate whether the unit with "lowest fixed costs" should be chosen based on total cost or cost per kilowatt.[7] The two previous Demand Curve update studies selected the appropriate peaking technology based in part on $/kW figures. The relative sizes of the LMS-100 and LM6000 units combined with the numbers of units installed at a generation station can result in significantly different choices depending upon how the phrase "lowest fixed costs" is interpreted. For both the LMS-100 and the LM6000 technologies, the Consultants developed costs for a two-unit installation, which significantly reduces the $/kW cost, but increases the total plant cost. The NYISO concurs with the Consultants' analysis and recommendation that fixed costs be measured on a $/kW basis, recognizing the efficiencies of building two-unit sites, and the increased Energy and Ancillary Services revenue be captured.

2. Choice of Peaking Unit by Region

The NERA/S&L Report (as did the two previous studies) focused on General Electric technologies, because they are representative of other manufacturers' designs and account for approximately 56 percent of the "peaking units" sold both nationally and in New York.[8] The NERA/S&L Report also considered the Rolls Royce Trent 60 WLE (Trent 60) unit as a possible peaking unit technology.

For LI and NYC, the Consultants considered three different peaking unit technologies, the LM6000, LMS-100 and the Trent 60. The LM6000 has been used extensively, with more than 600 units built with an operating history of 10 million hours. The LMS-100, developed in 2004, was considered for the first time in the last Demand Curve reset study. There are currently over 20 LMS-100 units installed with more than 35,000 cumulative hours as of the end of 2009. Like the other two technologies, the Trent 60 is also an aeroderivative design. It first entered the market in 1998; and the first installation in the United States began operation in 2008. The NERA/S&L Report reflects lower capital and operating costs, per kW, for the LMS-100 than the LM6000 and the Trent 60. The LMS-100 also has a better heat rate (9023 BTU/kWh HHV versus 9475 BTU/kWh HHV for the LM6000 and 9548 BTU/kWh HHV for the Trent 60), which results in a higher capacity factor and higher energy revenues on a per kW basis. The LMS-100 has a lower fixed cost on a $/kW basis compared with the LM6000 and the Trent 60.
Based on the Consultants' Study and discussions with the Market Monitoring Unit, the NYISO recommends the LMS-100 as the technology choice upon which to establish the Demand Curves in NYC and LI.

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[7] *See* Services Tariff, Section 5.14.1.2.

[8] NERA/S&L Report, p. 14, footnote 5.

Based on comments from stakeholders on the NERA/S&L Report, the figures cited in the NYISO's recommendations reflect revisions that the Consultants subsequently made. These revisions include an increase in capital investment costs for the Zone J unit due to brownfield site remediation, and the cost of emission reduction credits. Fixed operating and maintenance costs (O&M) increased due to the effect of capital investment on property taxes and property values, higher lease costs in NYC, and increased staffing. Gas transportation costs were revised, and emissions allowances for NOx and CO_2 were added.

For the NYCA, the 7FA unit is recommended for use in setting the NYCA Demand Curve. It has a lower fixed cost on a $/kW basis compared with either the LMS-100 or LM6000 and is economically viable outside of NYC and LI. Due to NOx emission restrictions and the inability to install selective catalytic reduction equipment on the unit, the 7FA would not be practical in NYC or LI and, therefore, could not feasibly satisfy the Services Tariff requirements for the peaking unit.

Certain market participants have raised a question concerning the ability of a 7FA facility to operate under the New Source Review standards for stationary sources. Sargent & Lundy and the NYISO have confirmed with the NYS Department of Environmental Conservation (DEC) that New Source Review standards would apply to any new facility emitting greater than 100 tons NOx annually. For the 2-unit 7FA under consideration as the peaking unit, the 100 ton limit would translate into a maximum run time in Zone F of 1461 hours[9]. The econometric analysis performed by NERA indicates that, at levels of excess considered for this study, a 2-unit 7FA would operate below 1200 hours and thus would not be subject to New Source Review standards.

In October 2010S&L informed the NYISO that a revision was necessary to the CO emissions rate for the LMS100 combustion turbine, based on discussions with the manufacturer in which the manufacturer indicated it will be updating the software the manufacturer provides for calculating CO emissions. The CO emissions rate is used along with the annual hours of operation to calculate annual emissions from the unit and determine whether or not an oxidation catalyst is needed and/or if Emissions Reductions Credits must be purchased.

S&L calculated the maximum CO emissions rate the 2-unit LMS100 configuration without an oxidation catalyst could have, based on the number of hours of operation estimated by NERA for Zones J and K, and still stay under the annual tonnage limit that would trigger the need for an oxidation catalyst. In consultation with the turbine manufacturer, S&L determined that the LMS100 could not meet the annual tonnage limit without an oxidation catalyst. Therefore, the based on the determination using the new information, S&L recommends the addition of an oxidation catalyst for the LMS100 in Zones J and K, and likely for the LMS100 unit in other zones in which it was considered as a possible peaking unit.

[9] NERA/S&L Report, p.19, Table II-2.

S&L has revised the cost estimate for the LMS100 cases in Zones J and K to add the oxidation catalyst, as follows

- Capital investment cost of 2-unit LMS100 in Zone J was $1,784/kW; now is $1,807/kW (2010 dollars)
- Capital investment cost of 1-unit LMS100 in Zone J was $2,100/kW; now is $2,123/kW (2010 dollars)
- Capital investment cost of 2-unit LMS100 in Zone K was $1,667/kW; now is $1,690/kW (2010 dollars).

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At the March 15, 2010 Installed Capacity Working Group meeting, the NYISO indicated that demand response presently available generally does not have the ability to respond to longer deployments under current market rule designs. Further, there is not an establish set of parameters or characteristics for a particular technology of demand response to be identified with any reasonable measure of certainty. Even if an identified technology could be ascertained with certainty, the fixed and variable costs make it unsuitable for consideration in the current Demand Curve reset review. The NYISO will consider the use of Demand Response as the peaking unit in the next reset cycle, contingent upon better definition of the process for identifying demand response resource technology types, and the methodology and a means to quantifying the fixed and variable costs associated with those technologies.

3. Capital Investment and Other Plant Costs

Capital cost estimates are provided in the NERA/S&L Report on pages 26-27. Included in these costs are direct costs within the engineering, procurement and construction (EPC) contracts, owner's costs not covered by the EPC including social justice costs, financing costs during construction and working capital and initial inventories. For the LMS-100 in NYC, capital costs are identified as $~~1,784~~1,807/kW while capital costs for the LMS-100 on Long Island are $~~1,667~~1,690/kW. For the NYCA, the capital costs for the 7FA are $820/kW. These dollar figures are in 2011 dollars. The NYISO concurs with the Consultants' estimates and recommendations.

3.1 Treatment of Deliverability Costs

Effective October 2008, the Federal Energy Regulatory Commission (Commission) approved modifications to the NYISO's interconnection process that created two types of interconnection service:

- Energy Resource Interconnection Service (ERIS), which allows a new project to participate in the NYISO's energy market but not as an Installed Capacity Supplier, and
- Capacity Resource Interconnection Service (CRIS), whereby a new project can participate in both the NYISO's Energy and Capacity markets

New projects requesting CRIS Rights are evaluated within the Class Year study process using the deliverability test defined in Sec. 25.7.8 of the OATT. The projects that are determined to be deliverable in full or in part are awarded CRIS Rights up to their MW deliverability level. For those projects deemed undeliverable in full or in part, the NYISO determines the least cost system upgrade(s) to achieve full deliverability (termed System Deliverability Upgrade costs, or SDU costs). Projects identified as fully or partially non-deliverable are assigned a share of the total SDU costs, in $/MW, based upon their impact on the constrained facility/facilities. Projects accepting their SDU costs are granted CRIS Rights.

The Consultant's report identifies on pp. 72-73 how the Net CONE model treats SDU costs. The Consultants identify the range of Net CONE results for ROS with and without SDU costs. The Consultants do not take a position on the issue of whether to include or exclude SDU costs as an element of the Demand Curves.

The deliverability tariff provisions[10] were designed to comply with the Commission's interconnection and cost allocation policies. Those policies require that interconnection customers that wish to participate in capacity markets must fund the entire cost of the requisite interconnection facilities, any network upgrades that would not have been constructed but for the interconnection, and any upgrades needed to make the customer's capacity deliverable. Among other considerations, these policies give interconnection customers an economic incentive to locate in areas where their capacity would be deliverable.[11] Consequently, the NYISO's cost allocation rules for SDU costs provide that they shall be borne predominantly by interconnection customers with other entities, such as LSEs, assuming a portion only under limited circumstances.[12] The NYISO's deliverability rules, including their cost allocation components, have been approved by the Commission. Moreover, the Commission stated that approved "approach allocates costs of transmission consistent with Commission policy and recognizes the competing

[10] OATT Attachment S.

[11] *See New York Independent System Operator, Inc.*, 122 FERC ¶ 61,267 at P 39 (2008) (accepting the NYISO-New York Transmission Owners' Deliverability Consensus Plan, whose cost allocation procedures were described by the NYISO and New York Transmission Owners as necessary to "maintain price signals for efficient location."); *see also, Old Dominion Electric Cooperative v. PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,052 at PP (2007) (finding PJM's network upgrade cost allocation procedures, which required interconnection customers to pay the costs of network upgrades "that would not have been otherwise incurred by transmission customer to meet the reliability needs of the ... system" as consistent with Order No. 2003's acceptance of the use of the "but for" test in ISO/RTO systems because "it encourages generators to make proper siting decisions that take into account all the costs of building the generation facility."); *cf. PJM Interconnection, LLC,*, 119 FERC ¶ 61,318 at P 77 (2007) (noting that the "universal deliverability" concept was a failure and accepting PJM's locational capacity pricing proposal because it "creates a construct that is designed to send the proper price signals" that will "ensure that required generation, demand response and/or transmission infrastructure are developed where they are most needed.").

[12] Specifically, entities other than interconnection customers would pay a share of SDU costs only to the extent the 90 percent threshold is not realized for highway facilities (*i.e.*, only if the minimum feasible upgrade is more than 90 percent of the size of the actual upgrade). *New York Independent System Operator, Inc. and New York Transmission Owners*, 122 FERC ¶ 61,267 at P 46 (2008).

interests of those involved."[13]

It is not reasonable to examine deliverability costs in the context of the Demand Curve tariff in isolation of the Commission's orders accepting the NYISO's deliverability tariff provisions. Those orders unquestionably establish that interconnection customers must pay SDUs so that they will have an incentive to make efficient decisions regarding the locations of new investments. If SDU costs were incorporated into the Demand Curves, the desired economic signal would be suppressed, in contravention of Commission policy, since SDU costs would effectively be subsidized by capacity buyers.

The Demand Curve tariff provisions can and should be read consistently with the deliverability tariff provisions and related Commission orders. The Services Tariff does not expressly state that SDU costs should be included in the computation of the cost of new entry for the peaking unit when establishing the Demand Curves (§ 5.14.1.2). There likewise does not appear to be any precedent from other ISO/RTO capacity markets that requires the inclusion of those costs. Similarly, the question of whether SDU costs should be included in the cost of new entry computation was not substantively engaged in prior Demand Curve reset proceedings.

In addition to providing the economic signal, equitable considerations also favor excluding SDU costs from the cost of new entry calculation. Including SDU costs would increase the value of Net CONE at equilibrium, resulting in a proportionate increase to the Demand Curves at all levels of excess capacity. New and existing generators would thus all receive higher capacity payments at the expense of other customers that are not supposed to be paying the SDU costs in the first place. Such an outcome seems especially inappropriate considering that existing generators have already received grandfathered CRIS rights. The Demand Curves are designed to not only attract new entry but to send the proper signal for retirements. Thus, including the costs would skew the economic signal to existing generators. In addition, any generator that funds transmission upgrades would be awarded potentially valuable Incremental Transmission Congestion Contracts, a form of supplemental compensation that helps to offset the cost of new investments.

The NYISO is mindful of concerns raised by some stakeholders regarding the possibility that excluding SDU costs from the cost of new entry would discourage investment. The NYISO believes, however, only investments in locations that Commission policy disfavors would be discouraged. Moreover, the creation of criteria by which new Capacity zones may be developed has the potential to send clearer economic signals for efficient new investment. The NYISO is committed to pursuing the development of the criteria new Capacity zones with stakeholders as a separate activity from this Demand Curve review process. The NYISO has proposed possible criteria for establishing such zones, and criteria will be submitted to the Commission in one or more filings.

For these reasons, NYISO staff recommends that Deliverability costs be excluded from the calculation of the peaking unit's cost of new entry.

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[13] *Id.*

4. Fixed Operating and Maintenance Costs

Fixed operating and maintenance costs are discussed in the NERA/S&L Report on pages 27-30. It is assumed that the land associated with the plant site is leased. Property taxes are based on those typical in the jurisdictions chosen for each market (NYC, LI and Capital Zone).

As a result of the addition of oxidation catalysts to the LMS100 peaking units in NYC and LI, the fixed O&M costs change by impacting property taxes and insurance, as follows:

- Fixed O&M cost of 2-unit LMS100 in Zone J was $107.70/kW-yr; now is $108.85/kW-yr
- Fixed O&M cost of 1-unit LMS100 in Zone J was $135.42/kW-yr; now is $136.59/kW-yr
- Fixed O&M cost of 2-unit LMS100 in Zone K was $48.81/kW-yr; now is $49.33/kW-yr.

The effect varies by case because of differing property tax rates in each zone and differing size of project investment (1 or 2 units).

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4.1 NYC Tax Abatement

At the time of the 2007 demand curve filing, the NYC Industrial and Commercial Incentive Program (ICIP) provided reductions in real property taxes to new industrial and commercial projects, including power plants. Under ICIP, full property tax abatement was in effect for the first eleven years of operation, and ramped down in 20 percent increments over the next five years until, in year sixteen, no tax abatement was granted. In July 2008 a revised program established that specifically excluded "utility property," which effectively removed the tax abatement for new generating facilities in NYC. Based on the analysis from the last Demand Curve reset process, removing the ICIP tax abatement for NYC generating facilities would increase the annual NYC Demand Curve net CONE by approximately 39 percent. The NYISO's Board of Directors considered the program revision in respect of the Commission-approved Demand Curves and determined that the repeal of the ICIP for new generation did not present an exigent circumstance that would warrant an off-cycle re-determination of the NYC Demand Curve.[14] The NYISO Board further stated that its expectation for the next Demand Curve review would include a "thorough evaluation of … any other development incentives."[15]

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[14] August 27, 2008 NYISO Board of Directors Decision on Whether Repeal of the ICIP Requires Resetting the NYC ICAP Demand Curve, located at: http://www.nyiso.com/public/webdocs/documents/regulatory/market_participant_notices/ICIP_Repeal.pdf

[15] *Independent Power Producers of New York, Inc. et al*, Answer to the Complaint of. New York Independent System Operator, Inc. at Att. 1 p.5 (*NYISO Board of Directors Decision on Whether Repeal of the ICIP Requires Resetting the NYC ICAP Demand Curve)*, EL09-04-000 (filed August 27, 2008). *See*

On August 3, 2010, the Board of Directors of the New York City Industrial Development Authority (NYCIDA), an agency administered by the New York City Economic Development Corporation (NYCEDC), approved the Third Amended and Restated Uniform Tax Exemption Policy (Policy). As part of the Policy, inducements for new installation of peaking units (defined by the NYCIDA as PlaNYC Energy Program Projects) in NYC were established; specifically:

> A PlaNYC Energy Program Project consists of the acquisition, construction, equipping, furnishing and/or installation of a Peaking Unit. For a PlaNYC Energy Program Project, "inducement" consists of the following: (i) the proposed Peaking Unit will use natural gas, or a demonstrably cleaner fuel, as its primary fuel; and (ii) the proposed Peaking Unit will have a full-load heat rate not exceeding either (aa) 7,850 btuLHV/kwh (ISO 59º, 60% RH, zero losses, sea level) as measured at generator terminals, or (bb) 8,250 btuLHV/kwh (9,150 btuHHV/kwh) as measured net of power plant parasitic loads; and (iii) nitrogen oxide (NOx) emissions from the Peaking Unit will not exceed the lesser of (aa) 25 ppm, or (bb) the then-applicable air-emissions limit as set for the City by the air-emissions permitting agency or agencies having jurisdiction; and (iv) the proposed Peaking Unit will be electrically interconnected to the City's electrical grid; and (v) 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. For purposes of this Policy: "NYISO" means the New York Independent System Operator; "transmission owner" means the owner of local facilities for the transmission of electricity within the City; and "Peaking Unit" means a facility for the generation of electricity that conforms to at least one of the following: (aa) the definition applicable on the date hereof (August 3, 2010) for a "peaking unit" as provided in NYISO Services Tariff, Section 5.14.bl ; or (bb) for a period to which a particular cost-of-entry analysis (i.e., a "CONE") applies, the electricity-generating facility on which NYISO has based such CONE; or (cc) at any point in time, a facility that is generally recognized in the industry as being a "peaking unit." As defined herein, a Peaking Unit shall not include the land upon which it is situated.[16]

PlaNYC Energy Program Projects may submit project documents between August 3, 2010 and December 31, 2017. The following tax exemptions are available:[17]

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also, *Independent Power Producers of New York, Inc. et al,* 125 FERC ¶ 61,311 (2008) (denying the complaint and requested relief.)

[16] Third Amended and Restated Uniform Tax Exemption Policy of the New York Industrial Development Agency (UTEP), pp.2-3, available at http://www.nycedc.com/AboutUs/PublicMeetings/NYCIDAPublicHearing/Documents/THREE%20UTEP.pdf

[17] UTEP, pp.9-10.

- Exemption from real property taxes (full exemption for twelve years, no abatement thereafter)
- Exemption from recording taxes
- Exemption from mortgage recording taxes
- Exemption from sales and use taxes

For the current Demand Curve review, the NERA/S&L Report[18] does not take a position a specific tax abatement level, but includes in its model the ability to exclude or include any set of terms and conditions on levels of tax abatement. Table 1-1 on page 9 of the NERA/S&L Report shows the impact of no tax abatement ($262.97/kW-yr) and full tax abatement per PlaNYC Energy Program terms ($192.32/kW-yr).

The now repealed ICIP benefits were granted as of right to all applicants whose projects qualified under the provisions of the legislation. Unlike ICIP, the PlaNYC Energy Program is discretionary on the part of the NYCIDA Board of Directors. NYISO staff believes the conditions for financial assistance are clear, and projects meeting the criteria set forth in the Policy should be granted full tax abatement in accordance with the Policy provisions. Therefore, NYISO staff recommends that full tax abatement treatment be applied to the peaking unit in NYC. Nevertheless, it is critical that future Demand Curve reset reviews build upon the actual disposition of generators' applications for the PlaNYC Energy Program benefits. Thus, prior to the next Demand Curve reset cycle, the NYISO will review the outcome of applications to the PlaNYC Energy Program and will recommend that the percentage of tax abatement applied in establishing the next NYC Demand Curve reflect the actual awards made.

Table 1 below summarizes the change in the Demand Curve parameters as a function of the level of tax abatement assumed. For this and other tables, the values shown represent a sensitivity analysis based on a single variable (in Table 1, the level of tax abatement), with other variables held constant per the assumptions made in the NERA/S&L report.[19]

The proposed Demand Curve reference points, translated into Summer monthly ICAP values, are shown in the middle columns. The three right-hand columns calculate the estimated annual Capacity revenue (in $/kW-yr) a generator would be paid under each of the proposed Demand Curve, at current levels of capacity excess and with current levels

[18] NERA/S&L Report, pp. 29-30.

[19] Unless otherwise noted, the model parameters used are those assumed in the NERA/S&L Report:

- All figures in 2011 dollars; 2010-2011 demand curve escalated by the currently effective 7.8% escalation rate.
- 1.5*MW peaking unit used as level of excess for Capacity and Energy calculations.
- Standard deviation for Capacity and Energy calculations equal to one-half the level of excess modeled.
- Taxes, fixed O&M, residual value as identified in the NERA/S&L Report.
- NYISO-determined seasonality adjustment as noted in the table at the end of Attachment A.
- For the 2011 estimated capacity revenue, level of excess assumptions are NYC: 5%; NYCA: 9%; LI: 14%; winter/summer ratio NYC: 5.6%, NYCA: 1.1%; LI: 2.6%.

of UCAP seasonality adjustment, beginning in May 2011. In this and all similar tables, the first row summarizes the reference points for the current 2010-2011 Capability Year as specified in Section 5.14.1.2 of the Services Tariff.

Table 1 – Sensitivity Analysis, NYC Tax Abatement

	Summer Reference Point ($/kW-mo)			2011 Est. Capacity Revenue ($/kW-yr)		
	NYCA	NYC	LI	NYCA	NYC	LI
Current Demand Curve (2011$)		$ 17.24			$ 117.23	
with 100% tax abatement		$ 20.35			$ 138.38	
with 80% tax abatement		$ 21.89			$ 148.85	
with 70% tax abatement		$ 22.66			$ 154.09	
with 50% tax abatement		$ 24.20			$ 164.56	
no tax abatement		$ 28.85			$ 196.18	

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5. Variable Operating and Maintenance Costs

Variable O&M costs are discussed in the NERA/S&L Report.[20] Variable O&M costs are primarily driven by periodic maintenance cycles: for the LMS-100, maintenance is recommended every 50,000 factored operating hours; for the 7FA, the shorter of 48,000 hours or 2,400 factored starts is recommended. Other variable O&M costs are directly proportional to plant generating output, as outlined in the NERA/S&L Report. The NYISO concurs with the Consultants' recommendations therein.

Fuel Costs are discussed in the NERA/S&L Report.[21] In addition to the direct fuel costs, which are determined statistically from historical fuel prices, the analysis captures transportation costs. The NYISO concurs with the Consultants' recommendations.

6. Development of Levelized Carrying Charges

A discussion of the elements used in developing levelized carrying charges can be found in the NERA/S&L report.[22] The annual carrying charge rate is determined using the same methodology that was used for the previous Demand Curve reset study. Financing assumptions were discussed at length by stakeholders and in written comments, and are discussed in the NERA/S&L Report.[23] Stakeholders provided differing views on a number of issues, including:

- Corporate versus project financing,
- The credit rating on which the cost of capital should be based,

[20] NERA/S&L Report, pp. 30-32.

[21] NERA/S&L Report, pp. 32-35.

[22] NERA/S&L Report, pp. 35- 39.

[23] NERA/S&L Report, pp. 58 – 67.

- Use of only bond yields rather than a combination of bank and bond financing for the debt portion of financing, and
- Assumptions concerning equity beta.

The Consultants have proposed a set of financing assumptions that reflect those associated with a larger corporate capital structure, but also recognize the reasonable possibility of a peaking unit not associate with a larger corporate capital structure being developed. The NYISO believes that the debt/equity parameters chosen provide a reasonable balance, and concur with the Consultant's recommendations.

7. Assumptions Regarding the Expected Level of Capacity

Expectations as to the amount of Installed Capacity relative to the annual Locational and NYCA Minimum Installed Capacity Requirement will impact the level of Energy and Ancillary Services revenues received by the new peaking unit. For the three-year period covered by this Demand Curve update, the NYISO recommends using a capacity level of 100.5 percent of the target Installed Capacity level for computing Energy and Ancillary Services revenues. This level comports with the Services Tariff, which states that Energy and ancillary Services are to be determined "under conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement."[24]

For the remainder of the nominal life of the facility (thirty years) (*i.e.*, the 27 years beyond the 3 years of the Demand Curve), the NERA/S&L Report recommends that the average percent excess in each region be determined by "first multiplying the ICAP of the peaking unit by 1.5 and then dividing that value by the minimum capacity requirement for the region."[25] The level of excess Capacity modeled is a judgment based upon the expected frequency and size of new entry, retirements, and the minimum level of excess anticipated before new Capacity would be likely to enter the market. The NYISO believes that signals for new entry will be provided before the level of excess drops to the equilibrium point; but the timing of that entry could reasonably coincide with the time at which the excess is anticipated to fall to zero. The addition of the new entry peaking unit will bring the excess to 1.0*MW peaking unit. As the excess is absorbed by load growth, the cycle repeats, resulting in an average level of excess of 0.5*MW peaking unit. Using the NERA/S&L peaking unit sizes reported in Table II-1, this would result in an average excess in NYC and LI of 0.5*195 = 98 MW, and 207 MW in NYCA. Based on the average requirement levels noted in the NERA/S&L report on page 69 (36,000 MW for NYCA, 8575 MW for NYC and 4700 MW for LI), levels of excess are determined to 1.1% for NYC, 2.1% in LI and 0.6% in NYCA. The NYISO believes it is unrealistic to assume that, over time, an average level of excess below 1% is reasonable. Therefore, the NYISO recommends that the level of excess in NYCA be modeled at 1%, with NYC modeled at 1.1% and LI at 2.1%.

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[24] Services Tariff Section 5.14.1.2.

[25] NERA/S&L Report, p. 70.

Table 2 – Sensitivity Analysis, Levels of Excess Capacity Modeled

	Summer Reference Point ($/kW-mo)			2011 Est. Capacity Revenue ($/kW-yr)		
	NYCA	NYC	LI	NYCA	NYC	LI
Current Demand Curve (2011$)	$ 10.67	$ 17.24	$ 9.37	$ 26.14	$ 117.23	$ 26.14
1.5*MW peaking unit	$ 9.38	$ 20.35	$ 11.08	$ 22.98	$ 138.38	$ 23.19
1.0*MW peaking unit	$ 8.86	$ 18.43	$ 8.36	$ 21.71	$ 125.32	$ 21.71
NYISO recommendation*	$ 8.86	$ 16.91	$ 6.31	$ 21.71	$ 114.99	$ 21.71
@100.5% of equilibrium	$ 8.39	$ 15.99	$ 4.88	$ 20.56	$ 108.73	$ 21.71

*NYISO recommended excess: NYCA: 1%; NYC: 1.1%; LI: 2.1%

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8. Energy and Ancillary Services Revenue

The Consultants used historical data from November 1, 2006 through October 31, 2009 to benchmark the operation of the NYISO system in order to determine likely projected Energy and Ancillary Services Revenues to utilize in computing the Net CONE. The Consultant's statistical model allows for the identification and variance of any causal variables that may impact future Energy prices. These prices are used to dispatch the hypothetical peaking unit, calculating both day-ahead and real-time Energy revenues while recognizing Capacity commitment considerations and operating constraints.

The NERA/S&L Report[26] also covers several additional considerations that were raised by stakeholders, including:

- Impact of Lake Erie loop flow
- Use of forward gas prices instead of a regression fit of historical gas prices
- Impact of recession / cool weather adjustments.

The NYISO agrees with the Consultants' conclusions on those topics.

The results reported in the NERA/S&L Report have been modified to take into account several facts which were identified by stakeholders:

- CO_2 and NOx allowance credit costs have been included as additional operating costs.
- One set of LBMP regression equation parameters and one LBMP forecast using the appropriate gas price index for each zone were used.

9. Demand Curves Slope and Length

[26] NERA/S&L Report, pp. 51-55.

The Consultants reviewed the shapes of the current Demand Curves and found no basis to change the current shape and zero crossing points.[27] As the Consultants note, the demand curve methodology determines the level of Capacity revenue needed to yield the same amount of total revenue (Capacity plus Energy plus Ancillary Services revenues). Consequently, any increase in the Demand Curve slope due to a lower percentage excess zero crossing point will compensate by raising the Demand Curve reference point at equilibrium. The NYISO's parallel analysis using NERA's Demand Curve model supports this relationship, and also emphasizes the sensitivity of such adjustments on capacity revenue under current market conditions.

Table 3 – Sensitivity Analysis, Demand Curve Slope

	Summer Reference Point ($/kW-mo)			2011 Est. Capacity Revenue ($/kW-yr)		
	NYCA	NYC	LI	NYCA	NYC	LI
Current Demand Curve (2011$)	$ 10.67	$ 17.24	$ 9.37	$ 26.14	$ 117.23	$ 26.14
NYC, LI at 118%		$ 20.35	$ 11.08		$ 138.38	$ 23.19
NYC, LI at 115%		$ 23.58	$ 12.93		$ 135.82	$ 21.71
NYC, LI at 112%		$ 28.17	$ 16.00		$ 118.31	$ 21.71
NYCA at 115%	$ 8.54			$ 37.23		
NYCA at 112%	$ 9.38			$ 22.98		
NYCA at 110%	$ 10.41			$ 6.25		
NYCA at 108%	$ 12.42			$ -		

As depicted on Table 3, at the current levels of excess, Capacity revenue in NYC is projected to be maintained for zero crossing points down to 115%. Beyond that point, the influence of modeling assumption differences between the Demand Curve methodology and current levels of excess, and seasonal revenues, tends to reduce projected capacity revenue. Adjustments to the Long Island Demand Curve slope are bounded by NYCA Market-Clearing Prices (assuming no change to the 112% NYCA Demand Curve). In NYCA, current excess Capacity is in the range of 109-110%, and is therefore clearing on the extreme right portion of the Demand Curve. Adjusting the slope to reduce the NYCA Demand Curve zero crossing point has a significant impact on capacity revenue: from 112% to 110%, projected capacity revenue drops from $22.98/kW-yr to $6.25/kW-yr, a 73% decline.

The NYISO's analysis identifies the widely-varying and potentially significant consequences of slope adjustment on projected Capacity revenue under current conditions. The likelihood of unintended consequences is great, as can be seen from the sensitivity of the NYCA Demand Curve to increased slopes under current conditions. In addition, market power issues associated with withholding capacity would likely need to be addressed, as would the interaction with existing Pivotal Supplier and buyer-side mitigation rules in NYC. Based upon the NYISO staff's analysis, there is no compelling evidence to adjust the zero-crossing points on any of the demand curves. The NYISO

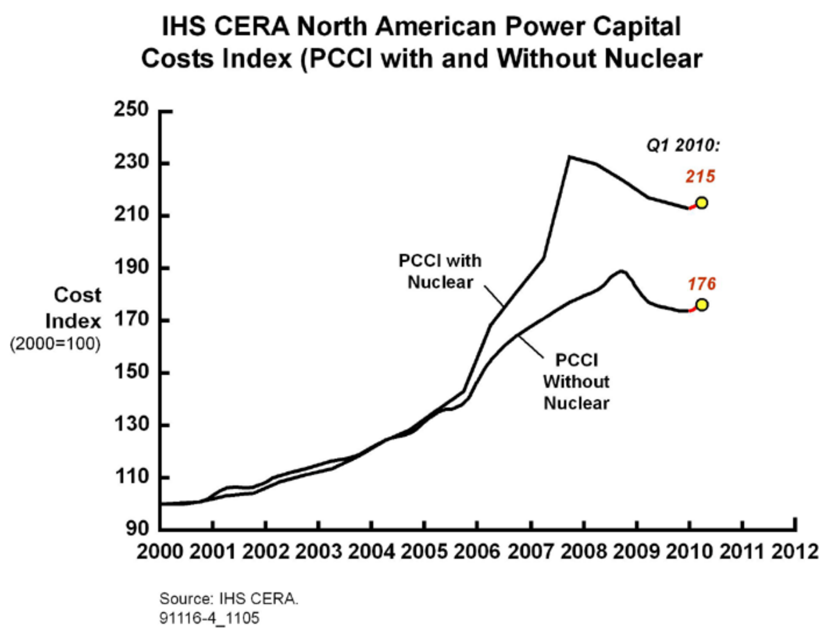
[27] NERA/S&L Report, pp. 75-79.

believes that the rationale proffered by stakeholders is far outweighed by the consequences attendant to adjusting the slope or zero crossing.

10. Escalation of Demand Curves

The previous Demand Curve study used the Handy-Whitman Index for power-plant construction to determine a projected escalation rate. The lack of a strong economic recovery and the uncertainty created by inaction on carbon legislation would suggest that historic equipment escalation rates will not be sustainable. This conclusion is supported by the IHS CERA Power Capital Costs Index (PCCI) as reported on July 15, 2010.[28] The report states:

> *"…the market for major equipment remains on a downward trend as a result of weak demand and greater competition among manufacturers. Engineering and project management costs were also relatively flat for both regions. Having cut margins as much as they can, firms are managing the downturn through more flexible contract terms."*



While the PCCI index (without nuclear) would likely produce a flat escalation forecast, the NYISO believes it is reasonable to base the escalation rate on a combination of three

[28] IHS, Cambridge Energy Research Associates, Inc. IHS CERA Power Capital Costs Index (PCCI), July 15, 2010. Available at http://press.ihs.com/article_display.cfm?article_id=4280

publicly-available inflation rate forecasts.[29] The NYISO recommends the use of a 1.7% escalation factor for the second and third years of the three-year reset period.

Table 4 – Inflation Rate Estimates

Data Source	Avg. Forecast Inflation Rate 2010-2014
SPF	1.9%
OMB	1.7%
CBO	1.5%
Average	**1.7%**

11. Winter/Summer Adjustment

The NYISO ICAP market operates in two six-month Capability Periods with different amounts of capacity available in each. The primary reason for this variation is that generators normally are capable of higher Capacity output in winter than summer due to lower ambient temperature conditions. Installed Capacity imported from External Control Areas, new generation, retirements and Special Case Resources also influence the quantity of Capacity available. The monthly ICAP reference point for the NYCA and each Locality is derived from the annual reference value for new entry, less an estimate of annual net revenue from the Energy and Ancillary Services.

The annual reference value is a $/kW-year value based on an average generator rating. The ICAP Demand Curve reference point used in monthly ICAP Spot Market Auctions must include adjustments to take these seasonal effects into account. Each monthly Demand Curve reference point is set to the level that would permit a peaking unit to be paid an amount over the course of the year that is equal to the annual reference value established by this update.

The Services Tariff specifies that the translation of the annual net revenue requirement into monthly values take into account "seasonal differences in the amount of Capacity available in the ICAP Spot Market Auctions."[30] The NYISO has determined the amount of Capacity available as that amount of Capacity that could be offered into the ICAP Spot Market Auctions. A table showing the NYISO estimate of available Capacity over the 2011-2014 reset period is included in Appendix A to this report.

[29] *See* Federal Reserve Bank of Philadelphia, Third Quarter 2010 Survey of Professional Forecasters (August 13, 2010) at Table Seven (SPF), available at http://www.phil.frb.org/research-and-data/real-time-center/survey-of-professionalforecasters/ 2010/spfq310.pdf; U.S. Office of Management and Budget, Mid-Session Review: Budget of the U.S. Government – Fiscal Year 2011 (July 23, 2010) at 9 (OMB), available at ttp://www.whitehouse.gov/sites/default/files/omb/assets/fy2011_msr/11msr.pdf
(; U.S. Congressional Budget Office, The Budget and Economic Outlook: An Update (August 2010) at 78 (CBO), available at http://www.cbo.gov/ftpdocs/117xx/doc11705/08-18-Update.pdf.
[30] Services Tariff Section 5.14.1.2.

For the current Demand Curve reset cycle, the Consultants have built into the spreadsheet model a more accurate representation of the impact of seasonal capacity levels on anticipated Energy and Ancillary Service revenues over the nominal thirty-year lifetime of the peaking unit. The model uses the winter-to-summer ratios identified in Appendix A for each of the 2013-2014 Capability Years.

In this Demand Curve reset review, the New York Transmission Owners[31] provided an alternative seasonality adjustment based upon the levels of Capacity actually sold over the 2007-2010 period. Although the values that result from applying the New York Transmission Owners adjustment accurately reflect winter-to-summer Capacity sales at current levels of Capacity excess, they are not appropriate for the same reason the NYISO identified in its previous Demand Curve reset filing:

> The ICAP demand curve parameters are based on approximate equilibrium conditions and the Services Tariff specifies "available" capacity. It would be inconsistent to reflect only capacity that might be offered in an auction because that quantity cannot be determined objectively. Available capacity can be determined most objectively from data routinely published by the NYISO in its annual Load and Capacity Reports.

Table 5 – Sensitivity Analysis, Seasonality Adjustment

	Summer Reference Point ($/kW-mo)			2011 Est. Capacity Revenue ($/kW-yr)		
	NYCA	NYC	LI	NYCA	NYC	LI
Current Demand Curve (2011$)	$ 10.67	$ 17.24	$ 9.37	$ 26.14	$ 117.23	$ 26.14
per historical NYISO calc	$ 9.38	$ 20.35	$ 11.08	$ 22.98	$ 138.38	$ 23.19
10% decrease in ratio	$ 9.07	$ 19.42	$ 10.74	$ 22.22	$ 132.06	$ 22.74
20% decrease in ratio	$ 8.78	$ 18.56	$ 10.42	$ 21.51	$ 126.21	$ 22.31
30% decrease in ratio	$ 8.50	$ 17.78	$ 10.11	$ 20.83	$ 120.90	$ 21.90

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12. ICAP Demand Curves, Reference Values, and Reference Points

Appendix A to this report contains:

- A summary of the annual and monthly Demand Curve parameters by Capacity region for the three years covered by the Current Demand Curve reset period;
- Details of the NYISO's winter-to-summer seasonality adjustment, which was used with the Consultant's demand curve model; and

[31] Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority, the New York Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

- Plots of the Demand Curves on an ICAP basis from Capability Years 2003 through 2013.
- The NYISO's computed seasonality adjustment factors based upon the 2010 Load and Capacity Data (Gold Book).

Table 6 summarizes the NYISO's recommended parameters for the 2011-2014 Demand Curve period.

Table 6 NYISO Recommended Demand Curve Parameters, 2011-2014

	NYCA	NYC	LI
Reference Point ($/kW-yr)	$89.79	$157.21	$66.63
Reference Point ($/kW-mo, summer)	$8.86	$16.91	$6.31
Zero Crossing (% of req)	112	118	118
Modeled Level of Excess (%)	101	101.1	102.1
Escalation Factor (%)	1.7	1.7	1.7

13. Independent Review of Demand Curve Parameters

The NYISO has consulted with the Market Monitor, Dr. David Patton, regarding the conclusions in this report. He independently monitors and evaluates the patterns of bids, offers and market outcomes in the New York capacity markets. He believes that the stability provided by the demand curves facilitates the forward contracting for both capacity and energy that is needed to support investment in new and existing generation.

Dr. Patton generally concurred with most of the conclusions in this report. However, he expressed concern that the NYISO's proposed level of expected excess capacity in New York City of 1.1 percent. He indicated that it is not reasonable to expect this low a level of excess capacity over the long-term.

Appendix A - Demand Curve Parameters and Demand Curves

	2011/2012			NERA/NYISO Proposal
	NYCA	**NYC**	**LI**	
Annual Revenue Req. (per KW)	$117.23	$258.87	$235.40	$/kW-Year (ICAP basis) - (LMS-100 updated)
Net Revenue (per kW)	$27.44	$101.67	$168.77	$/kW-Year (ICAP basis)
Annual ICAP Revenue Req. (per kW) =	$89.79	$157.21	$66.63	$/kW-Year (ICAP basis)
DMNC @ 90°	378.4	180.5	183.3	MW (@ 90°)
Total Annual Revenue Req. =	$33,973,936	$28,375,806	$12,212,605	
Ratio of Winter to Summer DMNCs	1.052	1.098	1.062	Adjusted from 2010 GB values
Summer DMNC	391.4	190.4	194.2	MW (@ 90°)
Winter DMNC	436.7	196.0	196.0	MW (@ Capital - 15.3°, NYC/LI - 28°)
Summer Reference Point =	$8.86	$16.91	$6.31	$/kW-Month (ICAP basis)
Winter Reference Point =	$5.02	$7.70	$4.14	$/kW-Month (ICAP basis)
Monthly Revenue (Summer) =	$3,467,556	$3,219,664	$1,225,150	
Monthly Revenue (Winter) =	$2,192,003	$1,509,354	$811,523	
Seasonal Revenue (Summer) =	$20,805,336	$19,317,984	$7,350,898	
Seasonal Revenue (Winter) =	$13,152,018	$9,056,124	$4,869,137	
Total Annual Revenue =	$33,957,354	$28,374,108	$12,220,034	validates "Total Annual Revenue Req." is met
Demand Curve Parameters				
ICAP Monthly Reference Point =	$8.86	$16.91	$6.31	$/kW-Month (ICAP basis)
ICAP Max. Clearing Price =	$14.65	$32.36	$29.43	$/kW-Month (ICAP basis)
Demand Curve Length	112%	118%	118%	

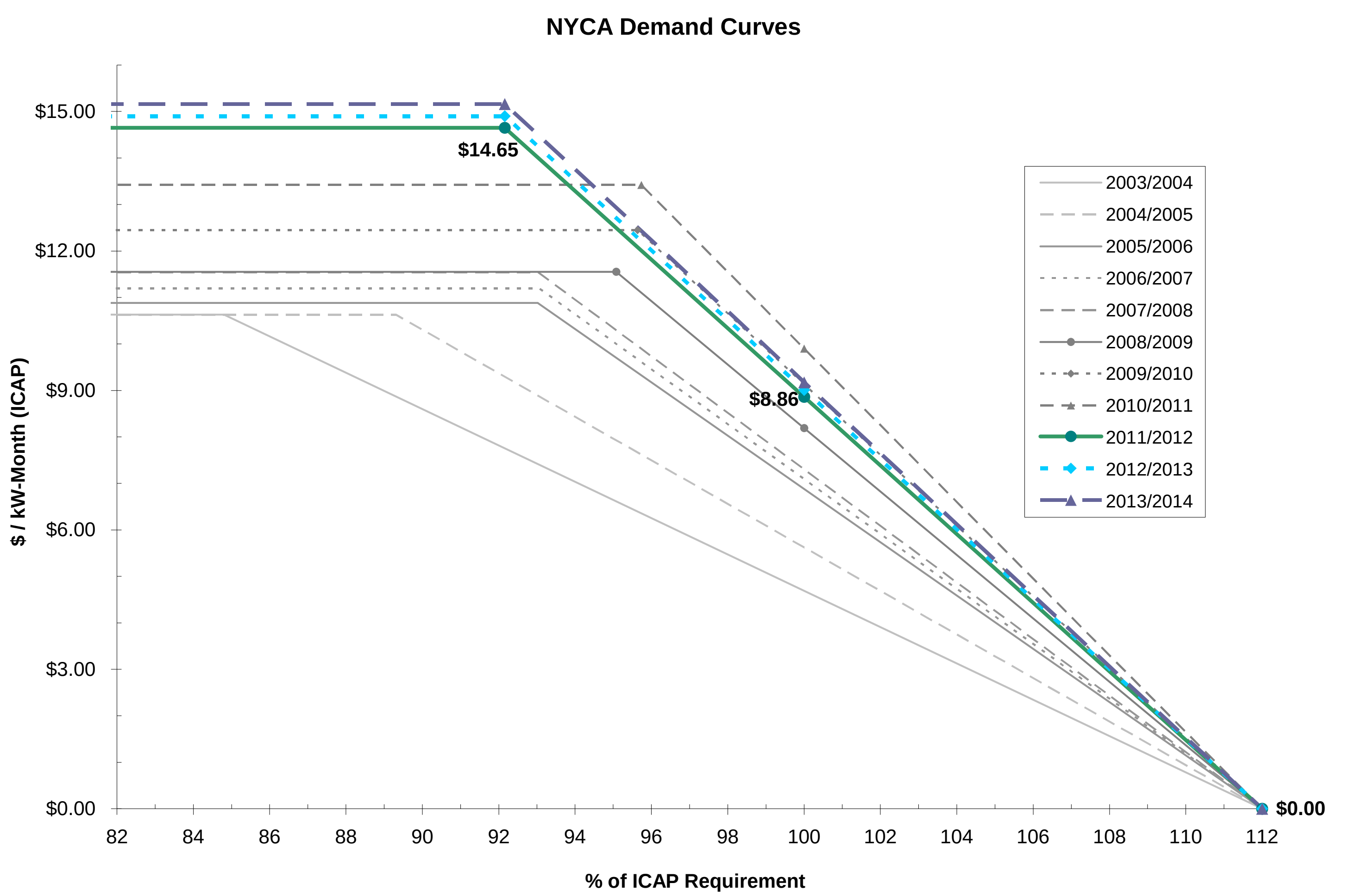
	2012/2013			Escalation Factor = 1.7%
	NYCA	**NYC**	**LI**	
Annual Revenue Req. (per KW)	$119.22	$263.27	$239.40	$/kW-Year (ICAP basis) - (LMS-100 updated)
Net Revenue (per kW)	$27.91	$103.39	$171.64	$/kW-Year (ICAP basis)
Annual ICAP Revenue Req. (per kW) =	$91.31	$159.88	$67.77	$/kW-Year (ICAP basis)
DMNC @ 90°	378.4	180.5	183.3	MW (@ 90°)
Total Annual Revenue Req. =	$34,551,492	$28,858,195	$12,420,219	
Ratio of Winter to Summer DMNCs	1.052	1.098	1.062	Adjusted from 2010 GB values
Summer DMNC	391.4	190.4	194.2	MW (@ 90°)
Winter DMNC	436.7	196.0	196.0	MW (@ Capital - 15.3°, NYC/LI - 28°)
Summer Reference Point =	$9.01	$17.20	$6.42	$/kW-Month (ICAP basis)
Winter Reference Point =	$5.11	$7.84	$4.21	$/kW-Month (ICAP basis)
Monthly Revenue (Summer) =	$3,526,262	$3,274,880	$1,246,507	
Monthly Revenue (Winter) =	$2,231,302	$1,536,797	$825,244	
Seasonal Revenue (Summer) =	$21,157,570	$19,649,280	$7,479,043	
Seasonal Revenue (Winter) =	$13,387,812	$9,220,781	$4,951,465	
Total Annual Revenue =	$34,545,382	$28,870,061	$12,430,508	validates "Total Annual Revenue Req." is met
Demand Curve Parameters				
ICAP Monthly Reference Point =	$9.01	$17.20	$6.42	$/kW-Month (ICAP basis)
ICAP Max. Clearing Price =	$14.90	$32.91	$29.93	$/kW-Month (ICAP basis)
Demand Curve Length	112%	118%	118%	

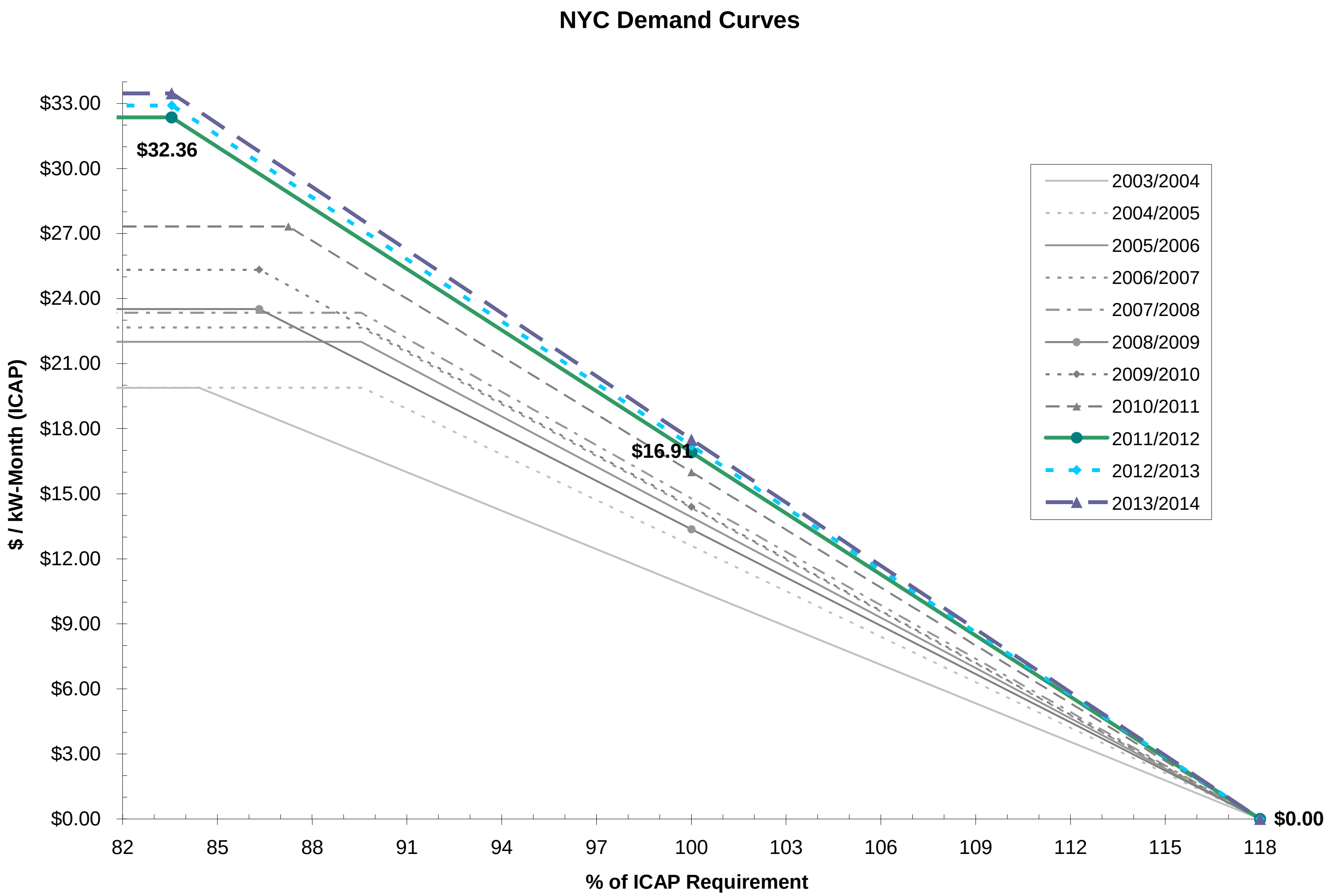
2013/2014				Escalation Factor = 1.7%
	NYCA	**NYC**	**LI**	
Annual Revenue Req. (per KW)	$121.25	$267.75	$243.47	$/kW-Year (ICAP basis) - (LMS-100 updated)
Net Revenue (per kW)	$28.39	$105.15	$174.55	$/kW-Year (ICAP basis)
Annual ICAP Revenue Req. (per kW) =	$92.86	$162.60	$68.92	$/kW-Year (ICAP basis)
DMNC @ 90°	378.4	180.5	183.3	MW (@ 90°)
Total Annual Revenue Req. =	$35,138,868	$29,348,784	$12,631,363	
Ratio of Winter to Summer DMNCs	1.052	1.098	1.062	Adjusted from 2010 GB values
Summer DMNC	391.4	190.4	194.2	MW (@ 90°)
Winter DMNC	436.7	196.0	196.0	MW (@ Capital - 15.3°, NYC/LI - 28°)
Summer Reference Point =	$9.17	$17.49	$6.52	$/kW-Month (ICAP basis)
Winter Reference Point =	$5.20	$7.97	$4.27	$/kW-Month (ICAP basis)
Monthly Revenue (Summer) =	$3,588,881	$3,330,096	$1,265,923	
Monthly Revenue (Winter) =	$2,270,601	$1,562,279	$837,005	
Seasonal Revenue (Summer) =	$21,533,287	$19,980,576	$7,595,539	
Seasonal Revenue (Winter) =	$13,623,605	$9,373,676	$5,022,032	
Total Annual Revenue =	$35,156,892	$29,354,252	$12,617,572	validates "Total Annual Revenue Req." is met
Demand Curve Parameters				
ICAP Monthly Reference Point =	$9.17	$17.49	$6.52	$/kW-Month (ICAP basis)
ICAP Max. Clearing Price =	$15.16	$33.47	$30.43	$/kW-Month (ICAP basis)
Demand Curve Length	112%	118%	118%	

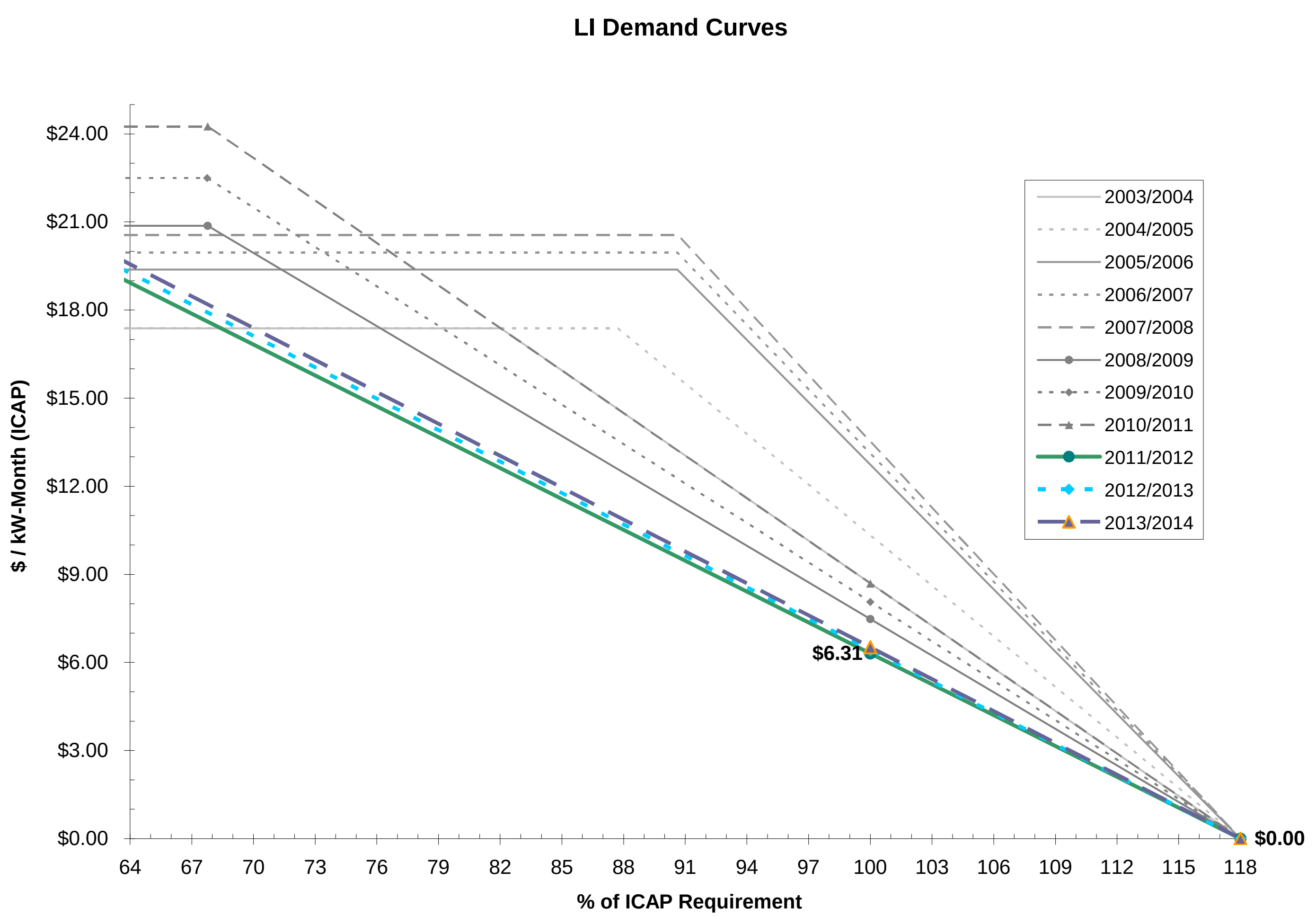
NYISO Winter/Summer Adjustment Ratio for 2011-2014 Demand Curve Update

	*2010 Base Data			2011			2012			2013		
	NYCA	NYC	LI	NYCA	NYC	LI	NYCA	NYC	LI	NYCA	NYC	LI
					Summer							
CRIS-Adjusted DMNC	37,334.3	8,954.8	5,542.7	37,334.3	8,954.8	5,542.7	37,334.3	8,954.8	5,542.7	37,334.3	8,954.8	5,542.7
Additions (GB V-2 p 72)	659.0	24.0	-	1,723.0	1,086.5	-	1,814.2	1,177.7	-	1,814.2	1,177.7	-
Wind Additions (GB V-1 p52)	-	-	-	-	-	-	-	-	-	-	-	-
Retirements (GB V-2 p 72)	-	-	-	-	-	-	-	-	-	-	-	-
Reratings (GB IV-2 p.64)	30.0	-	-	30.0	-	-	30.0	-	-	30.0	-	-
Special Case Resources (GB V-2 p.72)	2,251.0	583.0	197.0	2,251.0	583.0	197.0	2,251.0	583.0	197.0	2,251.0	583.0	197.0
Net Purchases and Sales (GB V-2 p72)	1,541.9	300.0	760.0	1,228.2	300.0	760.0	1,260.6	300.0	760.0	1,951.6	300.0	760.0
Est. Avail. Summer Capacity	41,816.2	9,861.8	6,499.7	42,566.5	10,924.3	6,499.7	42,690.1	11,015.5	6,499.7	43,381.1	11,015.5	6,499.7
					Winter							
CRIS-Adjusted DMNC	40,085.5	9,998.6	6,019.8	40,085.5	9,998.6	6,019.8	40,085.5	9,998.6	6,019.8	40,085.5	9,998.6	6,019.8
Additions (GB V-2 p 72)	663.5	24.0	-	1,826.0	1,186.5	-	1,921.5	1,282.0	-	1,921.5	1,282.0	-
Wind Additions (GB V-1 p52)	-											
Retirements (GB V-2 p 72)	-	-	-	-	-	-	-	-	-	-	-	-
Reratings (GB IV-2 p.64)	30.0	-	-	30.0	-	-	30.0	-	-	31.8	-	-
Special Case Resources	2,112.0	519.0	123.0	2,112.0	519.0	123.0	2,112.0	519.0	123.0	2,112.0	519.0	123.0
Net Purchases and Sales (GB V-2 p72)	824.6	300.0	760.0	744.6	300.0	760.0	777.0	300.0	760.0	1,469.7	300.0	760.0
Est. Avail. Winter Capacity	43,715.6	10,841.6	6,902.8	44,798.1	12,004.1	6,902.8	44,926.0	12,099.6	6,902.8	45,620.5	12,099.6	6,902.8
W/S Ratio	1.045	1.099	1.062	1.052	1.099	1.062	1.052	1.098	1.062	1.052	1.098	1.062

* 2010 Gold Book Data except where noted
Note1 - Installed Capacity Manual Section 4.9.6


NYCA Demand Curves
$15.00
$12.00
$9.00
$6.00
$3.00
$0.00
$ / kW-Month (ICAP)
82
84
86
88
90
92
94
96
98
100
102
104
106
108
110
112
% of ICAP Requirement
$14.65
$8.86
$0.00
2003/2004
2004/2005
2005/2006
2006/2007
2007/2008
2008/2009
2009/2010
2010/2011
2011/2012
2012/2013
2013/2014


NYC Demand Curves
$ / kW-Month (ICAP)
$33.00
$30.00
$27.00
$24.00
$21.00
$18.00
$15.00
$12.00
$9.00
$6.00
$3.00
$0.00
$32.36
$16.91
$0.00
82
85
88
91
94
97
100
103
106
109
112
115
118
% of ICAP Requirement
2003/2004
2004/2005
2005/2006
2006/2007
2007/2008
2008/2009
2009/2010
2010/2011
2011/2012
2012/2013
2013/2014


LI Demand Curves
$ / kW-Month (ICAP)
$24.00
$21.00
$18.00
$15.00
$12.00
$9.00
$6.00
$3.00
$0.00
64
67
70
73
76
79
82
85
88
91
94
97
100
103
106
109
112
115
118
% of ICAP Requirement
2003/2004
2004/2005
2005/2006
2006/2007
2007/2008
2008/2009
2009/2010
2010/2011
2011/2012
2012/2013
2013/2014
$6.31
$0.00

Appendix B – Timeline

New York Independent System Operator, Inc.
Final Timeline for Fall 2010 Determination of New ICAP Demand Curves
For the 2011/2012 through 2013/2014 Capability Years

The NYISO anticipates following the timeline set forth below to complete the remaining aspects of the Periodic Independent Review of the ICAP Demand Curves, as provided for in Section 5.14.1.2 of the Services Tariff. Stakeholder and NYPSC review and input has been provided through the several ICAP Working Group meetings since the July 1, 2010 release of the NERA/S&L Report.

All comments received from stakeholders will be posted on the ICAP Working Group page of the NYISO website. All deadlines should be considered as of “close of business,” and should be provided to the NYISO electronically at the website address that will be provided to the ICAP Working Group.

- September 7, 2010 – NYISO issues proposed ICAP Demand Curves, initiating thirty-day period for stakeholder submissions of comments (limited to twenty pages) and/or requests for oral argument before the NYISO Board of Directors’ Market Performance Committee.

- October 8, 2010 - Close of thirty-day comment period.

- October 18, 2010 – NYISO Board of Directors’ Market Performance Committee considers stakeholder comments and hears oral arguments, if requested. Total time for oral argument shall be limited to no more than 90 minutes.

- November 15, 2010 – at its regular November meeting, the NYISO Board of Directors acts on the new ICAP Demand Curves

- By November 30, 2010 – NYISO submits the NYISO Board-issued ICAP Demand Curves to the Commission

- By February 1, 2011 – Anticipated Commission action on filing.