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FILE NO: 55430.000063

July 17, 2007

Via Electronic Filing

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

New York Independent System Operator, Inc.
Report on Implementation of
the New York Installed Capacity Demand Curves, ER03-647-009

Dear Ms. Bose:

Attached is the report of the New York Independent System Operator, Inc. ("NYISO") submitted in response to FERC's May 18, 2007 Order Conditionally Accepting Informational Reports ("May 18 Order").[1]

I. Background

On January 16, 2007, the NYISO submitted a compliance report in the above docket reporting on the implementation of its Installed Capacity Demand Curves ("January 16 Report").[2] This report was combined with a report on the NYISO's Demand Response Programs, as specified in the Commission's Notice issued November 28, 2006 in these two dockets. The May 18 Order found the information in the NYISO's Demand Response

[1] *New York Independent System Operator, Inc.*, 119 FERC ¶ 61,162 (2007).

[2] Unless otherwise specified, capitalized terms have the meanings specified in the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff").

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Programs report to be sufficient,[3] but directed that further information and analysis be submitted on the ICAP Demand curves.

This filing submits the further information and analysis on the implementation of the NYISO's ICAP Demand Curves required by the May 18 Order. In addition, the May 18 Order indicated that certain spreadsheet data submitted with the January 16 Report was difficult to analyze because of the small font size and lack of clarity of the photocopies of the printouts. Accordingly, this information has been reformatted, and is submitted as Attachment A to this filing.[4]

II. List of Documents Submitted

The NYISO is submitting with this filing letter its Report on Implementation of, and Withholding under, the New York Installed Capacity Demand Curves, July 17, 2007.

III. Correspondence

Copies of correspondence concerning this filing should be addressed to:

[3] May 18 Order at P15. The NYISO's Summer 2007 Report on Demand Response Programs in Docket ER01-3001-006 was submitted on June 1, 2007.

[4] This information can be submitted electronically as a spreadsheet file if the Commission so desires. For the Commission's information, the NYISO's current interconnection queue can be found on the NYISO's website at: http://www.nyiso.com/public/services/planning/interconnection_studies_process.jsp.

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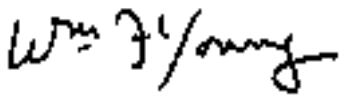
IV. Service

The NYISO is serving an electronic copy of this filing on each party on the service list prepared by the Secretary of the Commission in Docket No. ER03-647-009.

Respectfully submitted,



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Counsel for
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New York Independent System Operator, Inc.
Report on Implementation of, and Withholding under, the New York Installed Capacity Demand Curves

July 17, 2007

I. Executive Summary

The New York Independent System Operator ("NYISO") implemented the Installed Capacity ("ICAP") Demand Curves during the 2003 Summer Capability Period.[1] The NYISO believes that the ICAP Demand Curves, which are applied in the ICAP Spot Market Auctions, are beneficial because they provide price stability and predictability, reduce incentives to withhold capacity, and should provide appropriate price signals to generation developers.

The capacity committed to the New York markets has trended upwards for the NYCA and for the New York City and Long Island localities since the inception of the Demand Curves. This upward trend can be attributed to a variety of factors such as growth of loads and requirements, annual adjustments of the Demand Curves, new in-state capacity, and steady imports from other control areas.

Similar to previous reports, capacity prices in 2006 and the first half of 2007 continue to remain stable on a statewide basis. New York City and Long Island prices remain stable, due also partly to the effects of price caps in New York City and the largely bilateral nature of the Long Island market. For this reporting period, there was no significant increase or decrease in the proportion of load-serving entity ("LSE") capacity requirements being met from purchases in the NYISO-administered capacity markets versus other sources, such as bilateral contracts, when compared to previous years.

The performance of the ICAP markets does not raise concerns about significant physical or economic withholding in the overall New York Control Area ("NYCA") market or on Long Island. In New York City, the NYISO has observed certain bidding behavior that has kept prices at the Commission-approved cap for certain owners of generation divested from Consolidated Edison before the NYISO was formed. Overall, the clearing prices resulting from the ICAP Demand Curves in the ICAP Spot Market Auctions support the conclusion that the ICAP Spot Market Auctions continue to be attractive to capacity suppliers and provide a venue for them to

[1] Unless otherwise specified, capitalized terms used in this report have the meanings specified in the NYISO's Market Administration and Control Area Services Tariff.

offer previously unsold capacity resources for the month. In the overall NYCA market, the quantity of unsold capacity does not exceed a few percent of available supplies. In addition, capacity offered and purchased throughout the state has consistently exceeded the minimum capacity requirements, and prices have been below the costs of entry reflected on the ICAP Demand Curves. Thus, the performance of the market does not raise concerns about withholding in the overall NYCA or Long Island markets. The observed bidding behavior in New York City is consistent with expectations under the Commission-approved mitigation measures.

It is difficult to reach any definite conclusions regarding the effects of the ICAP Demand Curves on investment in new generation in New York mainly because, over the past several years, New York has had capacity available in excess of the minimum requirements to maintain reliability. On the other hand, the behavior of key market variables suggests that the system is geared to providing the signals necessary to provide appropriate incentives to new investment. The NYISO's Reliability Needs Assessment ("RNA") process has identified future capacity needs and the NYISO has solicited and received market-based proposals to address those needs. The NYISO understands that developers will look to anticipated future revenues when making investment decisions in the near term. Those revenues will be influenced, in part, on updating the ICAP Demand Curves, which is currently underway in the stakeholder process and will be filed with the Commission in November, 2007.

The NYISO continues to believe that the ICAP Demand Curves remain sound in principle and are structured to provide a positive incentive to the development of new capacity when it is needed, particularly when compared to the *de facto* vertical demand curve in place prior to the summer of 2003. Although there will always be debate about the specific parameters of the ICAP Demand Curves, *i.e.* the slope and the height, in the ICAP Demand Curve update process, there can be little doubt that the resulting incentives are positive when viewed against a vertical demand curve. The ICAP Demand Curves by their very design (i) ameliorate the unstable prices resulting from the prior *de facto* vertical demand curve, (ii) provide market-driven compensation for capacity above minimum capacity requirement, and (iii) reduce incentives for withholding.

II. Implementation of the ICAP Demand Curves

A. Recent Installed Capacity Auction Results and Capacity Purchases

This section discusses trends in the amount of capacity purchased in recent auctions and, in particular, the level of capacity purchased relative to the applicable minimum requirement.

Similar to past reports, this filing compares successive Summer Capability Periods, from year to year. Generally, the amount of capacity continues to keep pace with or exceeds the increasing capacity requirements in the NYCA, New York City and on Long Island.

Committed capacity has increased on a statewide basis, as well as in the New York City and Long Island Localities. When compared with the minimum capacity requirements, the average percent excess capacity sold on a statewide basis increased from 5.5% in the 2003 Summer Capability Period to 9.6% in the 2004 and 2005 Summer Capability Periods and to 10.3% in the 2006 Summer Capability Period. This fact still indicates that the actual capacity sold kept pace with the increased load and installed capacity requirements. The Winter Capability Periods showed similar excess capacity sold ranging from 8.4% in the 2003/2004 Winter Capability Period 8.9 % the 2006/2007 with greater excesses in the intervening Winter Capability Periods.

In general, the Dependable Maximum Net Capability ("DMNC") available from many generators in New York increases in the winter because of the lower ambient temperatures. Capacity offers from external control areas can also vary seasonally. It should also be noted that the NYCA Demand Curve price declines to zero when supply exceeds the minimum capacity requirement in the NYCA by 12% or more in any case.

As previously mentioned, the amount of capacity committed to the NYCA continues to increase. The NYISO also noted in its prior report that imports of external capacity increased from 1,650 MW for the 2002 Summer Capability Period to the 2,755 MW level for the 2003 Summer Capability Period, which is the NYCA maximum level allowed for capacity imports. This level of import capacity continued for the 2004, 2005 and 2006 Summer Capability Periods. So far in the 2007 Summer Capability Period, imports are around the 2,500 MW level while exports have increased to approximately 600 MW. The Winter Capability Period import levels were somewhat lower than summer levels, subject primarily to market conditions in neighboring control areas. Nevertheless, the total capacity committed to the NYCA continues to be well in excess of the minimum requirements.

Market clearing prices and auction activity levels from November 1999 through July 2007 for the NYCA, New York City and Long Island are shown in tabular form in Appendix A. Also, market clearing prices are depicted in graphic form in Figures 1, 2, and 3 and capacity commitment levels are depicted in Figures 4, 5 and 6, below.

Figure 1

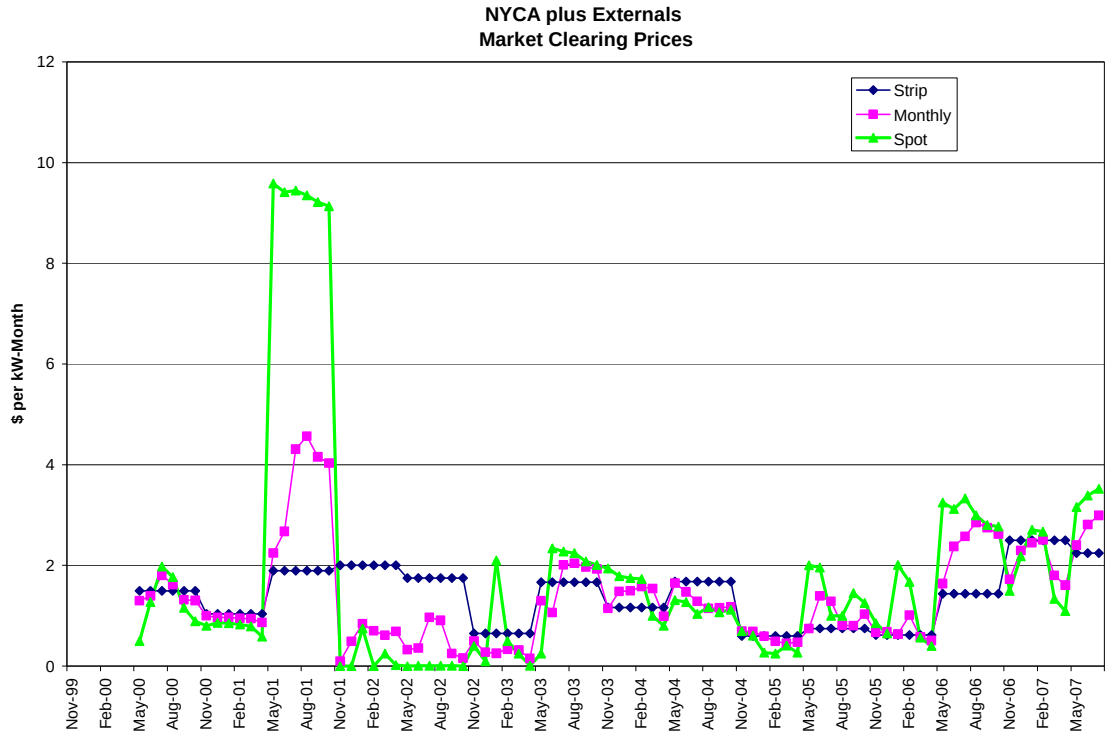


Figure 2

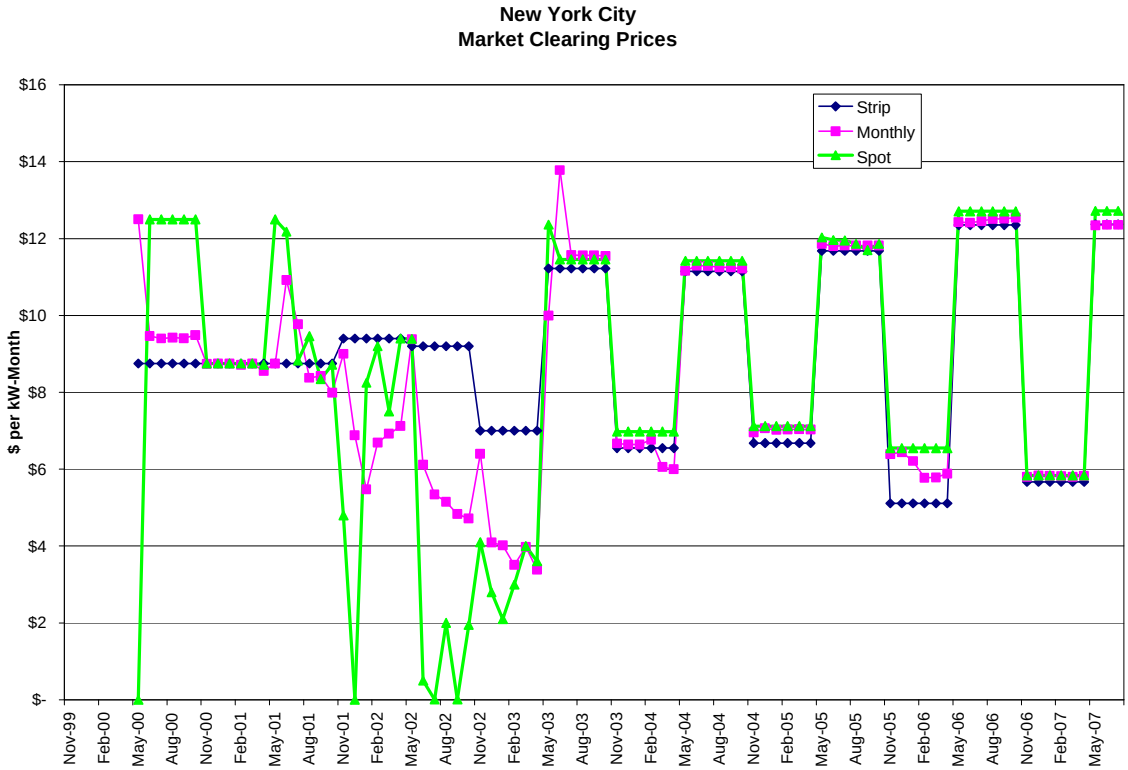


Figure 3

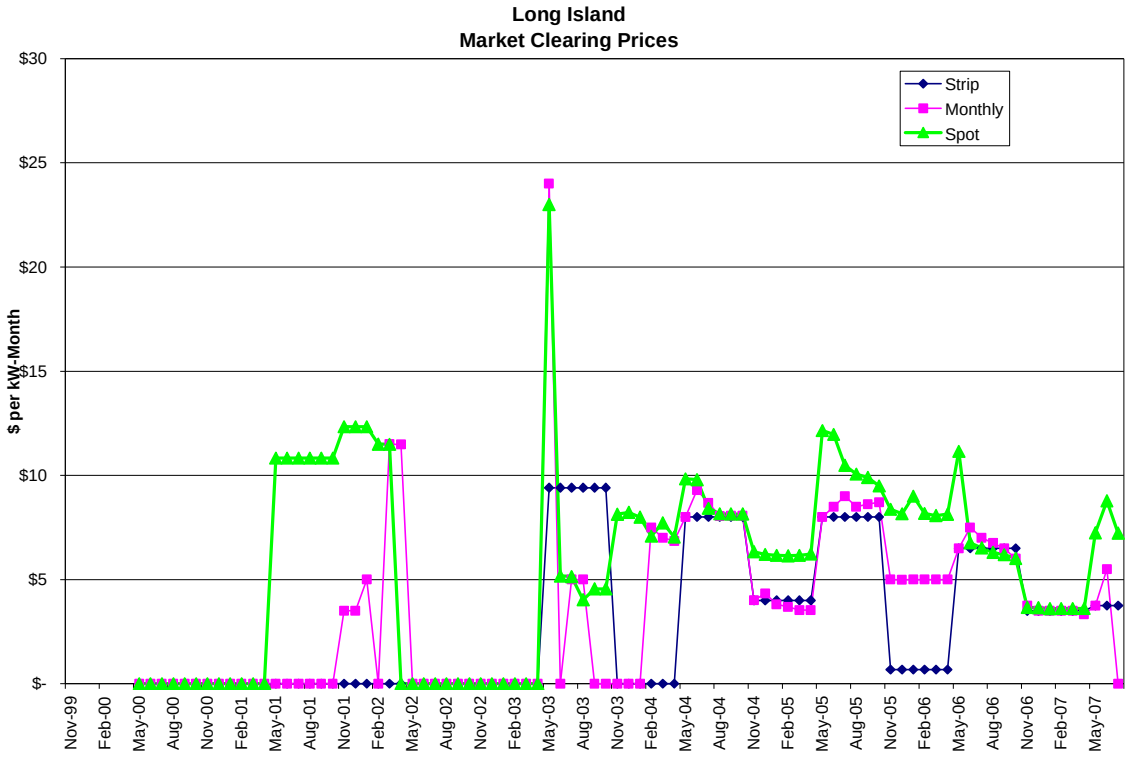


Figure 4

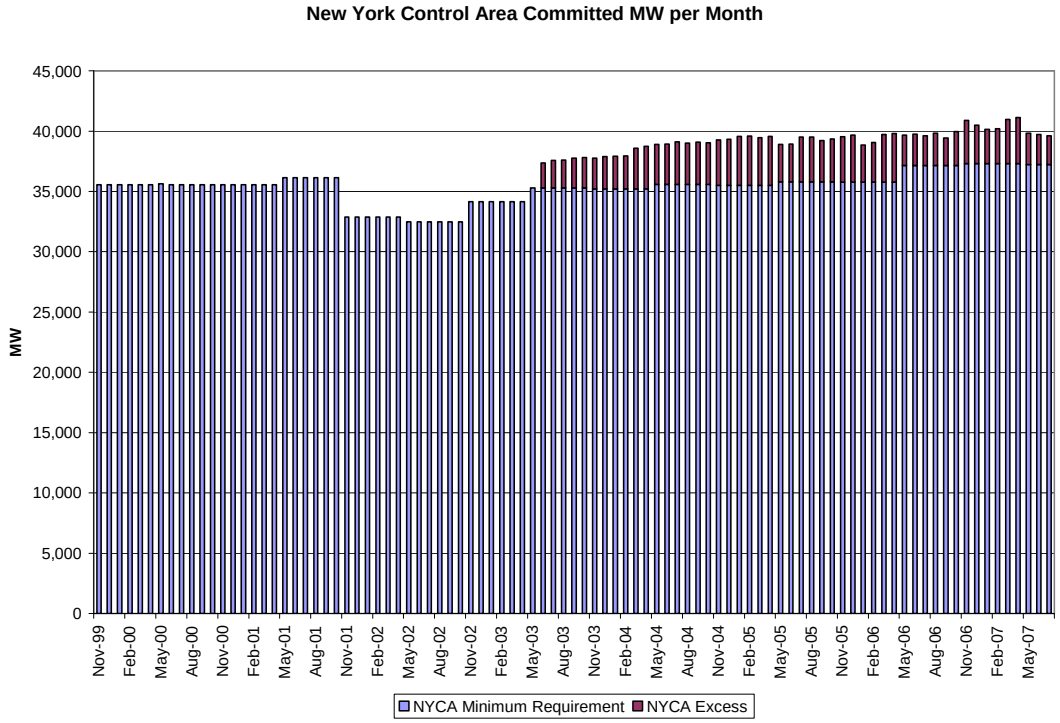


Figure 5

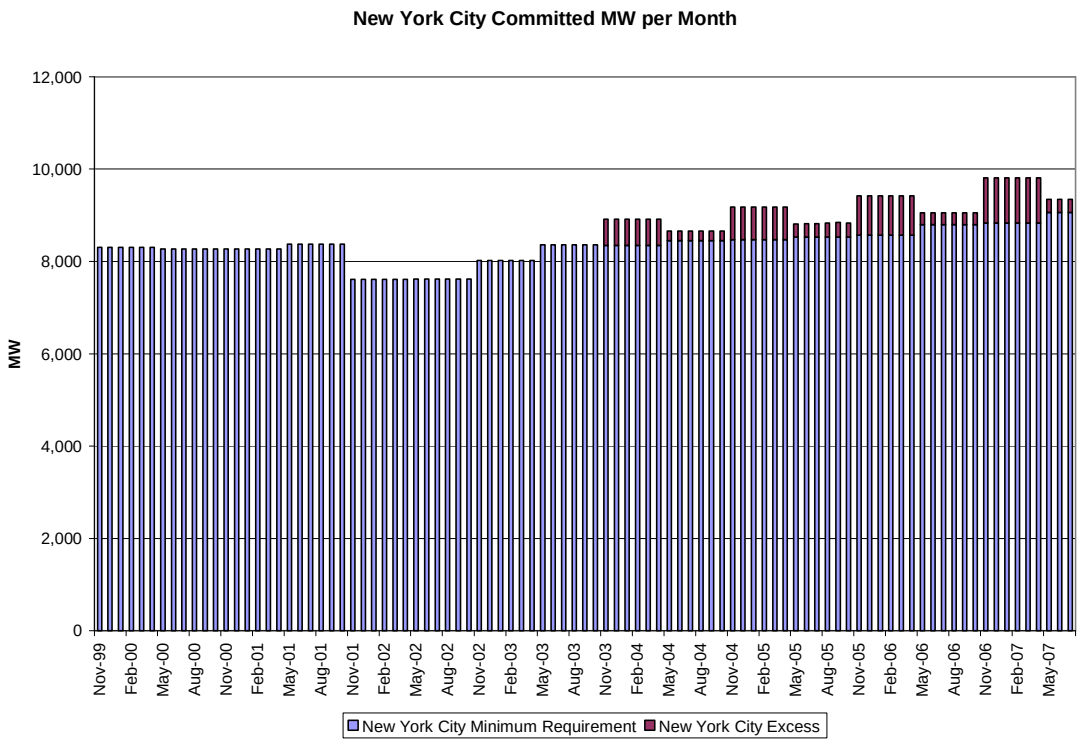
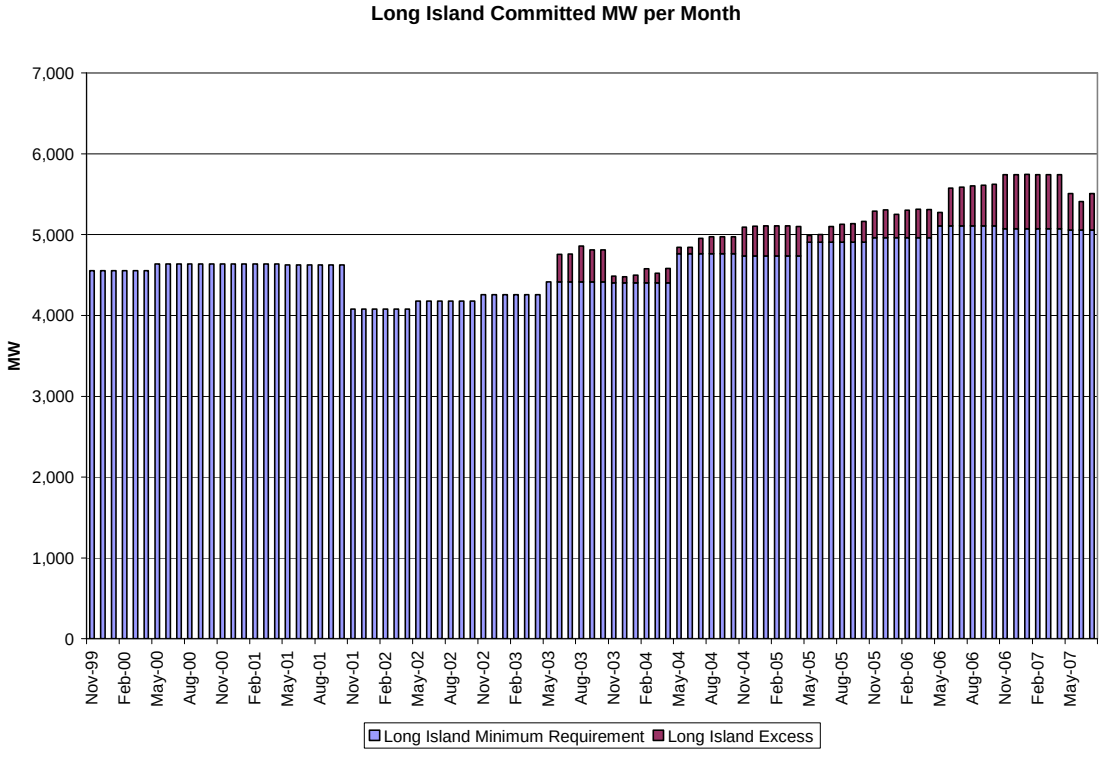


Figure 6



B. Effect of Sloped Demand Curve on Price Stability and Withholding

This section of the report evaluates how the implementation of the sloped ICAP Demand Curves has affected the stability of prices in the New York capacity markets. The first part of this section discusses how the shape of the Demand Curve affects the determination of clearing prices and how this impacts suppliers' incentives. Then this section analyzes market outcomes before and after the implementation of the sloped ICAP Demand Curves to determine its effect on the competitiveness and stability of clearing prices.

Use of the sloped ICAP Demand Curves has contributed to the stability and predictability of capacity prices in New York. Prior to the introduction of the sloped ICAP Demand Curves, the NYISO-operated markets were used to satisfy a fixed capacity requirement. Operating the market with a fixed requirement subject to a price cap is equivalent to having a vertical demand curve at the requirement level extending up to the price cap. With this type of curve in place, the amount of capacity purchased is the same without regard to price, which (as explained below) may lead prices to fluctuate even when supply and demand are constant.

These *de facto* vertical demand curves were replaced with the sloped ICAP Demand Curves in June 2003. The sloped ICAP Demand Curves induce a direct relationship between prices and the capacity margins in New York. To the extent that capacity prices vary under the same ICAP Demand Curve in the ICAP Spot Market Auctions, it is a result of changes in supply offers.

1. Use of Sloped Versus Vertical Demand Curves

Prior to the implementation of the sloped ICAP Demand Curves, the New York capacity market was cleared using a *de facto* vertical demand curve. Under the vertical demand curve, load serving entities procured enough capacity in the auction to meet the minimum requirements, which at the time were set at 118 percent of forecast peak load for the NYCA and 80 percent of peak forecasted load in New York City and 99 percent for Long Island. When available supply was insufficient to meet the requirement, the clearing price in the auction was set at a deficiency price. Otherwise, the highest-priced offer accepted in the auction set the clearing price. Under these circumstances, a small reduction in supply or rise in demand can lead to a dramatic shift in clearing prices.

When a vertical demand curve is used to clear a capacity market that has a small reserve margin, suppliers have strong incentives to withhold. The gain from withholding (*i.e.*, the benefit of a higher clearing price) is likely to outweigh the cost of withholding (*i.e.*, lost sales at a

lower clearing price (or a zero price)). These incentives may lead some suppliers to experiment with offering at higher prices, which leads to higher and more erratic market clearing prices.[2]

The essential difference between sloped demand curves and vertical demand curves is that the former recognize that capacity above the minimum requirement has value, albeit diminishing as the quantity offered increases. Such additional installed capacity improves reliability, increases the potential supply in the energy and ancillary services markets, and potentially reduces the incidence of real-time energy shortage prices.

In an auction with a sloped demand curve, the clearing price depends on the amount of capacity that clears the market. The higher the amount that clears, the lower the clearing price and, conversely, a higher price is associated with a lower quantity. The clearing price can be non-zero even if all supply is offered at $0 because the clearing price in that case would be set by the sloped demand curve rather than the marginal supply offer. Conversely, in a market with a vertical demand curve, if all supply is offered at $0 and the requirement is met, then the clearing price will drop to $0. Thus, a sloped demand curve produces more stable and predictable capacity prices than a vertical demand curve because the entry of a small amount of additional supply does not cause the market clearing price to drop precipitously.

Sloped demand curves also promote stable and more predictable prices to the extent that they mitigate strategic withholding. A sloped demand curve causes the clearing price to rise much more slowly when capacity is withheld, which reduces or eliminates the incentive to withhold.

2. Stability of Spot Auction Prices

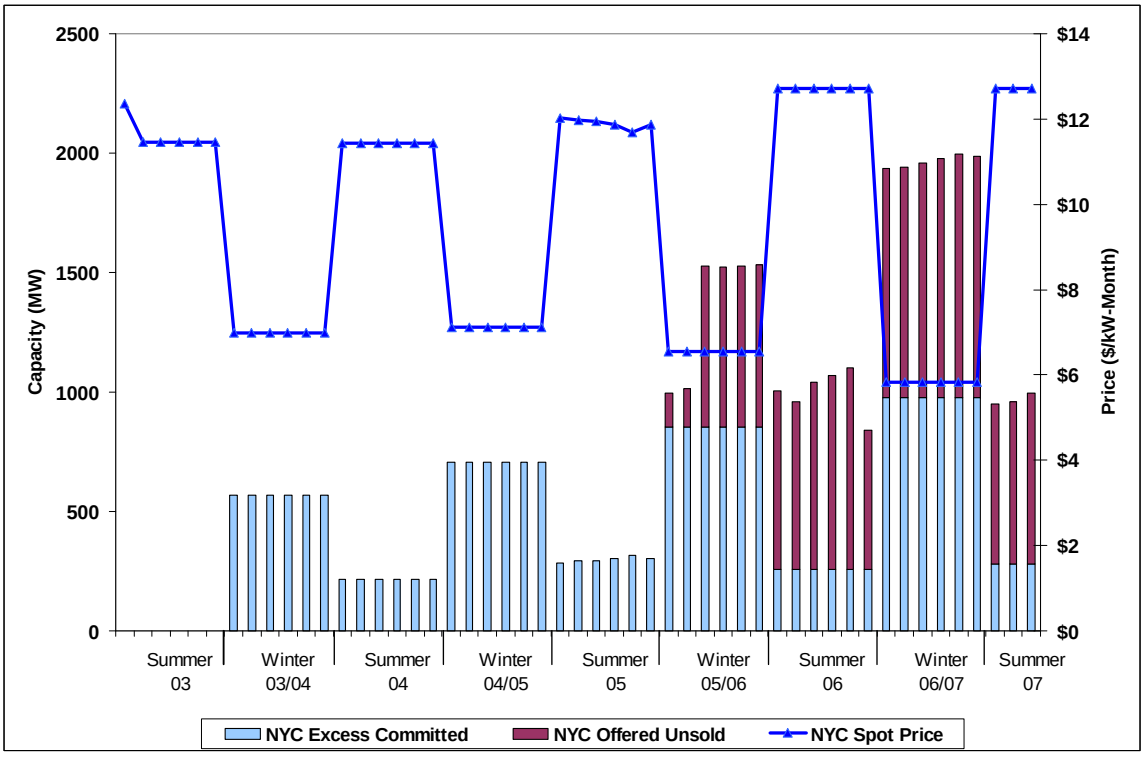
Generally, in any well-functioning market, price fluctuations should reflect changes in supply and demand. Consistent with this paradigm, in the ICAP Spot Market Auction, prices respond principally to changes in load, capacity requirements, and additions and retirements of generating capacity. The following analysis compares capacity prices in the spot auctions to the quantity of "Excess Capacity" in the market. For purposes of this analysis, Excess Capacity includes capacity sold in excess of the minimum capacity requirement plus offered capacity that was unsold.

[2] In New York City, stable capacity prices were sustained for a long period during which time both sloped and vertical demand curves were used to clear the auction.

Because of the relationship between the market clearing quantity and price, as described above, variation in clearing prices should be inversely related to changes in Excess Capacity. When Excess Capacity is close to zero, which means that supply is close to the minimum level necessary to maintain reliability, prices should be higher under the ICAP Demand Curve, to provide incentives to new investment. As Excess Capacity increases substantially, clearing prices should decline accordingly.

The first of the following two figures summarizes Excess Capacity and clearing prices in the spot auction for New York City from May 2003 to July 2007.[3] The second figure provides a summary of Excess Capacity and clearing prices under the NYCA demand curve. Excess Capacity is expressed in UCAP rather than ICAP terms.[4]

Figure 10.
Excess Capacity and Spot Prices in New York City
May 2003 to July 2007



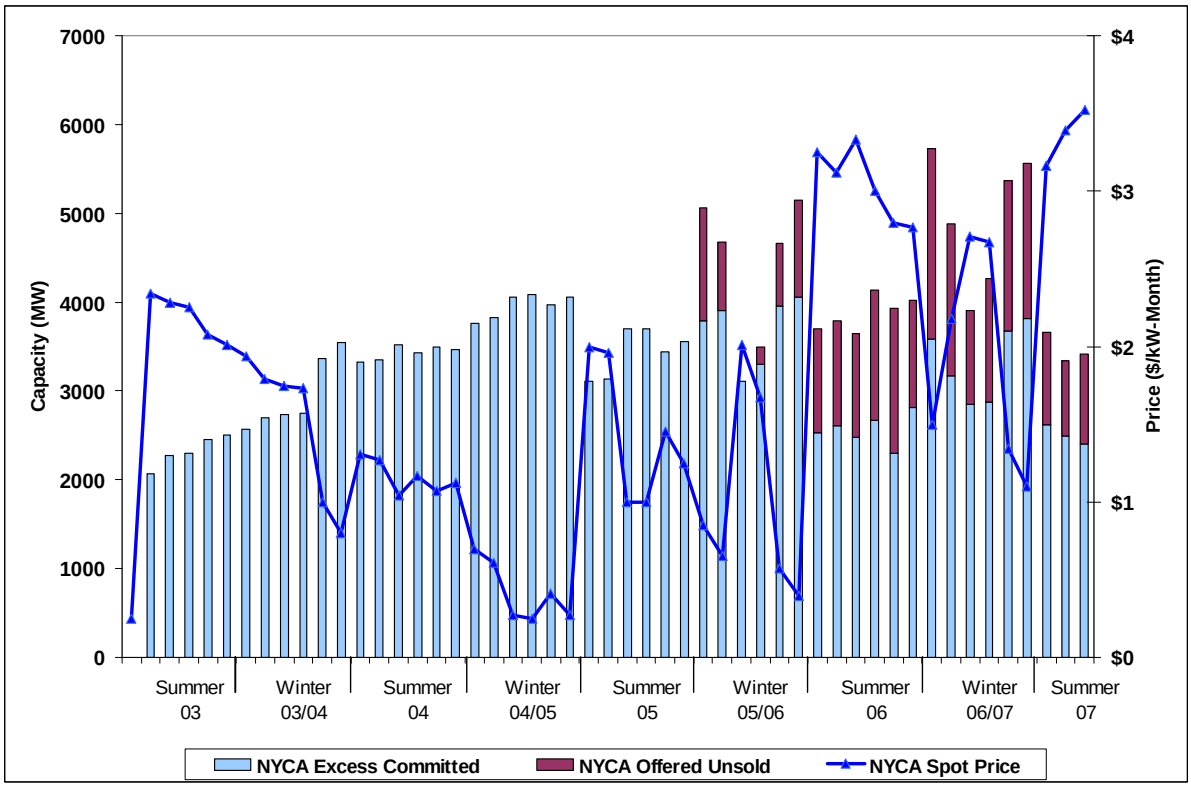
[3] Due to data limitations, the Offered Unsold figures are available only for the last 4 capability periods, i.e. from Nov. 2005 to Jul. 2007.

[4] A unit's Installed Capacity is reduced by an outage factor (*i.e.*, its Equivalent Forced Outage Rate on Demand, or EFORd) to determine its Unforced Capacity (UCAP) rating.

In New York City, during the summer capability periods prior to 2006, the volume of Excess Capacity was low, generally ranging between 0 MW and 300 MW. As shown in Figure 2 above, prior to the introduction of the sloped ICAP Demand Curve in June 2003, spot prices fluctuated substantially. After the introduction of the Sloped Demand Curve through the end of 2005, spot prices and Excess Capacity levels in New York City were relatively stable and continued to remain so after the addition of 500 MW in January 2006. In the summer of 2006, spot prices maintained their established pattern even with the addition of approximately 500 MW of ICAP. During the succeeding winter capability period, the price pattern was similar.

The chart below shows the relationship between Excess Capacity and spot prices in NYCA.

Figure 11.
NYCA Excess Capacity and Spot Prices
May 2003 to July 2007



For the NYCA, spot price fluctuations appear to be inversely related with changes in the volume of Excess Capacity after the implementation of the sloped ICAP Demand Curve for several years. For example, during the summer capability periods, spot prices declined when Excess Capacity increased from 2003 to 2004 and then again in the middle of 2005. Similarly, winter capability periods also exhibit a negative relationship between spot prices and Excess

Capacity after the implementation of the sloped ICAP Demand Curve. (However, when the *de facto* vertical demand curve was used, there were considerable fluctuations in spot prices that did not correspond to changes in Excess Capacity.)

The analysis in this section, together with the evidence shown in Figure 4, indicates that price stability improved considerably after the implementation of the sloped ICAP Demand Curves in 2003. To the extent that prices have varied since May 2003, they have generally been negatively correlated with the levels of Excess Capacity. In early 2006, however, there was an increase in Excess Capacity in New York City that was not accompanied by a decrease in clearing prices. This is discussed in greater detail below.

3. Analysis of Capability Period and Monthly Auction Prices

Prior to the spot auction for each month, the NYISO conducts Capability Period Auctions, which cover every month for either the summer or winter period, and Monthly Auctions, which cover the remaining months within a Capability Period. In these auctions, all sales and purchases are voluntary, which means that the demand is not represented by the ICAP Demand Curves as it is in the spot market. Rather, these markets only clear if bids to buy and offers to sell are in "equilibrium."[5] The prices in these auctions should largely be driven by market participants' expectations of future spot prices.

Absent significant changes in supply or demand, prices in these voluntary auctions are relatively stable because market participants know that they can wait for the spot auction. The New York Public Service Commission requires advance notice of generation unit retirements,[6] and market participants are able to apply this information to their purchases and sales well ahead of time. When a large installation is anticipated at a specific point in time, prices may decline in the Capability Period and Monthly Auctions in anticipation of a decline in spot prices.

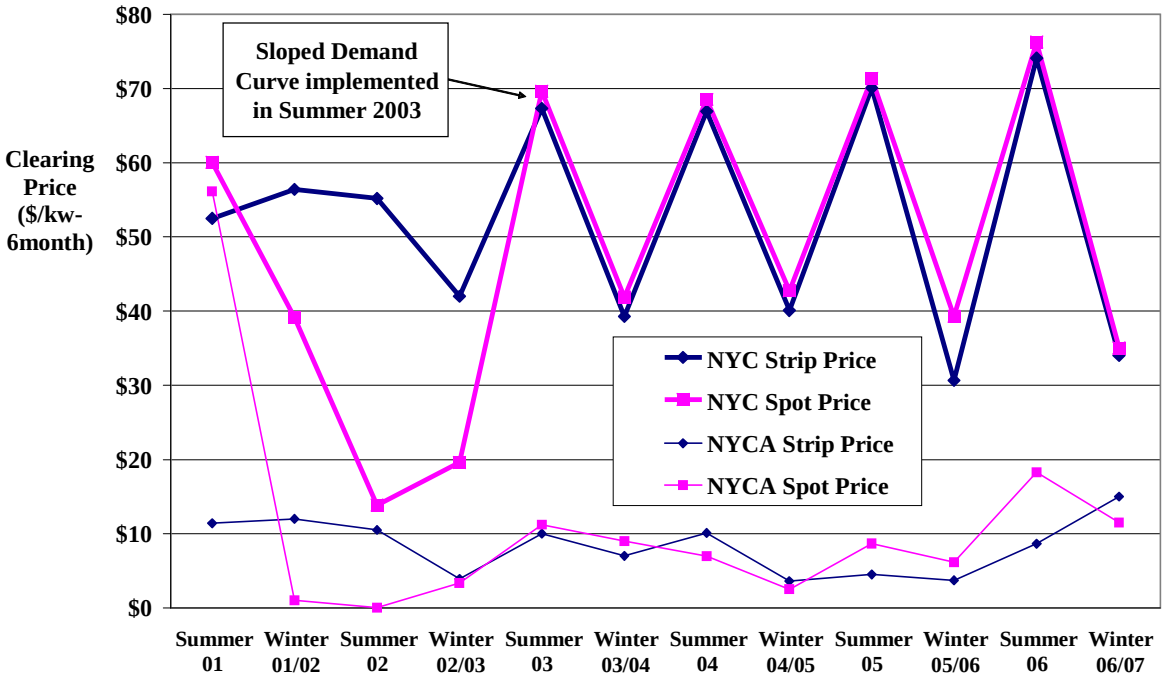
Convergence between Capability Period Auction prices and ICAP Spot Market Auction prices is a sign that market participants are able to predict spot price changes that result from changes in market fundamentals. Thus, good convergence between Capability Period Auction prices and ICAP Spot Market Auction prices are an indication of overall efficiency of market

[5] Market Administration and Control Area Services Tariff, § 2.102b.

[6] *Proceeding on Motion of the Commission to Establish Policies and Procedures Regarding Generation Unit Retirements*, Order Adopting Notice Requirements for Generation Unit Retirements, Case 05-E-0889 (Dec. 20, 2005) (requiring a 180-day notice of retirement for generators 80 MW or greater and a 90-day notice for generators under 80 MW).

processes. The following figure summarizes how Capability Period Auction prices have converged with spot prices in New York City and the NYCA in each capability period from May 2001 to April 2007.

Figure 12.
Clearing Prices from Capability Period ("Strip") Auctions
and ICAP Spot Market Auctions
May 2001 to April 2007



The figure shows that convergence between the Capability Period Auction price and spot prices improved considerably after the implementation of the sloped ICAP Demand Curves in the spot auction early in the summer of 2003. From the summer of 2001 through the winter of 2002/03, the average difference between the Capability Period Auction price and the sum of the spot prices was about $22/kw-6-month in New York City and $17/kw-6-month in the NYCA. From the summer of 2003 through the summer of 2006, when the sloped ICAP Demand Curves were in effect, the average difference between the Capability Period Auction price and the sum of the spot prices declined to about $3/kw-6-month in New York City and the NYCA.

This analysis supports the conclusion that price stability improved considerably after the implementation of the sloped ICAP Demand Curves. To the extent that prices have varied since

this time, it has generally been anticipated in the Capability Period Auction, which is consistent with the expectations of an efficient market with adequate price signals. Convergence between the Capability Period Auction prices and the spot auction prices improved dramatically after the implementation of the sloped ICAP Demand Curves.

C. Potential Withholding in the Capacity Market

In its prior report to the Commission on withholding in capacity markets, the NYISO indicated that it had not observed any significant economic or physical withholding in the period between May 2003 – when the ICAP Demand Curves were implemented – and October 2005. This report extends the same analysis through July 2007. Since the objective is to examine the issue of economic withholding in the context of the ICAP Demand Curves, an attempt is made to focus on market outcomes and related behavior since their implementation.

In order to determine whether any significant economic withholding occurred, the NYISO analyzed the differences between available supply and the supply committed through self-supply, bilateral transactions or through NYISO administered auctions, and in particular has examined:

- qualified available capacity not sold, and
- unsold capacity as a percentage of available capacity.

Examining the MWs of capacity offered but not sold – as distinct from MWs not offered at all – provides a threshold measure of whether economic withholding may have occurred. Certain New York City units are subject to price mitigation and have a requirement to offer. On Long Island, a 99% locational requirement coupled with the rights to virtually all of the existing capacity on the Island having been secured by contract results in an implied offering requirement.

The existence of unsold capacity by itself does not necessarily imply economic or physical withholding that is motivated by strategic market behavior with the purpose and effect of raising market prices. It is important to also consider extraneous market factors including decisions that pre-date the demand curves and the costs of and the increasingly variable flows of capacity between control areas. If the amounts of unsold capacity are found to be relatively insignificant, then no further detailed analysis is likely warranted because, for there to be concern, there must be a significant price impact.

Since the last report, patterns of relative quantities of unsold capacity have varied across the NYCA and the New York City and Long Island localities. Long Island is distinct in that, with one exception, it experienced little to no unsold capacity during the past two years.[7] Furthermore, the rise in the relative amount of unsold capacity in New York City coincides with the addition of 1,000 MW of new capacity. For the NYCA as a whole, both the developments in New York City and the growing variability of imports contributed to the observed fluctuations in unsold capacity when measured as a percentage of available capacity.[8]

There are three types of auctions in each Capability Period: a six-month "strip" auction, six sets of Monthly Auctions, and six Spot Market Auctions. Capacity may be offered into any or all of the auctions. The NYCA's ICAP requirements are settled in three categories: one each for the New York City and the Long Island Localities and one for the NYCA as a whole. Local reliability rules require LSEs in New York City and on Long Island to procure minimum percentages of capacity from facilities that are electrically located within their respective zones. Such capacity is also credited toward each New York City and Long Island LSE's NYCA obligation. The NYISO establishes locational ICAP requirements on an annual basis according to NYISO Procedures.

Under NYISO ICAP market rules, with the exception of the New York City Locality, the tariff does not require capacity suppliers to offer into the ICAP markets. In the New York City load zone, the majority of capacity — owners of capacity divested from Consolidated Edison — is subject to Commission-approved ICAP market mitigation measures that specifically require such capacity to be offered into the ICAP auctions to the extent that it has not been sold in a previous auction. A subset of New York City generation, for example capacity resources constructed subsequent to the Commission's approval of current tariff market mitigation provisions, is not subject to the mandate to offer into the auctions. Other capacity inside and

[7] In May 2006, the Long Island Power Authority failed to offer some Long Island capacity into the ICAP Spot Market Auction and, as a result, it was not sold. *See generally*, FERC Docket No. EL07-16-000.

[8] Capacity imported from neighboring control areas are subject to an overall limit that is currently at 2,755 MW of ICAP that translates into approximately 2700 MW of UCAP. Accordingly, there is also capacity located within NYCA that is exported to other control areas. While the levels of both imports and exports of capacity can exhibit variability and also possess the ability to influence auction prices, it is appropriate to disregard them for purposes of studying economic withholding because both flows are heavily dependent not on the demand curve but other factors like the rules governing external flows both in the NYCA and other control areas and relative prices.

outside the NYCA may be sold bilaterally, or may be offered into one or more of the NYISO's ICAP auctions.

In developing the information for this report, the NYISO examined the average values from auction data for the following Capability Periods:

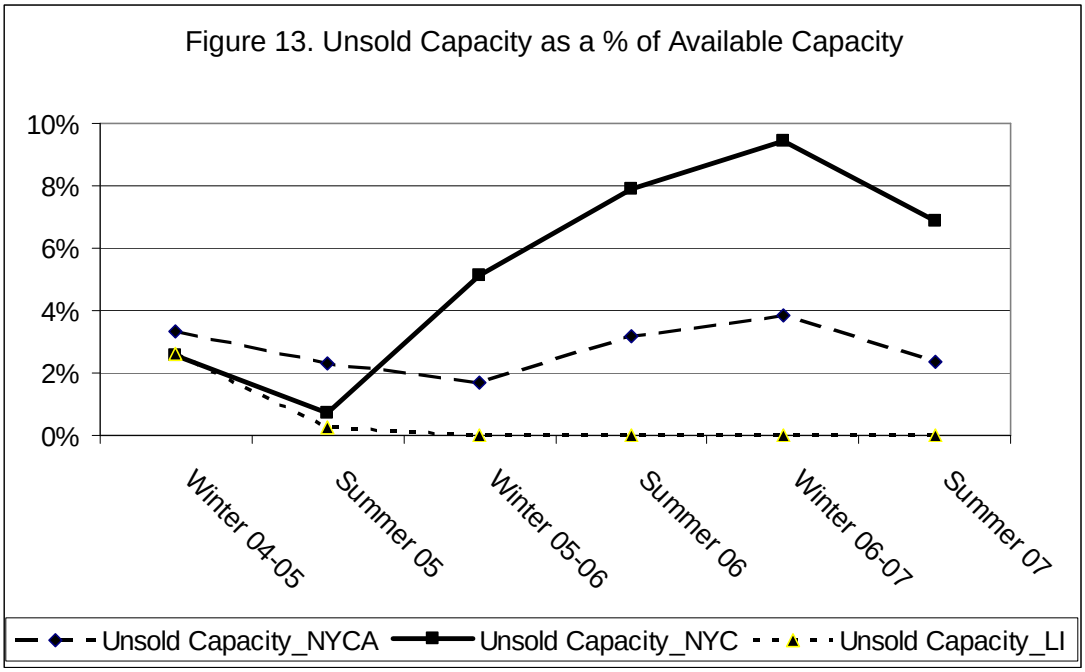
- Winter 2004-2005 (November 1, 2004 through April 30, 2005)
- Summer 2005 (May 1, 2005 through October 31, 2005)
- Winter 2005-2006 (November 1, 2005 through April 30, 2006)
- Summer 2006 (May 1, 2006 through October 31, 2006)
- Winter 2006-2007 (November 1, 2006 through April 30, 2007)
- Summer 2007 (May 1, 2007 through July 31, 2007)[9]

Since the product transacted in NYISO-administered ICAP auctions is Unforced Capacity, or UCAP, the following information was examined:

1. Certification data, reflecting the certified MW of Unforced Capacity (UCAP) available from all Resources seeking to supply capacity to the NYCA. Included were resources from within the NYCA, including the New York City and Long Island Localities and from PJM, ISO-NE, Hydro-Quebec;
2. The amount of UCAP supplied (sold, self-supplied or committed through bilaterals) in all categories; and
3. ICAP Import Rights as posted on the NYISO website.

The following chart displays the percentage of available capacity that was unsold for each of the four categories of capacity – i.e. NYCA, the New York City and Long Island Localities, and imports from external control areas. (See Appendix B for the data).

[9] Note that as of this report's date, only the data for May, June, and July 2007 was available. Accordingly, the average figures reported are the averages over the three months.



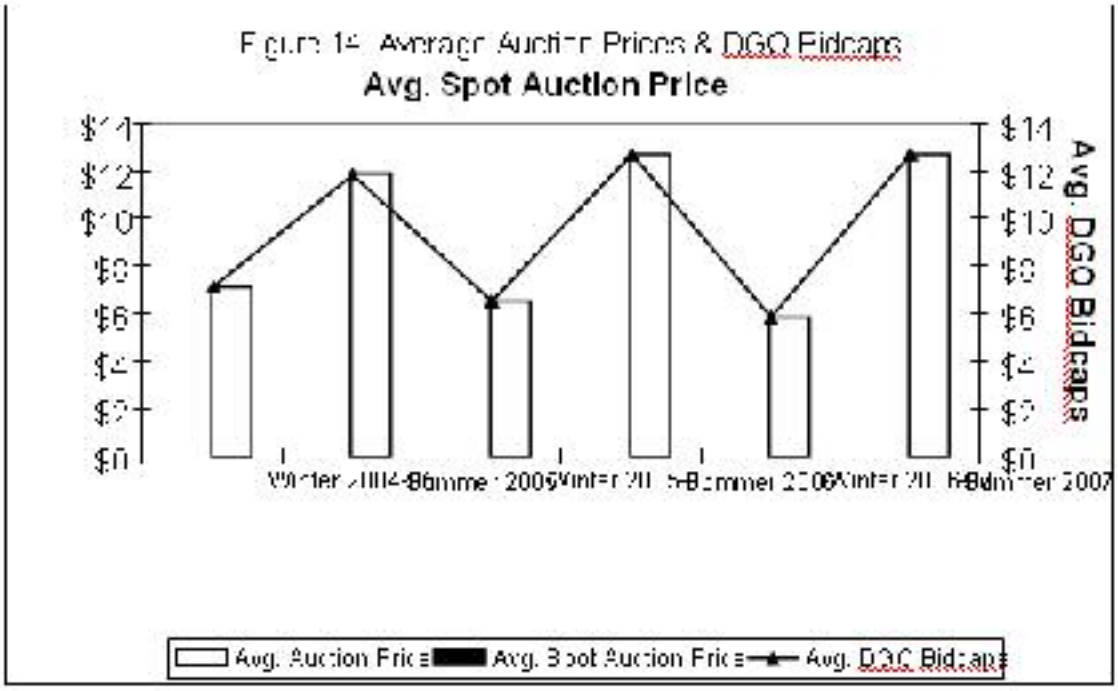
Clearly, there has been an absence of Long Island capacity that was offered but went unsold in the last several Capability Periods. In Summer Capability Periods, when available capacity is at a minimum, almost every resource in Rest of State is offered into the ICAP auctions and sold. The NYISO has examined the MWs of Rest of State capacity offered and sold under the NYCA demand curve, and the levels of unsold capacity were generally a small percentage of the total.[10]

Since the last report, there has been a rise in the quantity of New York City capacity that was offered but unsold. Despite the annual adjustments in the demand curve (to account for the effects of inflation on the cost of new entry) and load growth between 2005 and 2006, there was a rise in the average percentage of New York City capacity that did not clear the spot auctions. As mentioned above, this can be attributed to the introduction of 1,000 MW of new generation capacity in New York City and the offering behavior of market participants. Interestingly, there was a decline in the relative amount of unsold capacity during the first three months of the Summer 2007 capability period. This suggests that the amount of unsold capacity may fall if no new generation is added and load growth increases the minimum capacity requirement. .

As mentioned above, in the New York City zone, the majority of capacity is subject to Commission-approved ICAP market mitigation measures that include bid caps that are specific to each of the divested generation owners ("DGOs") as determined by their respective Summer-

[10] Note that despite a reduction in the required reserve margin from 118% to 116.5% beginning May 2007, there was a reduction in the percentage of unsold capacity.

to-Winter DMNC ratios. Figure 14 demonstrates that, as predicted by the Commission in its 1998 order accepting currently effective market power mitigation measures, the market continues to clear at the DGO caps.[11]



By continually offering their capacity at the prescribed bid-caps, the DGO can ensure that prices for New York City capacity remain at a level that reflects the cap of $105/kW-year under the current supply conditions. Given their pivotal market shares, the DGOs may have an incentive to keep prices at their respective caps by offering at that level. The DGO offering behavior appears to be consistent with the Commission's expectation expressed in its 1998 order and is within the currently effective mitigation rules. The existence of unsold New York City capacity at this time appears to be a byproduct of the level of supply, the currently effective mitigation measures, and the offering behavior of market participants.

III. New Generation Projects and Net Revenue Analysis

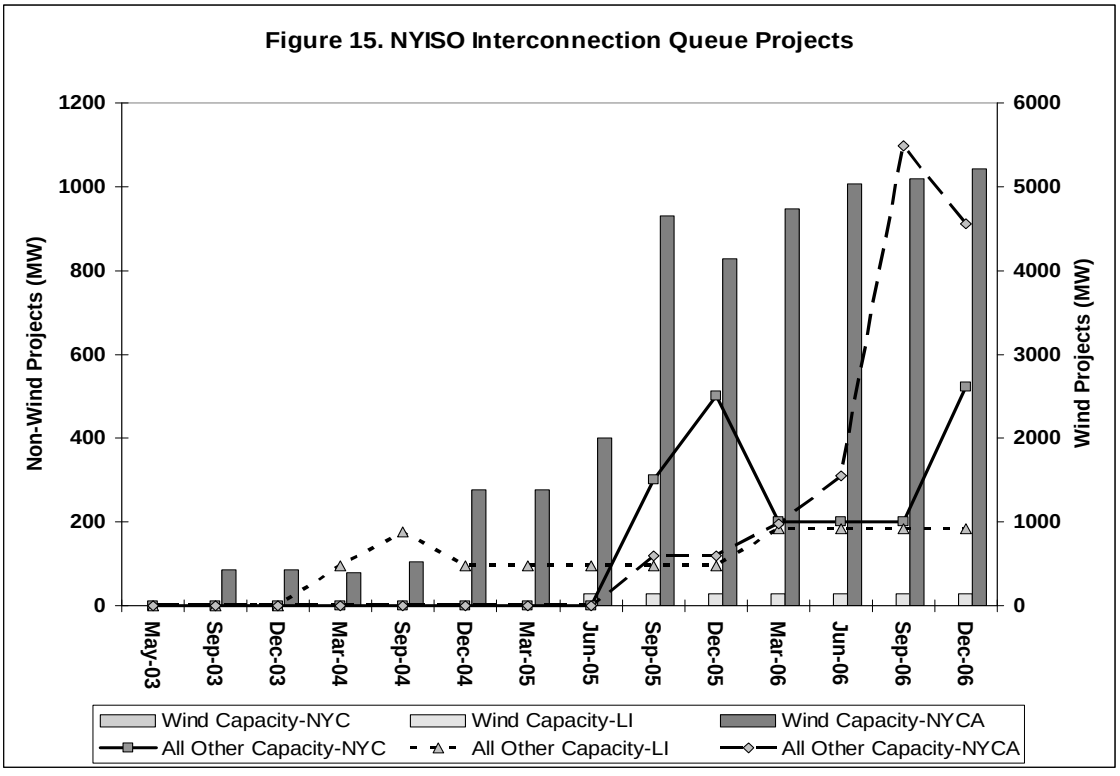
[11] *Consolidated Edison of New York, Inc.*, 84 FERC ¶ 61,287, fn. 17 (1998) ("Given the circumstances present here, existing suppliers are likely to bid the price cap and set the market clearing price at that level even as new generation is added and supply increases. This is because, until the supply increases sufficiently to supplant substantial amounts of existing capacity, the existing suppliers will be assured that at least some of their capacity will be selected at any price and so they have an incentive to bid the price cap to maximize revenues on those sales.").

1. New Generation Projects

The NYISO anticipated that the ICAP Demand Curves would increase the incentives to build new generation when it is needed. In past reports, the NYISO stated that it is difficult to relate the development of new generation to the ICAP Demand Curves given the lead time required to site, develop, and construct new generation, and the other barriers to new entry. To an extent, that is still true today. For example, the last two significant generation additions in New York City occurred in 2006, but both of those projects appeared on the interconnection queue before the ICAP Demand Curves were in effect. In the next few years, new generation projects should be built that were planned and constructed since the NYISO implemented the ICAP Demand Curves. The projects currently in the study processes are listed on the NYISO's interconnection queue.

The graph below depicts the amount of generation listed on the NYISO's interconnection queue since 2003 by zone except for wind projects, which are shown separately. Generally, the amount of generation in the interconnection process has increased since the ICAP Demand Curves became effective in June, 2003.

Figure 15. NYISO Interconnection Queue Projects



This analysis is based on periodically updated versions of the NYISO Interconnection Queue dating from May 2003 through December 2006.[12] For purposes of this analysis, only the projects that entered the queue after May 1, 2003 were considered. Since the queue includes projects at various stages, for purposes of this study it is reasonable to include only projects that are deemed active. Accordingly, for the pre-2005 period projects with codes "I", "W", or "C" were excluded; for the 2005-2006 period, status code 0, 1, 12, 13, and 14 were omitted.

The number of megawatts associated with projects based on technologies other than wind (measured on the left Y-axis, above) did not increase significantly until the summer of 2005. In all three localities, there are proposals that have remained in the queue for several years. One or two relatively large projects can have a large impact on the graph above when projects are added to the queue, and possibly withdrawn.[13] The graph above shows that New York City and the NYCA had no activity in the non-wind category until the middle of 2005, but subsequent to that both localities saw the introduction of multiple projects – most of which continue to remain in the queue.

The overwhelming portion of the wind projects – shown on the right Y-axis – are Rest of State capacity. Starting in mid-2005 there was a dramatic increase in the number of MWs associated with wind generation. Although this increase in wind generation projects may have been caused by a combination of factors, including certain legislative/policy measures and tax-related provisions, the NYISO anticipates that these projects, if constructed, will likely participate in the ICAP markets and become ICAP Suppliers.

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[12] Each project that is placed in the queue is awarded a status code that identifies its relative position in the progression that ranges from nomination to being in service. Prior to 2005, each project was awarded a status-code based on the NYISO System Reliability Impact Study from the following: *P=Pending, A=Active, I=Inactive, R=Under Review, C=Completed, W=Withdrawn.* 2005 onwards, the classification system was changed and status-codes were based on norms in NYISO's Large Facility Interconnection Procedures as follows: *1=Scoping Meeting Pending, 2=FES Pending, 3=FES in Progress, 4=SRIS Pending, 5=SRIS in Progress, 6=SRIS Approved, 7=FS Pending, 8=Rejected Cost Allocation/Next FS Pending, 9=FS in Progress, 10=Accepted Cost Allocation/IA in Progress, 11=IA Completed, 12=Under Construction, 13=In Service for Test, 14=In Service Commercial, 0=Withdrawn, where FES=Feasibility Study Available, SRIS=System Reliability Impact Study Available, FS=Facilities Study and/or ATRA Available*

[13] Some examples are the 752 MW Huntley re-powering project by NRG that was introduced in the NYCA list in mid-2006 and the 150 MW Fortran project by Canadian Niagara Power, which appeared on the NYCA list in summer 2006 and was withdrawn by fall 2006.

The graph above provides an illustration of the capacity under study backward in time. Going forward, the NYISO has a process to identify future needs that are necessary to maintain the reliability of the bulk power system in New York. Most recently, the NYISO identified certain reliability needs in the 2007 Reliability Needs Assessment.[14] The most immediate need identified was in 2011. The NYISO determined that additional generation capacity is needed in the Lower Hudson Valley or in New York City.

After the need is identified, the responsible transmission owners in the relevant areas must identify regulatory backstop solutions that are adequate to meet the reliability needs identified in the RNA. Those regulatory backstop solutions, however, are not preferred and will not be triggered unless there are no market-based solutions to satisfy the identified need. The primary difference between market-based solutions and regulatory backstops is that market-based project developers do not have a guarantee of cost recovery and will get revenues through the NYISO's markets, including energy, capacity, and ancillary services, and any other bilateral contracts the developer obtains. In contrast, regulated backstop solutions will recover their costs under either the NYISO tariff or the New York Public Service Law, as applicable.

On March 8, 2007, the NYISO solicited market-based solutions to the identified needs in the 2007 RNA. According to a draft report issued on June 29, 2007, the NYISO has received market-based proposals that are sufficient to meet the needs identified in the 2007 RNA. Developers included 2,790 MW in projects to either build new generation in New York or enable the import of external resources into the state. Some of the proposed projects may enter into bilateral contracts, such as those associated with the New York Power Authority's Request for Proposals in March, 2005, which is fully consistent with the NYISO-administered markets. Currently, approximately 50 percent of the overall market for capacity in New York is comprised of bilateral contracts, and the NYISO's market design allows the use of such contracted capacity to satisfy an LSE's Unforced Capacity Obligation. Although several developers have indicated that they may need to secure a bilateral contract prior to construction, which may be needed to secure financing or other developer-specific reasons, all of the projects below appear to be viable at this time.

The 250 MW Spagnoli Energy Center

[14] New York Independent System Operator, Inc., Comprehensive Reliability Planning Process, 2007 Reliability Needs Assessment, at 14-17 (Mar. 16, 2007), available at http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2004_planning_trans_report/2007_RNA.pdf (last visited July 3, 2007).

KeySpan Ravenswood, LLC submitted the Spagnoli Road Energy Center, and is scheduled to be in service and available for the summer of 2009. The project will be a nominal 250MW combined cycle plant consisting of one GE Frame 7FA gas turbine generator, one steam turbine generator, a heat recovery steam generator (HRSG) with Selective Catalytic Reduction (SCR) for control of nitrogen oxides (NOx), an oxidation catalyst for control of carbon monoxide (CO) and volatile organic compounds (VOC), and an exhaust stack. It is project number 20 in the NYISO interconnection queue.

The 500 MW Astoria Repowering Project [375MW Net]
NRG Power Marketing, Inc. submitted this project, which is identified as the Astoria re-powering project. This project is scheduled to be phased in with 200 MW in service in 2009 (project #201 in the NYISO interconnection queue) and the remaining 300 MW (project #224 in the NYISO interconnection queue) in service by 2011. The repowering project will result in the retirement of 126 MW of existing simple cycle combustion turbine for a net increase in capacity of approximately 375 MW. The project location is NYCA Zone J into the Astoria West 138kV substation and has numbers 201 and 224 in the NYISO interconnection queue.

The 600 MW Arthur Kill Combined Cycle Unit
NRG Power Marketing, Inc. also proposed this project, which is identified as the Arthur Kill combined cycle project. The facility is scheduled to in service by July of 2012. The project location is NYCA Zone J.

The 660 MW Hudson Transmission Project (HTP)
Hudson Transmission Partners submitted a high-voltage direct current (HVDC) project that will provide a new controllable transmission line into New York City that is rated at 660 MW. The HTP consist of Back-to-Back HVDC system ("converter-circuit-converter") in a single building (the Converter Station) located in Ridgefield, N.J. near PSE&G Bergen substation - which is part of the PJM transmission system. A high-voltage 345kV AC transmission line will connect the converter station to Consolidated Edison's transmission system at the West 49th St. substation. The HTP is being developed in response to the Request for Proposals, "Long-Term Supply of In-City Unforced Capacity and Optional Energy" issued by the New York Power Authority (NYPA) dated March 11, 2005 (the "RFP"). The project was selected by NYPA's Board of Trustees for further negotiation and review. The project has a proposed in-service date of late 2010. This project is #206 in the NYISO interconnection queue.

The Red Oak, NJ Combined Cycle Generating Unit (500 MW in Response to NYPA RFP)
This solution was submitted by FPL Energy. The Red Oak project is an existing 817 MW three on one (3x1) combined cycle, natural gas fired power generation project, located in Sayreville, New Jersey. Red Oak began commercial operation in 2002. Red Oak's major equipment includes three Westinghouse 501F combustion turbines ("CTs"), one Toshiba Steam Turbine ("ST"), and three Foster Wheeler heat recovery steam generators ("HRSGs"), each with selective catalyst reduction. FPL Energy proposed the Red Oak project to the New York Power Authority ("NYPA") as a supplement to Hudson Transmission Partners' ("HTP" or "Hudson") response to the Request for Proposals, "Long-Term Supply of In-City Unforced Capacity and Optional Energy" issued by NYPA dated March 11, 2005 (the "RFP"). The Red Oak project would provide reliable capacity to NYPA's New York City customers via the HTP**.** The project was selected by NYPA's Board of Trustees for further negotiation and review of a 500MW capacity contract.

The 550 MW Harbor Cable Project and Generating Portfolio

Brookfield Energy Marketing submitted the Harbor Cable Project, which will provide a 550 MW fully controllable electric transmission pathway from generation sources located in New Jersey to New York City (Zone J). The HCP will consist of a back-to-back HVDC converter station located in Linden, New Jersey with 200 MW going to the Goethals substation on Staten Island via a single circuit 345 kV AC transmission cable and 350 MW going to Manhattan near the new World Trade Center substation via double circuit 138 kV AC transmission cables. The developer proposes to bundle the transmission project with up to 550 MW of capacity and energy from existing and/or new capacity located in New Jersey to be available in June 2011. This is project number 195 in the NYISO interconnection queue.

The 300 MW Linden Variable Frequency Transformers (VFT)
GE Energy Financial Services submitted a project for a 300 MW bidirectional controllable AC transmission tie between the PJM and NYISO systems. It will be physically located adjacent to Linden Cogen plant. Three (3) 100 MW Variable Frequency Transformer (VFT) "channels" will tie an existing PJM 230 kV transmission line to existing 345 kV cables connecting Linden Cogen into Con Edison's Goethals substation. This will result in a continuously variable 300 MW tie between the northern New Jersey PJM system and New York City (Zone J) of NYISO. This proposal does not contain any associated capacity but would rely on existing resources in PJM. This project is # 125 on the NYISO's interconnection queue and is scheduled to be in service in late 2009.

The 300 MW Indian Point Peaking Facility
Entergy Nuclear Power Marketing submitted the Entergy Buchanan Generation Project consisting of 300 to 330 MW of simple cycle gas turbine peaking capacity to be located on the site of the existing Indian Point nuclear plant. The facility will be interconnected to Consolidated Edison Company's Buchanan substation at 138 kV. This project is scheduled to be in service in mid-2011.

In addition to the projects listed above, there is other evidence that generation developers are pursuing projects in New York. For example, Astoria Energy LLC, a subsidiary of SCS Generating, constructed 500 MW of its planned project, which was studied in the interconnection process at 1000 MW. When describing its project, Astoria Energy refers to it as a 1000 MW facility, of which 500 MW have already been installed. Astoria Energy also has a project pending in the interconnection queue. These indicators tend to show that Astoria Energy is looking at completing its project, possibly on a merchant basis.

Overall, the ICAP Demand Curves have been characterized as a positive regulatory change that has fostered price stability, which should increase confidence in project financial projections and a better ability to enter into longer term contracts. The NYISO's capacity markets and ICAP Demand Curves also appear to have been considered by neighboring ISOs/RTOs. Both PJM Interconnection and ISO-New England have recently implemented newly designed capacity market that rely on long-term forward contracting and procurement.. PJM is using an administratively-determined demand curve for its forward auctions, which is

similar in design to the NYISO's ICAP Demand Curves used in the spot auctions. The NYISO currently has short-term forward capacity markets (*i.e.*, the 6-month Capability Period Auctions) and is evaluating whether some type of auction mechanism several years into the future would be beneficial. The NYISO plans on discussing forward market proposals in its stakeholder process this summer and fall.

2. Revenue Analysis

The Commission's order stated that the NYISO should include a complete net revenue analysis to provide information about whether revenue from all sources is adequate in regions where capacity is needed. Where there is a growing pressure on existing capacity, *i.e.*, the reserve margin is shrinking, there should be a rise in combined revenues from energy and capacity markets. The NYISO examined the level of "need" by looking at the percentage of capacity in excess of the applicable minimum requirement. The NYISO then looked at possible revenues from the capacity and energy markets for a hypothetical combustion turbine. The analysis shows that, in general, there is a tendency for revenues to increase as the excess capacity margin decreases and vice versa.

a. Quantification of "Need"

For purposes of this analysis, the excess of capacity relative to the minimum requirement was used as a proxy for need. So, if the reserve margin required to maintain reliability is X%, and the existing capacity is X + 2%, the excess amounts to 2%. Capacity Margins are calculated as:

$$\text{Capacity Margin \%} = \frac{\text{Availability}}{\text{Requirement}} \times 100$$

Using this definition, a value in excess of 100% reflects an excess capacity margin. A relatively high value indicates less of a need for new capacity and, conversely, declining values suggest a growing need. The following table displays the required and actual amounts of capacity (ICAP) as published in NYISO's Load & Capacity Data Reports.

Table 1. Available Capacity vs. Required Capacity

		2003	2004	2005	2006
NYCA	Requirement (MW)	37,087	37,217	37,710	39,288
	Availability (MW)	37,943	38,762	38,522	40,036
	Capacity margin %	**102.31%**	**104.15%**	**102.15%**	**101.90%**

NYC	Requirement (MW)	8,192	7,815	8,930	9,304
	Availability (MW)	9,207	9,186	9,373	9,964
	Capacity margin %	**112.39%**	**117.54%**	**104.96%**	**107.09%**
LI	Requirement (MW)	4,943	4,681	5,242	5,295
	Availability (MW)	5,248	5,198	5,373	5,515
	Capacity margin %	**106.17%**	**111.05%**	**102.50%**	**104.16%**

In this table, the Requirements are based on Summer peaks, and Available capacity incorporates Demand Response (SCRs) but not capacity imported via external transactions.

b. Measure of Revenues

The NYISO assumed a revenue requirement based on the ICAP Demand Curves, which use a levelized annual revenue requirement for a given capability year (May – Apr) that is derived from a Cost of New Entry (CONE) of a gas-fueled simple-cycle, combustion turbine (GT) for a particular location in the NYCA. For purposes of this analysis, the NYISO used the established methodology based on Summer/Winter DMNCs to convert these annual revenue requirements into Summer and Winter $/kW-Month equivalents. Next, these monthly values were used to compute calendar-year revenue requirements for each year in the 2003-2006 period.[15] In terms of $/MW-year, these annual figures are as follows:

Table 2. Annual Revenue Requirements ($/MW)

	2003	2004	2005	2006
NYCA	$83,776	$86,258	$88,842	$91,504
NYC	$177,155	$182,435	$187,935	$193,628
LI	$156,060	$160,723	$165,572	$170,500

The following table shows the individual elements of revenues (*i.e.*, those earned in the Energy, Ancillary Services, and ICAP markets) that a hypothetical GT may have received based on actual LBMPs, natural gas prices, and reasonable parameters used to calculate variable costs.[16]

[15] Note that the results presented are based on calendar years as opposed to NYISO's capability years.

[16] These values are the same as the ones used to calculate the revenues as submitted to the Commission in January 2007.

Table 3. Benchmark Annual Revenues ($/MW)

		Revenue Elements in $				Revenue Elements as % of Total			
		2003	2004	2005	2006	2003	2004	2005	2006
NYCA[17]	Energy	$7,830	$1,144	$4,238	$4,327	24.4%	6.2%	15.9%	9.3%
	A/S	$8,122	$2,708	$11,668	$19,044	25.3%	14.8%	43.7%	40.7%
	Capacity	$16,104	$14,490	$10,806	$23,392	50.2%	79.0%	40.5%	50.0%
	Total	***$32,057***	***$18,342***	***$26,712***	***$46,764***	***100.0%***	***100.0%***	***100.0%***	***100.0%***
NYC	Energy	$48,928	$19,531	$45,393	$38,582	29.5%	14.9%	27.6%	22.1%
	A/S	$9,362	$2,265	$8,638	$11,807	5.6%	1.7%	5.3%	6.8%
	Capacity	$107,572	$108,852	$110,370	$123,872	64.9%	83.3%	67.1%	71.1%
	Total	***$165,862***	***$130,648***	***$164,400***	***$174,261***	***100.0%***	***100.0%***	***100.0%***	***100.0%***
Long Island	Energy	$45,944	$12,699	$46,678	$87,372	30.9%	11.7%	29.9%	48.1%
	A/S	$9,458	$2,307	$8,503	$8,158	6.4%	2.1%	5.4%	4.5%
	Capacity	$93,346	$93,268	$100,962	$85,996	62.8%	86.1%	64.7%	47.4%
	Total	***$148,748***	***$108,275***	***$156,143***	***$181,526***	***100.0%***	***100.0%***	***100.0%***	***100.0%***

This table is based on the data submitted with the NYISO's January 2007 report. It is important to note that there have been considerable shifts in the distribution of total revenues, especially for NYCA as a whole. Due to a new modeling methodology introduced in 2005, earnings from Ancillary Services rose in both absolute and relative terms. A hypothetical unit in New York City (Zone J) and on Long Island (Zone K), however, would have received a greater share of its revenue from the capacity market.

In order to determine revenue adequacy, this analysis uses the Revenue Margin, which is Benchmark Revenues expressed as a percentage of Required Revenues, as the metric. Revenue Margins are calculated as:

$$\text{Revenue Margin \%} = \frac{\text{Benchmark Revenue}}{\text{Required Revenue}} \times 100$$

Using this approach, a higher value indicates a greater degree of adequacy of revenues. The following table displays the values of Revenue Margins for the hypothetical peaking unit:

Table 4. Revenue Margins

	2003	**2004**	**2005**	**2006**
NYCA	38%	21%	30%	51%
NYC	94%	72%	87%	90%

[17] These values are for the Capital Zone (Zone F), which is assumed as a representation of the NYCA as a whole.

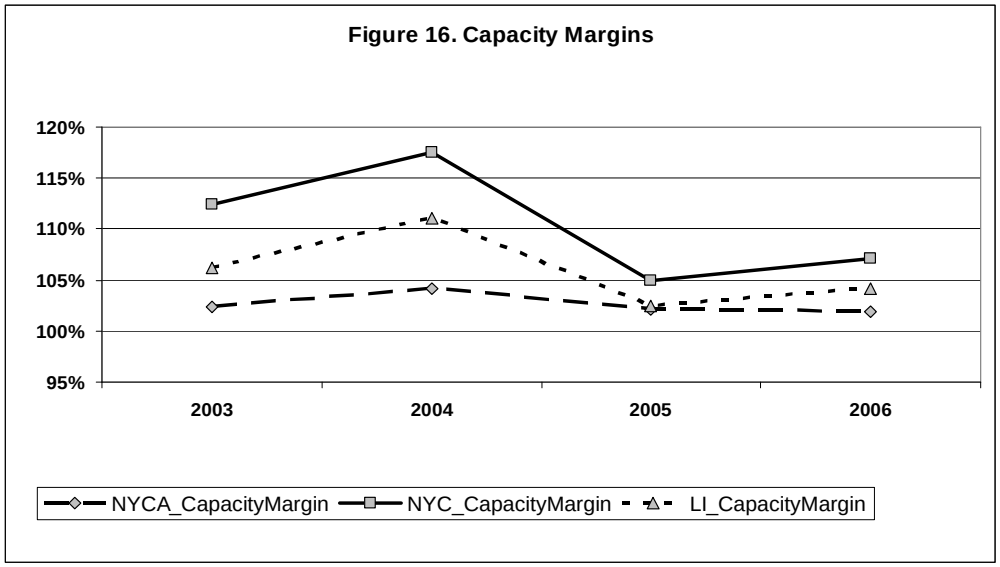
LI	95%	67%	94%	106%

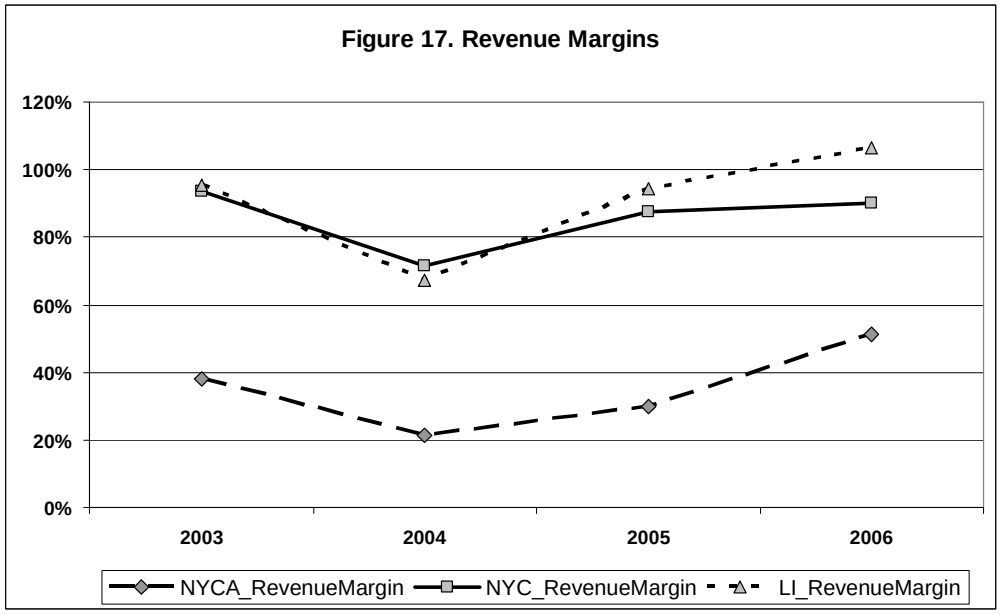
These figures indicate that revenue margins for the hypothetical unit have been rising steadily since 2004, the year after the ICAP Demand Curves went into effect. However, revenues remain well below what is necessary to attract new entry of a hypothetical benchmark GT in Rest of State. Although both NYC and LI were experiencing revenues values below their respective CONE equivalents through 2005, revenues for the hypothetical units have been approaching adequacy in NYC and LI with the latter experiencing above-CONE values in 2006.

This analysis does not provide insight, however, into whether it may be worthwhile to construct additional generation that would be inframarginal to the hypothetical unit analyzed. The ICAP Demand Curves, and this analysis, are based on hypothetical "peaking units." The curves currently in place are based on gas turbines constructed in simple-cycle mode. If a developer can construct additional capacity that would be inframarginal to the hypothetical unit, such as a combined cycle unit, then it has a greater likelihood of earning additional revenues. Accordingly, it may be worthwhile to construct capacity even if revenues for the hypothetical unit used for the ICAP Demand Curves and this analysis may not be adequate.

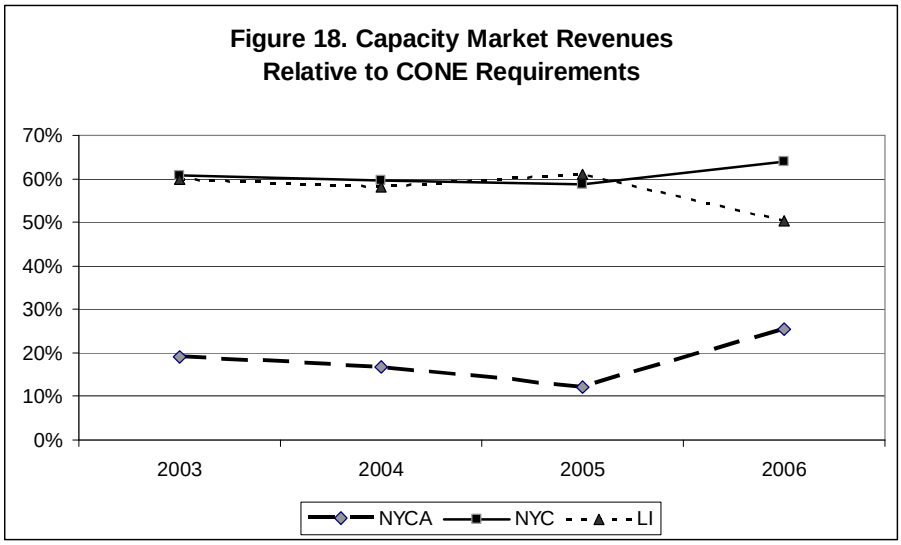
In order to assess whether revenue streams are appropriate given the degree of need for new capacity, data from Tables 1 and 4 are graphed below.

A comparison of the two charts suggests that as Capacity Margins have declined, there is evidence that revenues have tended to respond as expected. Discounting for the additions of combined cycle capacity in NYC and LI that were initiated prior to the Demand Curves, evidence points to a strong tendency of revenues beginning to rise along with the growing need for new capacity. It is notable that despite the offer and revenue cap on capacity divested from Consolidated Edison in New York City, energy revenues have begun rising to support the type of market signal necessary to provide incentives for new entry.





One can conclude that market forces in NYISO-administered ICAP markets are indeed behaving appropriately with revenue signals responding as expected to changes in the capacity margins.



If the analysis is restricted to non-wind projects, it is interesting to note that rises in the volume of MWs being placed in the interconnection queue seem to coincide with changes in the strength of revenue signals. Evidence from Figures 16 and 17 suggests that there is support for the idea that the combination of low capacity margins and growing revenues – from the capacity market and overall – in NYCA are positively correlated with the increased MWs in the interconnection queue. While the capacity margin remains relatively high in NYC, the rising capacity market revenues do exhibit a positive correlation with additions to the interconnection queue.

VII. Independent Market Advisor Opinion

The NYISO has consulted with the independent Market Advisor, Dr. David Patton, and he concurs in 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 curve facilitates the forward contracting for both capacity and energy that is needed to support investment in new and existing generation. In addition, he concurs with the withholding analysis presented.

♦ ♦ ♦

Appendix A

Figure 1.a.

Nov. 1999 – July 2007
Installed Capacity Auction Activity
New York Control Area (NYCA) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
November-99							35563.1	
December-99							35563.1	
January-00	Installed Capacity Market Existed but all purchases and sales were bilateral						35563.1	
February-00							35563.1	
March-00							35563.1	
April-00							35563.1	
May-00	1976.0	$1.50	434.2	$1.30	32.7	$0.50	35636.0	1976.0
June-00	1976.0	$1.50	528.4	$1.40	37.1	$1.28	35563.1	1976.0
July-00	1976.0	$1.50	344.2	$1.80	140.8	$1.98	35563.1	1976.0
August-00	1976.0	$1.50	351.4	$1.62	194.8	$1.77	35563.1	1976.0
September-00	1976.0	$1.50	648.9	$1.32	81.3	$1.16	35563.1	1976.0
October-00	1976.0	$1.50	681.6	$1.30	96.9	$0.89	35563.1	1976.0
November-00	4010.6	$1.04	1813.6	$1.00	157.7	$0.80	35563.1	4010.6
December-00	4010.6	$1.04	1854.1	$0.97	167.2	$0.86	35563.1	4010.6
January-01	4010.6	$1.04	1847.6	$0.97	170.5	$0.85	35563.1	4010.6
February-01	4010.6	$1.04	1893.8	$0.95	177.2	$0.83	35563.1	4010.6
March-01	4010.6	$1.04	2032.8	$0.95	208.1	$0.79	35563.1	4010.6
April-01	4010.6	$1.04	1659.7	$0.87	192.3	$0.59	35563.1	4010.6
May-01	2738.6	$1.90	852.3	$2.25	1022.2	$9.58	36132.0	2738.6
June-01	2738.6	$1.90	397.6	$2.68	1521.0	$9.41	36132.0	2738.6
July-01	2738.6	$1.90	1776.6	$4.31	1534.9	$9.44	36132.0	2738.6
August-01	2738.6	$1.90	1788.4	$4.56	1601.3	$9.35	36132.0	2738.6
September-01	2738.6	$1.90	1701.2	$4.16	1498.0	$9.21	36132.0	2738.6
October-01	2738.6	$1.90	1787.1	$4.03	1473.4	$9.14	36132.0	2738.6
November-01	1760.4	$2.00	878.0	$0.10	5.8	$ -	32892.3	1760.4
December-01	1760.4	$2.00	687.2	$0.49	6.5	$ -	32892.3	1760.4
January-02	1760.4	$2.00	750.5	$0.84	133.0	$0.75	32892.3	1760.4
February-02	1760.4	$2.00	836.2	$0.70	25.5	$ -	32892.3	1760.4
March-02	1760.4	$2.00	901.3	$0.61	30.0	$0.25	32892.3	1760.4
April-02	1760.4	$2.00	677.9	$0.69	5.6	$0.02	32892.3	1760.4
May-02	3201.6	$1.75	552.1	$0.33	2.3	$ -	32479.5	3201.6
June-02	3201.6	$1.75	438.3	$0.36	20.3	$0.01	32479.5	3201.6
July-02	3201.6	$1.75	721.9	$0.97	11.1	$0.01	32479.5	3201.6
August-02	3201.6	$1.75	722.6	$0.91	55.4	$0.01	32479.5	3201.6
September-02	3201.6	$1.75	714.0	$0.25	71.2	$0.01	32479.5	3201.6
October-02	3201.6	$1.75	712.1	$0.16	1.4	$ -	32479.5	3201.6
November-02	3486.7	$0.65	1024.3	$0.50	85.0	$0.40	34169.7	3486.7
December-02	3486.7	$0.65	1219.3	$0.28	51.4	$0.10	34169.7	3486.7

Figure 1.a.

Nov. 1999 – July 2007
Installed Capacity Auction Activity
New York Control Area (NYCA) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-03	3486.7	$0.65	1584.4	$0.26	189.1	$2.10	34169.7	3486.7
February-03	3486.7	$0.65	1623.1	$0.34	85.6	$0.50	34169.7	3486.7
March-03	3486.7	$0.65	1825.9	$0.32	58.8	$0.25	34169.7	3486.7
April-03	3486.7	$0.65	1571.5	$0.15	4.2	$0.01	34169.7	3486.7
May-03	2889.2	$1.67	1634.8	$1.30	101.5	$0.25	35303.5	0
June-03	2889.2	$1.67	1866	$1.06	2148.7	$2.34	35303.5	2073.2
July-03	2889.2	$1.67	1249.2	$2.01	2824.2	$2.28	35303.5	2274.1
August-03	2889.2	$1.67	1344.1	$2.04	3096.6	$2.25	35303.5	2299.3
September-03	2889.2	$1.67	1396.7	$1.97	3134.1	$2.08	35303.5	2448.1
October-03	2889.2	$1.67	1408.4	$1.93	3253.2	$2.01	35303.5	2504.8
November-03	2163.2	$1.17	2128.8	$1.15	6833	$1.94	35203.4	2566.9
December-03	2163.2	$1.17	1860.1	$1.48	7203.1	$1.79	35203.4	2698.6
January-04	2163.2	$1.17	2083.6	$1.50	6972.2	$1.75	35203.4	2732.1
February-04	2163.2	$1.17	2475.9	$1.58	6379.9	$1.73	35203.4	2747.4
March-04	2163.2	$1.17	2180	$1.54	6569.8	$1.00	35203.4	3369.3
April-04	2163.2	$1.17	2646.7	$0.99	6987.5	$0.80	35203.4	3543.8
May-04	2441	$1.68	2489.7	$1.65	6189.1	$1.31	35584.5	3328
June-04	2441	$1.68	2133.6	$1.48	6239.9	$1.27	35584.5	3355.3
July-04	2441	$1.68	1756.7	$1.29	6410.6	$1.04	35584.5	3518.8
August-04	2441	$1.68	2046.5	$1.15	6544.7	$1.17	35584.5	3428.1
September-04	2441	$1.68	2258.8	$1.16	6456.2	$1.07	35584.5	3499.6
October-04	2441	$1.68	2460.8	$1.18	6633.9	$1.12	35584.5	3465.6
November-04	3050.7	$0.60	2344.4	$0.70	6730.6	$0.70	35515.9	3759.3
December-04	3050.7	$0.60	3058.4	$0.69	6011.5	$0.61	35515.9	3823.5
January-05	3050.7	$0.60	2945.8	$0.59	5928.6	$0.27	35515.9	4064.8
February-05	3050.7	$0.60	2769.6	$0.49	6256.2	$0.25	35515.9	4082.2
March-05	3050.7	$0.60	2890.9	$0.45	6025.4	$0.41	35515.9	3966.2
April-05	3050.7	$0.60	2891.5	$0.48	6241.1	$0.27	35515.9	4064.8
May-05	2624.6	$0.75	1630	$0.75	6975.7	$2.00	35799.2	3110.8
June-05	2624.6	$0.75	1752.9	$1.40	6306.6	$1.96	35799.2	3135.2
July-05	2624.6	$0.75	4077.8	$1.29	5073.3	$1.00	35799.2	3703.4
August-05	2624.6	$0.75	3819.1	$0.81	5147.3	$1.00	35799.2	3703.4
September-05	2624.6	$0.75	3412.5	$0.81	5303.5	$1.45	35799.2	3436.7
October-05	2624.6	$0.75	3861.2	$1.03	5142	$1.25	35799.2	3555.2
November-05	2987.1	$0.62	2676.1	$0.67	6661.9	$0.85	35761.5	3789
December-05	2987.1	$0.62	3466.7	$0.68	6306	$0.65	35761.5	3907.2

Figure 1.a. (cont'd)

Nov. 1999 – July 2007
Installed Capacity Auction Activity
New York Control Area (NYCA) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-06	2987.1	$0.62	3966.1	$0.63	5625.3	$2.01	35761.5	3102.5
February-06	2987.1	$0.62	3379.8	$1.01	6432.7	$1.67	35761.5	3305.2
March-06	2987.1	$0.62	5214.9	$0.58	5234.1	$0.57	35761.5	3954.5
April-06	2987.1	$0.62	4899.7	$0.51	5357.5	$0.40	35761.5	4055
May-06	3014.5	$1.44	2196.7	$1.64	6936.8	$3.25	37154.2	2526.4
June-06	3014.5	$1.44	2747.7	$2.38	6163	$3.12	37154.2	2601.6
July-06	3014.5	$1.44	2914.1	$2.58	5901.1	$3.33	37154.2	2481.4
August-06	3014.5	$1.44	3447.6	$2.85	5488.5	$3.00	37154.2	2675.1
September-06	3014.5	$1.44	4041.3	$2.75	5087.8	$2.80	37154.2	2295.3
October-06	3014.5	$1.44	4258	$2.62	5368.3	$2.77	37154.2	2814.8
November-06	3167.7	$2.50	3170.9	$1.73	7454.7	$1.50	37319.2	3577.8
December-06	3167.7	$2.50	2475.7	$2.30	7841.7	$2.18	37319.2	3170.5
January-07	3167.7	$2.50	2756.5	$2.45	7780.6	$2.71	37319.2	2853.4
February-07	3167.7	$2.50	3308.7	$2.51	7029.1	$2.67	37319.2	2876.6
March-07	3167.7	$2.50	4699.7	$1.80	5932.2	$1.34	37319.2	3673.8
April-07	3167.7	$2.50	4653.5	$1.61	5912	$1.10	37319.2	3817.9
May-07	3196.6	$2.25	2610.6	$2.40	6283.6	$3.16	37228.3	2618.7
June-07	3196.6	$2.25	2748	$2.81	5876.5	$3.39	37228.3	2485.6
July-07	3196.6	$2.25	2849.9	$2.99	5749.7	$3.52	37228.3	2407.6

Figure 2.a.

Nov. 1999 – July 2007
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
November-99							8305.6	
December-99							8305.6	
January-00	Installed Capacity Market Existed but all purchases and sales were bilateral						8305.6	
February-00							8305.6	
March-00							8305.6	
April-00							8305.6	
May-00	5408.8	$8.75	59.4	$12.50	0.0	-	8272.0	
June-00	5408.8	$8.75	313.4	$9.46	52.7	$12.50	8272.0	
July-00	5408.8	$8.75	342.7	$9.40	100.0	$12.50	8272.0	
August-00	5408.8	$8.75	332.6	$9.42	133.9	$12.50	8272.0	
September-00	5408.8	$8.75	344.5	$9.40	149.5	$12.50	8272.0	
October-00	5408.8	$8.75	304.2	$9.49	214.0	$12.50	8272.0	
November-00	4861.4	$8.75	735.0	$8.74	170.3	$8.75	8272.0	
December-00	4861.4	$8.75	785.1	$8.74	154.8	$8.75	8272.0	
January-01	4861.4	$8.75	899.5	$8.74	154.8	$8.75	8272.0	
February-01	4861.4	$8.75	921.7	$8.71	154.8	$8.75	8272.0	
March-01	4861.4	$8.75	936.5	$8.74	156.0	$8.75	8272.0	
April-01	4861.4	$8.75	985.6	$8.56	156.7	$8.72	8272.0	
May-01	5316.6	$8.75	248.7	$8.75	235.1	$12.50	8375.0	(est.)
June-01	5316.6	$8.75	228.4	$10.92	299.0	$12.18	8375.0	(est.)
July-01	5316.6	$8.75	407.8	$9.77	292.5	$8.83	8375.0	(est.)
August-01	5316.6	$8.75	440.1	$8.38	350.1	$9.46	8375.0	(est.)
September-01	5316.6	$8.75	434.9	$8.42	316.0	$8.34	8375.0	(est.)
October-01	5316.6	$8.75	430.1	$7.99	343.4	$8.72	8375.0	(est.)
November-01	3972.5	$9.40	772.8	$9.00	77.7	$4.80	7613.3	
December-01	3972.5	$9.40	906.8	$6.88	11.5	$ -	7613.3	
January-02	3972.5	$9.40	492.6	$5.47	377.3	$8.25	7613.3	
February-02	3972.5	$9.40	631.1	$6.69	229.3	$9.20	7613.3	
March-02	3972.5	$9.40	784.3	$6.92	90.6	$7.50	7613.3	
April-02	3972.5	$9.40	932.9	$7.12	11.6	$9.40	7613.3	
May-02	4355.2	$9.20	684.1	$9.38	30.5	$9.39	7621.6	
June-02	4355.2	$9.20	671.2	$6.11	16.7	$0.50	7621.6	
July-02	4355.2	$9.20	684.7	$5.34	0.3	$0.01	7621.6	
August-02	4355.2	$9.20	693.8	$5.15	15.1	$2.00	7621.6	
September-02	4355.2	$9.20	688.4	$4.83	24.5	$0.01	7621.6	
October-02	4355.2	$9.20	699.0	$4.72	19.2	$1.95	7621.6	
November-02	4540.0	$7.00	748.1	$6.40	61.1	$4.10	8021.8	
December-02	4540.0	$7.00	762.7	$4.09	29.9	$2.80	8021.8	

Figure 2.a.

Nov. 1999 – July 2007
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-03	4540	$7.00	787.9	$4.02	13.3	$2.10	8021.8	
February-03	4540	$7.00	808.6	$3.51	1.5	$3.00	8021.8	
March-03	4540	$7.00	799.7	$3.97	21.9	$4.00	8021.8	
April-03	4540	$7.00	829.7	$3.39	9.1	$3.60	8021.8	
May-03	2501.7	$11.22	3016.3	$10.00	110.2	$12.36	8356.7	0.0
June-03	2501.7	$11.22	683	$13.78	2375.5	$11.46	8356.7	0.0
July-03	2501.7	$11.22	527.9	$11.57	2558	$11.46	8356.7	0.0
August-03	2501.7	$11.22	567.9	$11.56	2497.9	$11.46	8356.7	0.0
September-03	2501.7	$11.22	558.1	$11.56	2499.5	$11.46	8356.7	0.0
October-03	2501.7	$11.22	638.8	$11.55	2415.1	$11.45	8356.7	0.0
November-03	475	$6.55	579.3	$6.67	5029.3	$6.98	8346.1	571.0
December-03	475	$6.55	909.4	$6.64	4711	$6.98	8346.1	571.0
January-04	475	$6.55	968.9	$6.64	4644.8	$6.98	8346.1	571.0
February-04	475	$6.55	2167.5	$6.77	3422.4	$6.98	8346.1	571.0
March-04	475	$6.55	1938	$6.05	3841.5	$6.98	8346.1	571.0
April-04	475	$6.55	2047.2	$6.00	3779.1	$6.98	8346.1	571.0
May-04	1245.3	$11.15	2022.4	$11.16	2898.3	$11.42	8444.6	214.9
June-04	1245.3	$11.15	2532.8	$11.29	2391.9	$11.42	8444.6	214.9
July-04	1245.3	$11.15	2705.7	$11.29	2261.3	$11.42	8444.6	214.9
August-04	1245.3	$11.15	3126.1	$11.25	1854.4	$11.42	8444.6	214.9
September-04	1245.3	$11.15	3272.4	$11.25	1798.6	$11.42	8444.6	214.9
October-04	1245.3	$11.15	2771.9	$11.21	2336.3	$11.42	8444.6	214.9
November-04	2249.4	$6.68	1253.8	$6.96	3137.5	$7.12	8469.5	705.9
December-04	2249.4	$6.68	1606	$7.07	2758.3	$7.12	8469.5	705.9
January-05	2249.4	$6.68	2433.6	$7.03	1919.3	$7.12	8469.5	705.9
February-05	2249.4	$6.68	2596.5	$7.03	1761.5	$7.12	8469.5	705.9
March-05	2249.4	$6.68	2671.8	$7.03	1784	$7.12	8469.5	705.9
April-05	2249.4	$6.68	2611.4	$7.03	1851.9	$7.12	8469.5	705.9
May-05	2547.2	$11.68	1035.2	$11.86	2547.1	$12.03	8526.8	284.0
June-05	2547.2	$11.68	2657.9	$11.80	974.2	$11.96	8526.8	291.3
July-05	2547.2	$11.68	2742.6	$11.82	992.5	$11.95	8526.8	292.5
August-05	2547.2	$11.68	2689.7	$11.82	1134.8	$11.86	8526.8	301.6
September-05	2547.2	$11.68	2842	$11.82	1086.6	$11.70	8526.8	318.2
October-05	2547.2	$11.68	2644.5	$11.82	1238.1	$11.86	8526.8	301.6
November-05	1846.4	$5.11	943.9	$6.39	3865.4	$6.55	8569.2	854.3
December-05	1846.4	$5.11	2130.4	$6.44	2674.7	$6.55	8569.2	854.3

Figure 2.a. (cont'd)

Nov. 1999 – July 2007
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess
								Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-06	1846.4	$5.11	2558.2	$6.21	2116.6	$6.55	8569.2	854.3
February-06	1846.4	$5.11	3162.5	$5.78	2037.4	$6.55	8569.2	854.3
March-06	1846.4	$5.11	2704.7	$5.78	2031.7	$6.55	8569.2	854.3
April-06	1846.4	$5.11	3237.1	$5.88	1540.4	$6.55	8569.2	854.3
May-06	2186.7	$12.35	1422.7	$12.43	2209.8	$12.71	8798.1	255.9
June-06	2186.7	$12.35	1447.8	$12.41	2165.3	$12.71	8798.1	255.9
July-06	2186.7	$12.35	1580.0	$12.45	1909.6	$12.71	8798.1	255.9
August-06	2186.7	$12.35	1604.5	$12.51	1870.7	$12.71	8798.1	255.9
September-06	2186.7	$12.35	1603.6	$12.51	1953.5	$12.71	8798.1	255.9
October-06	2186.7	$12.35	1628.1	$12.54	2316.7	$12.71	8798.1	255.9
November-06	3298.4	$5.67	1023.5	$5.80	2057.8	$5.84	8831.5	974.8
December-06	3298.4	$5.67	1039.2	$5.84	2018.8	$5.84	8831.5	974.8
January-07	3298.4	$5.67	1193.4	$5.82	1973.8	$5.84	8831.5	974.8
February-07	3298.4	$5.67	1143.1	$5.81	2144.0	$5.84	8831.5	974.8
March-07	3298.4	$5.67	1199.7	$5.80	2008.8	$5.84	8831.5	974.8
April-07	3298.4	$5.67	1105.5	$5.82	1971.6	$5.84	8831.5	974.8
May-07	1894.0	$12.37	1099.1	$12.34	3125.4	$12.72	9058.3	281.1
June-07	1894.0	$12.37	1209.4	$12.36	2951.5	$12.72	9058.3	281.1
July-07	1894.0	$12.37	1154.3	$12.36	3073.0	$12.72	9058.3	281.1

Figure 3.a.

Nov. 1999 – July 2007
Installed Capacity Auction Activity
Long Island Locality (LI) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
November-99							4555.3	
December-99							4555.3	
January-00	Installed Capacity Market Existed but all purchases and sales were bilateral						4555.3	
February-00							4555.3	
March-00							4555.3	
April-00							4555.3	
May-00	0	-	0	-	0	-	4638.0	
June-00	0	-	0	-	0	-	4638.0	
July-00	0	-	0	-	0	-	4638.0	
August-00	0	-	0	-	0	-	4638.0	
September-00	0	-	0	-	0	-	4638.0	
October-00	0	-	0	-	0	-	4638.0	
November-00	0	-	0	-	0	-	4638.0	
December-00	0	-	0	-	0	-	4638.0	
January-01	0	-	0	-	0	-	4638.0	
February-01	0	-	0	-	0	-	4638.0	
March-01	0	-	0	-	0	-	4638.0	
April-01	0	-	0	-	0	-	4638.0	
May-01	0	-	0	-	3.2	$10.83	4625.0	
June-01	0	-	0	-	7.0	$10.83	4625.0	
July-01	0	-	0	-	20.2	$10.83	4625.0	
August-01	0	-	0	-	21.3	$10.83	4625.0	
September-01	0	-	0	-	33.0	$10.83	4625.0	
October-01	0	-	0	-	33.0	$10.83	4625.0	
November-01	0	-	0.6	$3.50	8.5	$12.33	4077.6	
December-01	0	-	1.3	$3.50	37.4	$12.33	4077.6	
January-02	0	-	1.3	$5.00	39.7	$12.33	4077.6	
February-02	0	-	0	$ -	40.6	$11.50	4077.6	
March-02	0	-	14.0	$11.50	26.4	$11.49	4077.6	
April-02	0	-	41.4	$11.48	0	-	4077.6	
May-02	0	-	0	-	0	-	4177.8	
June-02	0	-	0	-	0	-	4177.8	
July-02	0	-	0	-	0	-	4177.8	
August-02	0	-	0	-	0	-	4177.8	
September-02	0	-	0	-	0	-	4177.8	
October-02	0	-	0	-	0	-	4177.8	
November-02	0	-	0	-	0	-	4256.2	
December-02	0	-	0	-	0	-	4256.2	

Figure 1.a.

Nov. 1999 – July 2007
Installed Capacity Auction Activity
Long Island Locality (LI) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-03	0	-	0	-	0	-	4256.2	
February-03	0	-	0	-	0	-	4256.2	
March-03	0	-	0	-	0	-	4256.2	
April-03	0	-	0	-	0	-	4256.2	
May-03	6.6	$9.41	2.2	$24.00	0.2	$23.00	4415.3	0.0
June-03	6.6	$9.41	0.0	--------	341.9	$5.17	4415.3	341.9
July-03	6.6	$9.41	1.0	$5.00	344.7	$5.14	4415.3	344.7
August-03	6.6	$9.41	1.1	$5.00	441.8	$4.03	4415.3	441.8
September-03	6.6	$9.41	0.0	--------	397.8	$4.55	4415.3	396.2
October-03	6.6	$9.41	0.0	--------	397.8	$4.55	4415.3	396.0
November-03	0.0	$4.00	0.0	--------	114.3	$8.14	4401.9	83.7
December-03	0.0	$4.00	0.0	--------	107.5	$8.22	4401.9	76.9
January-04	0.0	$4.00	0.0	--------	128.2	$7.99	4401.9	97.0
February-04	0.0	$4.00	0.6	$7.50	202.6	$7.08	4401.9	176.0
March-04	0.0	$4.00	0.6	$7.00	142.6	$7.72	4401.9	119.9
April-04	0.0	$4.00	0.6	$6.85	199	$7.04	4401.9	179.7
May-04	11.2	$8.00	1.6	$8.00	97.5	$9.83	4761.5	81.2
June-04	11.2	$8.00	11.2	$9.29	90.8	$9.79	4761.5	84.3
July-04	11.2	$8.00	15.9	$8.67	193.4	$8.42	4761.5	192.9
August-04	11.2	$8.00	16.4	$8.05	213.1	$8.16	4761.5	213.1
September-04	11.2	$8.00	16.2	$8.06	214.2	$8.15	4761.5	214.2
October-04	11.2	$8.00	16.2	$8.06	214.2	$8.15	4761.5	214.2
November-04	13.9	$4.00	10.9	$4.00	358.2	$6.34	4736.0	357.7
December-04	13.9	$4.00	9.0	$4.33	368.5	$6.21	4736.0	367.6
January-05	13.9	$4.00	9.0	$3.81	372.1	$6.16	4736.0	371.4
February-05	13.9	$4.00	7.6	$3.68	373.3	$6.14	4736.0	372.8
March-05	13.9	$4.00	7.0	$3.54	371.9	$6.16	4736.0	371.9
April-05	13.9	$4.00	7.0	$3.54	367.4	$6.23	4736.0	365.8
May-05	10.6	$8.00	2.7	$8.00	85.5	$12.15	4904.9	85.4
June-05	10.6	$8.00	2.0	$8.50	100.4	$11.96	4904.9	97.8
July-05	10.6	$8.00	4.3	$9.00	195.3	$10.48	4904.9	195.0
August-05	10.6	$8.00	4.6	$8.50	222.5	$10.06	4904.9	222.5
September-05	10.6	$8.00	4.6	$8.61	233	$9.90	4904.9	233.0
October-05	10.6	$8.00	4.6	$8.71	260	$9.49	4904.9	260.0
November-05	15.0	$0.68	10.0	$5.00	330.5	$8.37	4962.4	330.5
December-05	15.0	$0.68	10.1	$4.99	344.5	$8.16	4962.4	344.5

Figure 1.a. (cont'd)

Nov. 1999 – July 2007
Installed Capacity Auction Activity

Long Island Locality (LI) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess
								Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-06	15.0	$0.68	10.0	$5.00	288.1	$9.00	4962.4	288.1
February-06	15.0	$0.68	10.0	$5.00	343.1	$8.18	4962.4	343.1
March-06	15.0	$0.68	10.0	$5.00	350.8	$8.07	4962.4	350.8
April-06	15.0	$0.68	10.0	$5.00	346.1	$8.14	4962.4	346.1
May-06	4.0	$6.50	9.0	$6.50	166.8	$11.15	5110.3	165.0
June-06	4.0	$6.50	2.3	$7.50	469.3	$6.76	5110.3	462.5
July-06	4.0	$6.50	3.0	$7.00	483.0	$6.52	5110.3	478.8
August-06	4.0	$6.50	3.0	$6.75	497.2	$6.31	5110.3	493.0
September-06	4.0	$6.50	4.6	$6.50	503.4	$6.19	5110.3	500.8
October-06	4.0	$6.50	7.2	$6.00	513.6	$6.02	5110.3	512.6
November-06	1.5	$3.50	9.6	$3.75	672.0	$3.66	5072.2	669.4
December-06	1.5	$3.50	11.1	$3.50	670.6	$3.65	5072.2	669.7
January-07	1.5	$3.50	14.6	$3.50	673.0	$3.60	5072.2	672.9
February-07	1.5	$3.50	14.6	$3.50	672.3	$3.61	5072.2	672.3
March-07	1.5	$3.50	14.6	$3.50	672.3	$3.61	5072.2	672.3
April-07	1.5	$3.50	14.6	$3.32	672.3	$3.61	5072.2	672.3
May-07	2.2	$3.75	3.0	$3.75	450.3	$7.25	5056.3	450.2
June-07	2.2	$3.75	3.0	$5.50	353.1	$8.78	5056.3	353.1
July-07	2.2	$3.75	0.0	$-	451.5	$7.23	5056.3	451.4

Appendix B

Table 1.a. Decomposition of Unsold UCAP (MW): NYCA				
	Monthly Average UCAP Available	Monthly Average UCAP Committed From All Auctions or as Bilaterals	Monthly Average Unsold UCAP	Unsold UCAP as a percent of Available UCAP
Winter 2004-05	41094.8	39725.0	1369.9	3.3%
Summer 2005	40277.9	39345.9	932.0	2.3%
Winter 2005-06	40117.5	40100.4	670.5	1.7%
Summer 2006	41024.5	40230.7	1304.5	3.2%
Winter 2006-07	42273.2	41293.9	1622.2	3.8%
Summer 2007 \2	41555.1	40584.8	970.3	2.3%

Table 1.b. Decomposition of Unsold UCAP (MW): NYC				
	Monthly Average UCAP Available	Monthly Average UCAP Committed From All Auctions or as Bilaterals	Monthly Average Unsold UCAP	Unsold UCAP as a percent of Available UCAP
Winter 2004-05	9414.3	9175.6	238.7	2.5%
Summer 2005	8883.8	8819.1	64.7	0.7%
Winter 2005-06	9676.2	9425.7	498.4	5.2%
Summer 2006	9455.8	9061.0	746.3	7.9%
Winter 2006-07	10486.2	9808.3	991.1	9.5%
Summer 2007 \2	10026.7	9339.8	686.9	6.9%

Table 1.c. Decomposition of Unsold UCAP (MW): Long Island				
	Monthly Average UCAP Available	Monthly Average UCAP Committed From All Auctions or as Bilaterals	Monthly Average Unsold UCAP	Unsold UCAP as a percent of Available UCAP
Winter 2004-05	5242.3	5104.0	138.3	2.6%
Summer 2005	5099.5	5086.6	12.9	0.3%
Winter 2005-06	5263.7	5298.1	0	0.0%
Summer 2006	5414.4	5591.1	0	0.0%
Winter 2006-07	5621.3	5743.7	0	0.0%
Summer 2007 \2	5474.5	5474.5	0	0.0%

Table 1.d. Decomposition of Unsold UCAP (MW): Externals\1				
	Monthly Average	Monthly Average UCAP Committed	Monthly Average Unsold UCAP	Unsold UCAP as a percent of

	UCAP Available	From All Auctions or as Bilaterals		Available UCAP
Winter 2004-05	2644.8	2252.1	392.7	14.9%
Summer 2005	2699.9	2658.1	41.8	1.6%
Winter 2005-06	2699.9	2166.7	533.2	19.7%
Summer 2006	2699.9	2581.3	118.6	4.4%
Winter 2006-07	2699.9	1770.5	811.5	30.1%
Summer 2007 [\2]	2699.9	2487.9	212.0	7.9%

1. This includes capacity from Hydro Quebec, PJM, and ISO-NE. The combined ICAP total is limited to 2755 MW.

Submission Contents