NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow ... Today℠
10 Krey Boulevard ⬩ Rensselaer, NY 12144

January 15, 2008

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

Re: Compliance Filing in Docket Nos. ER01-3001-___, ER03-647-___

Dear Ms. Bose:

Enclosed for filing in the above-referenced dockets are the New York Independent System Operator, Inc.'s ("NYISO") reports to the Commission regarding the NYISO's Demand Side Management programs, new generation projects in the New York Control Area, and the Installed Capacity ("ICAP") Demand Curves.

In Docket No. ER01-3001, the NYISO files semi-annual reports regarding its Demand Side Management programs and new generation projects. In Docket No. ER03-647, the Commission ordered the NYISO to provide certain data and analysis related to the implementation of the ICAP Demand Curves along with information on demand-side resources and new generation projects.[1] By Notice dated November 28, 2006, the Commission granted the NYISO permission to submit by January 15 each year a single filing in both dockets to satisfy its obligation to submit the winter report in Docket No. ER01-3001 and the annual report in Docket No. ER03-647.[2]

In its last order accepting the NYISO's compliance filing on the ICAP Demand Curves, the Commission ordered the NYISO to include additional analysis regarding capacity located in Rest-of-State (outside of the New York City and Long Island Localities) that was not sold in the New York Control Area.[3] The report on implementation of the ICAP Demand Curves includes a discussion of the offering behavior for certain Rest-of-State capacity and the possible effects of that behavior on the market. In addition, the section of the ICAP report on new generation projects includes a discussion of the NYISO's enhanced program to track the progress of the market-based solutions that were proposed in response to needs identified in the Reliability Needs Assessment and Comprehensive Reliability Planning Process.

[1] *New York Indep. Sys. Operator, Inc.*, 117 FERC ¶ 61,086 (2006).

[2] *New York Indep. Sys. Operator, Inc.*, Notice of Extension of Time, Docket Nos. ER01-3001-006, *et al.* (Nov. 28, 2006) ("[T]he NYISO is granted an extension of time to and including January 15, 2007 (and to January 15 in subsequent years), to submit a report on the ICAP demand curve and its winter report on demand-side resource and new generation.").

[3] *New York Indep. Sys. Operator, Inc.*, 121 FERC ¶ 61,090 at P 37 (2007).

I. List of Documents Submitted

The NYISO is submitting the following documents along with this letter:

1. NYISO Report on 2007 Demand Response Programs
2. NYISO Report on New Generation Projects
3. NYISO Report on Installed Capacity Demand Curves

II. Correspondence

Copies of correspondence concerning this filing should be addressed to:

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III. Service

The NYISO is serving an electronic copy of this filing on each party on the services lists prepared by the Secretary of the Commission in Docket Nos. ER01-3001 and ER03-647, the official representative of each of its Market Participants, on each participant in its stakeholder governance committees, on the New York Public Service Commission, and on the New Jersey Board of Public Utilities. The NYISO is providing a hard copy of this filing to the Pennsylvania Public Utility Commission. Finally, the NYISO will post this filing on its website.

Respectfully Submitted,

_/s/ Carl F. Patka ____________

Carl F. Patka
Joseph B. Willliams

Counsel for
New York Independent System Operator, Inc.

NYISO 2007 Demand Response Programs

The NYISO offers two demand response programs to support reliability: the Emergency Demand Response Program (EDRP) and the Installed Capacity-Special Case Resource Program (ICAP/SCR). An economic bidding program, the Day-Ahead Demand Response Program (DADRP), permits interruptible load resources to offer load reductions in the day-ahead energy market.

EDRP provides resources an opportunity to earn the greater of $500/MWh or the prevailing location-based marginal price (LBMP) for energy consumption curtailments provided when the NYISO calls on them. There are no consequences for enrolled participants that fail to curtail. Resources participate in EDRP through Curtailment Service Providers (CSPs), who serve as the interface between the NYISO and participants.

The ICAP/SCR program allows customers that can meet certification requirements to offer unforced capacity (UCAP) to Load Serving Entities (LSEs). Special Case Resources can participate in the ICAP Market just like any other ICAP Resource. Resources are obligated to curtail when called upon to do so with two or more hours notice, provided that they were notified the day ahead of the possibility of such a call. In addition, ICAP/SCR resources are subject to testing each capability period to verify that they can fulfill their curtailment requirement. Failure to curtail could result in penalties administered under the ICAP program. Curtailments are called when reserve shortages are anticipated. Participants may register either for EDRP or ICAP/SCR but not both. SCR resources are eligible for an energy payment during an event, using the same performance calculation as EDRP resources. Resources participate in ICAP/SCR through Responsible Interface Parties (RIPs), who serve as the interface between the NYISO and participants.

The Targeted Demand Response Program (TDRP) was introduced in July 2007. TDRP is a new NYISO reliability program that deploys existing EDRP and SCR resources on a voluntary basis, at the request of a transmission owner, in targeted subzones to solve local reliability problems. The TDRP program is currently available in Zone J, New York City.

The DADRP program provides retail customers with an opportunity to bid their load curtailment capability into the day-ahead spot market as energy resources. Customers submit bids by 5:00 a.m. specifying the hours and amount of load curtailment they are offering for the next day, and the price at which they are willing to curtail. Prior to November 1, 2004, the minimum bid price was $50/MWh. The bid floor price is currently $75/MWh. Bids are structured like those of generation resources. DADRP program participants may specify minimum and maximum run times and effectively submit a block of hours on an all-or-nothing basis. They are eligible for bid production cost guarantee payments to make up for any difference between the market price received and their block bid price across the day. Load scheduled in the Day-Ahead Market (DAM) is obligated to curtail the next day. Failure to curtail results in the imposition of a penalty for each such hour defined by the MW curtailment shortfall multiplied by the greater of the corresponding day-ahead or real-time market price of energy.

Summary of Significant Findings

Emergency Demand Response Program / ICAP Special Case Resources

As of August 2007, a total of 39 organizations offer programs that deliver the NYISO EDRP and ICAP/SCR programs to retail customers, an increase of two aggregators over 2006 figures. Participating organizations include:

- 7 transmission owners
- 6 load serving entities unaffiliated with transmission owners
- 23 aggregators
- 3 EDRP/SCR direct customers

Non-Transmission Owner providers currently sponsor 62.3% of the total EDRP and ICAP/SCR registered megawatts, up from the 59.7% registered in 2006. In 2007, non-Transmission Owners did not have any resources registered in the EDRP program.

EDRP and ICAP/SCR had a total of 2,705 participants enrolled providing a total of 1,801.9 MWs of demand response, a slight increase over the 2006 MW registration. There were 719 resources in EDRP and 1,986 participants in ICAP/SCR. ICAP/SCR represents 73% of the total reliability program enrollments and 74% of the total reliability program registered MWs. The Targeted Demand Response Program, which deploys EDRP and ICAP/SCR resources in subzones of Zone J, New York City, for local reliability, included 9% of total EDRP participants registered and encompassed 22% of total registered EDRP MWs. The TDRP also included 52% of total ICAP/SCR participants, representing 28% of the total registered ICAP/SCR MWs.

Since participation in EDRP and ICAP/SCR has become mutually exclusive, EDRP registration and MWs have decreased and ICAP/SCR registration and MWs have increased, as would be expected given the more lucrative nature of the ICAP/SCR program. Aggregations by RIPs now account for 96% of ICAP/SCR participants and 67% of registered MWs in the program.

In 2007, the NYISO activated EDRP and ICAP/SCR resources in the Targeted Demand Response Program on only two occasions for a total of 20 hours. There were no other activations of the EDRP or ICAP/SCR programs during the summer of 2007. EDRP performance in the 2007 TDRP events was above average (43% on July 19 and 80% on August 3). Average hourly performance exceeded ICAP/SCR energy performance and participating resources by 25% or more. Given the voluntary nature of the TDRP program, average hourly ICAP/SCR performance in each event was 25% or less than the total registered MWs.

Day-Ahead Demand Response Program
For DADRP, only four resources submitted offers during the analysis period of September 2006 through August 2007. However, offer activity increased by more than 500% over the previous 12-month period. Also, more than twice as many hours of program participation were scheduled as compared to the prior year period. In 2007, 36.6% of offers were scheduled compared to 93% of offers in 2006. The average DAM LBMP during the analysis period was $72.69 in Zone A, below the DADRP bid floor price, and $75.11 in Zone F, just slightly above the bid floor price of

$75 and 28% lower than in 2006. The 12-month hourly average DAM LBMP for scheduled bids was $72.69 in Zone A and $87.79/MWh in Zone F.

Overall, the average hourly bid increased by 52%, from 3.06 MWs to 4.66 MWs, while scheduled bids decreased by 36% to 1.66MWs. Scheduled hours increased by 200% over the same period last year to 2,509 hours. Scheduled MWhs increased by 19% to 4,152 MWhs.

The overall average hourly price reduction from DADRP is $0.10/MWh, which represents no change from 2006. On a monthly basis, the average hourly price reduction was most significant in the months of January 2007 ($0.26/MWh) and February 2007 ($0.34/MWh), more than double that of the same months in 2006.

Participation in Reliability Supporting Demand Response Programs

Retail customers enroll in the NYISO's reliability-supporting demand response programs through one of five entities:

- Aggregators recruit customers to participate as part of an aggregation of several customers;
- Curtailment Program End-Use Customers enroll directly with the NYISO to participate only in the EDRP program;
- Direct Customers register with the NYISO to participate in any of its markets including its demand response programs;
- LSEs are competitive providers of commodity service to retail customers;
- TOs are the investor-owned utilities and public authorities located in New York State.

All entities sponsoring customers in the EDRP program are considered Curtailment Service Providers (CSPs); those sponsoring customers in the ICAP/SCR program are considered Responsible Interface Parties (RIPs). As of August 31, 2007 (the date customarily used for reporting participation statistics) a total of 39 CSPs and RIPs were offering programs that deliver the NYISO's EDRP and ICAP/SCR programs to retail customers. This level of participation represents an increase of two aggregators over 2006 figures. Participating CSPs and RIPs include:

- 7 transmission owners
- 6 load serving entities unaffiliated with transmission owners
- 23 aggregators
- 3 EDRP or ICAP/SCR direct customers

Non-Transmission Owner providers currently sponsor 62.3% of the total EDRP and ICAP/SCR registered megawatts, up from the 59.7% registered in 2006. In 2007, non-Transmission Owners did not have any resources registered in the EDRP program.

Targeted Demand Response Program (TDRP)

The Targeted Demand Response Program was designed to add granularity to the location of EDRP and ICAP/SCR resources called at the request of a TO to meet local reliability needs. While the tariff permitted NYISO to activate these programs at the request of a TO, NYISO was required to call all resources located in the zone in which the problem was identified. Con Edison asked NYISO to amend its tariffs and procedures in order to offer its EDRP and ICAP/SCR resources at the load pocket level as well as the zonal level. Con Edison could then target its request for load relief to the specific area in which it is needed. Based on 2006 demand response program activation data, the more efficient use of targeted resources could reduce participant payments for unneeded demand response (resulting from calling the entire zone) by approximately $3 million.

Effective July 1, 2007, NYISO implemented the Targeted Demand Response Program to respond to requests for assistance from Transmission Owners (TO) by activating EDRP and ICAP/SCR resources in one or more subzones. TDRP currently applies to Zone J, New York City, where 9 subzones have been defined. The TDRP presently includes 9% of registered EDRP participants representing 22% of the total MW in the EDRP program, and 52% of registered ICAP/SCR participants representing 28% of the total MW in the ICAP/SCR program.

Two activations of the TDRP occurred in 2007: July 19 from 8:00 – 23:00 and August 3 from 19:30 – 23:59.

Aggregation of ICAP/SCR Resources

Registration for ICAP/SCR resources can be tracked by both individual participant end-use customer and by RIP-created aggregations of multiple end-use customers. Table 1 indicates that there are a total of 67 RIP-created aggregations containing a total of 1,916 end-use customers and accounting for 904.9 MW of the total 1,338.5 MW of registered ICAP/SCR. Seventy (70) individual resources account for 433.5 MW. Individual resources enrolled in ICAP/SCR have dropped by 56% since 2006; many of these have moved to aggregations.

Table 1: Detail of 2007 ICAP/SCR Program Participation Level by Resource Type

	ICAP			ICAP UnSold		
Resource Type	# SCRs	# Participants	Sold MW	# SCRs	# Participants	Subscribed MW
Individual Resources	70	70	433.5	12	12	6.8
Aggregated Resources	67	1916	904.9	0	0	0.0
Total	**137**	**1986**	**1338.5**	**12**	**12**	**6.8**

The right-hand section of Table 1 provides information for unsold ICAP/SCR resources. In cases where an ICAP/SCR participant offers load reduction to an auction but it is not sold, that load is automatically enrolled in the EDRP program until the next auction or until the participant completes a bilateral transaction with an LSE. The EDRP program totals reported include the ICAP unsold participants and subscribed MW as EDRP resources.

EDRP and ICAP/SCR Program Participation

At the end of August 2007, the NYISO's reliability programs had a total of 2,705 participants enrolled providing a total of 1,801.9 MWs of demand response, a slight increase over the 2006 MW registration level.[1] There were 719 resources in EDRP (707 + 12 ICAP Unsold) and 1,986 participants in ICAP/SCR. ICAP/SCR represents 73% of the total reliability program enrollments and 74% of the total reliability program registered MWs. The average registered curtailable load for ICAP/SCR participants was 674 kWs, slightly higher than of that for EDRP participants (645 kWs).

Table 2: Program Participation Summary by Curtailment Service Provider Type

		EDRP (1)			ICAP UnSold (2)			ICAP (3)			DADRP (4)		
CSP Type #	**Agent Type**	# CSP	# Part.	MW	# CSP	# Part.	MW	# CSP	# Part.	MW	# CSP	# Part.	MW
23	Aggregator	0	0	0.0	2	12	6.8	23	1799	787.5	0	0	0.0
0	Curtailment Program End-Use Customer	0	0	0.0	0	0	0.0	0	0	0.0	0	0	0.0
3	Direct Customer	0	0	0.0	0	0	0.0	5	7	151.2	0	0	0.0
6	LSE	0	0	0.0	0	0	0.0	5	113	177.3	6	7	44.4
7	Transmission Owner	7	707	456.7	0	0	0.0	5	67	222.5	3	13	275.0
39	**Total**	**7**	**707**	**456.7**	**2**	**12**	**6.8**	**38**	**1986**	**1338.5**	**9**	**20**	**319.4**

Note 1: The sum of EDRP and ICAP UnSold = Total EDRP.

Note 2: Participants in the ICAP program with UnSold capacity are considered as EDRP resources in the month(s) that capacity is unsold. MW represent reductions registered in the ICAP program, but not sold.

Note 3: MW represent reduction MW sold in the ICAP program.

Note 4: Total NYISO participation is not necessarily the sum of all programs due to the rules that state that participants are allowed to participate in a reliability program (EDRP or ICAP) and economic (DADRP).

Table 2 shows the total number of CSPs registered for 2007 in the first column and the number of CSPs, by type, with participants in each of the program categories. In previous years the NYISO showed only the total number of CSPs with participants for each CSP type. This table now provides the participation detail by program and CSP type.

Enrollments in EDRP are exclusively through transmission owners this year; that is, no EDRP enrollments came through aggregators in 2007. ICAP/SCR enrollments have been dominated by aggregators, which provide 96% of participating resources and 67% of the registered MWs. Non-transmission owner LSEs sponsor 5.6% of participants and 13.2% of registered MWs to ICAP/SCR, a decrease in both from 2006.

Table 3 shows program participation detail by NYISO zone. Zones J and K, New York City and Long Island, respectively, have the majority (65%) of participants in the EDRP program, representing 56% of the total MWs enrolled. For the ICAP/SCR program, Zones J and K constitute an even greater percentage (78%) of statewide participants, but account for only 48% of the total enrolled MWs. Zones A through E as a group are characterized by greater load per

[1] A participant is defined as a single customer enrolled in a program individually or as part of an aggregated resource.

participant, providing 22% of participants in EDRP and 25% of total enrolled MWs and 16% of the participants in ICAP/SCR which provide 44% of the total program MWs**.** Although statistics on customer class are not recorded, participants in Zones A-E are more heavily weighted by industrial customers, while those downstate in Zones J and K are primarily commercial.

Table 3: 2007 Program Participation by Zone

	EDRP (1)		ICAP UnSold (2)		ICAP (3)		DADRP (4)	
Zone	#	MW	#	MW	#	MW	#	MW
A	23	34.3	2	0.3	160	372.9	4	58.0
B	15	6.9	0	0.0	61	53.3	1	2.8
C	59	25.1	0	0.0	65	103.5	2	38.0
D	11	4.9	0	0.0	6	45.5	1	100.0
E	44	40.6	0	0.0	32	19.4	1	10.0
F	44	43.6	0	0.0	50	64.6	8	92.0
G	24	34.4	0	0.0	22	16.5	0	0.0
H	9	6.8	0	0.0	2	0.3	0	0.0
I	18	7.4	0	0.0	36	21.0	0	0.0
J	99	127.9	7	4.3	1130	421.0	2	6.6
K	361	124.8	3	2.2	422	220.3	1	12.0
Total	**707**	**456.7**	**12**	**6.8**	**1986**	**1338.5**	**20**	**319.4**

Note 1: The sum of EDRP and ICAP UnSold = Total EDRP.

Note 2: Participants in the ICAP program with UnSold capacity are considered as EDRP resources in the month(s) that capacity is unsold. MW represent reductions registered in the ICAP program, but not sold.

Note 3: MW represent reduction MW sold in the ICAP program.

Note 4: Total NYISO participation is not necessarily the sum of all programs due to the rules that state that participants are allowed to participate in a reliability program (EDRP or ICAP) and economic (DADRP).

Targeted Demand Response Program Enrollment

Zone J is currently the only zone with resources assigned to the Targeted Demand Response Program. The zone has been divided into subzones designated by Con Edison and resources registered in EDRP and ICAP/SCR are assigned to one of the various subzones based on their location. Unassigned resources remain in the general Zone J category. The sub-load pockets correspond to the following Transmission Owner network area substation groupings:

- J1: Sherman Creek/Parkchester/E 179th
- J2: Astoria West/Queensbridge
- J3: Vernon/Greenwood
- J4: Staten Island
- J5: Astoria East/Corona/Jamaica
- J6: W 49th
- J7: E13th/East River
- J8: Farragut/Rainey
- J9: Shared Subzone

Table 4: EDRP Resources registered in the Targeted Demand Response program - Zone J

	J	J1	J2	J3	J4	J5	J6	J7	J8	J9	Total
Participants	35	4	5	11	6	8	7	7	13	3	99
MW	26.98	0.88	4.6	9.8	7.02	8.57	2.1	3.85	6.4	57.7	127.90

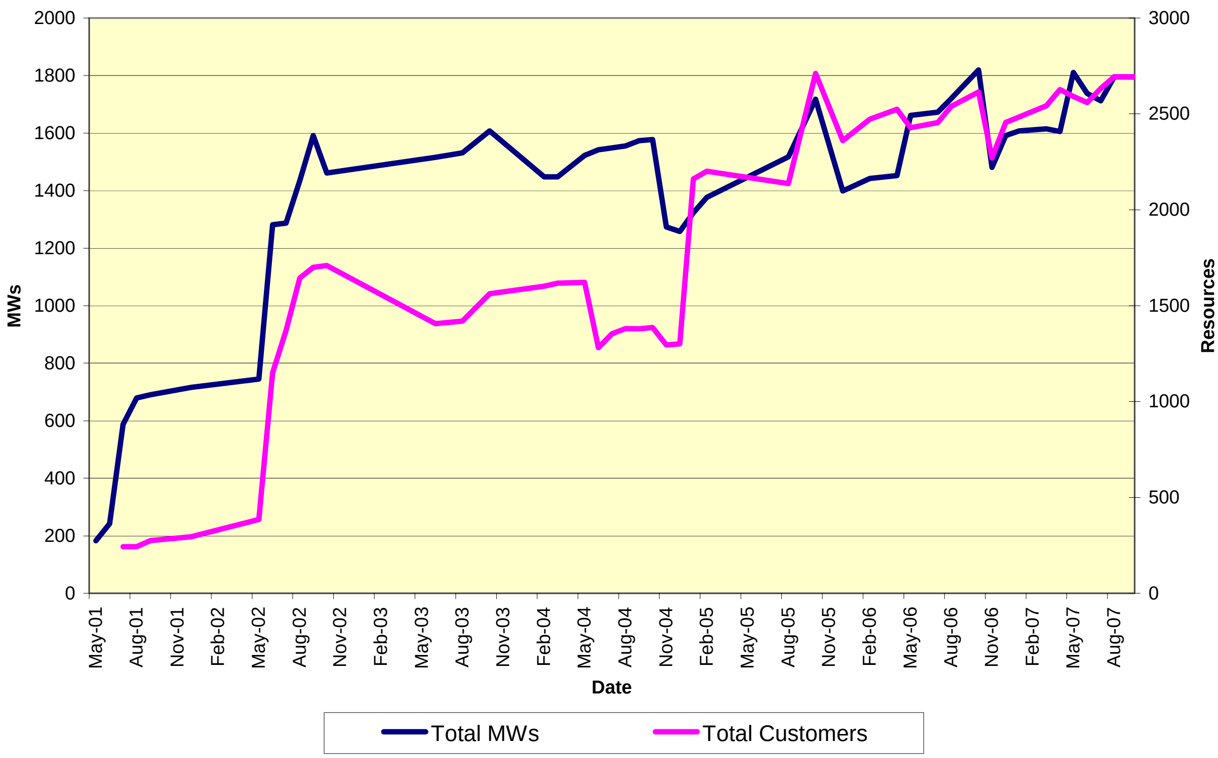
Table 5: ICAP/SCR Participants registered in the Targeted Demand Response Program – Zone J

	J	J1	J2	J3	J4	J5	J6	J7	J8	J9	Total
Participants	92	69	104	201	30	187	95	95	228	29	1,130
MW	44.04	36.22	32.38	44.77	22.51	46.93	42.43	52.11	74.64	24.98	421.00

Historical Program Growth in Reliability Programs

Figure 1 plots the growth in the NYISO's reliability-based programs from inception through August 2007. From May 2001 to August 2007, registration in EDRP and ICAP/SCR has grown from approximately 200 MWs to 1,801.9 MWs; the number of end-use customers participating has increased from roughly 200 in March 2002 to 2,705. Since 2004, there is a pattern of a roughly 300 MW drop in ICAP/SCR registration from October to November, the period coinciding with the shift from the summer to winter capability period.

Figure 1: Historical Growth in Customers and MW in EDRP and ICAP/SCR



Migration Summary

Table 6 shows the program enrollment changes by number of resources, meaning the number of IDs registered. ICAP counts are by ICAP/SCR resource ID in this table, not the total number of participants. Table 7 shows the program enrollment changes by number of participants. The change in participant count is significantly different when evaluating the number of participants for ICAP. By resource ID, ICAP/SCR enrollment appears to be dropping by 36% (Table 6), when in fact the number of participants in aggregations has increased by 14% (Table 7).

Table 6: Program Entrollment by Resources - Changes 2006 to 2007

	2006		2007		Percent Change From 2006 to 2007		Subscribed MW per Participant		
	Count	MW	Count	MW	Participant Count	Subscribed MW	2005	2006	Percent Change
EDRP	830	566.1	707	456.7	-15%	-19%	0.68	0.65	-5%
ICAP UnSold	4	7.2	12	6.8	200%	-5%	1.80	0.57	-68%
ICAP	213	1216.2	137	1338.5	-36%	10%	5.71	9.77	71%
DADRP	18	385.9	20	319.4	11%	-17%	21.44	15.97	-26%

Table 7: Program Enrollments by Participants - Changes 2006 to 2007

	2006		2007		Percent Change From 2006 to 2007		Subscribed MW per Participant		
	Count	MW	Count	MW	Participant Count	Subscribed MW	2005	2006	Percent Change
EDRP	830	566.1	707	456.7	-15%	-19%	0.68	0.65	-5%
ICAP UnSold	19	7.2	12	6.8	-37%	-5%	0.38	0.57	50%
ICAP	1745	1216.2	1986	1338.5	14%	10%	0.70	0.67	-3%
DADRP	18	385.9	20	319.4	11%	-17%	21.44	15.97	-26%

Figure 2, Figure 3 and Figure 4 track registration and MW in EDRP, ICAP/SCR and DADRP over the period 2001-2007. The primary difference between Figure 2 and Figure 3 is the representation of ICAP customers: Figure 2 shows the number of resource IDs, which represents aggregations as single units. Figure 3 provides information on the total number of participants (*i.e.*, individual customers that comprise an aggregation). The number of individual resource IDs decreased by 36% and the number of participants in aggregations increased by 14%. ICAP/SCR registration of individual resource IDs was initiated in 2004; prior to that period, the registered participants shown in Figure 2 and Figure 3 for ICAP/SCR were based on aggregations of individual participants. In addition, for 2001 and 2002, program registration was non-exclusive, *i.e.*, a participant could register for both EDRP and ICAP/SCR. Beginning in 2003, participate in the EDRP and ICAP/SCR programs became mutually exclusive.

Figure 4[2] shows that, since making EDRP and ICAP/SCR mutually exclusive, the general trend has been for EDRP registration and MW to decrease and ICAP/SCR registration and MW to increase, as would be expected given the more lucrative nature of the ICAP/SCR program.

[2] Changes to DADRP program enrollment are administrative. Reduction in the number of participants and enrolled MW results from the removal of zonal bus assignments that have never been used.

Figure 2: Demand Response Program Registration History by Resource ID, 2001 - 2007

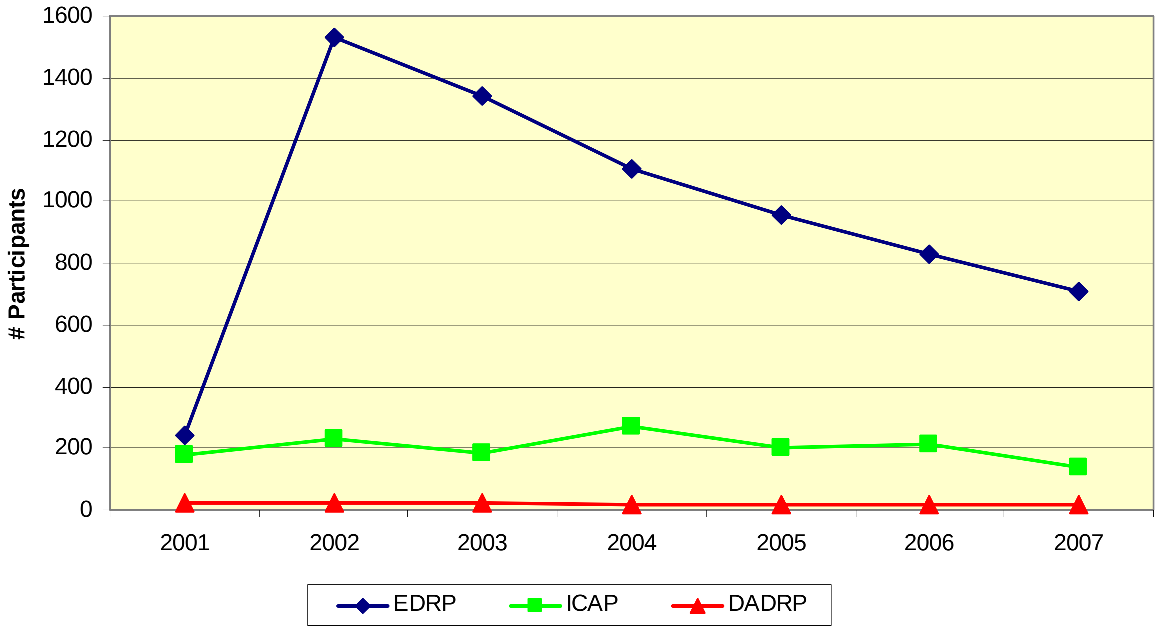


Figure 3: Demand Response Program Registration History by Participant, 2001 - 2007

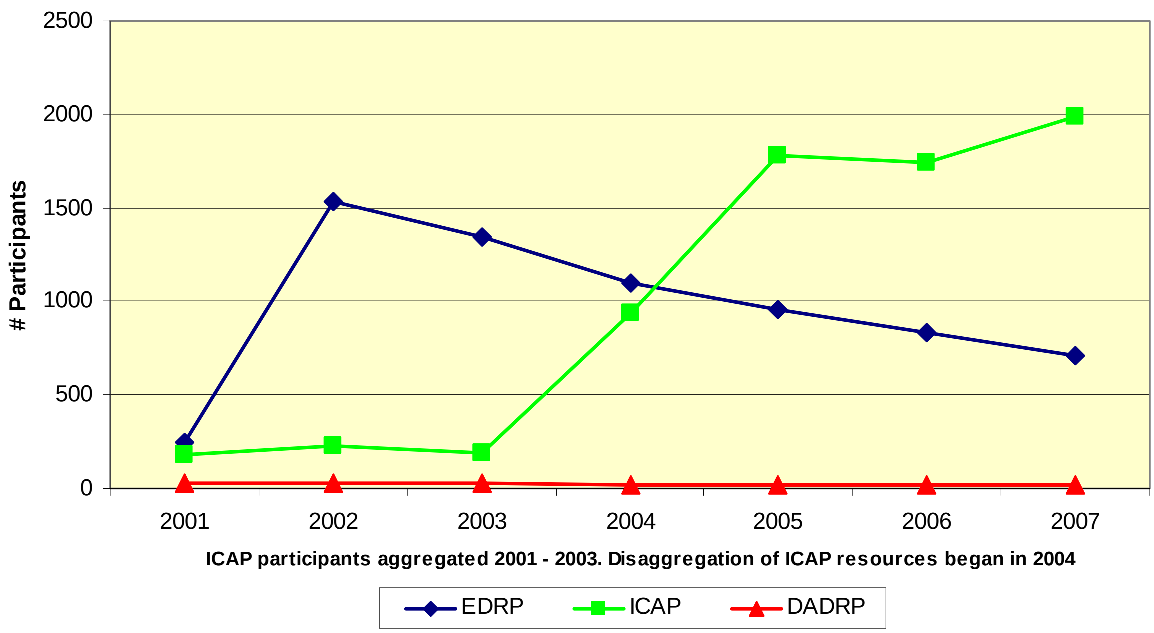
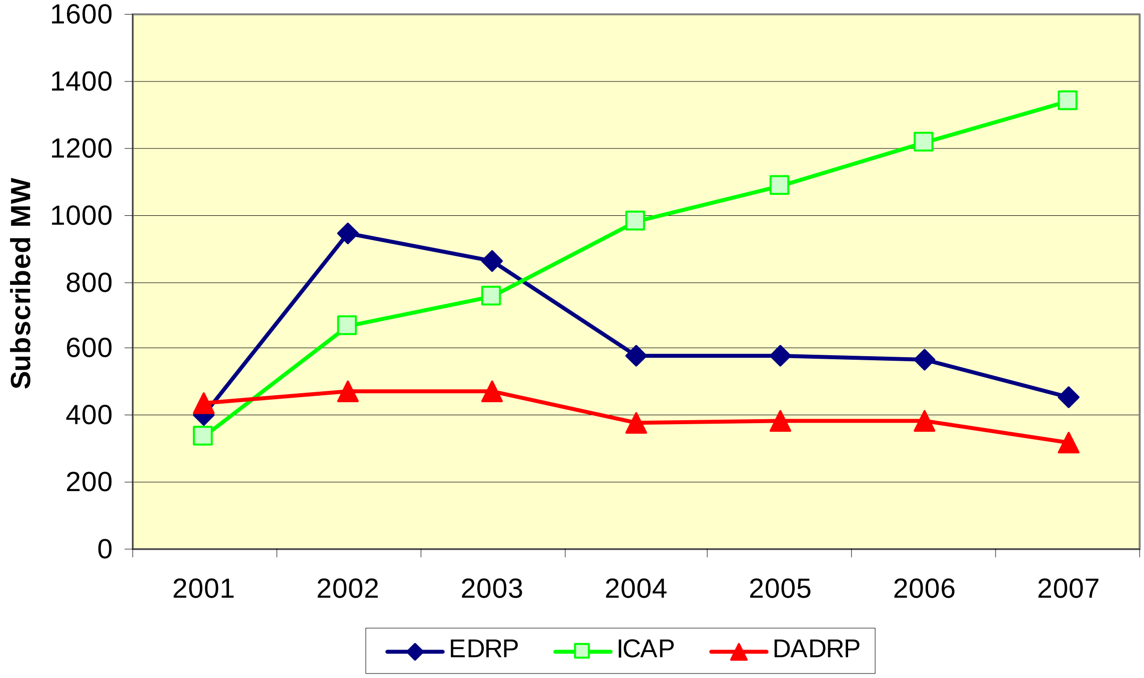


Figure 4: Demand Response Program MW Registration History, 2001 - 2007

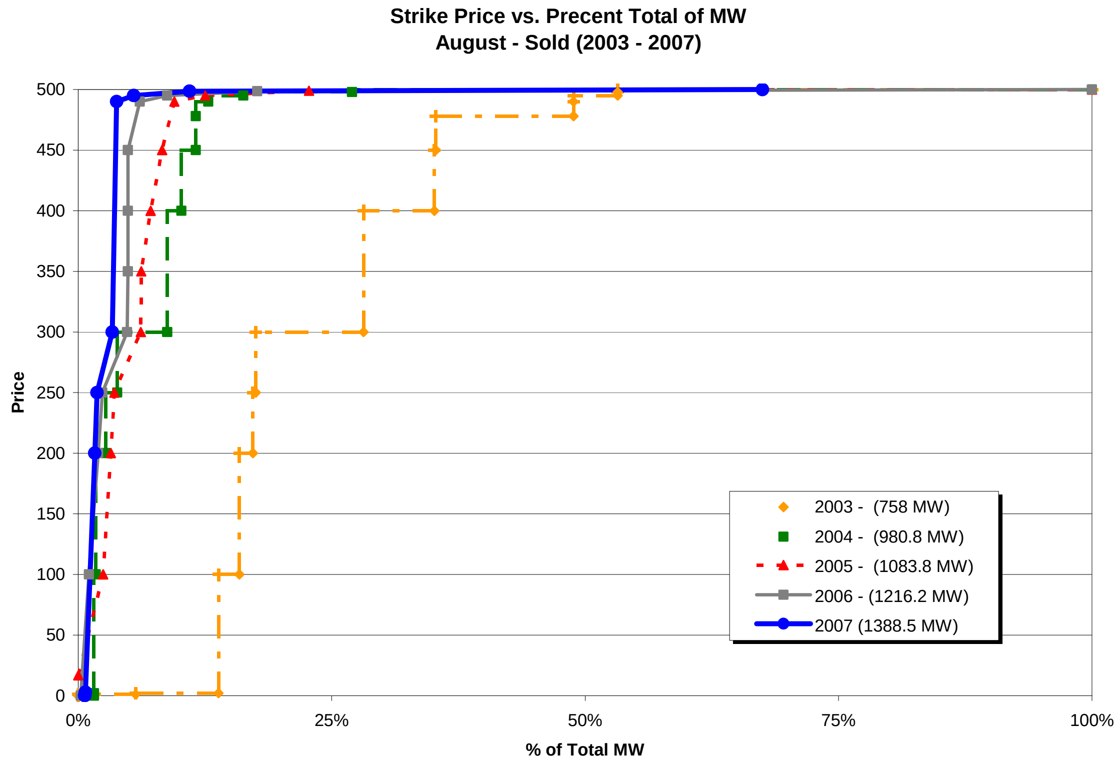


Analysis of ICAP/SCR Strike Prices

Beginning in 2003, participants in the ICAP/SCR program were required upon enrollment to indicate a curtailment strike price, between $0-$500/MWh, which would be used by the NYISO to determine which resources to call upon for curtailments in the case where all resources in a given Zone or Zones are not needed to restore system security to its equilibrium state.

To characterize how participants responded to this requirement, strike price curves were developed for all resources for 2007. The curves map out the percentage of registered MW at a given strike price. Figure 5 illustrates the strike price curves for 2003 to 2007, covering the period of time that the program provision has been in place. The steeper slope for the strike price curve overall indicates that strike prices are clustered close to the bid ceiling of $500/MWh. It is evident that participants have, over time, increased the number of higher strike prices. This phenomenon may result from the lack of events in which partial zonal load reduction calls have been initiated. With little likelihood of partial zonal calls, participants are less inclined to submit strike prices significantly below $500/MWh, since the strike price is used only to determine which resources are required to run during a partial zonal call.

Figure 5: 2003 - 2007 ICAP/SCR Curtailment Bid Curves



Emergency Demand Response Program/ICAP Special Case Resources 2007 Event Performance

In 2007, the NYISO activated EDRP and ICAP/SCR resources twice in the Targeted Demand Response Program, at the request of Con Edison.

Since response to a TDRP call is voluntary for ICAP/SCR resources in the activated subzone, no capacity performance is calculated for these events. Performance for purposes of determining energy payments is based upon the EDRP method of performance measurement, which calculates a Customer Baseline Load (CBL) from recent historical data to determine what the participant's energy consumption would have been if it had not reduced load. The CBL is determined as follows:

- Beginning with the weekday two days prior to the demand response event, look back ten weekdays and determine the five highest energy consumption days corresponding to the time period of the event. For example, if the demand response event occurs between noon and 4 pm, the baseline consumption is determined by the five previous days with the highest energy consumption between noon and 4 p.m.
- Take the average of the five readings for each hour to determine the baseline for that hour.

The difference between the hourly CBL and hourly interval meter readings serves as the measure of load reduction.

July 19:
EDRP and ICAP/SCR resources were activated in subzone J3 from 8 am to 11 pm in response to Con Edison's request in Zone J.

SCR resources provided 69% of the total MWh reductions (183.7 MWhs) for the 15-hour TDRP event (Table 8). While EDRP only provided 31% of the total MWh reductions for the event, on average EDRP resources provided 43% of the registered MWs for EDRP (Table 9) in the subzone with 92% of the resources responding (Table 10). Average hourly performance for ICAP/SCR resources in subzone J3 provided 26% of the registered MWs in the subzone (Table 9) with 29% of the resources responding (Table 10).

Table 8: Hourly Performance: Targeted Demand Response Event - July 19, 2007

	HB8	HB9	HB10	HB11	HB12	HB13	HB14	HB15	HB16	HB17	HB18	HB19	HB20	HB21	HB22	Total MWh	Payments
SCR	7.6	9.2	10.3	11.0	11.4	11.3	11.0	10.5	10.1	9.2	7.5	6.2	5.5	3.9	2.8	**127.5**	**$ 63,750**
EDRP	2.2	3.9	4.9	4.9	4.9	4.7	4.5	4.6	4.3	4.1	3.3	2.9	2.8	2.4	1.8	**56.2**	**$ 28,118**
	9.8	13.1	15.2	16.0	16.4	16.0	15.5	15.0	14.4	13.2	10.9	9.1	8.3	6.3	4.6	**183.7**	**$ 91,868**

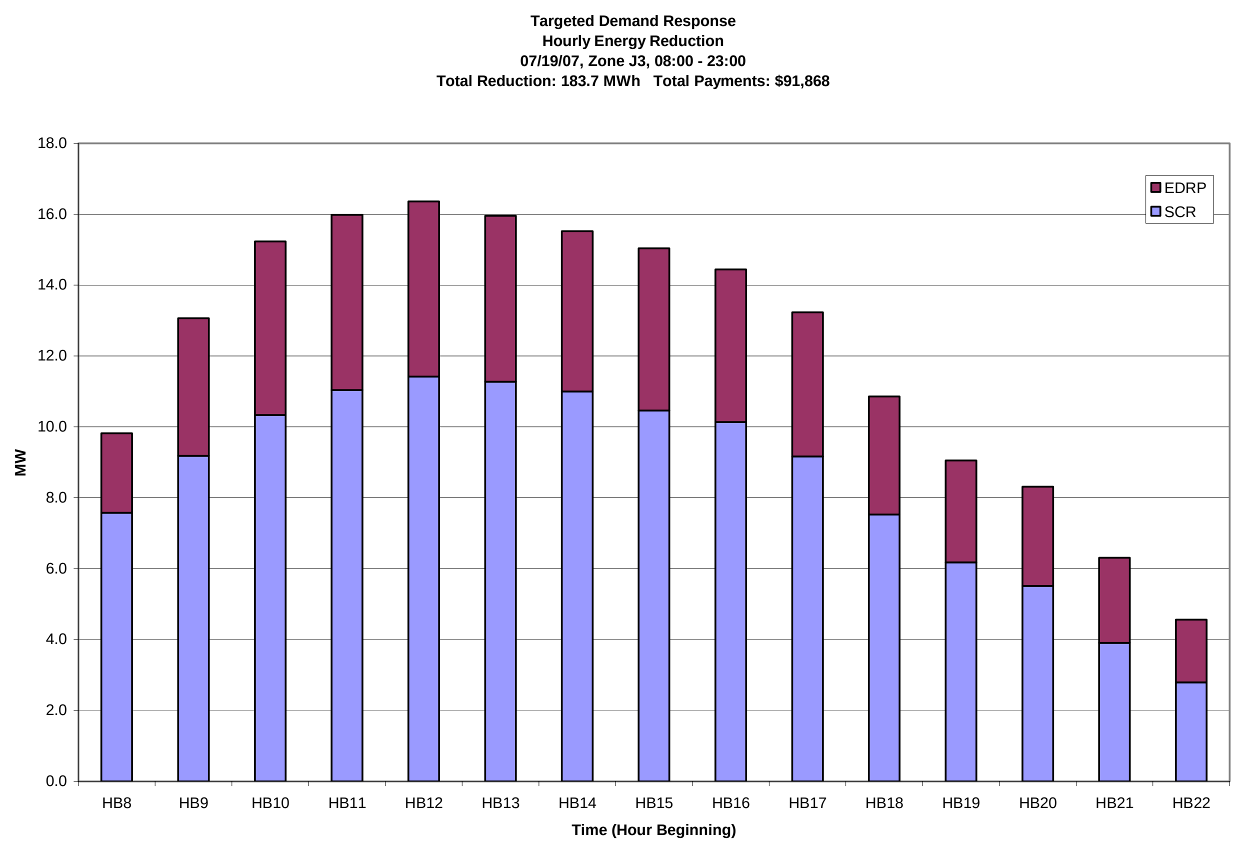
Table 9: Average Hourly Performance MW

	Avg. Hourly	Registered	% performance
SCR	9.9	38.9	25.5%
EDRP	4.2	9.8	42.7%
	14.1	48.7	28.9%

Table 10: Average Hourly Performance – Number of Resources

	Avg. Hourly	Registered	% performance
SCR	48	167	28.8%
EDRP	10	11	91.5%
	58.2	178	32.7%

Figure 6: Hourly Performance TDRP Event July 19, 2007



August 3:
EDRP and ICAP/SCR resources were activated in subzone J8 from 7:30 pm to midnight in response to Con Edison's request in Zone J.

EDRP resources provided 74% of the total MWh reductions (34.5 MWhs) for the 4.5-hour TDRP event (Table 11). On average EDRP resources provided 80% of the registered MW for EDRP (Table 12) in the subzone with 40% of the resources responding (Table 13). Average hourly performance for ICAP/SCR resources in subzone J3 provided 3% of the registered MWs (Table 12) in the subzone with 14% of the resources responding (Table 13).

Table 11: Hourly Performance: Targeted Demand Response Event – August 3, 2007

MWh	HB19	HB20	HB21	HB22	HB23	Total MWh	Payments
SCR	1.5	1.9	1.8	1.7	2.0	**9.0**	**$ 4,495**
EDRP	4.1	3.4	3.8	6.6	7.6	**25.5**	**$ 12,743**
	5.6	5.3	5.6	8.3	9.6	**34.5**	**$ 17,239**

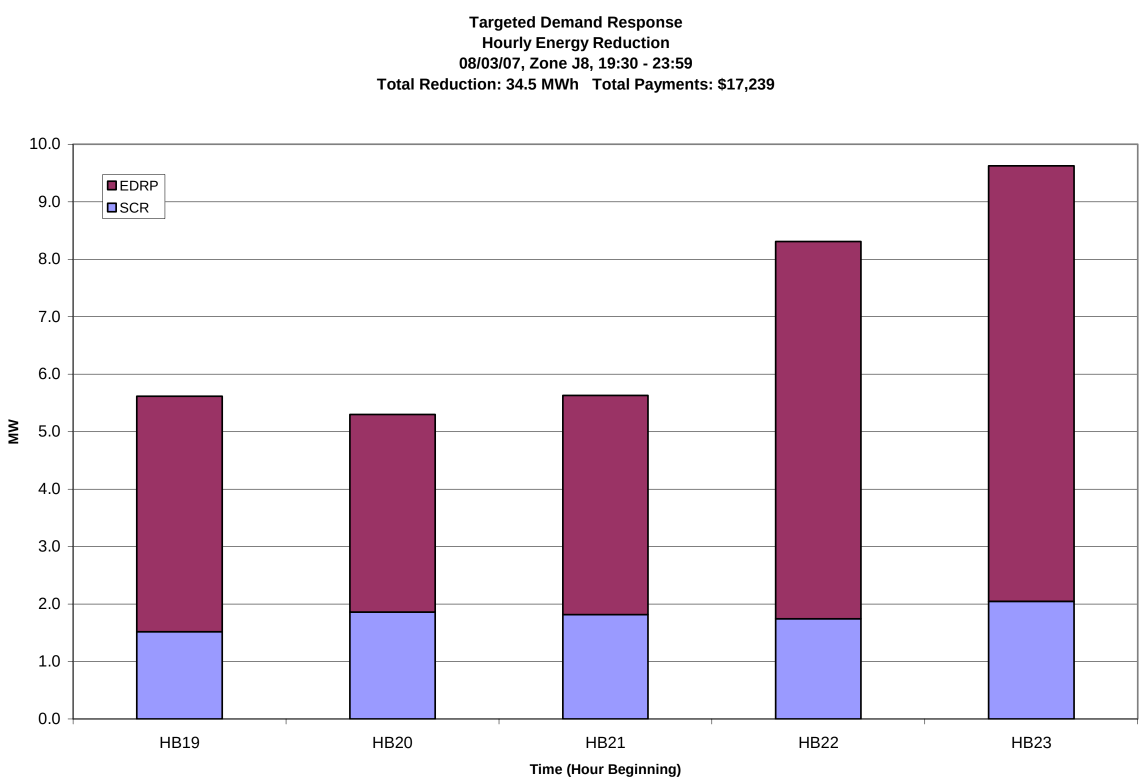
Table 12: Average Hourly Performance - MW

	Avg. Hourly	Registered	% performance
SCR	1.8	55	3.3%
EDRP	5.1	6.4	79.6%
	6.9	61.4	11.2%

Table 13: Average Hourly Performance - Number of Resources

	Avg. Hourly	Registered	% performance
SCR	32	233	13.6%
EDRP	5	12	40.0%
	36	245	14.9%

Figure 7: Hourly Performance TDRP Event – August 3, 2007



Day-Ahead Demand Response Program

The DADRP program provides retail customers with an opportunity to bid their load curtailment capability into the day-ahead spot market as supply resources. Customers submit bids by 5:00 a.m. specifying the hours and amount of load curtailment they are offering for the next day, and the price at which they are willing to curtail. Prior to November 1, 2004, the bid price had to be $50/MWh or higher. As of November 1, 2004, the minimum floor price for DADRP has been set at $75/MWh. Bids are structured like those of generation resources, so DADRP program participants may specify minimum and maximum run times and effectively submit a block of hours on an all or nothing basis. This structure makes participants eligible for bid production cost guarantee payments that make up for any difference between the market price during that block of hours and their block bid price. Load scheduled in the DAM is obligated to curtail the next day. Failure to curtail results in the imposition of a penalty defined by the MW curtailment shortfall multiplied by the greater of the corresponding day-ahead or real-time market price.

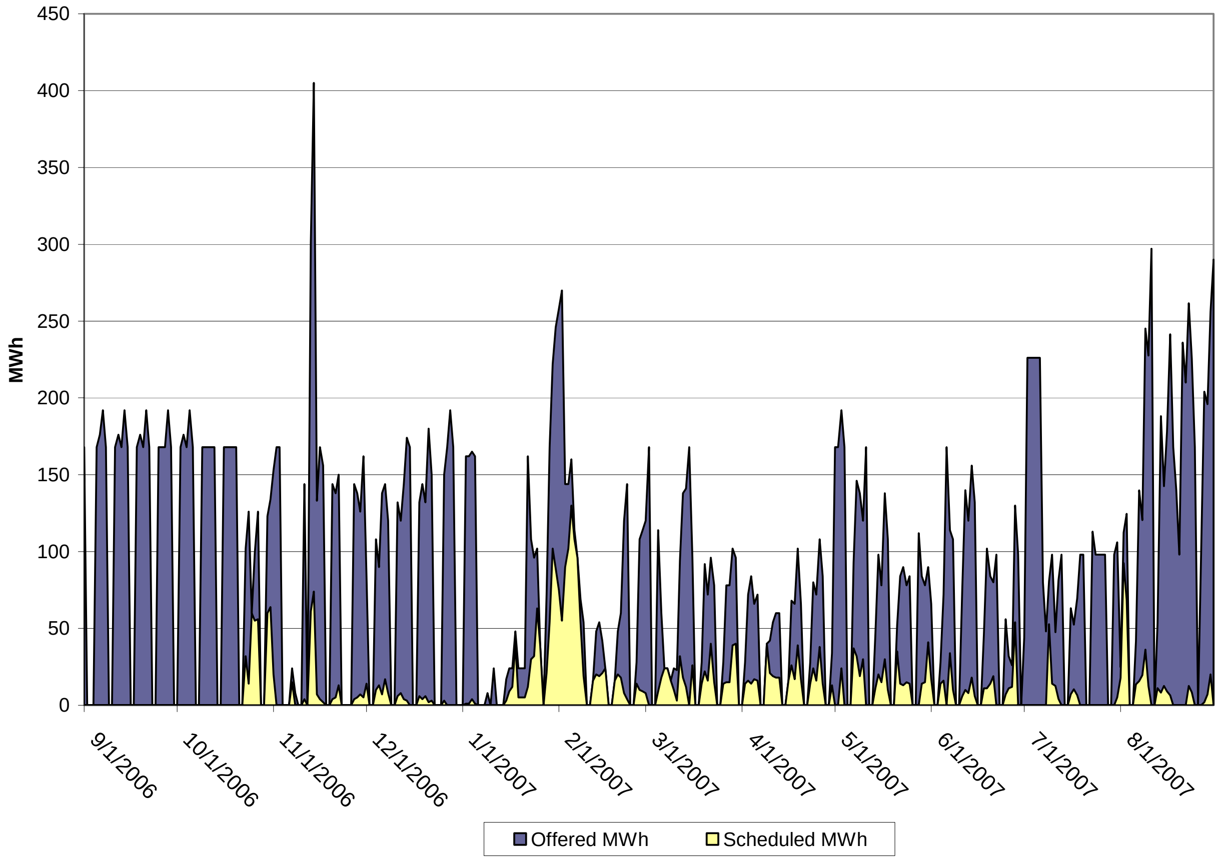
DADRP Participation and Bidding Summary

<u>Offered and Scheduled MWh</u>

During the analysis period of September 2006 through August 2007, only four resources submitted offers in Zone A (West) and Zone F (Capital). However, offer activity increased by more than 500% over the previous 12-month period and more than twice as many hours were scheduled as the previous period. In 2007, 36.6% of offers were scheduled compared to 93% of offers in 2006. The average DAM LBMP during the analysis period was $72.69 in Zone A, below the DADRP bid floor price, and $75.11 in Zone F, just slightly above the bid floor price of $75 and 28% lower than 2006.

Overall, the average hourly bid increased by 52%, from 3.06 MWs to 4.66 MWs, while scheduled bids decreased by 36% to 1.66MWs. Scheduled hours increased by 200% over the same period last year to 2,509 hours. Scheduled MWh increased by 19% to 4,152 MWhs.

Figure 8: DADRP MWh, Bid vs. Scheduled



In previous years, bidding was very limited, with a noteworthy number of bids occurring around holidays. In 2007, bidding occurred on a more regular, almost daily, basis (Figure 8). No DADRP bids were accepted in September because the average hourly DAM LBMP was $37.86 in Zone A and $48.44/MWh in Zone F, well below the bid floor in both zones. The maximum hourly DAM LBMP in September was also below the DADRP bid floor ($57.32 in Zone A and $69.40/MWh in Zone F).

DADRP bids scheduled in January and February accounted for more than one third of all scheduled MWhs (37.8%) in the analysis period. Average hourly DAM LBMPs in Zone F in January ($79.36/MWh) and February ($99.85/MWh) were among the four highest for the analysis period in the zone. In Zone A, February had the highest average hourly DAM LBMP in the analysis period ($55.73/MWh). As a result, average price reductions during these two months were two to three times higher during January and February, respectively (see Table 16). Although bidding was still very active in the summer months (June, July and August) of 2007, very few bids were scheduled due to average hourly DAM LBMPs below $75.00 in both zones.

Table 14 below shows a comparison of DADRP offer activity for the analysis periods of 2006 and 2007. In total, 37% of offered bids were accepted, while 13% of total MWhs offered were accepted. Overall, the average hourly bid increased by 52%, from 3.06 MWs in 2006 to 4.66

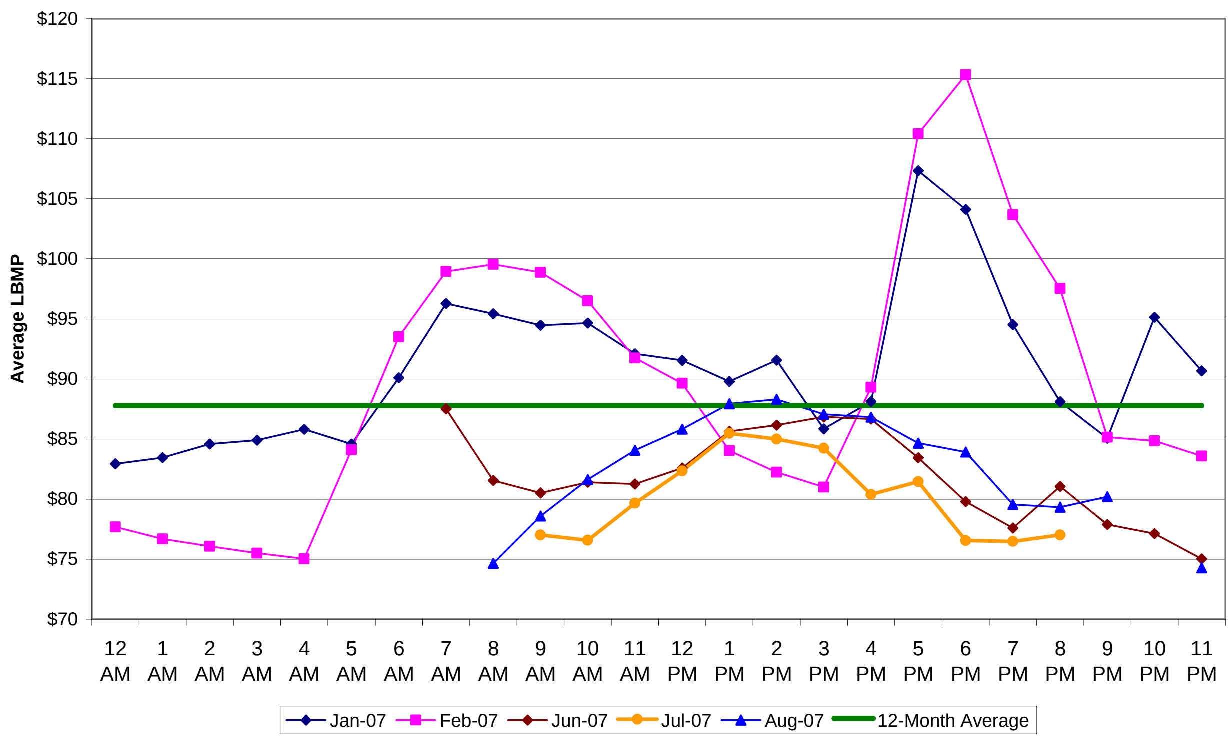
MWs. The average amount of scheduled MWs decreased by 42% from 2.88 MWs in 2006 to 1.65 MWs in 2007.

Table 14: DADRP Offer Activity – Comparison of 2006 and 2007

	2007	2006	% change
Total Offer Hours	6,860	1,301	427%
Scheduled Hours	2,509	1,210	107%
Offered MWh	31,943	3,982	702%
Scheduled MWh	4,152	3,479	19%
Average Offer	4.66	3.06	52%
Average Schedule	1.65	2.88	-42%

Figure 9 shows the average hourly DAM LBMP for scheduled DADRP bids for the months of January, February, June, July and August and the 12-month average of $72.69 in Zone A and $87.79/MWh in Zone F. Note that for all but two hours of the summer months, the average hourly DAM LBMP for scheduled bids is below the 12-month average. During the winter months of January and February, the average hourly DAM LBMP paid for scheduled bids ranges from $75.04/MWh to $115.33/MWh with 16 hours above the 12-month average in January and 12 hours above the 12-month average in February.

Figure 9: Average Hourly DAM LBMP by Month for Scheduled DADRP bids- selected months



When the top 50 hours in terms of Day-Ahead LBMP over the analysis period in Zone F are isolated, 27 hours had scheduled DADRP performance, including the highest hourly DAM LBMP. Table 15 shows the hours with the twenty highest Day-Ahead LBMPs; DADRP offers were scheduled in 13 of these top 20 hours. No DADRP offers were scheduled in any of the top 50 hours in Zone A.

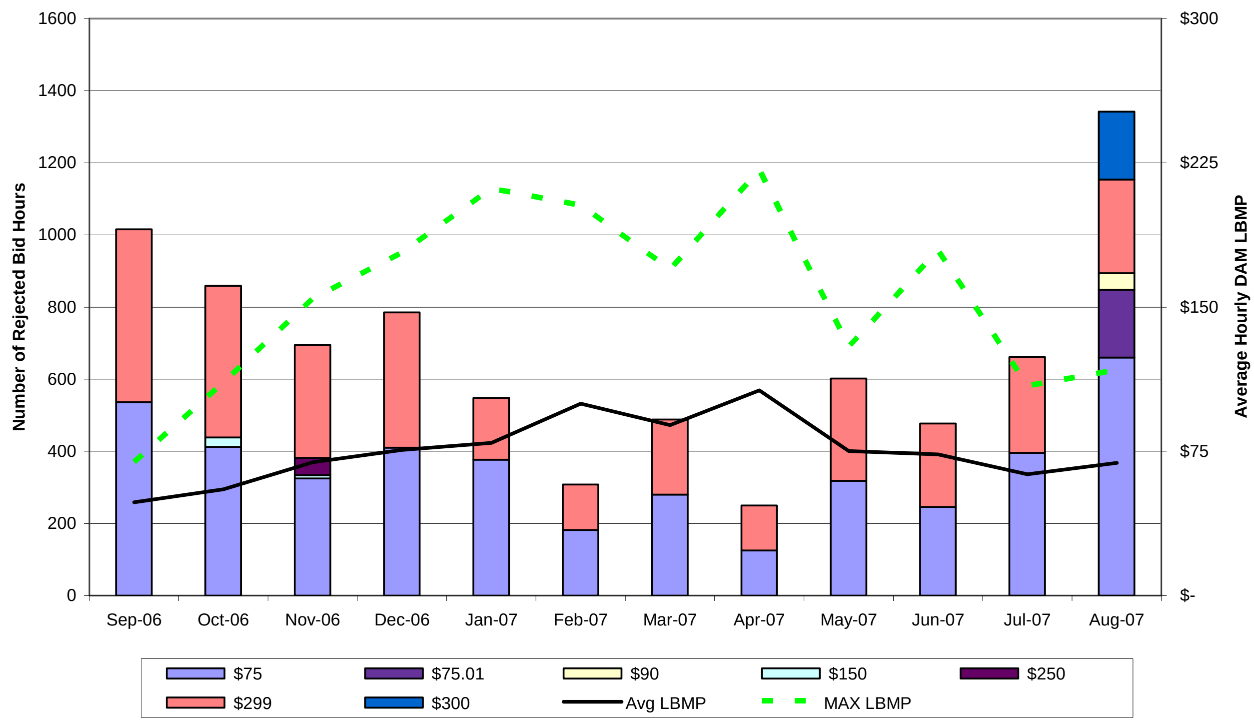
Table 15: Zone F (Capital) Scheduled DADRP Bids at High DAM LBMPs

Date	Hour	DAM LBMP	Scheduled MW
04/23/07	16	$ 221.46	1
01/26/07	17	$ 211.67	1
04/23/07	12	$ 210.30	1
04/09/07	20	$ 204.25	1
02/17/07	9	$ 202.91	0
04/23/07	11	$ 202.30	1
04/23/07	15	$ 198.21	1
01/25/07	17	$ 197.73	3.2
04/09/07	19	$ 194.42	1
04/23/07	14	$ 194.19	1
02/10/07	17	$ 194.18	0
04/08/07	19	$ 193.56	0
01/26/07	12	$ 191.08	2
01/26/07	11	$ 189.68	2
02/11/07	17	$ 189.59	0
01/26/07	18	$ 187.95	1
02/17/07	17	$ 187.57	0
04/21/07	20	$ 187.23	0
04/21/07	21	$ 186.68	0
04/23/07	13	$ 186.54	1

Rejected Offers

With the considerable increase in the number of offers by DADRP resources this year, the NYISO analyzed rejected bids for the reporting period of September 2006 through August 2007. Figure 10 shows the monthly distribution of the number of rejected hourly DADRP bids by price level with the monthly average DAM LBMP and monthly maximum DAM LBMP for the analysis period.. Unlike previous years, where bids were exclusively at the bid floor price, the analysis period shows offers at several price levels.

Figure 10: Rejected bids by Month



Price Reduction Impact

The DADRP offer data was analyzed to see how these scheduled load reductions affected the NYISO electricity market as a whole. Table 10 below outlines the results of the DADRP price reduction analysis for the period of September 2006 – August 2007 on a monthly basis. Performance is measured by the sum of all scheduled DADRP offers in that zone over the analysis period[3], while program payments are equal to the sum of the scheduled MWhs in a specific hour multiplied by the day-ahead LBMP[4]. The average price reduction represents the estimated impact that the DADRP performance had on the day-ahead LBMP.

The overall average hourly price reduction from scheduled DADRP load reductions is $0.10/MWh, no change from 2006. On a monthly basis, the average hourly price reduction was most significant in the months of January 2007 ($0.26/MWh) and February 2007 ($0.34/MWh), more than double that of the same months in 2006.

Table 16 shows price reduction analysis results. While one would expect the summer to generate the highest benefits when prices are typically higher, scheduled load reductions during the winter months (December, January and February) had the greatest price impact on day-ahead prices, followed by the spring months of March and April.

[3] We assume 100% compliance such that customer curtails the full scheduled MWh.

[4] This simplistic representation does not take into account any bid production cost guarantee potentially owed to the DADRP participant, but serves as a largely accurate proxy for payment.

Table 16: Price Reduction Analysis Results by Month

	Performance MWh	Program Payments	Average DAM LBMP ($) - Scheduled Hours	Average Price Reduction ($)	Number of Scheduled Hours
Sep-06	0	$ -	$ 48.44	$ -	0
Oct-06	341	$ 27,051.99	$ 55.19	$ 0.03	91
Nov-06	230	$ 19,605.06	$ 69.31	$ 0.03	75
Dec-06	114	$ 9,525.50	$ 75.73	$ 0.11	105
Jan-07	528	$ 49,122.38	$ 79.36	$ 0.26	191
Feb-07	928	$ 87,662.74	$ 99.85	$ 0.34	366
Mar-07	430	$ 38,318.09	$ 88.62	$ 0.14	304
Apr-07	427	$ 38,145.26	$ 106.62	$ 0.13	341
May-07	389	$ 31,693.93	$ 75.14	$ 0.06	216
Jun-07	278	$ 23,013.03	$ 73.33	$ 0.06	190
Jul-07	113	$ 9,386.87	$ 63.02	$ 0.02	58
Aug-07	374	$ 32,337.52	$ 69.00	$ 0.04	151
Total	4,152	$ 365,862.37	n/a	n/a	2,088
Average	346	$ 30,488.53	$ 75.30	$ 0.10	174

<u>Historical Analysis of DADRP</u>

Table 17 provides a summary of the scheduled reductions, scheduled hours, average hourly scheduled MWs, and program payments for each year since the DADRP program began. The results reported for 2001 reflect transactions in the months of July and August. For 2002, program payments include event months of April, July and August. All other totals for 2002 and all other years reflect DADRP transactions for the analysis period of September of the previous year through August of the current year. That is, the analysis period reported for 2007 includes all DADRP scheduled transactions between September 2006 and August 2007.

Table 17: DADRP Program Summary 2001-2007

	Scheduled DADRP MWh	Total Scheduled Hours	Average Hourly Schedule (MWh)	Program Payments**
2001	2,694	531	5.07	$ 217,487
2002	6,176	1,529	4.04	$ 110,216
2003	4,257	1,725	2.47	$ 263,311
2004	3,535	1,275	2.77	$ 209,624
2005	2,070	464	4.46	$ 172,376
2006	3,479	1,343	2.59	$ 332,941
2007	4,152	2,509	1.65	$ 365,862

** Total payments shown for 2001 are July and August. In 2002, payment totals include event months of April, July and August.

Figure 11 shows the history of scheduled MWhs by season since the program's inception. Winter 2007 had the greatest number of scheduled MWhs since the winter of 2002 and 22% above the overall average for winter. Spring 2007 had the greatest number of scheduled MWh since the program's inception and 60% above the overall average for spring. Scheduled MWh for summer 2007 are more than double the amount scheduled in the summer 2006 and 20% below the overall average for summer.

Figure 11: Total MWh Scheduled in DADRP by Season and Year, 2001-2007

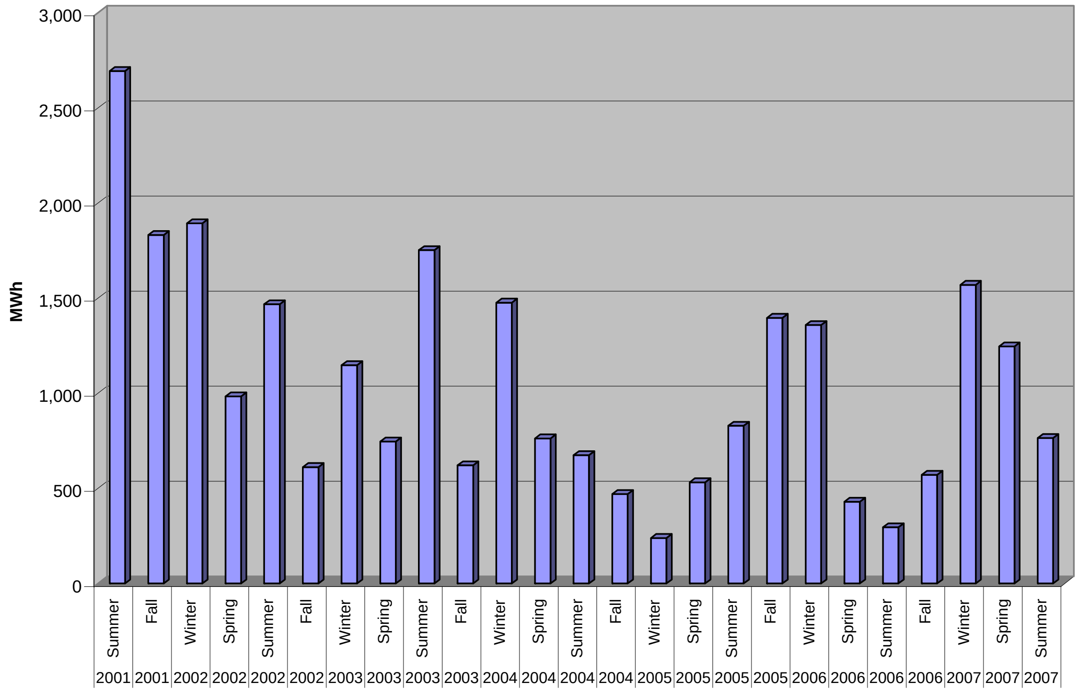


Figure 12 shows the history of the average scheduled DADRP bid by season since the program's inception. All four seasons in the 2007 analysis period were below the seasonal averages to date.

Figure 12: Average Scheduled DADRP Offer (MWh) by Season and Year, 2001-2007

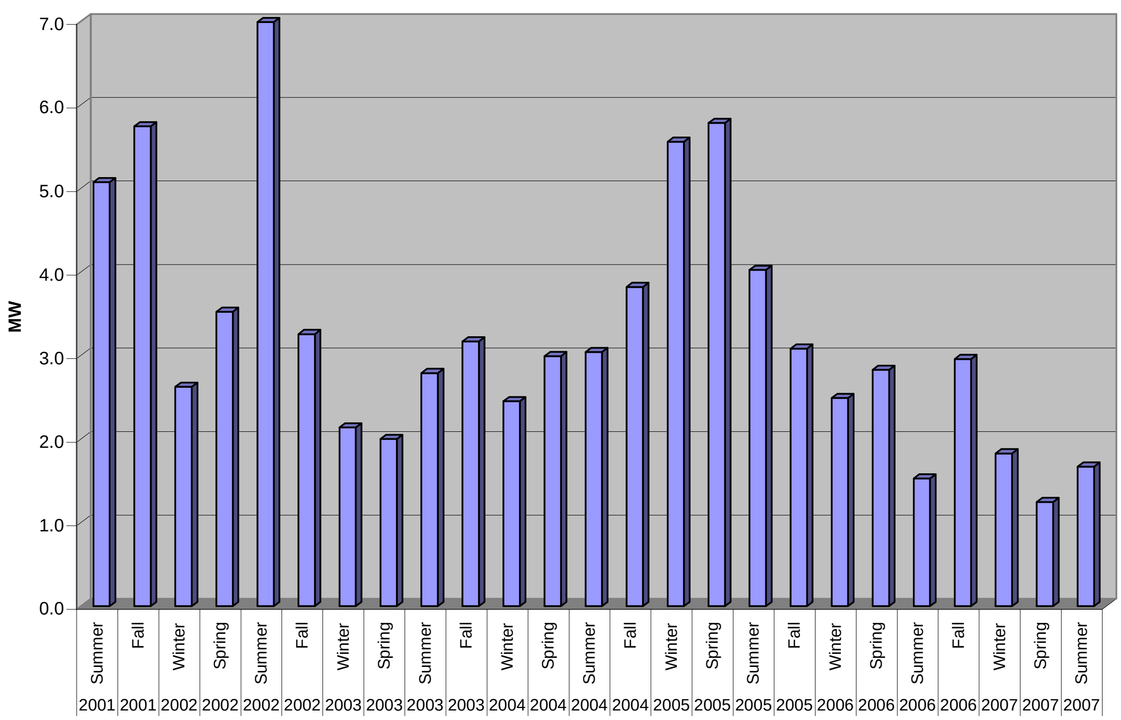
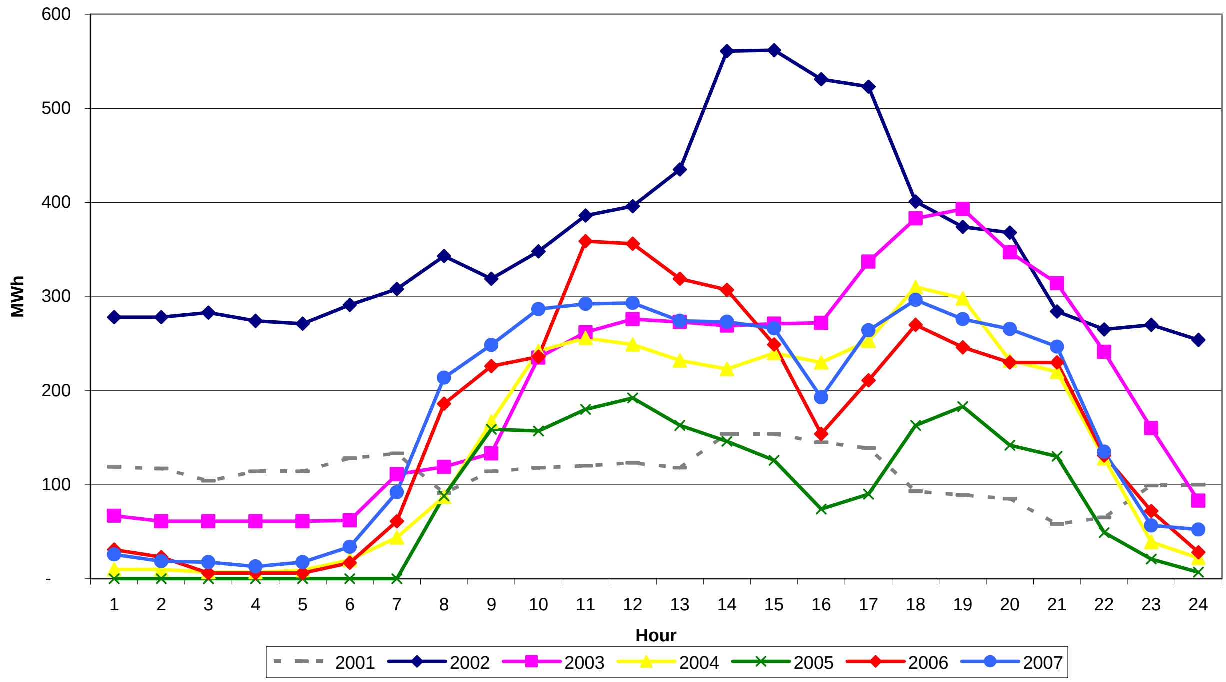


Figure 13 shows the distribution of scheduled DADRP offers by hour since the program's inception. Overall, scheduled bids in the overnight hours continue to be minimal since the program change in 2004 to raise the bid floor from $50/MWh to $75/MWh. Hourly scheduled MWhs in 2007 exceeded 2006 in all hours except the hours of 10 a.m. to 1 p.m.

Figure 13: Total Scheduled DADRP Offers (MWh) by Hour and Program Year (9/1 – 8/31) 2001*-2007 (*2001: July and August only)



DADRP Estimated Market Benefits Summary

When DADRP curtailments displaced higher-priced generation resources, the corresponding DAM clearing price dropped, thereby reducing the cost of purchases made by LSEs through fixed-price and price-cap load bids. Reduction in the average DAM LBMP for the summer of 2007 is compared to those from 2001 through 2006 in Table 18.

Table 18: DADRP Average Price Reductions (Summer Season)

	Scheduled DADRP MWh	Program Payments	Average Price Reduction ($)	Average Hourly Schedule (MWh)
2001	2,694	$ 217,487	$ 0.58	5.07
2002	1,468	$ 110,216	$ 0.30	6.99
2003	1,752	$ 121,144	$ 0.12	2.79
2004	675	$ 40,651	$ 0.07	3.04
2005	829	$ 77,885	$ 0.10	4.02
2006	295	$ 29,821	$ 0.05	1.53
2007	765	$ 64,737	$ 0.04	1.67

DADRP Conclusions

While 2007 reflected increased offers and total scheduled MWhs, there were a limited number of active participants. Offer prices varied more than in prior years. The 12-month average DAM LBMP of $87.79/MWh for scheduled hours, 17% above the DADRP bid floor. The overall average price reduction remained the same at $0.10/MWh, with greatest impact on prices occurring in the winter months of January and February at $0.26/MWh and $0.34/MWh, respectively. This is a trend change from previous years where average price reductions in winter months were only slightly higher than the overall average. Despite more than twice the number of MWh reductions scheduled over last summer, the average price reduction for the 2007 summer period was only $0.04/MWh.

NYISO Report on New Generation Projects

In its October 23, 2006 order, the Commission order the NYISO to submit "a list of investments in new generation projects in New York (including a description and current status of each such project), regardless of the stage of project development at the time of the filing."[1] The NYISO keeps a list of Interconnection Requests and Transmission Projects for the New York Control Area ("NYCA") that includes information about all generation projects in the state that have requested interconnection.

The NYISO interconnection process is described in Attachment X of the NYISO OATT, entitled, "Standard Large Facility Interconnection Procedures." Under Attachment X, Developers of Large Facilities[2] must submit an Interconnection Request to the NYISO. The NYISO assigns a Queue Position to all valid Interconnection Requests. Under Attachment X, proposed generation and transmission projects undergo up to three studies: the Feasibility Study, the System Reliability Impact Study, and the Facilities Study. The Facilities Study is performed on a Class Year basis for a group of eligible projects pursuant to the requirements of Attachment S of the NYISO OATT.

Proposed generation and transmission projects currently in the NYISO Interconnection Process are listed on the list of Interconnection Requests and Transmission Projects for the NYCA ("NYISO Interconnection Queue"). The generation projects on that list are shown in Attachment A, which is dated January 8, 2008.

The status of each project on the NYISO Interconnection Queue is shown in the column labeled "S." Explanations for this, and various other columns of the list, are provided in the notations at the bottom of each page of the report and are also explained in Attachment B. NYISO updates the NYISO Interconnection Queue on a weekly basis and posts the most recent list on the NYISO's public web site at http://www.nyiso.com/public/services/planning/interconnection_studies_process.jsp. Note that the proposed in-service dates for each project are those provided to the NYISO by the respective Owner/Developer, are updated only on a periodic basis, and are subject to change.

[1] *New York Indep. Sys. Operator, Inc.*, 117 FERC ¶ 61,086, at P 14 (2006).

[2] A Large Facility under Attachment X is either a Generating Facility with a capacity of more than 20 MW or a Merchant Transmission Facility.

INTERCONNECTION REQUESTS AND TRANSMISSION PROJECTS / NEW YORK CONTROL AREA

Queue Pos.	Owner/Developer	Project Name	Date of IR	SP (MW)	WP (MW)	Type/ Fuel	Location County/State	Interconnection Point	Utility	S	Last Update	Studies Available	Proposed In-Service
13	East Coast Power, LLC	Linden 7	3/25/99	100		ST-NG	Richmond, NY-NJ	Goethals 345kV	CONED	4	1/8/08	None	*None*
16	Oak Point Property, LLC	Oak Point Yard	4/15/99	500		CC-NG	Bronx, NY	Hell Gate/Bruckner 138kV	CONED	6	6/26/07	SRIS	2009/Q2
18	NYPA	Poletti Expansion	4/30/99	500		CC-NG	Queens, NY	Astoria 138kV	CONED	14	5/1/06	SRIS, FS	I/S
19	NYC Energy LLC	NYC Energy LLC	5/7/99	79.9		CT-NG	Kings, NY	Kent Ave 138kV	CONED	10	3/27/07	SRIS, FS	2008/Q4
20	KeySpan Energy, Inc.	Spagnoli Road CC Unit	5/17/99	250		CC-NG	Suffolk, NY	Spagnoli Road 138kV	LIPA	8	1/8/08	SRIS	2009/06
31	SCS Energy, LLC	Astoria Energy	11/16/99	1000		CC-NG	Queens, NY	Astoria 138kV	CONED	12,14	1/8/08	SRIS, FS	2010/05
33	Glenville Energy Park, LLC	Glenville Energy Park	11/30/99	540		CC-NG	Schenectady, NY	Rotterdam 230kV	NM-NG	6	6/26/07	SRIS	*None*
35	Gotham Power Zerega, LLC	Gotham Power - Bronx I	1/12/00	79.9		CT-NG	Bronx, NY	Parkchester/Tremont 138kV	CONED	5	1/8/08	None	*None*
36	Boundless Energy, LLC	Project Neptune DC NB-NYC	1/21/00	1200		DC	Kings, NY	Farragut 345kV	CONED	8	6/26/06	SRIS	*None*
65	Fortistar-Lockport Merchant	Lockport II Gen Station	5/15/00	79.9		CT-NG	Niagara, NY	Harrison Station 115kV	NYSEG	10	12/27/06	SRIS, FS	2007/Q2
69	Besicorp-Empire Power Co., LLC	Empire State Newsprint	7/14/00	660		CC-NG	Rensselaer, NY	Reynolds Road 345kV	NM-NG	11	3/27/07	SRIS, FS	2009/Q4
90	Fortistar, LLC	Fortistar VP	3/20/01	79.9		CT-NG	Richmond, NY	Fresh Kills 138kV	CONED	8	6/26/07	SRIS	2007/Q2
91	Fortistar, LLC	Fortistar VAN	3/20/01	79.9		CT-NG	Richmond, NY	Goethals/Fresh Kills 138kV	CONED	8	6/26/07	SRIS	2007/Q2
94	Atlantic Energy, LLC	Project Neptune DC PJM-LI	5/22/01	660		DC	Nassau, NY-NJ	Newbridge Road 138kV	LIPA	12	12/27/06	SRIS, FS	2007/Q3
96	Calpine Eastern Corporation	CPN 3rd Turbine, Inc. (JFK)	5/29/01	45		CT-NG	Queens, NY	Jamaica 138kV	CONED	10	3/27/06	SRIS, FS	2010
106	TransGas Energy, LLC	TransGas Energy	10/5/01	1100		CC-NG	Kings, NY	E13St, Rainey, or Farragut-345kV	CONED	8	6/26/07	SRIS	2012/Q3
107	Caithness Long Island, LLC	Caithness Long Island	10/9/01	310		CC-NG	Suffolk, NY	Brookhaven-Holbrook or H'ville	LIPA	10	8/14/07	SRIS	2008/Q2
111	River Hill Power Co., LLC	River Hill Project	2/5/02	290		CT-NG	Chemung, NY-PA	Homer City-Watercure 345kV	NYSEG	5		None	2008
113	Windfarm Prattsburgh, LLC	Prattsburgh Wind Park	4/22/02	55.5		W	Yates, NY	Eelpot Rd-Flat St. 115kV	NYSEG	11	3/27/06	SRIS, FS	2007/11
115	Central Hudson Gas & Electric	East Fishkill Transformer	4/24/02	N/A		AC	Dutchess, NY	East Fishkill 345kV/115kV	CONED/CHG&E	4		None	*None*
119	ECOGEN, LLC	Prattsburgh Wind Farm	5/20/02	79.5		W	Yates, NY	Eelpot Rd-Flat St. 115kV	NYSEG	10	3/12/07	SRIS, FS	2008/06
125	East Coast Power, LLC	Linden VFT Inter-Tie	7/18/02	300		AC	Kings, NY-NJ	Goethals 345kV	CONED	10	8/14/07	SRIS	2007/Q1
127A	Airtricity Developments, LLC	Munnsville	10/9/02	40		W	Madison, NY	46kV line	NYSEG	12,14	1/8/08	SRIS	2007/09
135	UPC Wind Management, LLC	Canandaigua Wind Farm	5/30/03	82.5	82.5	W	Ontario, NY	Avoca 230kV line	NYSEG	10	8/14/07	SRIS	2007/Q4
136	Rochester Gas & Electric	Rochester Transmission	6/12/03	N/A		AC	Monroe, NY	RG&E System	RG&E	6		SRIS	2008/F
138	Entergy Nuclear Operations, Inc.	Indian Point 2 Uprate	7/23/03	36		NU	Westchester, NY	Buchanan 345kV	CONED	14	12/27/06	SRIS, FS	I/S
139	Entergy Nuclear Operations, Inc.	Indian Point 3 Uprate	7/23/03	38		NU	Westchester, NY	Indian Point 345kV	CONED	14	12/27/06	SRIS, FS	I/S
140	National Grid	Leeds-PV Reconductoring	8/26/03	N/A		AC	Greene-Dutchess, NY	Leeds/Athens-Pl. Valley 345kV	NM-NG	5	3/27/06	None	*None*
141	Flat Rock Wind Power, LLC	Flat Rock Wind Power	8/27/03	321		W	Lewis, NY	Adirondack-Porter 230kV	NM-NG	14	12/27/06	SRIS, FS	I/S
142	Airtricity Developments, LLC	Hartsville Wind Farm	10/30/03	50		W	Steuben, NY	Bennett-Palmiter 115kV line	NYSEG	6	6/26/07	SRIS	*None*
143	Constellation	Ginna Uprate Project	1/30/04	95		NU	Wayne, NY	Ginna-115kV	RG&E	14	6/26/07	SRIS, FS	I/S
144	Invenergy Wind, LLC	High Sheldon Windfarm	2/18/04	129	129	W	Wyoming, NY	Stolle Rd-Meyer 230kV	NYSEG	9	8/14/07	SRIS	2007/12
145	KeySpan Energy for LIPA	LIPA Summer Mobile Gens	3/2/04	96		CT-NG	Suffolk, NY	Holtsville and Shoreham 138kV	LIPA	6	8/21/06	SRIS	2005-07
146	Con Edison	Mott Haven Substation	3/16/04	N/A		AC	Westchester, NY	Dunwoodie-Rainey lines	CONED	6		SRIS	2007/S

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147	NY Windpower, LLC	West Hill Windfarm	4/16/04	37.5		W	Madison, NY	Oneida-Fenner 115kV	NM-NG	10	8/14/07	SRIS	2007/12
150	Reunion Power, LLC	Cherry Valley Wind Power	6/17/04	70		W	Otsego, NY	East Springfield 115kV	NM-NG	5	12/27/06	None	2007/Q4
151	Con Edison	West Side Switching Station	6/30/04	N/A		AC	New York, NY	West 49th St & Farragut 345kV	CONED	4		None	2011S
152	Invenergy Wind, LLC	Stamford Wind Project	7/23/04	129	129	W	Delaware, NY	Axtell Road-Grand Gorge 115kV	NYSEG	6	6/26/07	SRIS	*None*
153	Con Edison	Sprain Brook-Sherman Creel	8/13/04	500		AC	Westchester, NY	Sprain Brook & Sherman Creek	CONED	6	1/30/07	SRIS	2009/03-2009/12
154	KeySpan Energy for LIPA	Holtsville-Brentwood-Pilgrim	8/19/04	N/A		AC	Suffolk, NY	Holtsville & Pilgrim 138kV	LIPA	5		None	2007/06
155	Invenergy NY, LLC	Canisteo Hills Windfarm	9/17/04	149		W	Steuben, NY	Bennett-Bath 115kV	NYSEG	5	8/23/07	FES	*None*
156	PPM Energy/Atlantic Renewable	Fairfield Wind Project	9/28/04	120	120	W	Herkimer, NY	Valley-Inghams 115kV	NM-NG	10	8/14/07	SRIS	2008/10
157	BP Alternative Energy NA, Inc.	Orion Energy NY I	10/12/04	100	100	W	Herkimer, NY	Watkins Rd.-Inghams 115kV	NM-NG	5	8/23/07	FES	2008/12
160	Jericho Rise Wind Farm, LLC	Jericho Rise Wind Farm	10/12/04	101.2	101.2	W	Franklin, NY	Willis-Malone 115 kV	NYSEG	6	8/23/07	FES, SRIS	2009-2011
160A	Innovative Energy Systems Inc.	DANC	11/19/04	4.8	4.8	M	Jefferson, NY	115kV	NM-NG	9	11/13/07	None	2007/10
161	Marble River, LLC	Marble River Wind Farm	12/7/04	84	84	W	Clinton, NY	Willis-Plattsburgh WP-1 230kV	NYPA	10	8/14/07	SRIS	2008/Q4
163	Clipper Windpower Dev. Co. Inc.	Paragon I Wind Generation	1/13/05	100	100	W	Steuben, NY	Bath-Montour Falls 115kV	NYSEG	5	8/23/07	FES	*None*
164	FPL Energy	Long Island Offshore Wind	1/28/05	140	140	W	Suffolk, NY	Sterling Substation	LIPA	5		None	2007/12-2008/06
164A	Casella Waste Systems	Clinton County Landfill	1/31/05	6.4	6.4	M	Clinton, NY	46kV	NYSEG		7/3/07	None	TBD
166	AES New York Wind, LLC	St. Lawrence Wind Farm	2/8/05	130	130	W	Jefferson, NY	Lyme Substation 115kV	NM-NG	9	8/14/07	SRIS	2008/12
168	Dairy Hills Wind Farm, LLC	Dairy Hills Wind Farm	2/8/05	120	120	W	Wyoming, NY	Stolle Rd.-Meyer 230kV	NYSEG	9	8/14/07	SRIS	2009/11
169	Alabama Ledge Wind Farm, LLC	Alabama Ledge Wind Farm	2/8/05	79.2	79.2	W	Genesee, NY	Oakfield-Lockport 115kV	NM-NG	6	4/24/07	SRIS	2009-2011
171	Marble River, LLC	Marble River II Wind Farm	2/8/05	134	134	W	Clinton, NY	Willis-Plattsburgh WP-2 230kV	NYPA	10	8/14/07	SRIS	2008/Q4
172	Noble Environmental Power, LLC	Clinton Windfield	2/14/05	80	80	W	Clinton, NY	Willis-Plattsburgh WP-2 230kV	NYPA	10	8/14/07	SRIS	2007/12
173	Noble Environmental Power, LLC	Bliss Windfield	2/14/05	72	72	W	Wyoming, NY	Arcade Substation 115kV	Village of Arcade	10	8/14/07	SRIS	2007/12
174	Noble Environmental Power, LLC	Altona Windfield	2/14/05	99	99	W	Clinton, NY	Willis-Plattsburgh WP-1 230kV	NYPA	10	8/14/07	SRIS	2007/12
175	Noble Environmental Power, LLC	Ellenburg Windfield	2/14/05	79.5	79.5	W	Clinton, NY	Willis-Plattsburgh WP-2 230kV	NYPA	10	8/14/07	SRIS	2007/12
177	Noble Wethersfield Windpark, LL(	Wethersfield 230kV	2/14/05	127.5	127.5	W	Wyoming, NY	Stolle-Meyer 230kV	NYSEG	9	1/8/08	SRIS	2008/12
178	Noble Centerville Windpark, LLC	Allegany Windfield	2/14/05	99	99	W	Cattaraugus, NY	Ellicottville - Springville 115kV	NM-NG	6	4/24/07	SRIS	2009/07
179	Noble Environmental Power, LLC	Cherry Hill Windpark	2/14/05	102	102	W	Franklin, NY	Nicholville-Malone 115kV	NYSEG	5	2/12/07	None	2008/10
182	Everpower Global	Howard Wind	3/21/05	62.5	62.5	W	Steuben, NY	Bennett-Bath 115kV	NYSEG	9	8/14/07	SRIS	2008/11
185	New York Power Authority	Blenheim Gilboa Storage	3/29/05	120	120	H	Schoharie, NY	Valenti Rd., Gilboa	NYPA	10	8/14/07	SRIS	2007/05
186	Community Energy	Jordanville Wind	4/1/05	150	150	W	Herkimer, NY	Porter-Rotterdam 230kV	NM-NG	10	8/14/07	SRIS	2007/12
187	NY Windpower, LLC	North Slope Wind	4/5/05	109.5	109.5	W	Clinton, NY	Willis-Plattsburgh 230kV	NYPA	5	8/23/07	FES	2009-2010
189	PPM Energy, Inc.	Clayton Wind	4/8/05	126	126	W	Jefferson, NY	Coffeen St-Thousand Island 115k	NM-NG	9	8/23/07	FES	2008/12
191	New York Regional	New York Regional	5/13/05	1200	1200	DC	Oneida-Orange NY	Edic - Rock Tavern	NM-NG/CH	5	6/26/07	None	2010
195	Brookfield Power US	Harbor Cable Project II	6/14/05	200	200	DC	NY, NY - Union, NJ	Goethal 345kV	CONED	4	8/23/07	FES	2011/06
197	PPM Roaring Brook, LLC / PPM	Tug Hill	7/1/05	79.9	79.9	W	Lewis, NY	Boonville-Lowville 115kV	NM-NG	5	8/23/07	FES	2009/12

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198	New Grange Wind Farm, LLC	New Grange Wind Farm	7/21/05	79.9	79.9	W	Chautauqua, NY	Dunkirk-Falconer 115kV	NM-NG	5	1/8/08	FES	2009-2011
199	UPC Wind Management, LLC	Canandaigua II	7/26/05	42.5	42.5	W	Ontario, NY	Meyer - Avoca 230kV	NYSEG	9	8/14/07	SRIS	2007/Q4
201	NRG Energy	Berrians GT	8/17/05	200	200	CC-NG	New York, NY	Astoria West Substation	CONED	5	3/27/07	None	2008/02
201A	Innovative Energy Systems	Seneca Energy Expansion	9/2/05	17.6	17.6	M	Seneca, NY	34.5kV	NYSEG	10	7/3/07	None	I/S
201B	Minnesota Methane, LLC	MM Albany Landfill	9/15/05	2	4	M	Albany, NY	34.5kV	NM-NG		7/10/07	None	2007/07
203	GenWy Wind, LLC	GenWy Wind Farm	10/21/05	478.5	478.5	W	Genesee, NY	Stolle Rd - Homer City 345kV	NYSEG	5	8/23/07	FES	2008/10
204	Clipper Windpower Dev. Co. Inc.	Paragon II Wind Generation	10/27/05	150	150	W	Steuben, NY	Avoca - Hillside 230kV	NYSEG	5	8/23/07	FES	2007/12
204A	Windhorse Power LLC	Windhorse Beekmantown	10/31/05	19.5	19.5	W	Clinton, NY	46kV	NYSEG	10	8/23/07	None	2008/Q4
205	National Grid	Luther Forest	11/2/05	40	40		Saratoga, NY	Round Lake 115kV	NM-NG	6	12/27/06	SRIS	2007/09
206	Hudson Transmission Partners	Hudson Transmission	12/14/05	660	660	DC/AC	NY, NY - Bergen, NJ	West 49th Street 345kV	CONED	5	8/23/07	FES	2009/Q2
207	BP Alternative Energy NA, Inc.	Cape Vincent	1/12/06	210	210	W	Jefferson, NY	Cape Vincent	NM-NG	5	8/23/07	FES	2009/Q4
209A	Casella Waste Systems	Hyland Landfill	2/28/06	4.8	4.8	M	Livingston, NY	34.5kV	NYSEG	9	12/18/07	None	2007/10
210	Canadian Niagara Power, Inc.	Fortran	3/14/06	150	150	AC	Niagara, NY	Huntley Station	NM-NG	4	11/13/07	None	2008/Q1
211	Noble Environmental Power, LLC	Clinton II Windfield	4/3/06	21	21	W	Clinton, NY	Willis-Plattsburgh WP-2 230kV	NYPA	9	8/14/07	SRIS	2007/12
212	Noble Environmental Power, LLC	Bliss II Windfield	4/3/06	30	30	W	Wyoming, NY	Freedom Substation 115kV	Village of Arcade	9	8/14/07	SRIS	2007/12
213	Noble Environmental Power, LLC	Ellenburg II Windfield	4/3/06	21	21	W	Clinton, NY	Willis-Plattsburgh WP-2 230kV	NYPA	9	9/4/07	SRIS	2008/12
214	Noble Environmental Power, LLC	Chateaugay Windpark	4/3/06	106.5	106.5	W	Franklin-Clinton, NY	Willis-Plattsburgh 230kV	NYPA	9	8/23/07	FES	2008/12
215	Noble Environmental Power, LLC	Noble Burke Windpower	4/3/06	120	120	W	Franklin-Clinton, NY	Willis Substation 230kV	NYPA	5	9/4/07	FES	2009/10
216	Nine Mile Point Nuclear, LLC	Nine Mile Point Uprate	5/5/06	168	168	NU	Oswego, NY	Nine Mile Piont Station #2	NM-NG	5	5/1/07	None	2010/Q3
217	AES Keystone Wind, LLC	Cherry Flats	6/6/06	90	90	W	Tioga, PA	Homer City-Watercure 345kV	NYSEG	5	6/5/07	None	2009/11
217A	New Athens Generating Co., LLC	Athens SPS Project	6/30/06	TBD	TBD	AC	Greene-W.Chester, NY	Athens - Millwood	NM-NG/CONED	6	4/24/07	SIS	2007
219	NRG Energy, Inc.	Huntley	7/12/06	752	752	CC	Niagara, NY	Tonawanda	NM-NG	4	8/23/07	None	2011/Q1
220	AES Keystone Wind, LLC	Armenia Mountain I	7/19/06	175	175	W	Bradford, PA	Homer City-Watercure 345kV	NYSEG	5	6/5/07	None	2009/11
221	AES Keystone Wind, LLC	Armenia Mountain II	7/19/06	75	75	W	Bradford, PA	Homer City-Watercure 345kV	NYSEG	5	6/5/07	None	2009/11
222	Noble Environmental Power, LLC	Ball Hill Windpark	7/21/06	99	99	W	Chautauqua, NY	Dunkirk-Gardenville 230kV	NM-NG	4	6/5/07	None	2008/10
224	NRG Energy, Inc.	Berrians GT II	8/23/06	322.5	316.5	CT-NG	New York, NY	Astoria Substation	CONED	3	8/14/07	None	2010/06
224A	Bio-Energy Partners	High Acres Landfill	8/25/06	6.4	6.4	M	Monroe, NY	34.5	NYSEG	10	11/13/07	None	2007/05
224B	Casella Waste Systems	Chemung Landfill	9/5/06	6.4	6.4	M	Chemung, NY	115kV	NYSEG	4	8/23/07	None	TBD
225	New York State Electric & Gas	Ithaca Transmission	9/7/06	TBD	TBD	AC	Thompkins, NY	Oakdale - Lafayette 345kV	NYSEG	6	4/24/07	SIS	2009/12
225A	Schenectady International, Inc.	SII Rotterdam Junctoin	9/8/06	9.3	9.3	W	Rotterdam, NY	69kV	NM-NG	10	7/3/07	None	TBD
225B	Burrstone Energy	Faxton/ St. Luke	9/15/06	2.2	2.2	NG	Utica, NY	TBD	NM-NG		7/3/07	None	TBD
227	Airtricity, Inc.	Orleans Wind	9/28/06	120	120	W	Orleans, NY	Shelby Substation - 115kV	NM-NG	3	3/12/07	None	2008/Q3
227A	Laidlaw Energy Group Inc.	Laidlaw Energy & Env.	10/30/06	7	7	Wo	Cattaraugus, NY	13.2kV	NM-NG		1/8/08	None	TBD
231	Seneca Energy II, LLC	Seneca	11/2/06	24	24	CT-NG	Seneca, NY	Goulds Substation	NYSEG	5	6/5/07	None	2009/07

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232	Hess Corporation	Bayonne Energy Center	11/27/06	512.5	512.5	D	Bayonne, NJ	Gowanus Substation 138kV	ConEd	4	11/13/07	None	2009/06
233	Erie Boulevard Hydro Power, LP	Sherman Island Uprate	11/27/06	39.5	39.5	H	Warren, NY	Spier - Queensbury 115kV	NM-NG	5	4/24/07	None	2007/10
234	Steel Winds, LLC	Steel Winds II	12/8/06	60	60	W	Erie, NY	Substation 11A 115kV	NM-NG	5	4/24/07	None	2007/12
236	Gamesa Energy USA, LLC	Dean Wind	12/14/06	150	150	W	Tioga - Schuyler, NY	Watercure-Oakdale 345kV	NYSEG	4	12/18/07	None	2009/12
237	Allegany Wind, LLC	Allegany Wind	1/9/07	79	79	W	Cattaraugus, NY	Homer Hill – Dugan Rd. 115kV	NM-NG	3	8/23/07	None	2009/10
237A	Chautauqua County	Chautauqua Landfill	1/11/07	6.4	6.4	M	Chautauqua, NY	Hartfield – South Dow 34.5kV	NM-NG	5	11/13/07	None	2007/12
238	Tonawanda Creek Wind, LLC	Tonawanda Creek Wind	1/30/07	75	75	W	Genesee, NY	Lockport – Batavia 115kV	NM-NG	3	8/23/07	None	2010/11
239	Western Door Wind, LLC	Western Door Wind	1/30/07	100	100	W	Yates, NY	Greenidge – Haley Rd. 115kV	NYSEG	3	8/23/07	None	2010/10
239A	Innovative Energy System, Inc.	Modern Innovative Plant	1/31/07	6.4	6.4	M	Niagara, NY	Youngstown – Sanborn 34.5kV	NM-NG	5	11/13/07	None	2007/12
240	Noble Environmental Power, LLC	Farmersville Windpark	2/26/07	100	100	W	Cattaraugus, NY-PA	Stolle Rd - Farmer's Valley 345kV	NM-NG	3	8/14/07	None	2009/07
241	Noble Environmental Power, LLC	Chateaugay II Windpark	3/15/07	19.5	19.5	W	Franklin, NY	Chateaugay Substation 115kV	NYSEG	3	8/14/07	None	2008/07
243	Astoria Energy, LLC	Astoria Uprate	4/12/07	100	230	CC-NG	Queens, NY	Astoria East Substation	ConEd	5	1/8/08	None	2010/05
244	AES Bainbridge, LLC	Jennison	4/13/07	650	650	C	Chenango, NY	Oakdale – Fraser 345kV	NYSEG	3	11/13/07	None	2012/12
245	Innovative Energy System, Inc.	Fulton County Landfill	4/17/07	3.2	3.2	M	Montgomary, NY	Ephratah – Amsterdam 69kV	NM-NG	3	8/23/07	None	2008/Q3
246	PPM Energy, Inc	Dutch Gap Wind	6/1/07	250	250	W	Jefferson, NY	Indian River Substation 115kV	NM-NG	3	8/23/07	None	2010/12
247	RG&E	Russell Station	6/11/07	300	300	CC-NG	Monroe, NY	Russell Station 115kV	RG&E	4	8/23/07	None	2013/07
250	Seneca Energy II, LLC	Ontario	7/2/07	6.4	6.4	M	Ontario, NY	Haley Rd. - Hall 34.5kV	NYSEG	3	10/16/07	None	2009/10
251	CPV Valley, LLC	CPV - Valley	7/5/07	630	630	CC	Orange, NY	Coopers – Rock Tavern 345kV	NYPA	3	10/16/07	None	2012/05
252	Brookfield Power	Manhattan Cable	8/1/07	350	350	DC	New York, NY	World Trade Center 138 kV	ConEd	2	10/2/07	None	2011/06
253	Marble River, LLC	Marble River SPS	8/13/07	TBD	TBD	N/A	Clinton, NY	Moses-Willis-Plattsburgh 230kV	NYPA	4	1/8/08	None	2007/12
254	Babcock & Brown, LP	Ripley-Westfield Wind	8/14/07	124.8	124.8	W	Chautauqua, NY	Ripley - Dunkirk 230kV	NM-NG	5	12/18/07	None	2009/12
255	In-City, LLC	Cross Hudson	8/23/07	550	550	CC-NG	New York, NY-NJ	W49th Street 345kV	ConEd	2	12/18/07	None	2010/06
256	Niagara Shore Winds, LLC	Niagara Shore Wind	9/4/07	70.5	70.5	W	Niagara, NY	Somerset Switch Yard	NYSEG	2	12/18/07	None	2010/11
257	RG&E	Brown's Race Uprate	9/12/07	2	2	H	Monroe, NY	Beebee Station 34kV	RG&E	4	12/18/07	None	2008/12
259	Delaware County Electric	Delaware County Landfill	9/24/07	1	1	M	Delaware, NY	TBD	NYSEG	1	11/27/07	None	2008/09
260	Beacon Power Corporation	Stephentown	9/25/07	20	20	F	Rensselaer, NY	Greenbush - Stephentown 115kV	NM-NG	1	12/11/07	None	2008/10
261	Astoria Generating Company	South Pier Improvements	10/2/07	150	150	CT	New York, NY	Gowanus Substation	ConEd	2	1/8/08	None	2010/06
262	RP Wind NY, LLC	Schoharie Highlands	10/5/07	70	70	W	Schoharie, NY	69kV	NM-NG	2	1/8/08	None	2011/12
263	Invenergy Wind North America, LLC	Buffalo Road	10/12/07	142.5	142.5	W	Wyoming, NY	Stolle Rd - Meyer 230kV	NYSEG	2	11/13/07	None	2010/01
264	RG&E	Seth Green	10/23/07	2.8	2.8	H	Monroe, NY	11kV	RG&E	4	12/18/07	None	2008/04
265	CityGreen Transmission	CityGreen	11/16/07	1100	1100	DC		Millwood 345kV	ConEd	1	12/18/07	None	2012/Q3
266	NRG Energy, Inc.	Berrians GT III	11/28/07	789	789	CC-NG	Queens, NY	Astoria 345kV	NYPA	1	12/18/07	None	2010/06
267	Winergy Power, LLC	Winergy NYC Wind Farm	11/30/07	601	601	W	New York, NY	E13th St. Substation 345kV	ConEd	1	12/18/07	None	2015/01
268	NRG Energy, Inc.	Arthur Kill	12/7/07	800	800.0	CC	New York, NY	Gowanus Substation	ConEd	1	12/18/07	None	2010/06

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INTERCONNECTION REQUESTS AND TRANSMISSION PROJECTS / NEW YORK CONTROL AREA

Queue Pos.	Owner/Developer	Project Name	Date of IR	SP (MW)	WP (MW)	Type/ Fuel	Location County/State	Interconnection Point	Utility	S	Last Update	Availability of Studies	Proposed In-Service
269	WM Renewable Energy, LLC	Madison County Landfill	12/10/07	2	2.0	M	Madison, NY	Canastota	NM-NG	1	1/2/08	None	2008/12
270	Babcock & Brown, LP	Hounsfield Wind	12/13/07	268.8	268.8	W	Jefferson, NY	Fitzpatrick - Edic 345kV	NM-NG	1	1/8/08	None	2010/09
271	Babcock & Brown, LP	State Line Wind	12/20/07	124.8	124.8	W	Chautauqua, NY	Ripley - Dunkirk 230kV	NM-NG	1	1/8/08	None	2010/12
273	Winergy Power, LLC	Winergy Long Island Wind	12/21/07	299	299	W	Suffolk, NY	Sterling Substation	LIPA	1	1/8/08	None	2014/01

NOTES:
- *The column labeled 'SP' refers to the maximum summer megawatt electrical output. The column labeled 'WP' refers to the maximum winter megawatt electrical output.*
- *Type / Fuel. Key: ST=Steam Turbine, CT=Combustion Turbine, CC=Combined Cycle, H=Hydro, W=Wind, NU=Nuclear, NG=Natural Gas, M=Methane, Wo=Wood, F=FlywheelO=Oil, C=Coal, D=Dual Fuel, AC=AC Transmission, DC=DC Transmission*
- *The column labeled 'S' refers to the status of the project in the NYISO's LFIP. Key: 1=Scoping Meeting Pending, 2=FES Pending, 3=FES in Progress, 4=SRIS/SIS Pending, 5=SRIS/SIS in Progress, 6=SRIS/SIS 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*
- *Availability of Studies Key: None=Not Available, FES=Feasibility Study Available, SRIS=System Reliability Impact Study Available, FS=Facilities Study and/or ATRA Available*
- *Proposed in-service dates are shown in format Year/Qualifier, where Qualifier may indicate the month, season, or quarter.*

1=	Scoping Meeting Pending	Interconnection Request has been received, but scoping meeting has not yet occurred
2=	FESA Pending	Awaiting execution of Feasibility Study Agreement
3=	FES in Progress	Feasibility Study is in Progress
4=	SRIS Pending	Awaiting execution of SRIS Agreement and/or OC approval of SRIS scope
5=	SRIS in Progress	
6=	SRIS Approved	SRIS Approved by NYISO Operating Committee
7=	FS Pending	Awaiting execution of Facilities Study Agreement
8=	Rejected Cost Allocation/ Next FS Pending--	Project was in prior class year, but rejected cost allocation—Awaiting execution of Facilities Study Agreement for next Class Year or the start of the next Class Year
9=	FS in Progress	Project in current Class Year Facilities Study
10=	Accepted Cost Allocation/ IA in Progress	Interconnection Agreement is being negotiated
11=	IA Completed	Interconnection Agreement is executed and/or filed with FERC
12=	Under Construction	Project is under construction
13=	In Service for Test	

14=	In Service Commercial	
0=	Withdrawn	Project is no longer in the Queue

New York Independent System Operator, Inc.
<u>Report on Implementation of the Installed Capacity Demand Curves</u>

<u>January 15, 2008</u>

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 improve price stability and predictability, reduce incentives to withhold capacity, and provide appropriate price signals to generation developers. ICAP Demand Curves also value capacity above and below minimum capacity levels at more appropriate levels than the prior *de facto* vertical demand curves.

The capacity committed to the New York markets continues to trend upward while allowing for modest retirements without threatening the reliability requirements for the NYCA and for the New York City and Long Island Localities. This upward trend can be attributed to a variety of factors such as adequate market price signals, increased capacity requirements, annual adjustments of the Demand Curves, new in-state capacity, growth in capacity committed by demand response and steady imports from other control areas.

As in previous reporting periods, capacity prices continue to remain stable on a statewide basis. New York City and Long Island prices also remain stable, due 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.

There is no significant physical or economic withholding of Rest-of-State capacity 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

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[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.

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 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 continues to be difficult to correlate 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. In addition, there have been incentives for demand response customers and wind generators to participate in New York's ICAP markets. 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. In addition, the NYISO has implemented a program to track the progress of these proposals. The NYISO understands that developers will look to anticipated future revenues when making investment decisions in the near term. A significant influence on those revenues will be the updates of the ICAP Demand Curves before the Commission for approval for implementation this year.

The NYISO continues to believe that the ICAP Demand Curves remain sound in principle and are structured to provide a positive incentive to developing new capacity when it is needed, particularly when compared to the *de facto* vertical demand curves 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 curves, (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 exceed the increasing capacity requirements in the NYCA, New York City and on Long Island.

Committed capacity remains well in excess of minimum requirement levels 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 ranges from 5.5% in the 2003 Summer Capability Period to 9.6% in the 2004 and 2005 Summer Capability Periods, and settling at 6.9% in the 2006 and 2007 Summer Capability Periods. This fact indicates that the actual capacity sold and committed is keeping pace with statewide load and installed capacity requirements. The Winter Capability Periods showed similar excess capacity sold and committed: 8.4% in the 2003/2004 Winter Capability Period, 8.9 % for the 2006/2007 Winter Capability Period, with greater excesses of 11.2% and 10.3% in the intervening Winter Capability Periods.

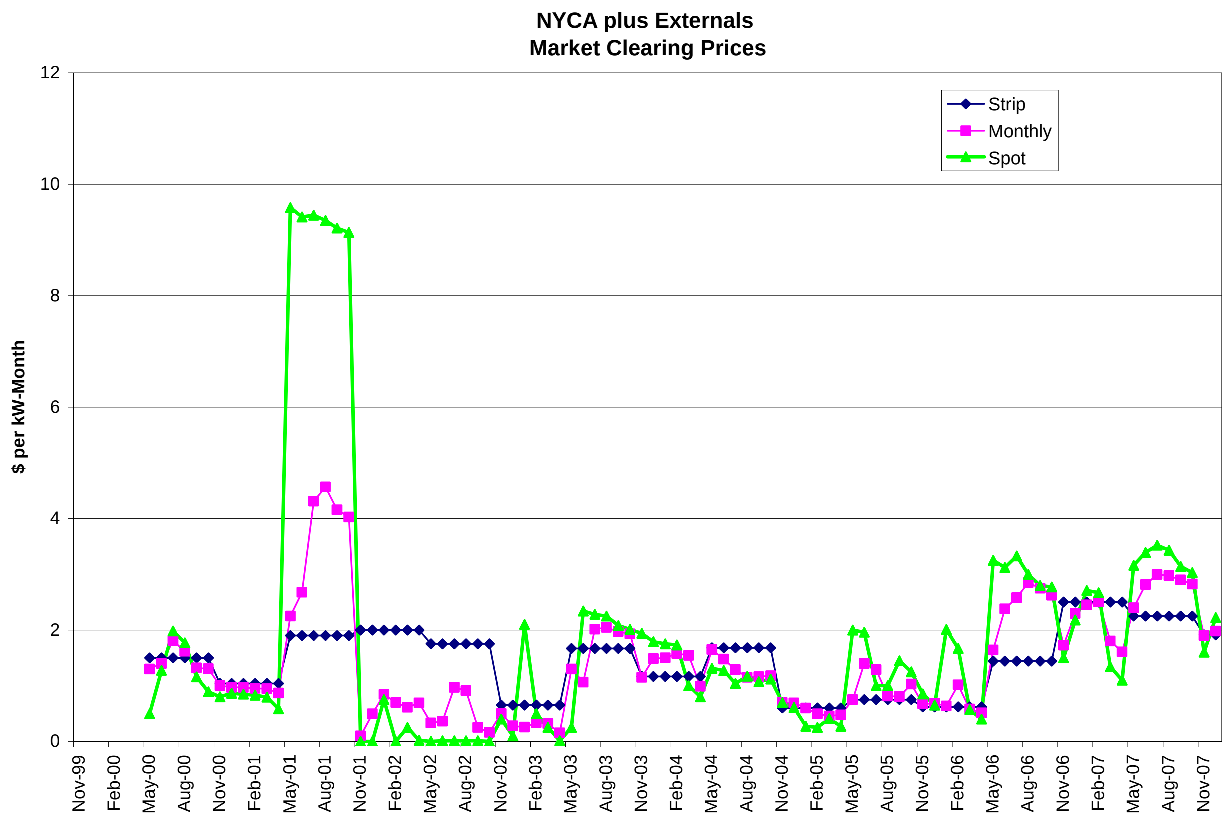
In general, the Dependable Maximum Net Capability ("DMNC") available from many generators in New York increases in the winter because of the lower ambient temperatures. Capacity offers from external control areas also varies seasonally. It should also be noted that the NYCA Demand Curve price declines to zero when supply exceeds the minimum capacity requirement in the NYCA by 12% or more in any case. Accordingly, NYCA auction clearing prices are consistently at or below half of the estimated net cost of entry for new peaking capacity.

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. In the 2007 Summer Capability Period, imports were around the 2,500 MW level while exports 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 December 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 Charts 1, 2, and 3 and capacity commitment levels are depicted in Charts 4, 5, and 6, below. Please note that NYCA Unsold MW depicted in Chart 4 includes unsold MW located in Rest-of-State as well as the unsold MW depicted in Charts 5 and 6 for the New York City and Long Island Localities, respectively.

Chart 1



NYCA plus Externals
Market Clearing Prices
$ per kW-Month
Strip
Monthly
Spot
0
2
4
6
8
10
12
Nov-99
Feb-00
May-00
Aug-00
Nov-00
Feb-01
May-01
Aug-01
Nov-01
Feb-02
May-02
Aug-02
Nov-02
Feb-03
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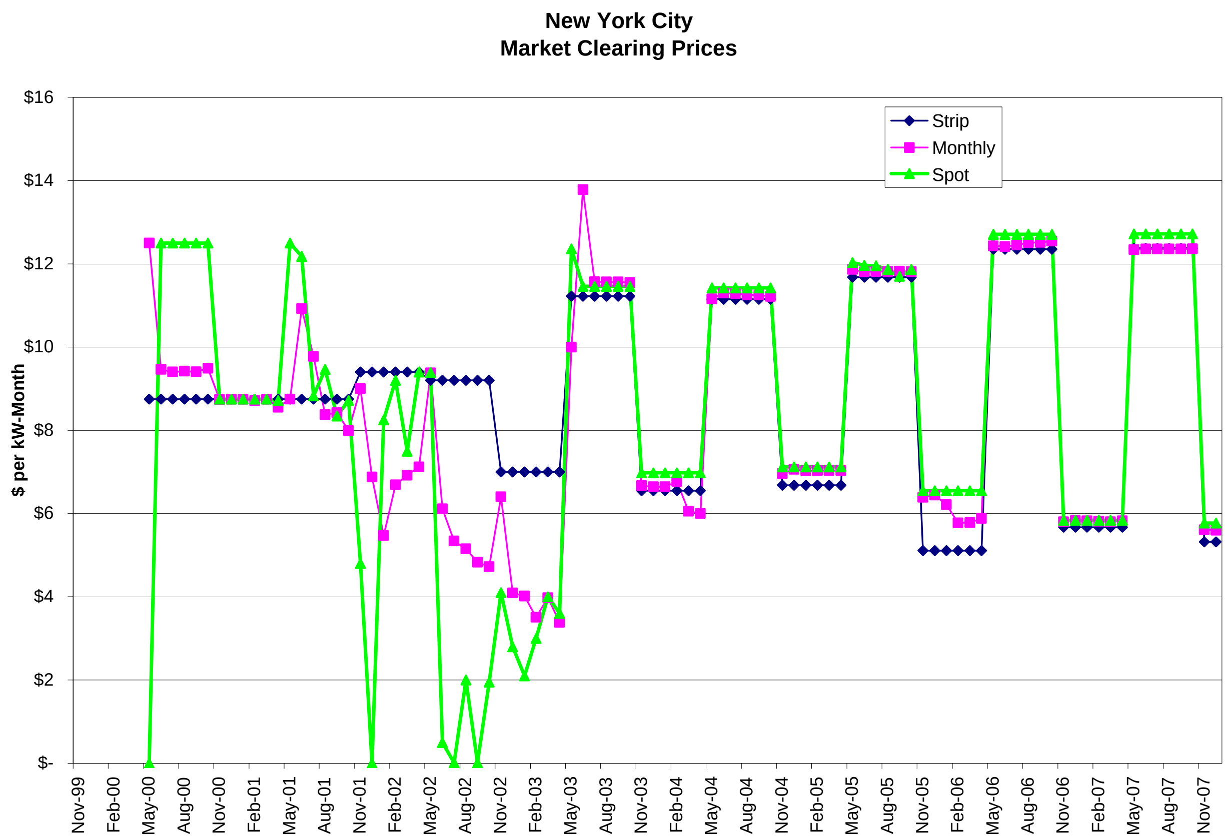
Nov-07

Chart 2


New York City
Market Clearing Prices
$ per kW-Month
$16
$14
$12
$10
$8
$6
$4
$2
$-
Strip
Monthly
Spot
Nov-99
Feb-00
May-00
Aug-00
Nov-00
Feb-01
May-01
Aug-01
Nov-01
Feb-02
May-02
Aug-02
Nov-02
Feb-03
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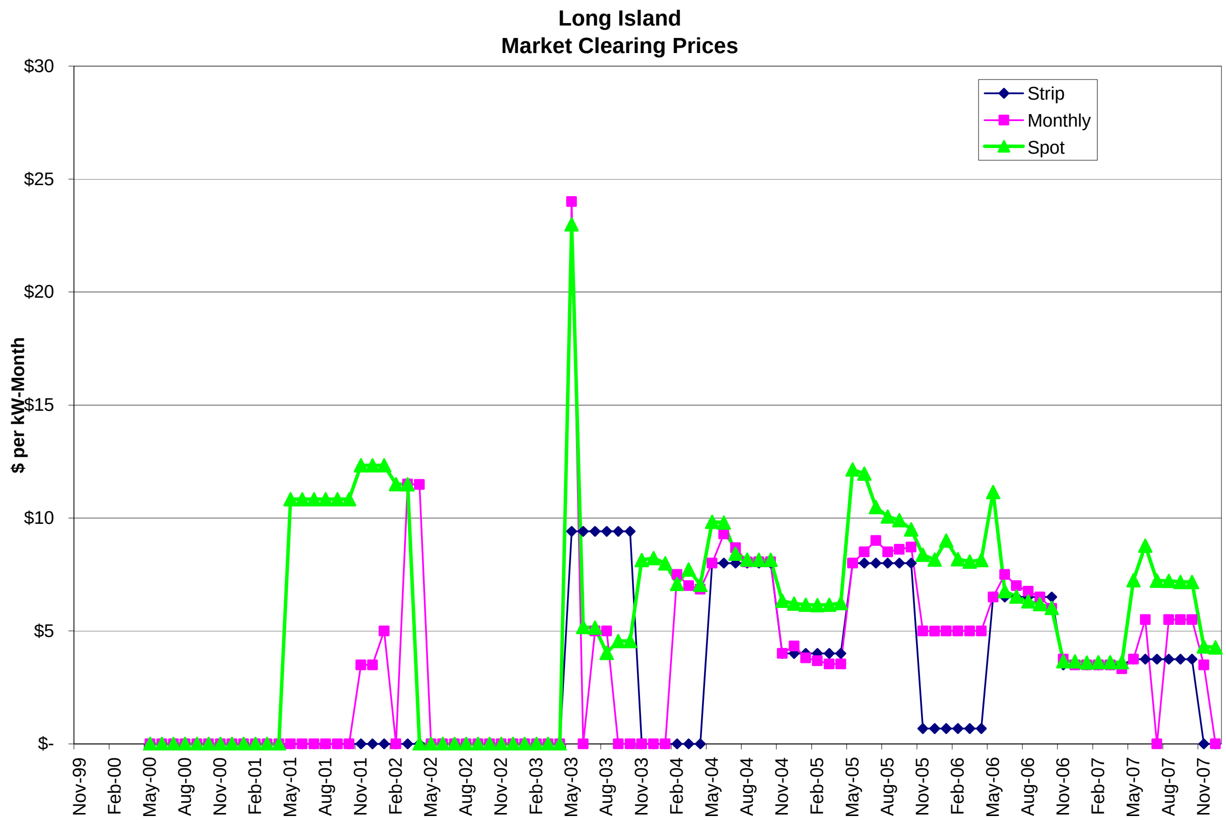
Feb-07
May-07
Aug-07
Nov-07

Chart 3


Long Island
Market Clearing Prices
$30
$25
$20
$15
$10
$5
$-
$ per kW-Month
Strip
Monthly
Spot
Nov-99
Feb-00
May-00
Aug-00
Nov-00
Feb-01
May-01
Aug-01
Nov-01
Feb-02
May-02
Aug-02
Nov-02
Feb-03
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Feb-05
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May-07
Aug-07
Nov-07

Chart 4

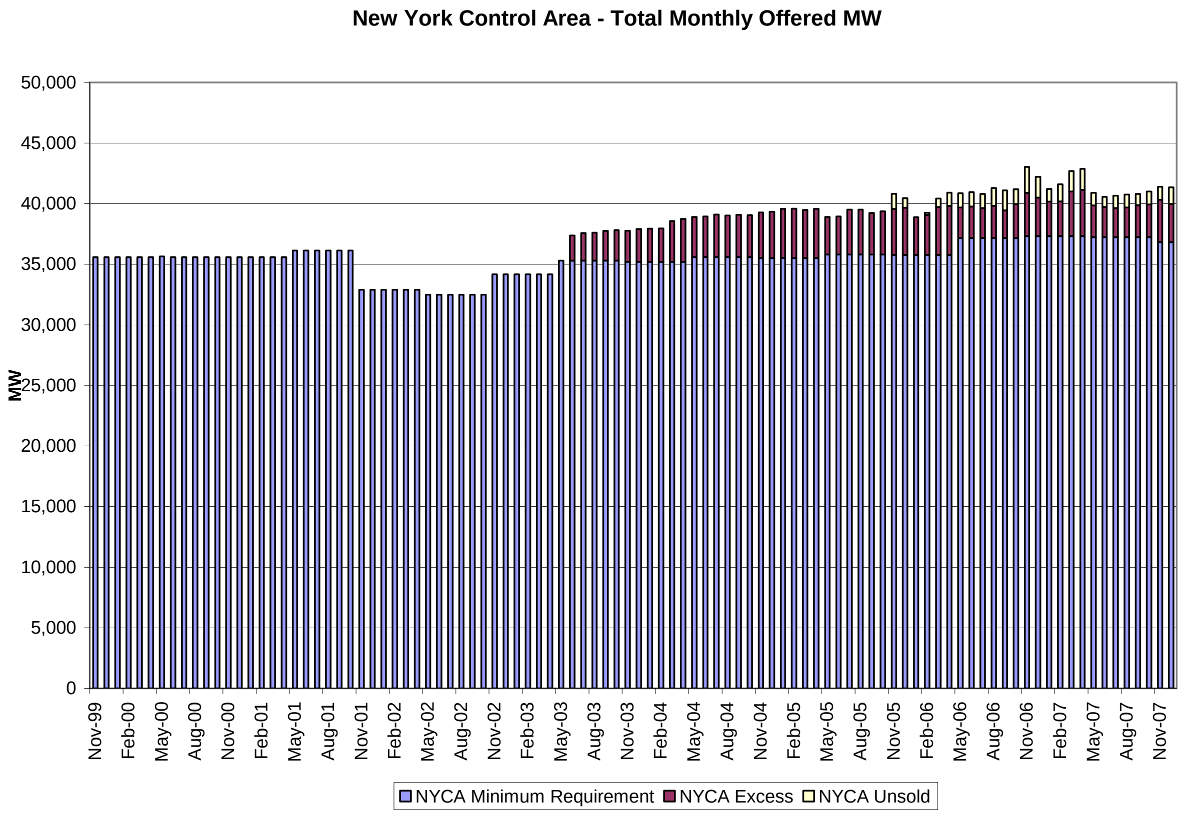


Chart 5

New York City - Total Monthly Offered MW

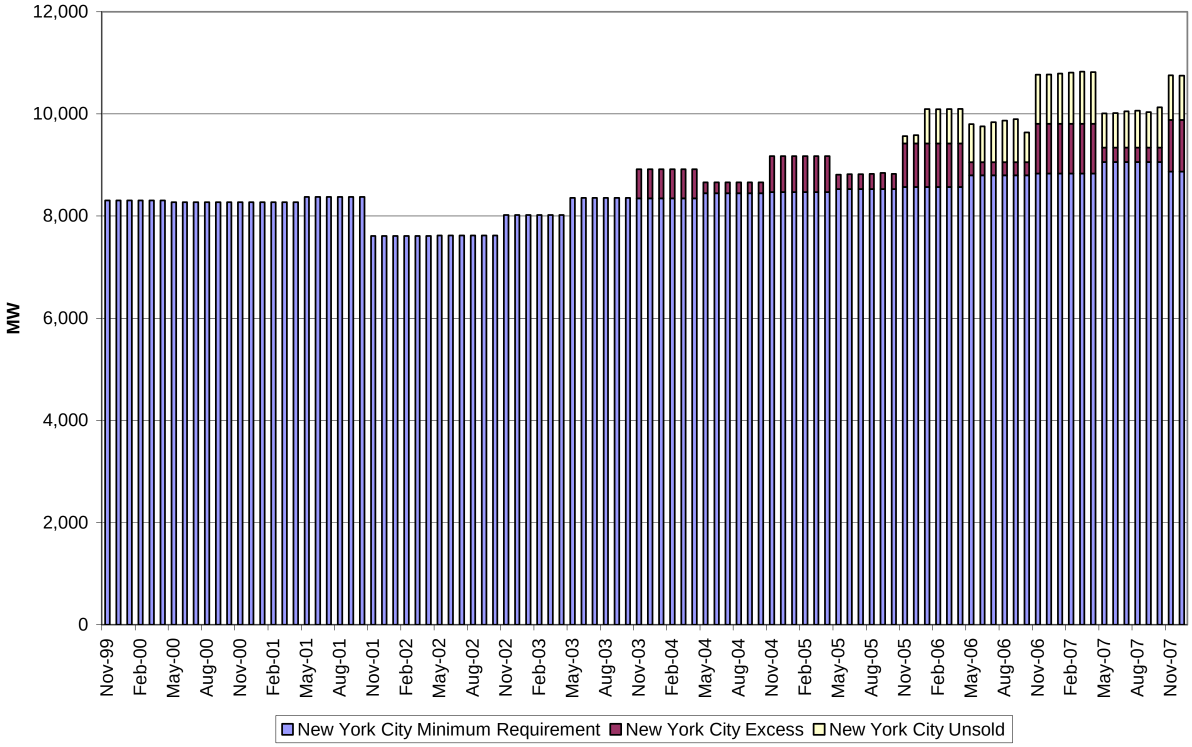
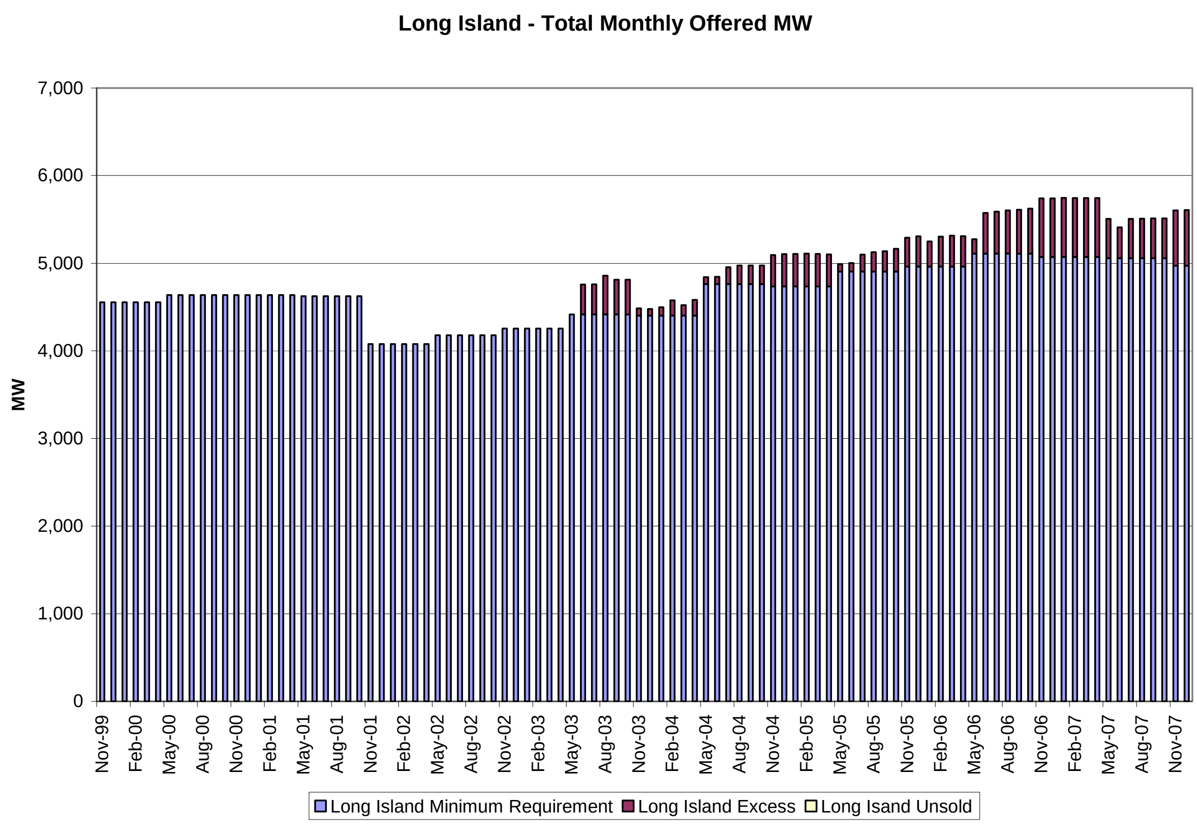


Chart 6



B. Potential Withholding in the Capacity Market

This section of the report addresses potential withholding in NYISO-administered capacity auctions in all regions of New York State through December 2007. This section focuses on market outcomes and related behavior since May 2004.

In order to determine whether any potential 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:

- to the extent data is available, the qualified NYCA capacity available but neither offered for sale nor used as self-supply,
- qualified capacity offered for sale and not sold, and
- unsold capacity as a percentage of available capacity.[2]

[2] Detailed data on capacity certifications (including availability of capacity) has been compiled since May 2006 in the automated ICAP system.

Examining the MWs of capacity offered but not sold – as distinct from MWs not offered at all – is one indication that economic withholding may have occurred, and, correspondingly, capacity available but neither offered for sale nor certified against an LSE's capacity obligation is an indication of whether physical withholding may have occurred.

It is useful to note that there is no "must-offer" requirement for capacity located in the Rest of State (ROS) region of NYCA. In contrast, 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 unoffered or unsold capacity by itself does not necessarily imply physical or economic withholding that is motivated by strategic market behavior with the purpose and effect of raising market prices on a sustained basis. 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 it is determined, however, that the amounts of unoffered capacity are relatively insignificant or that they cannot be attributed to systematic and sustained strategic behavior, then no further detailed analysis is likely warranted. Likewise, 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.[3] Furthermore, the rise in the relative amount of unsold capacity in New York City in 2006 coincides with the addition of 1000 MW of new capacity. For the NYCA as a whole, which includes capacity located in New York City, on Long Island, and in the Rest of State region, both the developments in New York City and the growing variability of exports and imports

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[3] 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.

contributed to the observed fluctuations in unsold capacity when measured as a percentage of available capacity.[4]

There are three types of auctions in each Capability Period: a six-month "strip" auction, six sets of Monthly Auctions, and six ICAP 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 overall 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 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:

- 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)
- Winter 2007-2008 (November 1, 2007 through April 30, 2008) [5]

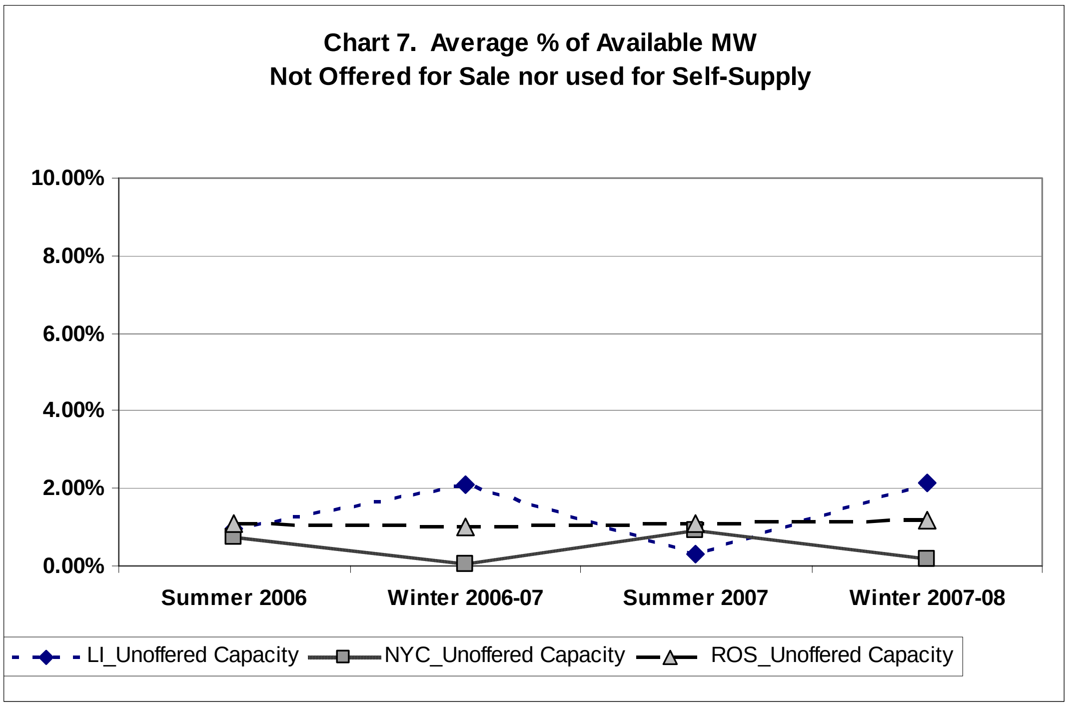
[4] Capacity imported from neighboring control areas are subject to an overall limit that is currently at 2,755 MW of ICAP that translates into approximately 2,700 MW of UCAP. There is also capacity located within NYCA that is exported to other control areas. With recently implemented changes in the rules governing the capacity markets in neighboring control areas, there have been significant changes in the level of flows into and out of the NYCA.

[5] The previous report had used data starting in Winter 2004-2005. For this report, only the data for November and December 2007 could be incorporated. Accordingly, the figures reported for the Winter 2007-2008 capability period are the averages over these two months.

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 within New York seeking to supply capacity to the NYCA. The analysis excludes resources from PJM, ISO-NE, or Hydro-Quebec;
2. The amount of UCAP supplied (sold, self-supplied or committed through bilaterals) in all categories; and
3. Imported capacity.

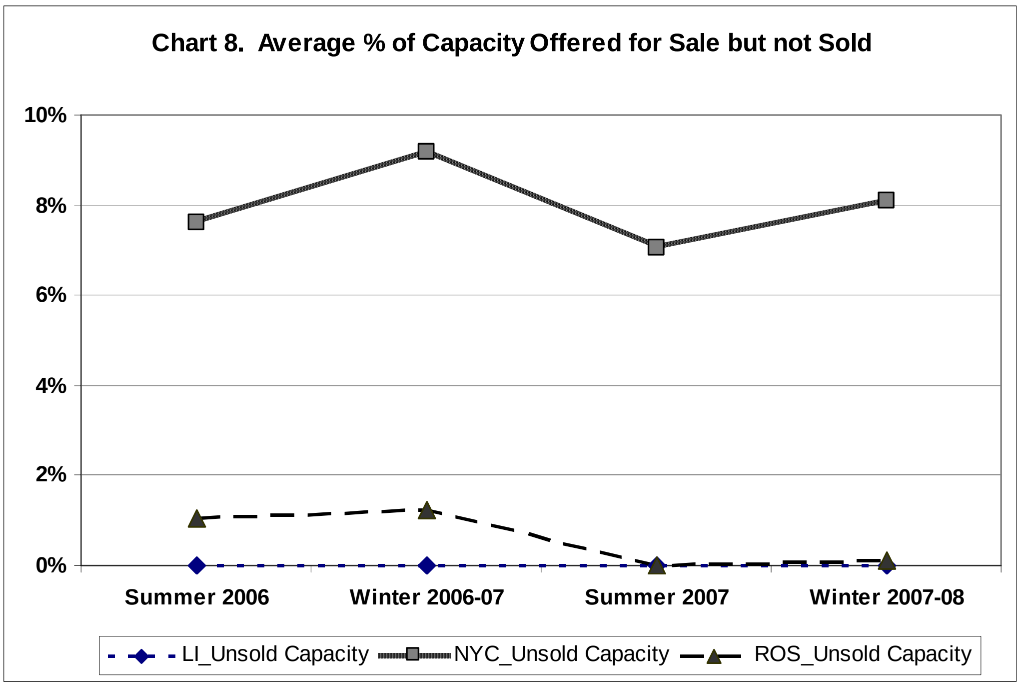
Charts 7 displays the percentage of available capacity in the NYCA that was neither offered for sale, certified against an LSE's capacity obligation, nor committed through bilaterals – *i.e.*, "unoffered capacity."



Given the relatively insignificant amounts of capacity that is unoffered in each region, it is evident that physical withholding is not a significant concern. A small but stable fraction of the unoffered capacity in each of the three regions is attributed to Special Case Resources that are not offered by Responsible Interface Parties. Both Long Island and NewYork City reveal a seasonality in the amounts of unoffered capacity. The Long Island Locality is characterized by capacity procurement ostensibly through bilaterals and self-supply and the rise in values in

Winter and typically experiences very low levels of unoffered capacity.[6] The near absence of unoffered capacity in New York City may be due principally to the must-offer requirement applicable to the majority of the generation located there. Likewise, the ROS region has also exhibited insignificant amounts of unoffered capacity as evidenced by offers in excess of 99% of the available capacity.

The chart below displays the percentage of capacity offered (offered for sale in NYCA, supplied to external control areas, certified against an LSE's capacity obligation, or committed in bilateral transactions) but not sold for the three regions.



Clearly, all Long Island capacity that was offered was sold in the last several Capability Periods. It is also significant that since May 2007, virtually all resources located in Rest of State that were offered into the ICAP auctions were sold, despite a reduction in the NYCA Installed Reserve Margin from 118% to 116.5%. As in the previous report, compared to the MWs of Rest of State capacity offered and sold under the NYCA demand curve, the levels of unsold capacity were generally a small percentage of the total.

The percentage of New York City capacity that was offered but unsold has fluctuated around the 8% level and has exhibited a gently declining trend since the Winter 2005-2006

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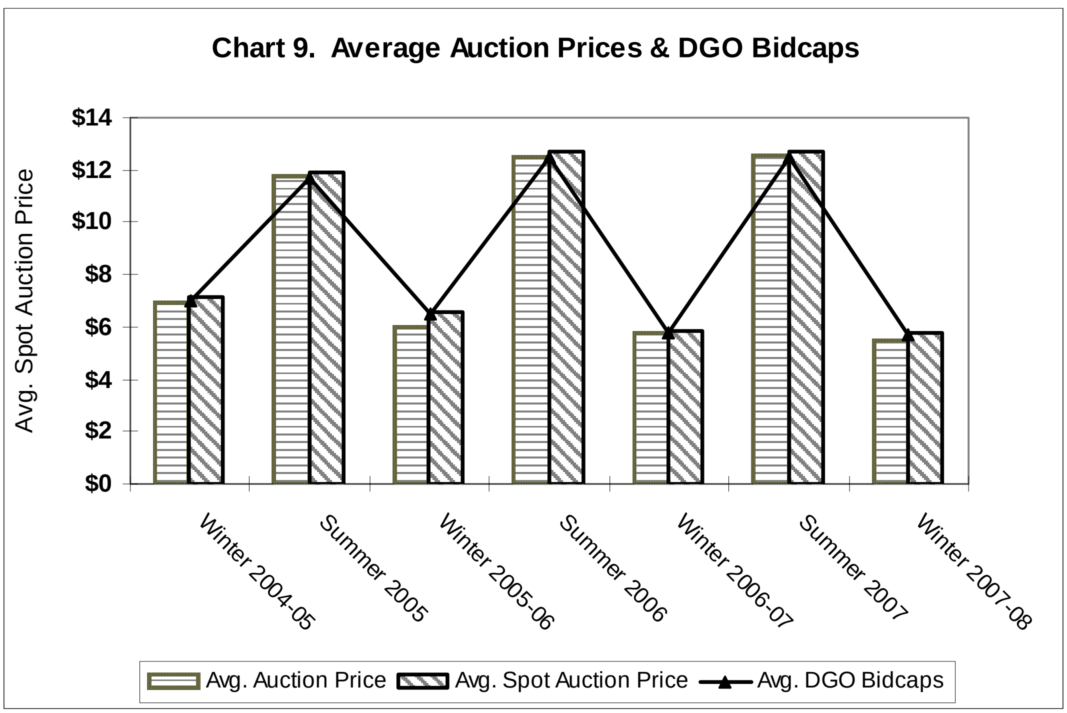
[6] In May 2006, the Long Island Power Authority failed to offer some Long Island capacity into the ICAP Spot Market Auction and, as a result, it was not sold. *See generally*, FERC Docket No. EL07-16-000.

Capability Period – when roughly 500 MWs of new capacity were introduced. Soon after, another 500 MWs were added in May 2006. This new capacity added in conjunction with the offering behavior of market participants led to the persistence of unsold capacity. However, there is evidence that the annual adjustments in the demand curve (to account for the effects of inflation on the cost of new entry) and steady load growth have begun to erode the share of unsold capacity in New York City.

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-to-Winter DMNC ratios. Chart 9 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.[7]



[7] *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.").

By continually offering their capacity at the prescribed bid-caps, the DGOs 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.[8]

Certain interested parties have argued that potentially available capacity outside of New York City went unsold in the Summer 2006 Capability Period and, had all of this unsold capacity been sold, the NYCA auction clearing price would have been lower. In its October 26, 2007 order, the Commission ordered the NYISO to conduct additional analysis of possible withholding of capacity located in the Rest of State region.

This issue may be a source of concern if the suppliers associated with the unsold Rest of State capacity had behaved with the intent of raising NYCA prices and maintaining them at uncompetitive levels on a sustained basis. The chart above does show a little over 1% of ROS offered capacity – approximately 220 MW – were unsold during the Summer 2006 and Winter 2007-2008 Capability Periods. The data also shows that the amount of unsold Rest of State capacity dropped to zero in the succeeding Capability Periods, which suggests an absence of a protracted strategy.

The analysis of unsold MWs in ROS in comments filed on NYISO's January 2007 report was limited to the Summer 2006 Capability Period. The comments rested on inferences drawn from analysis of data drawn from disparate sources – NYISO 2006 Load & Capacity Report published in 2005, statements by the NY DPS, and some publicly available information. It must be noted that the calculations of unsold MWs submitted in the comments incorporated available supplies attributed to capacity that was under bilateral contracts from external control areas. However, since flows of capacity between control areas are dependent on relative prices and factors unrelated to NYISO-administered markets, it is appropriate to exclude them from the

[8] The New York City ICAP market is the subject of extensive filings now pending before the Commission in Docket No. EL07-39-000.

analysis of possible withholding of capacity in the ROS region. The NYISO's analysis, therefore, is based solely on resources owned within the NYCA.[9]

The NYISO conducted a detailed analysis of:

- the amount and the composition of ROS capacity[10] that was neither offered for sale, certified to meet an LSE's capacity obligation, nor committed in bilateral transactions in NYCA or to external control areas, *i.e.*, unoffered capacity, and
- the amount and composition of ROS capacity offers that were not accepted, *i.e.* unsold capacity.

The NYISO conducted a detailed examination of the following data for the May 2006 to December 2007 period:

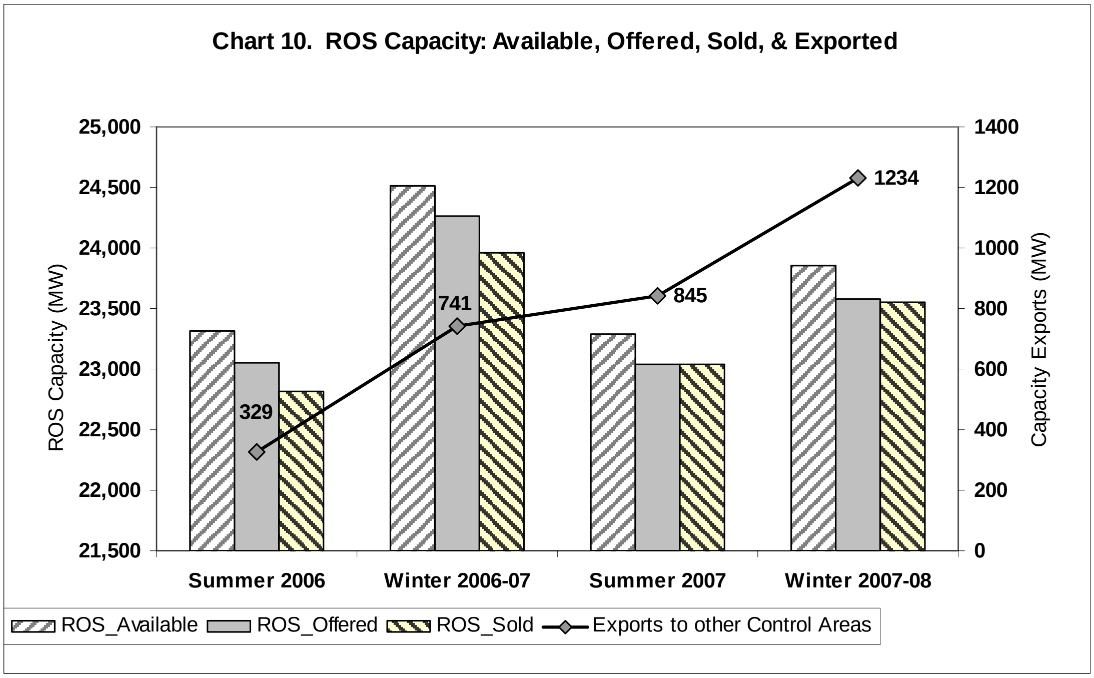
1. Monthly UCAP ratings of each unit of capacity, including SCRs,[11]
2. Monthly sales awards for each unit of capacity,
3. Spot auction offers and awards for each month, and
4. Monthly figures for ROS capacity committed to external control areas, (*i.e.*, exports).

The following chart shows the three broad ROS capacity aggregates – Available, Offered, and Sold. While there was unoffered capacity in all the last four capability periods, there was virtually no unsold capacity during the Summer 2007 and the Winter 2007-2008 Capability Periods.

[9] This includes New York resources involved in exports of capacity.

[10] This includes capacity that was certified in the region outside of the New York City and Long Island localities.

[11] A unit is represented by a unique PTID.



Examination of data pertaining to individual market participants revealed some general patterns in unoffered and unsold quantities of ROS capacity that suggest a three-way classification of suppliers – a group of four generation-owning utilities that are responsible for the majority of the unoffered capacity, a group of five generation owners that account for the bulk of the unsold capacity, and a group of other suppliers that includes three RIPs. Table 1. below summarizes the distribution of monthly averages for each capability period.

Table 1.

	Summer 2006		Winter 2006-2007		Summer 2007		Winter 2007-2008	
	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW
4 ROS Utilities	**133**	**0**	**112**	**0**	**140**	**0**	**159**	**0**
	51.3%	0.0%	48.2%	0.0%	55.5%	0.0%	57.1%	0.0%
5 ROS GenCo's	**7**	**227**	**71**	**303**	**94**	**2**	**63**	**29**
	2.8%	94.4%	30.6%	100.0%	37.4%	100.0%	22.8%	100.0%
All Others incl. SCRs	**119**	**13**	**49**	**0**	**18**	**0**	**56**	**0**
	45.9%	5.6%	21.1%	0.0%	7.1%	0.0%	20.1%	0.0%
Total Unoffered/Unsold	**259**	**240**	**232**	**303**	**252**	**2**	**278**	**29**
Total Available MW	23311		24509		23292		23862	

Salient facts from the above table are:

- The average levels of both unoffered and unsold (if there is any) capacity has remained approximately 1% of the available capacity.
- The group of four ROS generation-owning utilities have consistently had unoffered capacity and account for a majority share.
- The group of five generation owners offered practically all the capacity they own.
- Although the group of generation-owners was largely responsible for the offered but unsold MW in 2006, the group has sold almost all of their capacity for the last two Capability Periods.
- The quantity of capacity unoffered by the ”All Others” group has fluctuated greatly and had a significant magnitude only during the Summer 2006 capability period. The “All Others” group was comprised of, on average, 16 market participants a month, each with small amounts of unoffered or unsold capacity. However, the market participants with unoffered or unsold MW varied from month to month.

A deeper analysis of the unit-level figures for the three categories of capacity – available, offered, and sold - yields several insights that are useful in making determinations regarding possible physical and economic withholding.

Unoffered Capacity

The findings support the view that the reasons why the overwhelming share of capacity that was not offered was due to benign reasons unrelated to strategic motives to raise prices. While most observed instances are the outcomes of firmly established business and engineering practices or regulatory imperatives, there are several isolated one-time occurrences:

1. A generation-owning utility routinely does not offer the full quantity from each of its resources, which aggregates to around 100 MWs each month, on average, which appears to be a conservative operating approach;
2. Another utility keeps roughly 30 MWs of aging gas-fueled generation out of operation during the Summer Capability Periods due to environmental restrictions;

3. A generation owner mistakenly omitted an offer for approximately 180 MWs in the July 2006 Spot Auction, which was a one-time occurrence;
4. Another generation owner did not offer almost 250 MWs in each July and August 2007 apparently due to environmental restrictions; and
5. Although they account for a minor share of both the available and offered capacity, several Responsible Interface Parties (managing portfolios of Special Case Resources) routinely do not offer all available MWs in their portfolios.

These occurrences involved the overwhelming share of the unoffered capacity MWs shown in Table 1 above. None of these instances evidence clear proof of strategic behavior intended to artificially raise prices.

Unsold Capacity

In its October 27 Order, the Commission voiced agreement with NYISO that "withholding is less likely to occur when: (1) the amount of unsold capacity in the Rest of State does not exceed a few percent of available supplies; (2) capacity purchased has consistently exceeded the minimum requirements; and (3) prices have been below the costs of entry."[12] These conditions were present at the time of the last report and persist today.

Concerns of economic withholding raised in comments on last year's report relied on an analysis performed by an outside consultant. That analysis included calculations of idealized auction clearing prices for one month during a summer capability period. The NYTOs' consultant's analysis was flawed because of inaccurate information and assumptions.

The NYTOs' consultant used prospective figures of capacity availability from NYISO's Load & Capacity Report that are based on forecasted peak loads a year in advance. Naturally, the actual level of available capacity differs depending on the actual DMNC and EFORd rates, derates, additional SCRs, and other factors. The level of certified capacity in 2006 was lower than the prospective value. The consultant also assumed that the level of imported capacity would equal the maximum allowable limit. However, in early Summer 2006 there began a strong downward trend in imports—particularly from ISO-New England because of persistently higher prices relative to NYCA prices—that resulted in import levels lower than the 2755 MW limit. The NYTOs' consultant also assumed 270 MWs of exports, which is the prospective level

[12] *New York Indep. Sys. Operator, Inc.*, 121 FERC ¶ 61,090, fn. 19 (2007).

incorporated in NYISO's annual Load & Capacity Reports. However, not only was there a jump of 200 MWs in exports to ISO-NE in July 2006, with the onset of its Forward Capacity Market (FCM) transition period in December 2006, an attractive price differential was an incentive for increasing amounts of ROS capacity to be exported. Consequently, from a steady level of 300 MWs in the Summer 2006 Capability Period, exports rose almost 200% to 850 MWs by January 2007. The combination of decreasing imports and rising exports meant growing quantities of ROS capacity that would not be sold into the NYCA market, but do not constitute "withholding."

These sources of inaccuracy notwithstanding, the potential auction outcomes assumed in the consultant's analysis would require that all capacity suppliers offer as price takers. Not only is there no must-offer requirement for ROS capacity, there may be legitimate reasons why not all capacity offered may be sold. The auction results reveal that different suppliers have unsold capacity, which evidences competing offers with different winners and losers from month to month. There are also instances of very compressed supply stacks, with hundreds of MWs offered at the auction clearing price. Only the amount needed to meet the LSE Unforced Capacity Obligation is purchased and the remainder of capacity offered at the exact same price will not clear. For example, in one month approximately 900 MWs of capacity was offered at the auction clearing price, but was not sold. Even assuming that all capacity offered was at zero dollars, the potential impact on auction clearing prices is modest.

From Table 1 above, on average, 240 MW and 2 MW were unsold in Summer 2006 and Summer 2007, respectively.[13] Given the slopes of the NYCA ICAP Demand Curves for these two Capability Periods, if all offered capacity was sold, then the spot auction prices would have been to lower by, approximately, $0.40/kW-month in Summer 2006 and ostensibly unchanged in Summer 2007.

III. New Generation Projects and Net Revenue Analysis

1. New Generation Projects

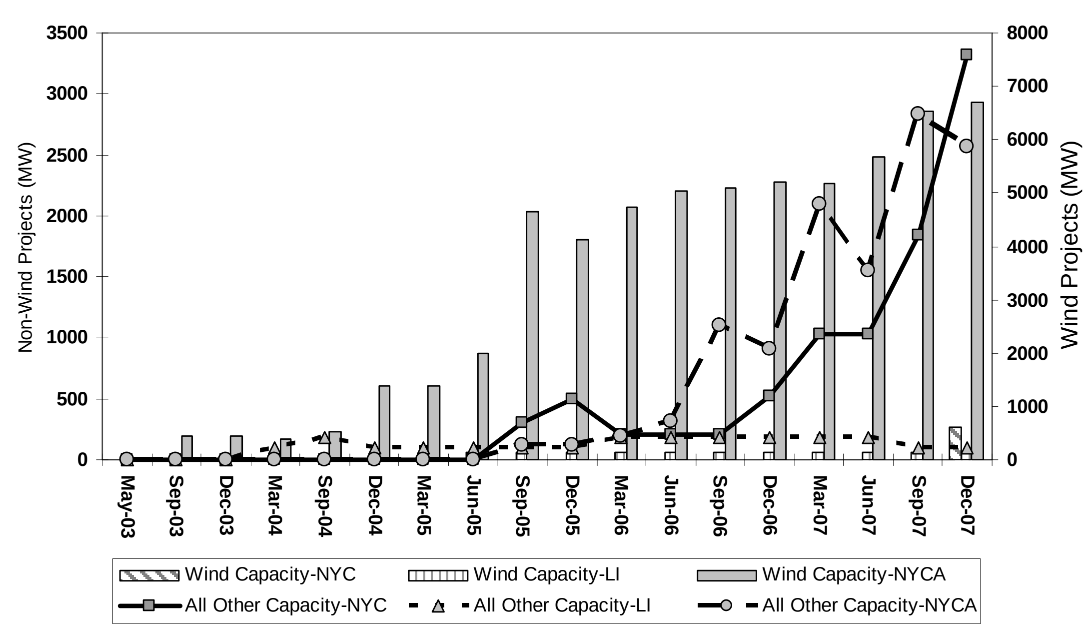
The NYISO anticipated that the ICAP Demand Curves would increase the incentives to build new generation when it is needed. In past reports, the NYISO stated that it is difficult to relate the development of new generation to the ICAP Demand Curves given the lead time

[13] The analysis of ROS capacity reveals that virtually all of the unoffered capacity can be explained by events and behavior that does not appear to be a strategy to artificially raise prices. These quantities, therefore, were not included.

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 – with wind projects depicted separately from proposed generation projects based on other fuels. Generally, the amount of generation in the interconnection process has increased since the ICAP Demand Curves became effective in May, 2003.

Chart 11. NYISO Interconnection Queue Projects



This analysis is based on periodically updated versions of the NYISO Interconnection Queue dating from May 2003 through December 2007.[14] For purposes of this analysis, only the

[14] 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,*

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 or withdrawn.[15]

The graph above shows that since the Winter 2006-2007 Capability Period both New York City and the NYCA have seen a sharply rising trends in the quantities of MWs in the interconnection queue. This trend is consistent with the declining trend in capacity margins and expectations of healthier earnings having a positive influence on developers' plans.

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.

The graph above illustrates the capacity resources that have been under study at the NYISO. Going forward, the NYISO has a process to identify additional resources that will be needed to maintain the reliability of the bulk power system in New York. In the 2008 Reliability

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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

[15] 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.

Needs Assessment (RNA),[16] the NYISO identified a need for new resources in New York beginning in 2012. The NYISO has determined that additional generation capacity or equivalent resources will be needed in that year in the lower Hudson Valley region or in New York City.

After the NYISO identifies the reliability needs in the RNA, the responsible transmission owners in the relevant areas must identify regulatory backstop solutions that are adequate to meet those needs. Those regulatory backstop solutions, however, are not preferred and will not be triggered unless the NYISO determines that sufficient market-based solutions to satisfy the identified need will not be available by the need date. 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 obtain 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 December 12, 2007, the NYISO submitted a letter to stakeholders requesting market-based and regulatory solutions to these identified needs.

Findings of the 2008 Reliability Needs Assessment. According to the *2008 Reliability Needs Assessment,* generation and transmission resources in New York State are expected to be adequate through 2011. The study found that a reliability need will occur by 2012, primarily in the state's southeastern region, and will become acute by 2017 if expected electricity demand increases are not met with additional resources.

The *2007Reliability Needs Assessment* had forecast the first reliability need year to be 2011. The new 2012 estimate is a result of upgrades and additions made by generation and transmission owners in response to the NYISO's Comprehensive Reliability Planning Process.

Approved by the NYISO's Board of Director's on December 10, 2007, the *2008 Reliability Needs Assessment* reports that an equivalent of 500 MWs in New York City, or a total of 750 MWs with 250 MWs each in the Capital region, the mid-Hudson Valley, or New York City, will be required to meet anticipated power needs in 2012.

[16] New York Independent System Operator, Inc., Comprehensive Reliability Planning Process, 2008 Reliability Needs Assessment (Dec. 10, 2007), *available at* http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2008_RNA__Supporting_FINAL_REPORT_12_12.pdf

By 2017, the equivalent of 2,750 MWs of resources should be added and available to the state's bulk electricity grid to accommodate the anticipated retirement of existing capacity and increased electricity demand, and to meet federally mandated reliability standards. About half of those megawatts need to be located in New York City and Long Island, according to the report.

That increase in resource requirements is largely driven by a forecasted increase in demand of more than 1,000 MWs by 2017 when compared to the *2007 RNA.*

Reliability needs: 2012-2017. New York's reliability need in 2012 is driven by load growth in excess of two percent per year in the Lower Hudson Valley, New York City and Long Island as well as generator retirements and thermal transmission constraints into these same regions.

By 2012, the NYISO forecasts that about two-thirds of the state's electricity demand will be located in southeastern New York; a little more than half of that demand will be in New York City and on Long Island.

The retirement of several generation units, including the planned 2010 retirement of New York Power Authority's Charles A. Poletti generating facility in Queens, plays a significant role in the 2012 reliability need. The Poletti unit and the other generators set to retire – Mirant Corporation's Lovett 5 and Rochester Gas & Electric's Russell Station – account for about 1,300 megawatts. They are scheduled for shutdown between 2008 and 2010.

The system's reliability need would be pushed back to 2013 as a result of a long-term capacity contract recently approved by the LIPA Board of Trustees that provides for delivery to Long Island over the Neptune Regional Transmission facility, a high voltage direct current line between Long Island and New Jersey, from a resource in the PJM Control Area.

Listed below are projects that were submitted to the NYISO in response to the 2007 RNA and that were accepted as market-based solutions to the reliability needs in the 2008 CRP. 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 660 MW Empire Generation Project
First Light Power Resources, Inc. is developing this project, which was formerly known as the Besicorp Empire State Newsprint project. Located in Rensselaer, New York, the project consists of a combined-cycle natural gas fired facility, and is expected to have 107 MW of peaking capacity. The project is expected to begin construction shortly, and is expected to be in service in early 2010. The project is #69 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 in service in summer 2010. The re-powering 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 800 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 summer 2010. 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 second quarter 2011. 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, entitled "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 (HCP) 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.

The 250 MW Spagnoli Energy Center
KeySpan Ravenswood, LLC submitted the Spagnoli Road Energy Center, and is presently on hold. 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 NYISO has recently implemented an enhanced monitoring program to track the progress of market-based solutions toward meeting reliability needs by the need date. The NYISO's Comprehensive Reliability Planning Process Manual provides a framework of monitoring criteria that solution proponents must use to periodically update the NYISO on the status of their projects. The NYISO recently issued Technical Bulletin No. 171 to provide more detailed procedures and methods to establish a comprehensive monitoring program. In order to assess the progress of market-based solutions against the requirements of the current Comprehensive Reliability Plan, status updates will be required on a quarterly basis. Solution proponents will be required to respond with status updates to the NYISO on or before the first day of each calendar quarter. Each quarterly update must include the NYISO's "Solution Performance Log," which delineates plans and progress against required tracking metrics. The metrics include site control, project schedule, status of major permits, easements, decertifications, energy and capacity sales agreements, financing, major equipment orders, contractual agreements for fuel supply and delivery, engineering labor, construction labor, operating arrangements, and progress toward major milestones within engineering, construction and commissioning activities. The NYISO's confidentiality policies apply to the information submitted.

Overall, the ICAP Demand Curves have been 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 implemented capacity markets 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 has discussed its forward market proposal in its stakeholder process and looks forward to submitting a proposal to the Commission.

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 available amounts of capacity (UCAP) as calculated from detailed data from DMNC certifications, auction offers, and sales awards.

Table 2. Available Capacity vs. Required Capacity

		2004	2005	2006	2007
NYCA	Requirement (MW)	35585	35799	37154	37228
	Availability (MW)	37,226	37,974	38,470	38,641
	Capacity margin %	**104.6%**	**106.1%**	**103.5%**	**103.8%**
NYC	Requirement (MW)	8,445	8,527	8,798	9,058
	Availability (MW)	8,520	9,043	9,880	10,158
	Capacity margin %	**100.9%**	**106.1%**	**112.3%**	**112.1%**
LI	Requirement (MW)	4,762	4,905	5,110	5,056
	Availability (MW)	4,946	5,100	5,279	5,192
	Capacity margin %	**103.9%**	**104.0%**	**103.3%**	**102.7%**

In this table, the Requirements are based on the assumptions used for establishing the ICAP Demand Curves for the Summer Capability Periods (May through October), and Available capacity reflects the aggregate of UCAP ratings excluding capacity imported via external transactions.[17]

b. Measure of Revenues

[17] In contrast to the prospective figures used in the previous reports (*i.e.*, from NYISO's annual Load & Capacity Reports), these charts reflect data based on realized outcomes.

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 given 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 UCAP values were used to compute calendar-year revenue requirements for each year in the 2004-2007 period.[18]

Table 3. Annual Revenue Requirements ($/MW)

	2004	2005	2006	2007
NYCA	$90,963	$93,697	$96,670	$98,964
NYC	$192,662	$198,766	$204,437	$208,650
LI	$168,903	$174,512	$177,122	$186,021

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.[19]

[18] For analytical ease and consistency with other data, these figures are the corresponding values in UCAP terms (as opposed to the ICAP-based data included in the previous Report) and maintain the same relative structure.

[19] These values deviate from those in earlier reports because previously the Capacity revenues were calculated in ICAP terms while the Energy and Ancillary Services Revenues were in UCAP terms. This report corrects that inconsistency. Similar to the last report, the assumed parameters for the benchmark combustion turbine are: Heat Rate = 10,500 btu/kWh, Variable Operating & Maintenance Costs = $3/MWh, and Forced Outage Rate = 5%. Due to different assumptions and methodologies used for the State of the Market Report, these results may vary from those submitted in Docket No. ER08-283. *See New York Indep. Sys. Operator, Inc.*, 117 FERC ¶ 61,086 at P 15 (requiring a summary of the analysis of net revenue included in the annual state of the market report).

Table 4. Benchmark Annual Revenues in UCAP terms ($/MW)

		Revenue Elements in $				Revenue Elements as % of Total			
		2004	2005	2006	2007	2004	2005	2006	2007
NYCA[20]	Energy	$1,144	$4,238	$4,327	$6,220	6.6%	15.5%	8.7%	10.9%
	A/S	$2,708	$11,662	$19,044	$19,567	15.5%	42.8%	38.1%	34.3%
	Capacity	$13,570	$11,360	$26,600	$31,310	77.9%	41.7%	53.2%	54.8%
	Total	***$17,421***	***$27,260***	***$49,972***	***$57,096***	***100.0%***	***100.0%***	***100.0%***	***100.0%***
NYC	Energy	$19,531	$45,393	$38,582	$32,575	14.7%	27.2%	23.5%	20.8%
	A/S	$2,265	$8,632	$11,807	$13,002	1.7%	5.2%	7.2%	8.3%
	Capacity	$110,680	$112,940	$114,140	$111,220	83.5%	67.6%	69.4%	70.9%
	Total	***$132,476***	***$166,965***	***$164,529***	***$156,797***	***100.0%***	***100.0%***	***100.0%***	***100.0%***
Long Island	Energy	$12,699	$46,678	$87,372	$58,548	11.6%	29.1%	48.8%	43.0%
	A/S	$2,307	$8,498	$8,158	$9,804	2.1%	5.3%	4.6%	7.2%
	Capacity	$94,880	$105,260	$83,650	$67,830	86.3%	65.6%	46.7%	49.8%
	Total	***$109,887***	***$160,436***	***$179,180***	***$136,182***	***100.0%***	***100.0%***	***100.0%***	***100.0%***

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

	2004	**2005**	**2006**	**2007**
NYCA	19%	29%	52%	58%
NYC	69%	84%	80%	75%
LI	65%	92%	101%	73%

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,

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

revenues remain well below what is necessary to attract new entry of a hypothetical benchmark Generating Turbine (GT) in Rest of State. Although in 2006 LI revenues for the hypothetical units attained above-Cost of New Entry (CONE) values, 2007 saw revenues drop significantly due mainly to relatively lower LBMPs.

In order to assess whether revenue streams are appropriate given the degree of need for new capacity, data from Tables 2 and 5 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 ICAP Demand Curves, evidence points to a strong tendency of revenues beginning to rise along with the growing need for new capacity.

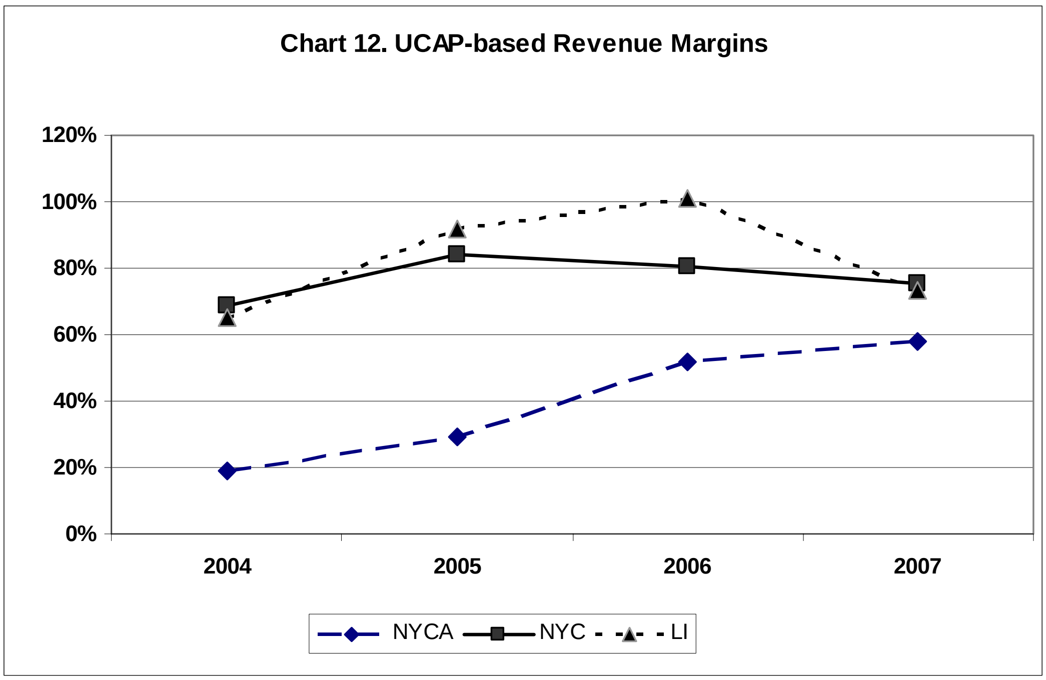
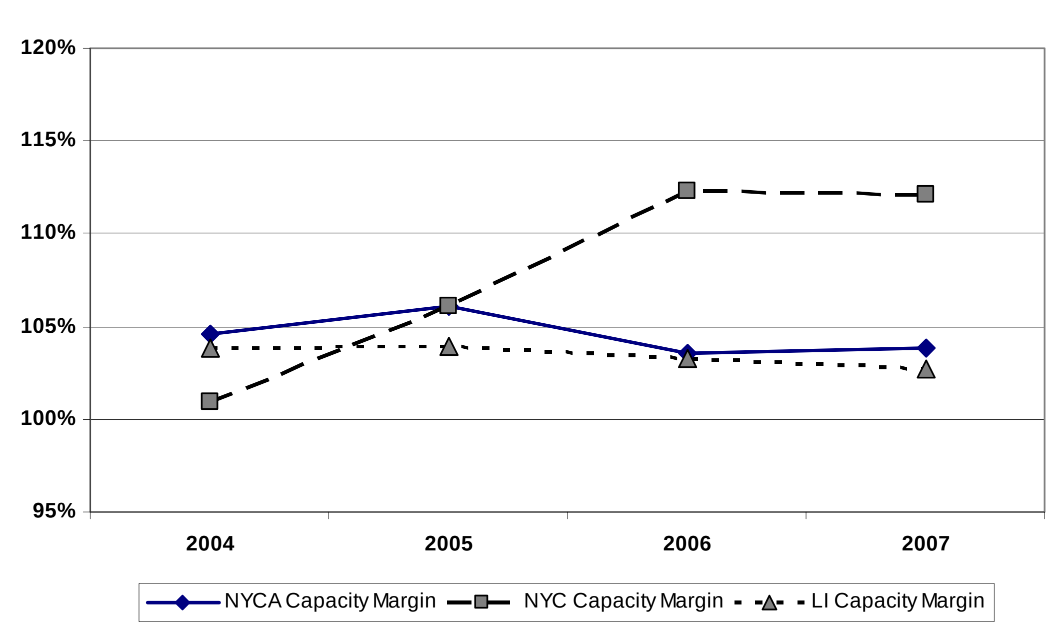
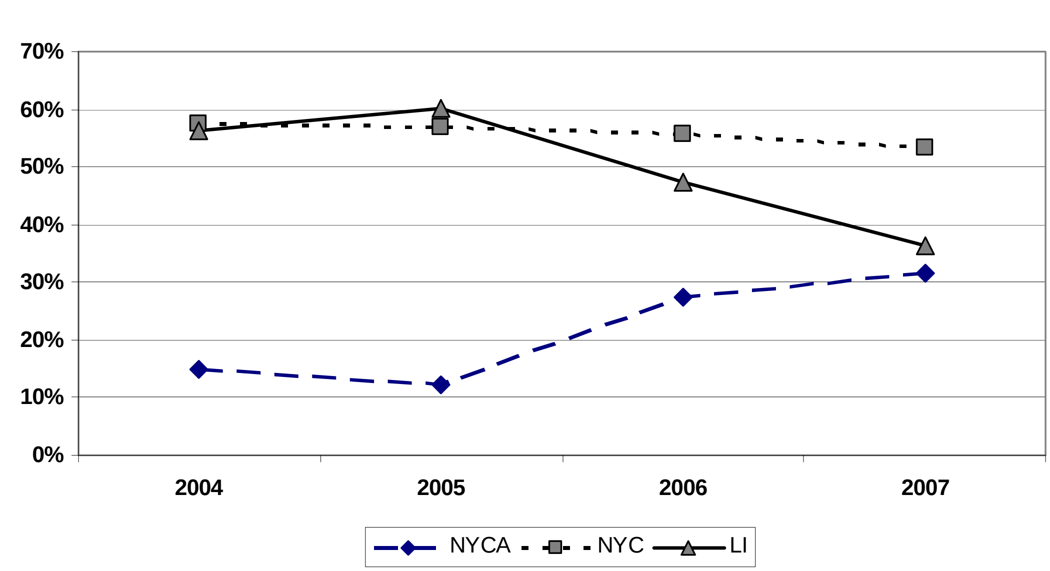


Chart 13. UCAP-based Capacity Margins



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.

Chart 14. Capacity Market Revenues Relative to CONE Requirements



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 Charts 12 and 13 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.

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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
August-07	3196.6	$2.25	3136.7	$2.98	5334.6	$3.43	37228.3	2462.4
September-07	3196.6	$2.25	3694.8	$2.90	5513.6	$3.14	37228.3	2631.6
October-07	3196.6	$2.25	3943.4	$2.82	5503.1	$3.03	37228.3	2698.2
November-07	3064.4	$1.91	2586.1	$1.90	9045.5	$1.60	36819.2	3503.7
December-07	3064.4	$1.91	2743.1	$1.98	8009.1	$2.22	36819.2	3149.2

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
August-07	1894.0	$12.37	1162.6	$12.36	3153.8	$12.72	9058.3	281.1
September-07	1894.0	$12.37	1252.0	$12.36	3037.9	$12.72	9058.3	281.1
October-07	1894.0	$12.37	1339.4	$12.36	2942.8	$12.72	9058.3	281.1
November-07	908.2	$5.32	1393.5	$5.61	4438.1	$5.77	8870.8	1009.5
December-07	908.2	$5.32	1632.1	$5.60	4067.3	$5.77	8870.8	1009.5

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	$0.0	451.5	$7.23	5056.3	451.4
August-07	2.2	$3.75	1.0	$5.50	454.0	$7.22	5056.3	672.3
September-07	2.2	$3.75	1.3	$5.50	455.6	$7.17	5056.3	672.3
October-07	2.2	$3.75	1.4	$5.50	455.7	$7.17	5056.3	450.2
November-07	0	$0.00	2.0	$3.5	631.5	$4.31	4972.5	630.6
December-07	0	$0.00	0	$0.00	635.9	$4.27	4972.5	633.0

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these proceedings.

Dated at Rensselaer, New York this 15th day of January, 2008.

/s/ Joseph B. Williams

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