NEW YORK INDEPENDENT SYSTEM OPERATOR

10 Krey Boulevard ⬩ Rensselaer, NY 12144

THIS FILING LETTER DOES NOT CONTAIN ANY PRIVILEGED OF CONFIDENTIAL INFORMATION. REPORT SECTIONS I AND III DO NOT CONTAIN ANY PRIVILEGED OR CONFIDENTIAL INFORMATION. THE BODY OF REPORT SECTION III, THE REDACTED VERSION OF ATTACHMENT 1 (MARKED PUBLIC) AND ATTACHMENT 4 TO REPORT SECTION III, DO NOT CONTAIN ANY PRIVILEGED OR CONFIDENTIAL INFORMATION. ATTACHMENTS 1, 2, 3, AND 5 TO REPORT SECTION III CONTAIN PRIVILEGED AND CONFIDENTIAL INFORMATION, AND ARE SUMITTED IN A SEPARATE, CLEARLY MARKED, ENVELOPE.

BY HAND DEL.IVERY

January 15, 2010

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

Re: Annual Report in Docket Nos. ER01-3001-___, ER03-647-___ and Request for Privileged Treatment of Attachments 1, 2, 3, and 5 to Report Section III

Dear Ms. Bose:

Enclosed for filing in the above-referenced dockets are the New York Independent System Operator's ("NYISO's") annual reports to the Federal Energy Regulatory Commission ("Commission") on 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.[1] In Docket No. ER03-647, the NYISO provides data and analyses regarding the ICAP Demand Curves.[2] 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 ICAP Demand Curve Report due annually in Docket ER03-647 and the two semi-annual reports due in the winter in Docket No. ER01-3001.[3] [4]

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

[2] *New York Independent System Operator, Inc.*103 FERC ¶ 61,201 (2003), 108 FERC ¶ 61,280 (2004), 121 FERC ¶ 61,090 (2007), 123 FERC ¶ 61,206 (2008).

[3] *New York Independent System Operator, Inc.*, Notice, Docket Nos. ER01-3001 and ER03-647 (Nov. 28, 2006).

[4] On January 11, 2010, the NYISO filed a motion in these dockets to advance the filing deadline of the report on Installed Capacity Demand Curves and winter semi-annual new generation report, for reports filed after the instant report. *See* Motion of the New York Independent System Operator, Inc. to Advance the Filing Deadline for Filing Certain Compliance Reports.

I. List of Documents Submitted

The NYISO submits a report comprised of the following three reports in separate sections:

I. NYISO Report on Demand Response Programs

II. NYISO Report on New Generation Projects

III. NYISO Report on Installed Capacity Demand Curves

II. Request for Confidential Treatment of Attachments 1, 2, 3 and 5 of Report Section III

In accordance with Sections 388.107 and 388.112 of the Commission's Regulations,[5] Article 6 of the NYISO's Market Administration and Control Area Services Tariff, Sections 1.0(4) and 4.0 of the NYISO's Code of Conduct, the NYISO requests Privileged and Confidential treatment of the contents of Attachments 1, 2, 3, and 5 of Report Section III (the "Confidential Attachments"). The NYISO also requests that Confidential Attachments be exempted from public disclosure under the Freedom of Information Act ("FOIA"), 5 U.S.C. § 522.[6]

The Confidential Attachments contain privileged and commercially sensitive, and trade secret information that is not made public by the NYISO and that could cause competitive harm to the affected Market Participants, and could adversely affect competition in the markets administered by the NYISO, if publicly disclosed. This information includes the identity of installed capacity suppliers and offers, and the basis therefor, and costs of the suppliers. This confidential, commercially sensitive information is exempt from disclosure under 5 U.S.C. § 522(b)(4). For this reason, the NYISO requests that the contents of Confidential Attachments received Privileged and Confidential treatment and be exempt from FOIA disclosure.

A redacted, public version of the contents of Attachment 1 is provided with the Report. A redacted, public version of the contents of Attachment 5 is set forth in Table 9 of Report Section III.

The NYISO requests waiver of any obligation it may have under the Commission's regulations or the Secretary's rules to submit redacted copies of Attachments 2 and 3. The NYISO incorporated into the body of Report Section III a masked or aggregated version of the information that is contained in Attachments 2 and 3 and thereby makes publicly available the information contained in the Confidential Appendices that is not confidential and commercially sensitive. In that regard, the NYISO has provided a redacted version of the information contained in those appendices within the body of the report.

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[5] 18 C.F.R. §§ 388.107, 388.112 (2009).

[6] The Information provided by the NYISO for which the NYISO claims an exemption from FOIA disclosure is labeled "Contains Privileged Information – Do Not Release."

Attachments 1, 2, 3, and 5 are identified and marked in accordance with the Commission's regulations and rules published by the Secretary's Office for submitting Privileged information.

III. Correspondence

Copies of correspondence concerning this filing should be addressed to:

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- persons designated to receive service.

Respectfully submitted,

/s/

Gloria Kavanah
Counsel for
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cc: Michael Bardee
Gregory Berson
Connie Caldwell
Anna Cochrane
Lance Hinrichs
Jeffrey Honeycutt
Michael McLaughlin
Kathleen E. Nieman
Daniel Nowak
Rachel Spiker

CERTIFICATE OF SERVICE

I hereby certify that I have on this day served the foregoing document on the official service lists compiled by the Secretary in these proceedings. I have also electronically served the foregoing on all market participants, on each participant in its stakeholder committees, on the New York State Public Service Commission, and on the electric utility regulatory agency of New Jersey.

Dated at Washington, DC, this 15th day of January 2010.

/s/ Cathy Karimi

Hunton & Williams LLP
1900 K Street, NW
Washington, DC 20006
(202) 955-1500

I. NYISO Demand Response Programs Report

Program Descriptions

The New York Independent System Operator, Inc. (“NYISO”) offers two demand response programs that support reliability: the Emergency Demand Response Program[1] (“EDRP”) and the Installed Capacity-Special Case Resource Program (“ICAP/SCR”). In addition, demand response resources may participate in the NYISO’s energy market through the Day-Ahead Demand Response Program (“DADRP”), or the Ancillary Services market through the Demand-Side Ancillary Services Program (“DSASP”).

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

The ICAP/SCR program allows demand resources that meet certification requirements to offer Unforced Capacity (“UCAP’) to Load Serving Entities (“LSEs”). Special Case Resources can participate in the Installed Capacity (“ICAP”) Market just like any other ICAP Resource; however, Special Case Resources participate through Responsible Interface Parties, which serve as the interface between the NYISO and resources. Resources are obligated to curtail when called upon to do so with two or more hours notice, provided the NYISO notifies the Responsible Interface Party 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 by the NYISO when reserve shortages are anticipated. Resources may register for either EDRP or ICAP/SCR but not both. Special Case Resources are eligible for an energy payment during an event, using the same performance calculation as EDRP resources.

The Targeted Demand Response Program (“TDRP”), introduced in July 2007, is a NYISO reliability program that deploys existing EDRP and SCR resources on a voluntary basis,

[1] Terms in upper case not defined in this Report have the meaning ascribed to them in the NYISO’s Market Administration and Control Area Services Tariff (“Services Tariff”).

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 demand resources with an opportunity to bid their load curtailment capability into the Day-Ahead Market ("DAM") as an energy resource. Resources 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 currently is $75/MWh. Bids are structured like those of generation resources: DADRP program resources may specify minimum and maximum run times and the hours that they are available. 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 DAM is obligated to curtail the next day. Failure to curtail results in the imposition of a penalty for each such hour equal to the product of the MW curtailment shortfall and the greater of the corresponding DAM or Real-Time Market price of energy.

The DSASP program, introduced in June 2008, provides demand resources that meet telemetry and other qualification requirements an opportunity to bid their load curtailment capability into the DAM and/or Real-Time Market to provide Operating Reserves and Regulation Service. DSASP resources must qualify to provide Operating Reserves or Regulation Service through standard resource testing requirements. Bids are submitted through the same process as generation resources. Resources submit bids by 5:00 a.m. specifying the ancillary service they are offering (Spinning or Non-Synchronous Reserves, and/or Regulation, if qualified) along with the hours and amount of load curtailment for the next day, and the price at which they are willing to curtail. Real-time offers may be made up to 75 minutes before the hour of the offer. Although DSASP resources are not scheduled for energy in the DAM, they are required to submit energy bids, which are used in the co-optimization algorithm for dispatching operating reserve resources. Similar to the DADRP, the energy bid floor price is currently $75/MWh. DSASP resources are not paid for energy. They are eligible for a Day-Ahead Margin Assurance Payment to make up for any balancing difference between their Day-Ahead Reserve or Regulation schedule and Real-Time dispatch, subject to their performance for the scheduled service. Performance indices are calculated on an interval basis for both Reserves and Regulation. Payment is adjusted by the performance index for the service provided. As of

December 31, 2009, there are no resources qualified in the Demand Side Ancillary Services Program.

Summary of Significant Findings

Emergency Demand Response Program / ICAP Special Case Resources

As of August 31, 2009 (the date customarily used for reporting NYISO's demand response program participation statistics) a total of 39 CSPs and Responsible Interface Parties were offering programs that deliver the NYISO's EDRP and/or ICAP/SCR programs to demand resources[2]. This level of participation represents a decrease of two aggregators and one resource representing itself (referred to herein as a "direct resource") since 2008 figures. Participating CSPs and RIPs include:

- 7 Transmission Owners
- 4 Load Serving Entities not affiliated with a Transmission Owner
- 22 aggregators that were not Load Serving Entities or Transmission Owners
- 6 EDRP or ICAP/SCR direct resources

Resource representatives that are not Transmission Owners or affiliates thereof, including Load Serving Entities not affiliated with Transmission Owners and aggregators, currently sponsor 71.7% of the total EDRP and ICAP/SCR registered MW, up from the 70.8% registered in 2008. In 2009, one non-Transmission Owner had resources registered in the EDRP program; all other EDRP resources were registered through Transmission Owners. Direct resources represent 4.4% of the registered MW in the ICAP/SCR program or 3.8% of the combined reliability program MW.

EDRP and ICAP/SCR had a total of 4,067 end-use locations enrolled providing a total of 2,383.6 MW of demand response capability, a 13.1% increase over the 2008 MW enrollment level. The demand response resources in NYISO reliability programs represent 7.7% of the 2009 Summer Capability Period peak demand of 30,844 MW, an increase of 1.2% from 2008. There were 392 end-use locations in EDRP and 3,675 end-use locations in ICAP/SCR. ICAP/SCR

[2] The report on reliability programs is based on a snapshot of the programs as of August 31, 2009.

represents 90% of the total reliability program enrollments and 86% of the total reliability program registered MW, increases of 1% and 3%, respectively, over 2008. The Targeted Demand Response Program, which deploys EDRP and ICAP/SCR resources in subzones of Zone J, New York City, for local reliability, included 40% of total EDRP end-use locations registered and encompassed 36% of total registered EDRP MW. The TDRP also included 49% of total ICAP/SCR end-use locations, representing 26% of the total registered ICAP/SCR MW, a 2% decrease in both end-use locations and registered MW.

Since participation in EDRP and ICAP/SCR became mutually exclusive, EDRP end-use locations and MW have continued to decrease while ICAP/SCR end-use locations and MW have increased, as expected, given the monthly reservation payment associated with the ICAP/SCR program. Aggregations by Responsible Interface Parties now account for 97.7% of ICAP/SCR resources and 77.9% of registered MW in the program, an increase from 2008 in registered MW of almost 3%.

There were no activations of the EDRP, ICAP/SCR, or TDRP programs during the summer of 2009.

Day-Ahead Demand Response Program

For DADRP, five resources representing over 30 end-use locations from Zones F (Capital), Zone G (Hudson Valley) and Zone K (Long Island) submitted load reduction offers. Although offer activity increased by 28% over the previous 12-month period, 79% fewer hours were scheduled (1,067) than in the previous period (7,727). In 2009, 12% of offers were scheduled compared to 73% of offers in 2008. The average DAM LBMP over all hours during the analysis period was $84.56 in Zone F, and $90.64 in Zone K[3].Overall, the average hourly offer decreased by 21%, from 2.9 MW to 2.28 MW, while scheduled offers increased by 36% to an average of 2.05 MW. Scheduled hours decreased by 79% over the same period to 1,067 hours. Scheduled MWh decreased by 72% to 2,192 MWh.

The overall average hourly wholesale LBMP reduction from scheduled DADRP load reductions is $0.27/MWh, a decrease of $1.18/MWh from 2008. On a monthly basis, the average hourly price reduction was most significant in the months of January 2009 ($0.93/MWh), November 2008 ($0.70/MWh) and September 2008 ($0.64/MWh). There were no

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[3] Analysis was not performed on Zone G (Hudson Valley) because no performance information was submitted for resources in this Zone.

price impacts for the summer months of May through August 2009, due to minimal load reduction offers and even fewer scheduled reductions.

Participation in Reliability-Supporting Demand Response Programs

Aggregation of ICAP/SCR Resources

Enrollments for ICAP/SCR resources are tracked by both (a) end-use location and (b) Program ID. Program IDs, used to identify demand resources[4] in NYISO's systems, may represent individually enrolled end-use locations or aggregations of end-use locations enrolled as a single resource. Table 1 of this Report Section I indicates that there are a total of 109 aggregations represented by Responsible Interface Parties, collectively containing a total of 3,590 end-use locations with 1,605.7 MW of the total 2,060.6 MW of registered ICAP/SCR. Eighty-five (85) individually enrolled resources account for 454.9 MW, an increase of less than 1% from 2008.

Table 1: Detail of 2009 ICAP/SCR Program Participation Level by Resource Type

	ICAP			ICAP Offered/Unsold		
Resource Type	# Program IDs	# End-use Locations	Sold MW	# Program IDs	# End-use Locations	Subscribed MW
Individual Resources	85	85	454.9	0	0	0.0
Aggregated Resources	109	3590	1605.7	0	0	0.0
Total	**194**	**3675**	**2060.6**	**0**	**0**	**0.0**

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

[4] A resource is defined as a single end-use location enrolled in a program individually or an aggregation of end-use locations enrolled as a unit. Resources are identified by a Program ID.

EDRP and ICAP/SCR Program Participation

At the end of August 2009, the NYISO's reliability programs had a total of 4,067 end-use locations enrolled, providing a total of 2,383.6 MW of demand response capability, a 13.1% increase over the 2008 MW enrollment level. There were 392 end-use locations in EDRP and 3,675 end-use locations in ICAP/SCR. ICAP/SCR represents 90% of the total reliability program enrollments and 86% of the total reliability program registered MW, increases of 1% and 3%, respectively over 2008. The average registered curtailable load for ICAP/SCR resources was 561 kW, 32% lower than of that for EDRP resources (824 kW). Since 2008, average curtailable load has increased in the ICPA/SCR program by 5.5% and decreased by the same amount in EDRP.

Table 2: 2009 Program Participation Summary by Curtailment Service Provider Type

		EDRP [1]			ICAP Offered/Unsold [2]			ICAP [3]			DADRP [4]		
CSP Type #	**Agent Type**	# CSP	# End-use Locations	MW	# RIP	# End-use Locations	MW	# RIP	# End-use Locations	MW	# DRP	# End-use Locations	MW
22	Aggregator	1	44	4.4	0	0	0.0	21	3202	1265.0	2	30	12.0
1	Curtailment Program End-Use Customer	0	0	0.0	0	0	0.0	1	1	40.8	0	0	0.0
5	Direct Customer	0	0	0.0	0	0	0.0	5	38	49.8	0	0	0.0
4	LSE	0	0	0.0	0	0	0.0	4	364	348.0	6	7	44.4
7	Transmission Owner	7	348	318.6	0	0	0.0	4	70	357.0	3	13	275.0
39	**Total**	**8**	**392**	**323.0**	**0**	**0**	**0.0**	**35**	**3675**	**2060.6**	**11**	**50**	**331.4**

Note 1: The sum of EDRP and ICAP Offered/Unsold = Total EDRP.
Note 2: Resources in the ICAP program with Offered/Unsold capacity are considered 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 enrollment is not necessarily the sum of all programs due to the rules that state that end-use locations are allowed to participate in a reliability program (EDRP or ICAP) and economic (DADRP or DSASP).

Table 2 of this Report Section I shows the total number of CSPs registered for 2009 in the first column and the number of CSPs, by type, with the number of end-use locations and enrolled MW for each of the program categories. This table provides the participation detail by program and CSP type.

Enrollments in EDRP in 2009 were primarily through Transmission Owners; with 1.3% of registered MW enrolled through an aggregator in 2009. ICAP/SCR enrollments have been dominated by aggregators, which provide 90% of participating end-use locations and 71.7% of the registered MW, including 15% of total resources and 16% of total registered MW sponsored by non-Transmission Owner Load-Serving Entities.

Table 3 of this Report Section I shows program participation detail by Load Zone. Load Zones J and K, New York City and Long Island, respectively, have the majority (48%) of resources in the EDRP program, representing 53% of the total MW enrolled. For the ICAP/SCR program, Zones J and K constitute an even greater percentage (65%) of statewide demand response end-use locations, but account for only 35% of the total enrolled MW. Load Zones A through E collectively have 30% of resources in EDRP and 26% of total EDRP MW, and 25% of the resources in ICAP/SCR and 52% of the total ICAP/SCR MW**.** Although statistics on resource class are not collected, resources in Zones A through E are typically industrial and retail resources, while those in Zones J and K include commercial office, retail, and multi-family residential resources.

Table 3: 2009 Program Participation by Zone

	EDRP (1)		**ICAP Offered/Unsold** (2)		**ICAP** (3)		**DADRP** (4)	
Zone	#	MW	#	MW	#	MW	#	MW
A	21	22.0	0	0.0	362	455.2	4	58.0
B	11	6.1	0	0.0	180	139.0	1	2.8
C	42	18.3	0	0.0	217	179.5	2	38.0
D	10	4.1	0	0.0	19	241.7	1	100.0
E	34	34.3	0	0.0	126	63.2	1	10.0
F	35	34.8	0	0.0	142	142.1	8	92.0
G	21	20.9	0	0.0	117	85.3	1	9.0
H	8	5.8	0	0.0	9	2.6	0	0.0
I	21	5.7	0	0.0	96	41.0	0	0.0
J	157	117.4	0	0.0	1791	531.4	2	6.6
K	32	53.6	0	0.0	616	179.6	30	15.0
Total	**392**	**323.0**	**0**	**0.0**	**3675**	**2060.6**	**50**	**331.4**

Note 1: The sum of EDRP and ICAP Offered/Unsold = Total EDRP.
Note 2: Resources in the ICAP program with Offered/Unsold capacity are considered 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 enrollment is not necessarily the sum of all programs due to the rules that state that end-use locations are allowed to participate in a reliability program (EDRP or ICAP) and economic (DADRP or DSASP).

Targeted Demand Response Program Enrollment

Load Zone J currently is the only Load Zone with resources assigned to the Targeted Demand Response Program. This Zone has been divided into subzones designated by Consolidated Edison Company of New York, Inc. ("Con Edison") 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 (J9: Shared Subzone). The sub-load pockets correspond to the following Con Edison 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 End-use Locations registered in the Targeted Demand Response Program - Zone J

	J1	J2	J3	J4	J5	J6	J7	J8	J9	Total
MW	0.6	1.9	8.0	3.5	3.7	2.2	3.0	7.6	87.0	117.4
End-use Locations	5	6	12	6	11	7	7	14	89	157

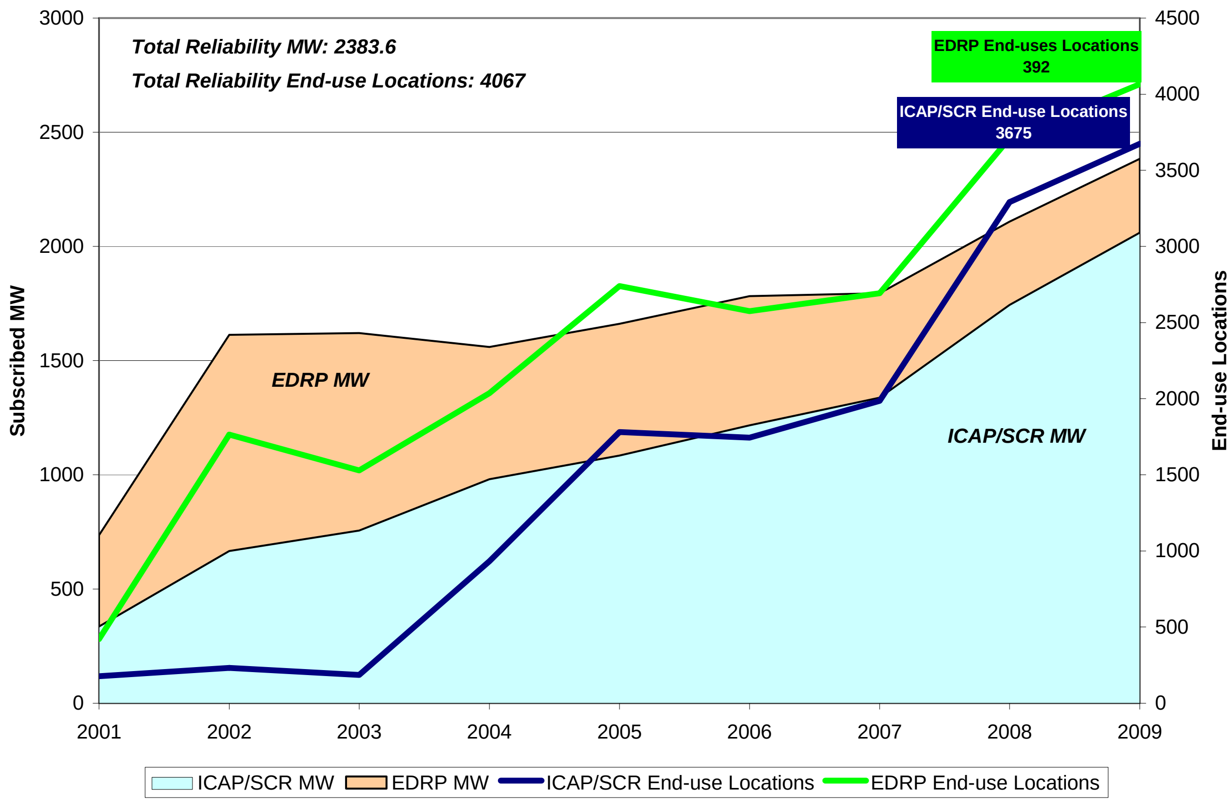
Table 5: ICAP/SCR End-use Locations registered in the Targeted Demand Response Program – Zone J

	J1	J2	J3	J4	J5	J6	J7	J8	J9	Total
MW	27.1	6.4	5	0.1	0.4	6.6	9.7	9	467.1	531.4
End-use Locations	17	41	33	5	10	35	93	53	1504	1791

Historical Program Growth in Reliability Programs

Figure 1 of this Report Section I plots the growth in the NYISO's reliability-based programs from inception through August 2009. The stacked area plots registered MW by program and year. The lines plot the number of end-use locations by program and year. From May 2001 through August 2009, combined enrollment in EDRP and ICAP/SCR has grown from approximately 200 MW to 2,383.6 MW; and the total number of end-use locations has increased from approximately 200 in March 2002 to 4,067. Since participation in EDRP and ICAP/SCR became mutually exclusive, EDRP resources and MW have continued to decrease while ICAP/SCR resources and MW have increased. Aggregations by Responsible Interface Parties now account for 97.7% of ICAP/SCR end-use locations and 77.9% of registered MW in the program.

Figure 1: Historical Growth in Resources and MW in NYISO Reliability Programs



<u>Migration Summary</u>

Table 6 of this Report Section I shows the program enrollment changes by number of program IDs registered, not the total number of end-use locations. Program IDs, used to represent a resource in NYISO's market systems, may represent individual end-use locations or aggregations of end-use locations. Table 7 of this Report Section I shows the program enrollment changes by number of end-use locations. Enrollment in ICAP/SCR is increasing at a faster pace than enrollment reductions in EDRP indicating that new resources continue to enroll, in addition to the EDRP resources that are migrating to ICAP/SCR.

Table 6: Program Enrollment by Program ID - Changes 2008 to 2009

	2008		2009		Percent Change From 2008 to 2009		Subscribed MW per End-use location		
	Count	MW	Count	MW	End-use Location Count	Subscribed MW	2008	2009	Percent Change
EDRP	419	364.4	392	323.0	-6%	-11%	0.87	0.82	-5%
ICAP/SCR Offered/Unsold	1	0.1	0	0.0	-100%	-100%	0.10	0.00	-100%
ICAP/SCR	175	1743.8	194	2060.6	11%	18%	9.96	10.62	7%
DADRP	22	331.4	22	331.4	0%	0%	15.06	15.06	0%

Table 7: Program Enrollments by End-use Location - Changes 2008 to 2009

	2008		2009		Percent Change From 2008 to 2009		Subscribed MW per End-use location		
	Count	MW	Count	MW	End-use Location Count	Subscribed MW	2008	2009	Percent Change
EDRP	419	364.4	392	323.0	-6%	-11%	0.87	0.82	-5%
ICAP/SCR Offered/Unsold	1	0.1	0	0.0	-100%	-100%	0.10	0.00	-100%
ICAP/SCR	3291	1743.8	3675	2060.6	12%	18%	0.53	0.56	6%
DADRP	22	331.4	50	331.4	127%	0%	15.06	6.63	-56%

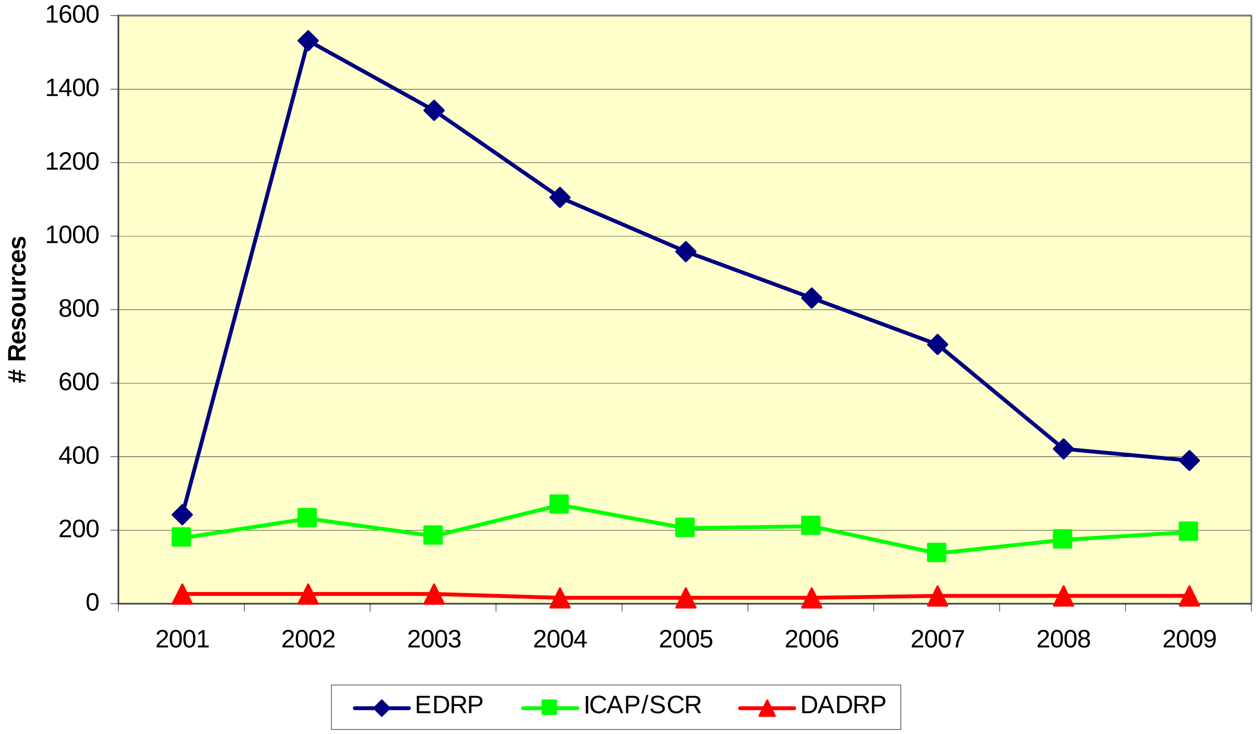
Figure 2, Figure 3, and Figure 4 of this Report Section I track enrollment and MW in EDRP, ICAP/SCR and DADRP, respectively, over the period 2001 through 2009. The primary difference between Figure 2 and Figure 3 is the representation of ICAP resources: Figure 2 shows percent change and average subscribed MW by Program ID, while Figure 3 shows percent change and average subscribed MW by end-use location.

Figure 2 of this Report Section I shows the number of Program IDs, including individually enrolled resources and aggregated resources. Figure 3 provides information on the total number of end-use locations. Eighty-five (85) individually enrolled resources account for 454.9 MW, an increase of less than 1% from 2008. ICAP/SCR enrollment of end-use locations was initiated in 2004; prior to that period, the registered resources shown in Figure 2 and Figure 3 for ICAP/SCR were based on program IDs. In addition, for 2001 and 2002, program enrollment was non-exclusive, *i.e.*, an end-use location could register for both EDRP and

ICAP/SCR. Beginning in 2003, participation in the EDRP and ICAP/SCR programs became mutually exclusive.[5]

Figure 4 shows that since making EDRP and ICAP/SCR mutually exclusive, the general trend has been for EDRP enrollment and MW to decrease and ICAP/SCR enrollment and MW to increase, as expected, given the monthly reservation payment associated with the ICAP/SCR program.

Figure 2: Demand Response Program Enrollment History by Program ID, 2001 – 2009



[5] Pursuant to the tariff, SCRs may participate in both the EDRP and the ICAP/SCR programs concurrently if the resource has metering to distinguish the MWs of Demand Reduction in the Special Case Resource from the MWs in the Emergency Demand Response Program. The metering requirement supports the program rule that MW cannot be committed both as Unforced Capacity and to the Emergency Demand Response Program.

Figure 3: Demand Response Program Enrollment History by Number of End-use locations, 2001 - 2009

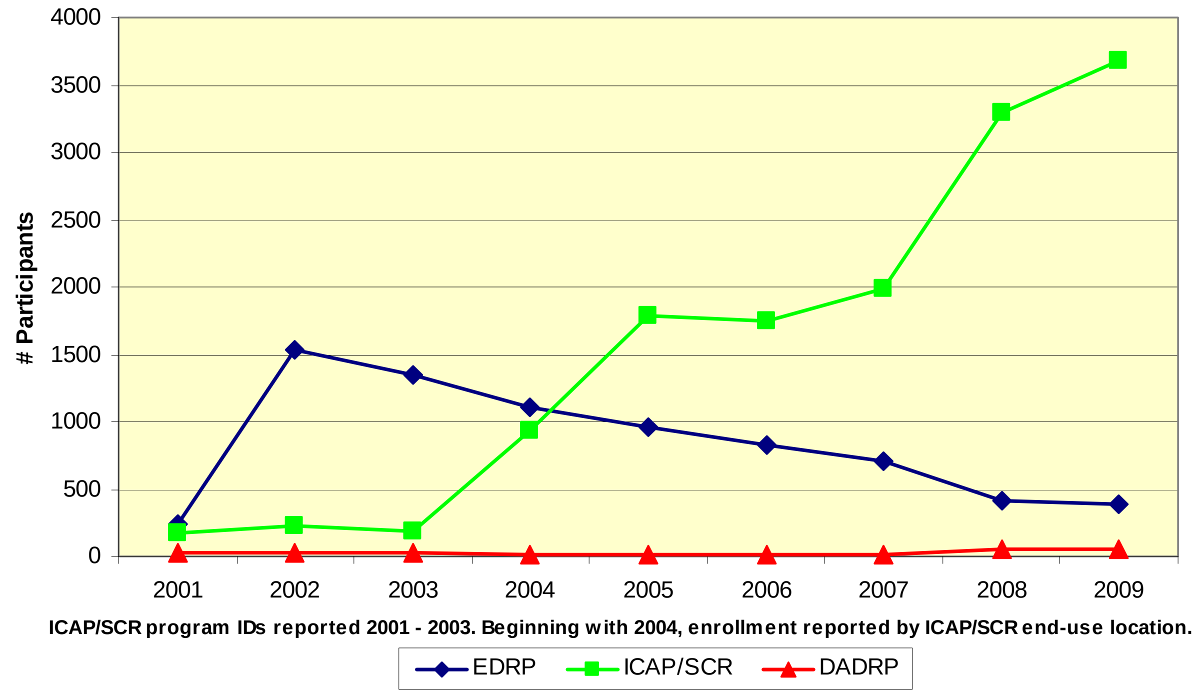
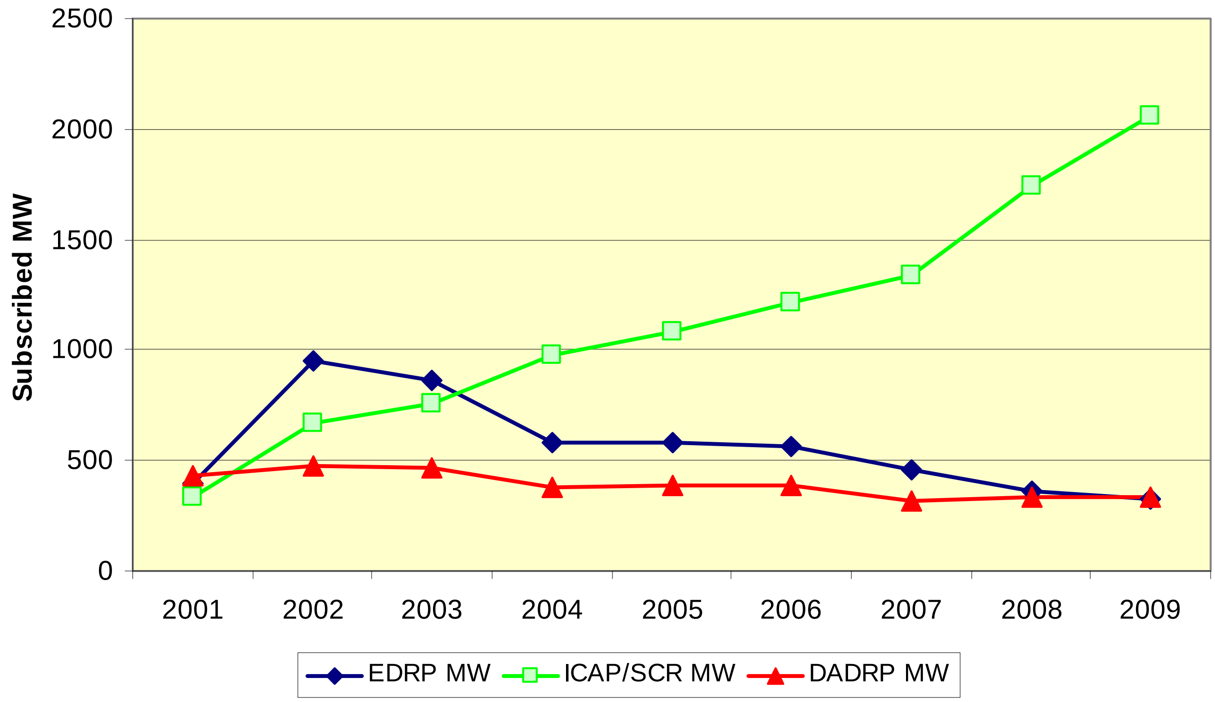


Figure 4: Demand Response Program MW Enrollment History, 2001 - 2009

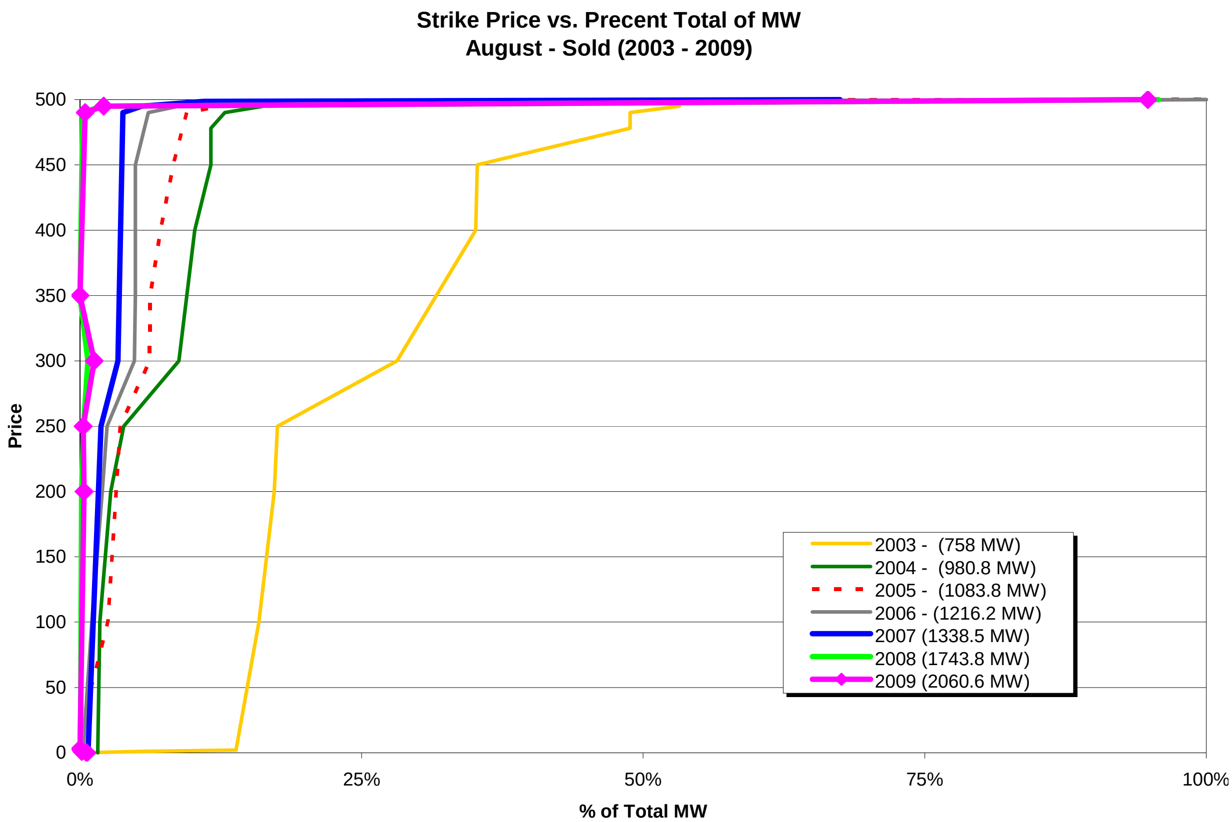


Analysis of ICAP/SCR Strike Prices

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

To characterize how resources responded to this requirement, strike price curves were developed for all resources for 2009. The curves map out the percentage of registered MW at a given strike price. Figure 5 of this Report Section I illustrates the strike price curves for 2003 to 2009, 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 resources have, over time, increased the number of higher strike prices. In 2009, 98% of the ICAP/SCR strike prices were at or above \$490/MWh, with 1% of the remaining 2% below \$200/MWh. This phenomenon may result from the lack of partial zonal load reduction calls. With a low likelihood of partial zonal calls, it is reasonable to conclude that resources 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 - 2008 ICAP/SCR Curtailment Bid Curves



Day-Ahead Demand Response Program

The DADRP program provides demand resources with an opportunity to offer their load curtailment capability into the Day-Ahead energy market as energy supply resources. Resources submit offers 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 offer price had to be $50/MWh or higher. As of November 1, 2004, the offer floor price for DADRP has been set at $75/MWh. Offers are structured like those of generation resources, so DADRP program resources may specify minimum and maximum run times and effectively submit a block of hours on an all-or-nothing basis. This structure makes resources 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 offer price. Load scheduled in the DAM is obligated to curtail the next day. Failure to curtail results in the imposition of a penalty equal to the product of the MW curtailment shortfall and the greater of the corresponding Day-Ahead and Real-Time market price.

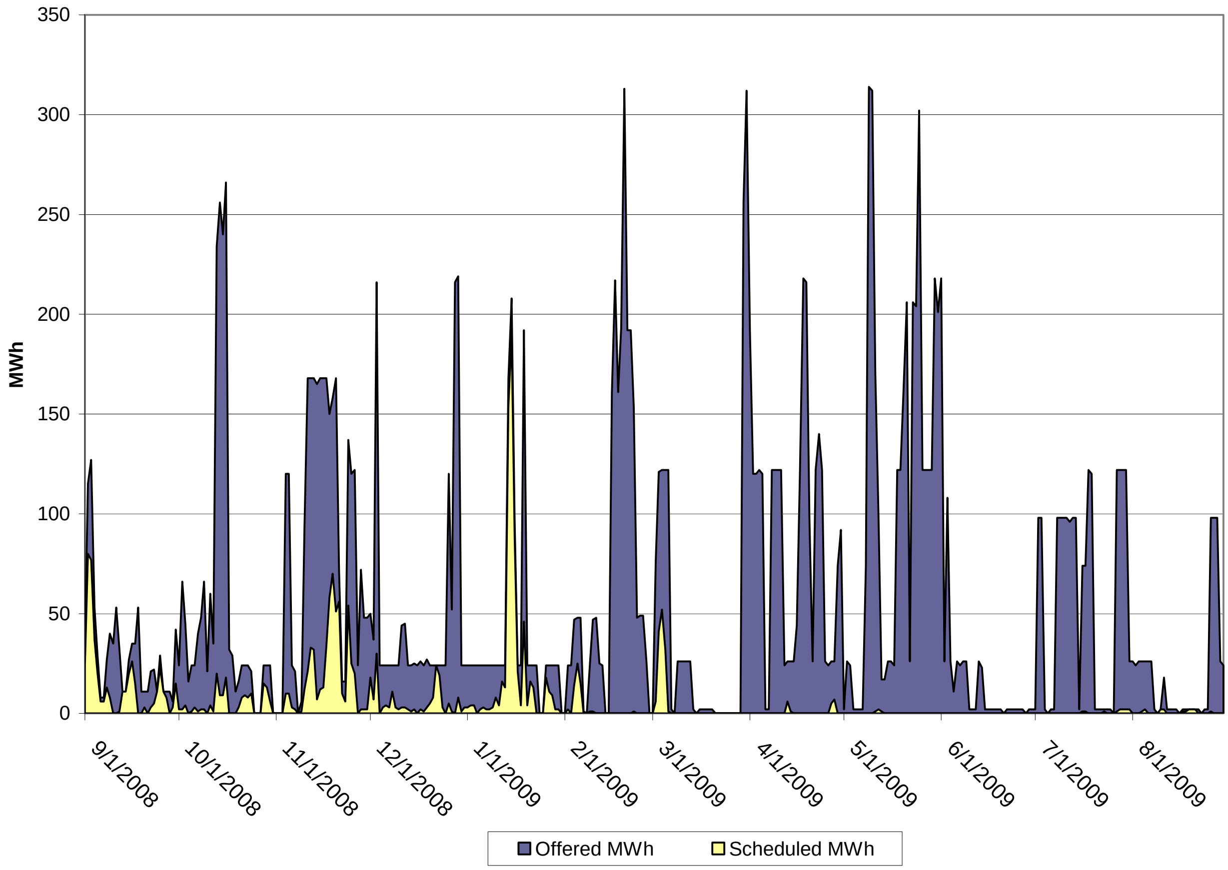
DADRP Participation and Offer Summary

Offered and Scheduled MWh

During the analysis period of September 2008 through August 2009, five resources representing over 30 end-use locations, submitted offers in Zone F (Capital), Zone G (Hudson Valley) and Zone K (Long Island). Although offer activity increased by 28% over the previous 12-month period, 72% fewer hours were scheduled (2,192) than in the previous period (7,727). In 2009, 12% of offers were scheduled compared to 73% of offers in 2008. The average DAM LBMP over all hours during the analysis period was $84.56 in Zone F, and $90.64 in Zone K[6]. Overall, the average hourly offer decreased by 21%, from 2.9 MW to 2.28 MW, while scheduled offers increased by 36% to an average of 2.05MW.

[6] Analysis was not performed on Zone G (Hudson Valley) because no performance information was submitted for resources in this Zone.

Figure 6: DADRP MWh, Bid vs. Scheduled



Prior to 2008, offers were very limited, with a noteworthy number of offers occurring around holidays. Beginning in 2008, load reduction offers occurred on a regular, almost daily, basis (Figure 6), exclusively at the offer floor price. While DADRP resources continued to offer on a regular basis throughout the analysis period, scheduling of DADRP load reductions trailed off after the end of the first quarter of 2009 as average prices stayed consistently below the bid floor of $75/MWh.

The winter months (November through April) had the greatest number of scheduled DADRP MWh and accounted for almost three quarters of all scheduled MWh (72%) in the analysis period. Overall average hourly DAM LBMPs in Zone F was $82.04/MWh with the highest average hourly price scheduled for the analysis period topping out at $92.92/MWh. The single highest day-ahead price scheduled in Zone F was $165.68/MWh (January 2009) and the lowest was $43.07/MWh (April 2009). In the Long Island zone, the highest average hourly price scheduled reached $109.72/MWh. The single highest day-ahead price scheduled in Zone K was $147.99/MWh (March 2009) and the lowest was $71.64/MWh (August 2009).

There were 28 hours when DADRP resources were scheduled below the offer floor of $75/MWh. These scheduled hours occur in the reliability stage of the Security Constrained Unit Commitment (SCUC) process that the NYISO uses to commit supply resources. As with generators who are scheduled below their offer price, DADRP resources are paid a Bid Production Cost Guarantee for load reductions.

Table 8 of this Report Section I shows a comparison of DADRP offer activity for the analysis periods of 2008 and 2009. In total, 12% of offers were accepted, while 11% of total MWh offered were accepted.

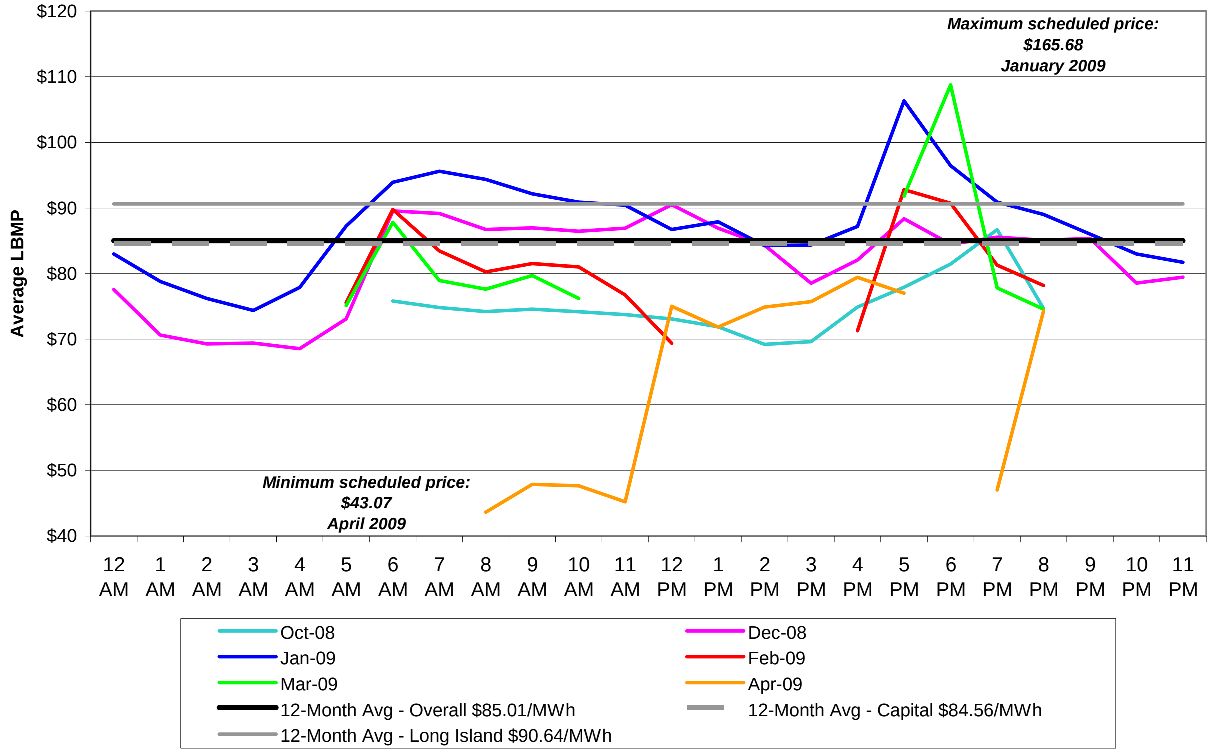
Table 8: DADRP Offer Activity – Comparison of 2008 and 2008

	2009	2008	% change
Total Offer Hours	9,024	7,034	28%
Scheduled Hours*	1,067	5,128	-79%
Offered MWh	20,536	20,364	1%
Scheduled MWh	2,192	7,727	-72%
Average Offer	2.28	2.90	-21%
Average Schedule	2.05	1.51	36%

Scheduled hours are cumulative for all resources, not unique.

Figure 7 of this Report Section I shows the average hourly DAM LBMP for scheduled DADRP offers in both Zone F and Zones K for the months of October, December, January, February, March, and April, and the 12-month average of scheduled hours for both Zone F and Zones K. The 12-month average prices for Zone F ($84.56/MWh) and Zone K ($90.64) are solid and dashed gray lines, respectively. Broken or incomplete lines indicate months where no DADRP schedules occurred for those hours. Average hourly LBMPs represent only the hours when a DADRP resource was scheduled; in some instances, this is a single hour. For example, the orange line representing April 2009 shows single values for the hours of 8am through 11 a.m. and 7 p.m. Afternoon hours between noon and 6 pm for April 2009 are the average of multiple resource schedules.

Figure 7: 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 for each Zone are isolated, only 12 hours in Zone F and no hours in Zone K had scheduled DADRP performance, including the highest hourly DAM LBMP in Capital. Table 9 of this Report Section I shows the hours with the 20 highest Day-Ahead zonal LBMPs; DADRP offers were scheduled in 12 of the top 20 hours in Zone F and none of the top 20 hours in Zone K. September had the highest DAM LBMPs in which DADRP resources were scheduled. The majority of the top 50 DAM LBMP hours in Zone F were in the Winter Capability Period (November through April), although there were a few high-priced hours in September. Approximately 90% of the top 50 hours in Zone K were in months in the Summer Capability Period.

Table 9: Scheduled DADRP Bids at High DAM LBMPs

Capital Zone

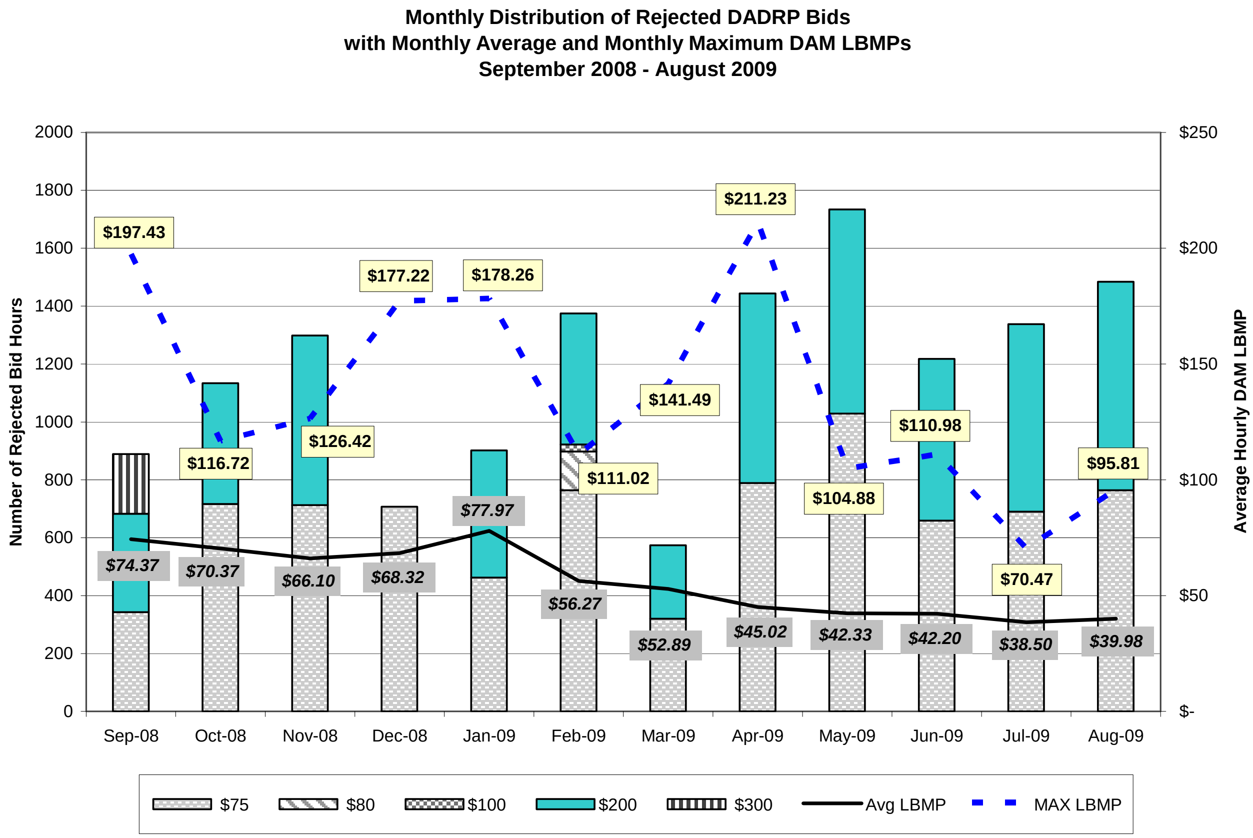
Date	Hour	DAM LBMP	Scheduled MW
04/07/09	10	$ 211.23	0
04/07/09	11	$ 202.07	0
09/14/08	20	$ 197.43	0
09/14/08	19	$ 183.44	0
09/14/08	17	$ 182.33	0
09/14/08	16	$ 181.24	1
09/14/08	15	$ 178.52	1
01/15/09	17	$ 178.26	9
12/23/08	17	$ 177.22	1
01/16/09	17	$ 174.19	1
01/15/09	18	$ 167.73	9
04/07/09	13	$ 167.08	0
01/16/09	18	$ 160.27	1
01/15/09	19	$ 152.20	9
12/23/08	18	$ 151.34	1
12/22/08	17	$ 150.64	1
09/14/08	18	$ 149.77	0
01/15/09	20	$ 146.68	9
12/23/08	19	$ 145.82	1
04/06/09	7	$ 144.73	0

Long Island

Date	Hour	DAM LBMP	Scheduled MW
09/03/08	15	$ 358.61	0
09/08/08	16	$ 301.65	0
09/13/08	17	$ 280.93	0
09/02/08	16	$ 275.73	0
09/03/08	16	$ 275.37	0
09/13/08	16	$ 271.64	0
09/08/08	17	$ 269.16	0
09/04/08	15	$ 267.51	0
09/04/08	16	$ 263.00	0
09/04/08	17	$ 261.63	0
09/08/08	15	$ 256.88	0
09/13/08	15	$ 256.51	0
09/15/08	15	$ 249.02	0
09/15/08	16	$ 247.68	0
03/01/09	18	$ 236.74	0
09/15/08	14	$ 235.10	0
09/01/08	15	$ 230.50	0
09/04/08	14	$ 229.86	0
09/13/08	14	$ 229.53	0
09/01/08	16	$ 228.78	0

With the considerable increase in the number of offers by DADRP resources, the rejected bids also were analyzed for the reporting period of September 2008 through August 2009. Figure 8 shows the monthly distribution of the number of rejected hourly DADRP offers by price level with the monthly average DAM LBMP and monthly maximum DAM LBMP for the analysis period. Offers that occur at price levels above the offer floor price are additional points on the price/MW bid curves submitted by DADRP resources.

Figure 8: Rejected Offers 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 of this Report Section I outlines the results of the DADRP price reduction analysis for the period of September 2008 through August 2009 on a monthly basis. Performance is measured by the sum of all scheduled DADRP offers in that Zone over the analysis period,[7] while program payments are equal to the sum of the scheduled MWh in a specific hour multiplied by the day-ahead LBMP.[8] The average price reduction represents the estimated impact that the DADRP performance had on the Day-Ahead LBMP.

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[7] The analysis assumed 100% compliance, namely, that resource curtails the full scheduled MWh. Scheduled hours for which performance data was unavailable were excluded from the price reduction impact analysis.
[8] This simplistic representation does not take into account any Bid Production Cost guarantee potentially owed to the DADRP resource, but serves as a largely accurate proxy for payment.

The overall average hourly price reduction from scheduled DADRP load reductions is $0.27/MWh, a decrease of $1.18 from 2008. On a monthly basis, the average hourly price reduction was most significant in the months of January 2009 ($0.93/MWh), November 2008 ($0.70/MWh) and September 2008 ($0.64/MWh). There were no price impacts for the summer months of May through August 2009, in part due to minimal load reduction offers and even fewer scheduled reductions.

Table 10: Price Reduction Analysis Results by Month

	Performance MWh	Program Payments	Average DAM LBMP ($) - Scheduled Hours	Average Price Reduction ($)	Number of Scheduled Hours**
Sep-08	437	$ 37,506.46	$ 80.82	$ 0.64	200
Oct-08	150	$ 11,905.35	$ 75.11	$ 0.44	97
Nov-08	546	$ 44,320.86	$ 78.89	$ 0.70	102
Dec-08	175	$ 14,664.12	$ 81.81	$ 0.30	125
Jan-09	642	$ 61,685.24	$ 87.44	$ 0.93	234
Feb-09	59	$ 4,964.78	$ 80.92	$ 0.11	36
Mar-09	132	$ 10,894.10	$ 82.83	$ 0.03	27
Apr-09	19	$ 1,258.86	$ 63.30	$ 0.12	19
May-09	4	$ 325.01	$ 79.77	$ -	0
Jun-09	0	$ -	$ -	$ -	0
Jul-09	12	$ 1,149.96	$ 94.30	$ -	12
Aug-09	16	$ 1,454.70	$ 88.99	$ -	16
Total	2,192	$ 190,129.44	n/a	n/a	868
Average	183	$ 15,844.12	$ 74.52	$ 0.27	72

Historical Analysis of DADRP

Table 11 of this Report Section I provides a summary of the scheduled reductions, scheduled hours, average hourly scheduled MW, 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 2009 includes all DADRP scheduled transactions from September 2008 through August 2009.

Table 11: DADRP Program Summary 2001-2009

	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
2008	7,727	5,128	1.51	$ 801,108
2009	2,192	1,067	2.05	$ 190,129

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

Figure 9[9] of this Report Section I shows the history of scheduled MWh by season since the program's inception. The summer season months[10] 2008 had the greatest number of scheduled MWh of any season since the initial summer of the program and almost double the overall average for summer months. Fall months[11] 2008 and Winter[12] 2009 scheduled MWh were slightly below average. Scheduled MWh for spring[13] and summer 2009 had the fewest number of scheduled MWh in the history of the DADRP program.

[9] References to seasons in Figure 9 correspond to the calendar seasons and not to "Summer" and "Winter" Capability Period months.

[10] June, July, and August.

[11] September, October, and November.

[12] December, January, and February.

[13] March, April, and May.

Figure 9: Total MWh Scheduled in DADRP by Season and Year, 2001-2009

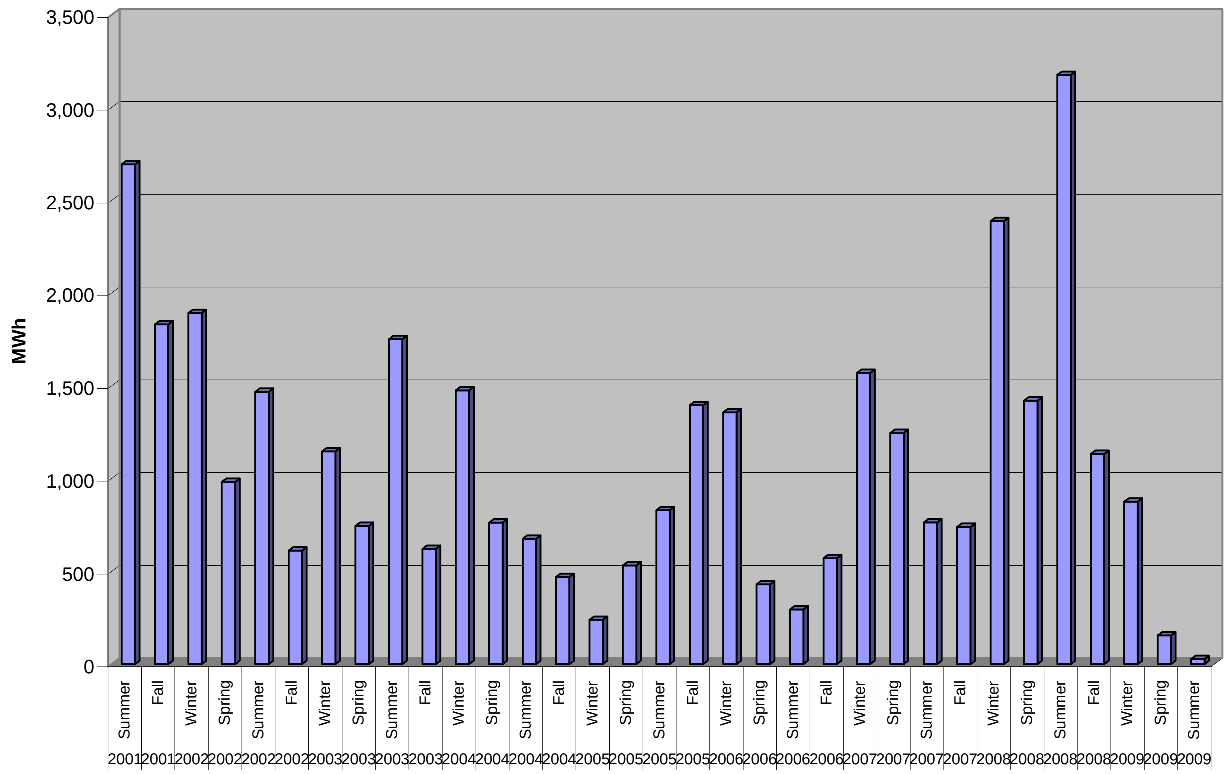


Figure 10 of this Report Section I shows the history of the average scheduled DADRP offered by season since the program's inception. Average scheduled MWh for three of the four seasons in the 2008-2009 analysis period were below the seasonal averages to date.

Figure 10: Average Scheduled DADRP Offer (MWh) by Season and Year, 2001-2009

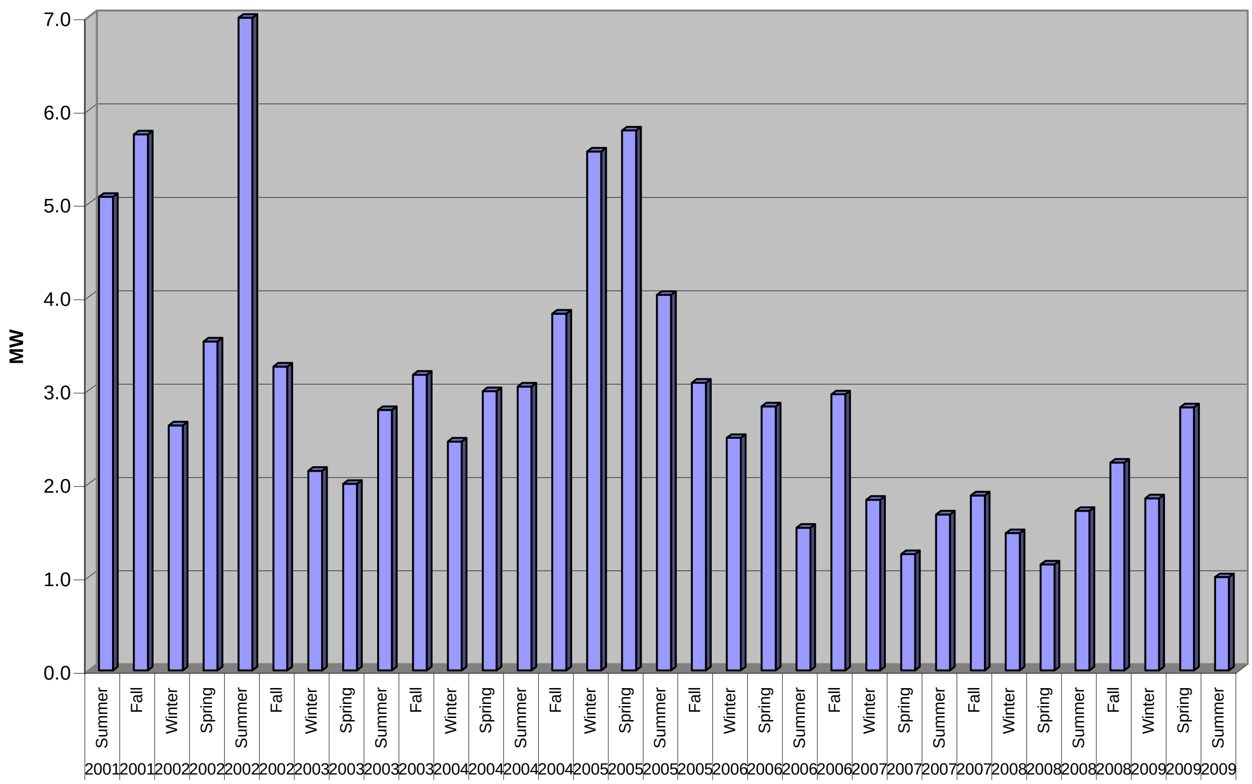
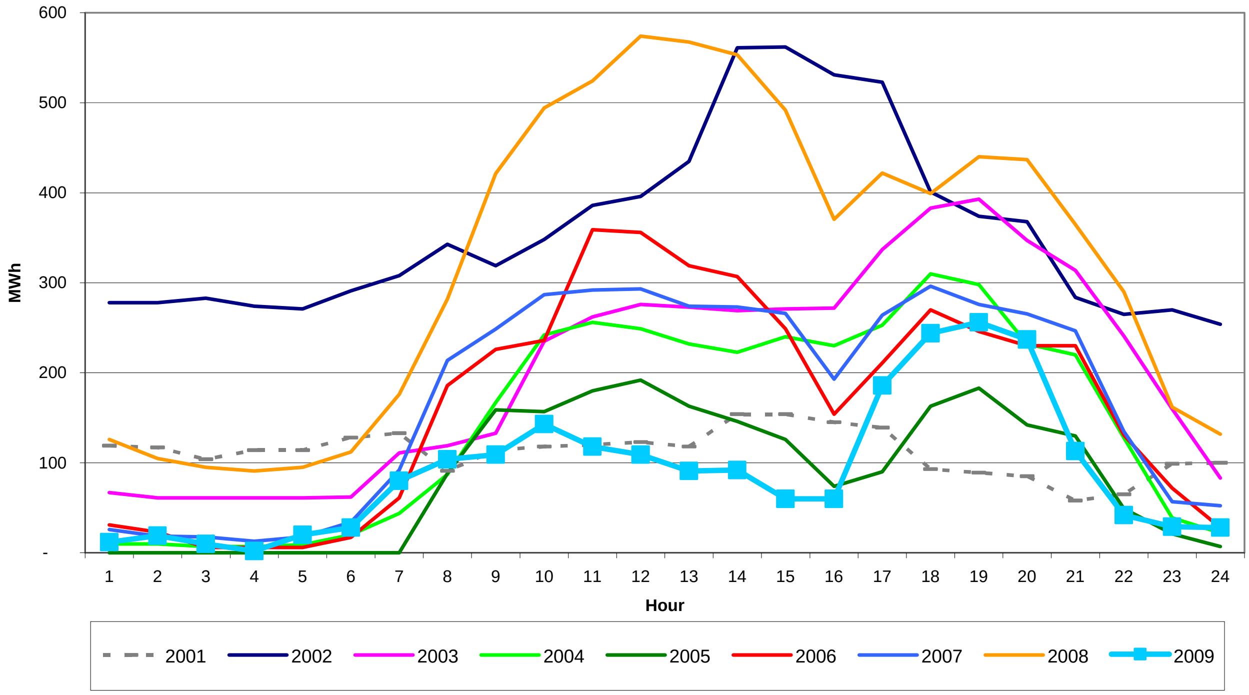


Figure 11 of this Report Section I shows the distribution of scheduled DADRP offers by hour since the program's inception. The current year is shown with hour markers on the line. In 2009, scheduled load reductions were among the lowest since DADRP began.

Figure 11: Total Scheduled DADRP Offers (MWh) by Hour and Program Year (9/1 – 8/31) 2001*-2009 (*2001: July and August only)



<u>DADRP Estimated Market Benefits Summary – Summer</u>

When DADRP curtailments displaced higher-priced generation resources, the corresponding DAM clearing price dropped, thereby reducing the cost of purchases. Reductions in the average DAM LBMP for the summer of 2009 is compared to those from 2001 through 2008 in Table 12 of this Report Section I.

The fewest number of scheduled hours (155) occurred in the Summer of 2009. As shown in the rejected bid chart (Figure 8), the average prices for the majority of the analysis period were significantly below the offer floor price of $75/MWh. As a result, the few hours scheduled during the summer month resulted in, on average, no impact on the day-ahead prices.

Table 12: 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
2008	3,177	$ 348,509	$ 2.05	1.71
2009	155	$ 2,605	$ -	1.00

DADRP Conclusions

While 2009 reflected increases in offers, there are still a limited number of active resources. Two new resources enrolled in 2008 and began to offer load reductions in late 2008 or early 2009. The major factor contributing to the marked decrease in scheduled hours for DADRP during this analysis period was that offer prices exclusively at the DADRP bid floor combined with very low day-ahead prices resulted in fewer opportunities for scheduling of DADRP resources. The NYISO will continue to evaluate resource participation and program parameters to ensure the programs are delivering the intended market outcomes.

Other Demand Response Initiatives

Demand Side Ancillary Services

The NYISO introduced the Demand Side Ancillary Services Program (DSASP) in June 2008. In late November 2009, the first DSASP resource completed its enrollment as an Ancillary Service provider. The resource will be eligible to offer Reserve and/or Regulation Services in the NYISO markets following prequalification in early 2010.

In its Order No. 719[14], the Federal Energy Regulatory Commission ("FERC" or the "Commission") directed the ISOs and RTOs to permit Aggregators of Retail Customers (ARCs)

[14] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) ("Order 719").

to offer aggregation of resources into Ancillary Service markets. In its October 2009 filing[15], the NYISO committed to provide semi-annual updates on its efforts to allow aggregations to provide ancillary services. In its response, the NYISO indicated that it needed to seek approval from the New York State Reliability Council to permit aggregations of small demand resources to provide Operating Reserves. At that time, the NYISO stated that for the near term, due to existing telemetry configurations, aggregations of small resources would be permitted to provide Operating Reserves but not Regulation Service.

On November 5, 2009, the NYISO presented the concept of aggregations of small demand resources providing Operating Reserves and Regulation Service to the Reliability Rules Subcommittee of the New York State Reliability Council (NYSRC). The Reliability Rules Subcommittee determined that there was no need for changes to any NYSRC rules. The NYISO shared with its stakeholders the NYSRC decision at the Price Responsive Load Working Group on November 9, 2009[16]. The presentation also outlined a list of next steps that the Working Group will undertake in 2010 to develop market rules that permit qualified aggregations of small demand resources to provide Operating Reserves.

<u>Demand Response Information System (DRIS)</u>

On November 12, the NYISO deployed the first phase of its Demand Response Information System. This internal deployment is the first phase in a project to automate the administration of the NYISO's demand response programs. The NYISO provided an update on the project status and the functionality of the first phase at its December 14, 2009 Price Responsive Load Working Group meeting[17]. Future phases planned for 2010 include market trials where Market Resources will begin to interact with the DRIS.

[15] Docket No. ER-09-1142-000, New York Independent System Operator, Inc., Compliance with Order 719 (October 28, 2009).
[16] NYISO presentation to Price Responsive Load Working Group available at: http://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2009-11-09/DSASP_update.pdf
[17] NYISO presentation to Price Responsive Load Working Group available at: http://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2009-12-14/DRIS_Project_Status_121409.pdf

Real-Time Energy for Demand Response

In its November 20, 2009 Order[18], FERC directed the NYISO to allow for qualified demand response resource participation in its Real-Time energy market by modifying its tariff to allow technically capable demand response resources to participate in the real-time energy market to provide energy imbalance service. At its December 14, 2009 Price Responsive Load Working Group meeting, the NYISO reviewed the Order with stakeholders and proposed an approach[19], along with a partial list of design issues that will be discussed in preparation for the NYISO's 90-day compliance filing on a plan of action to allow demand resources to offer load reductions into the real-time energy market. The NYISO responded to questions regarding the proposed approach and design issues. Stakeholders were encouraged to submit comments in writing before the January 2010 Price Responsive Load Working Group meeting.

[18] Docket No. ER-09-1142-000, New York Independent System Operator, Inc., *Order on Compliance Filing (November 20, 2009)1998)*, 129 FERC ¶ 61,164

[19] NYISO presentation to Price Responsive Load Working Group available at: http://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2009-12-14/FERC_Order_on_RT_Demand_Response.pdf

II. NYISO Report on New Generation Projects

In its October 23, 2006 order, the Commission ordered 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 for Large Facilities[2] is described in Attachment X of the NYISO OATT, entitled "Standard Large Facility Interconnection Procedures." The NYISO interconnection process for Small Generators[3] is described in Attachment Z of the NYISO OATT, entitled "Small Generator Interconnection Procedures (SGIP)." Under Attachment X, Developers of Large Facilities 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. Under Attachment Z, developers (referred to in the SGIP as "Interconnection Customers") of Small Generating Facilities also submit an Interconnection Request (or "Application") to the NYISO, and the NYISO assigns a Queue Position for those Interconnection Requests. Thereafter, the proposed Small Generating Facilities undergo either the Study Process, or other evaluation process as applicable under Attachment Z. Small Generating Facilities that are determined to require System Upgrade Facilities ("SUFs") are required to undergo the NYISO Class Year Facilities Study process the same as Large Facilities. Small Generating Facilities that do not require SUFs are not required to undergo a Class Year study.

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[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.

[3] A Small Generator under Attachment Z is a Small Generating Facility no larger than 20 MW.

All 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 the most recent list, dated December 22, 2009, are shown in Attachment A to this Section II. The NYISO updates the NYISO Interconnection Queue on at least a monthly basis and posts the most recent list on the NYISO's public web site at http://www.nyiso.com/public/markets_operations/services/planning/planning_resources/index.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.

The status of each project on the NYISO Interconnection Queue is shown in the column labeled "S." Explanations for this column, 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 to this Section II.

Section II – Attachment A

Interconnection Queue

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	Z	Interconnection Point	Utility	S	Last Update	Availability of Studies	Proposed In-Service Original	Proposed In-Service Current
19	NYC Energy LLC	NYC Energy LLC	5/7/99	79.9		CT-NG	Kings, NY	J	Kent Ave 138kV	CONED	10	10/29/08	SRIS, FS	2004/Q4	2010/Q4
20	KeySpan Energy, Inc.	Spagnoli Road CC Unit	5/17/99	250		CC-NG	Suffolk, NY	K	Spagnoli Road 138kV	LIPA	8	10/28/09	SRIS	2006	N/A
31	SCS Energy, LLC	Astoria Energy	11/16/99	1000		CC-NG	Queens, NY	J	Astoria 138kV	CONED	12,14	2/26/08	SRIS, FS	2006	2010/05
69	Empire Generating Co., LLC	Empire Generating	7/14/00	660		CC-NG	Rensselaer, NY	F	Reynolds Road 345kV	NM-NG	12	10/28/09	SRIS, FS	2006	2010/07
106	TransGas Energy, LLC	TransGas Energy	10/5/01	1100		CC-NG	Kings, NY	J	E13St, Rainey, or Farragut-345kV	CONED	8	2/26/08	SRIS	2007	2012/Q3
107	Caithness Long Island, LLC	Caithness Long Island	10/9/01	310		CC-NG	Suffolk, NY	K	Brookhaven-Holbrook or H'ville 138kV	LIPA	14	11/30/09	SRIS, FS	2008	I/S
113	Windfarm Prattsburgh, LLC	Prattsburgh Wind Park	4/22/02	55.5		W	Yates, NY	C	Eelpot Rd-Flat St. 115kV	NYSEG	11	10/28/09	SRIS, FS	2004/Q4	N/A
115	Central Hudson Gas & Electric	East Fishkill Transformer	4/24/02	N/A		AC	Dutchess, NY	G	East Fishkill 345kV/115kV	CONED/CHG&E	4	8/19/08	None	2007/06	2012
119	ECOGEN, LLC	Prattsburgh Wind Farm	5/20/02	79.5		W	Yates, NY	C	Eelpot Rd-Flat St. 115kV	NYSEG	10	11/30/09	SRIS, FS	2005/02	2010/Q3
125	East Coast Power, LLC	Linden VFT Inter-Tie	7/18/02	300		AC	Richmond, NY-NJ	J	Goethals 345kV	CONED	14	11/30/09	SRIS, FS	2005	I/S
127A	Airtricity Munnsville Wind Farm, LLC	Munnsville	10/9/02	40		W	Madison, NY	E	46kV line	NYSEG	12,14	10/28/09	SRIS	2005/12	2013/12
142	EC&R Northeast, LLC	Steuben Wind	10/30/03	50		W	Steuben, NY	C	Bennett-Palmiter 115kV line	NYSEG	7	9/1/09	SRIS	2006/12	2010/12
147	NY Windpower, LLC	West Hill Windfarm	4/16/04	31.5		W	Madison, NY	C	Oneida-Fenner 115kV	NM-NG	10	12/22/09	SRIS, FS	2006/Q4	N/A
150	Reunion Power, LLC	Cherry Valley Wind Power	6/17/04	70		W	Otsego, NY	E	Marshville - Sharon 69kV	NM-NG	6	11/30/09	SRIS	2006/09	N/A
151	Con Edison	West Side Switching Station	6/30/04	N/A		AC	New York, NY	J	West 49th St & Farragut 345kV	CONED	4	2/26/08	None	2011/Q3	2011/Q3
152	Moresville Energy LLC	Moresville Energy Center	7/23/04	99	99	W	Delaware, NY	E	Axtell Road-Grand Gorge 115kV	NYSEG	9	11/19/08	SRIS	2006/12	2009/12
153	Con Edison	Sprain Brook-Sherman Creek	8/13/04	500		AC	Westchester, NY	I, J	Sprain Brook & Sherman Creek	CONED	6	4/8/09	SRIS	2007/Q3	2011/Q2
154	KeySpan Energy for LIPA	Holtsville-Brentwood-Pilgrim	8/19/04	N/A		AC	Suffolk, NY	K	Holtsville & Pilgrim 138kV	LIPA	5	7/10/08	None	2007/06	2012/12
155	Invenergy NY, LLC	Canisteo Hills Windfarm	9/17/04	149		W	Steuben, NY	C	Bennett-Bath 115kV	NYSEG	6	10/28/09	FES, SRIS	2006/08	N/A
156	PPM Energy/Atlantic Renewable	Fairfield Wind Project	9/28/04	120	120	W	Herkimer, NY	E	Valley-Inghams 115kV	NM-NG	11	11/30/09	SRIS, FS	2006/09	2010/09
157	BP Alternative Energy NA, Inc.	Orion Energy NY I	10/12/04	100	100	W	Herkimer, NY	E	Watkins Rd.-Inghams 115kV	NM-NG	6	10/28/09	FES, SRIS	2006/07	N/A
160	Jericho Rise Wind Farm, LLC	Jericho Rise Wind Farm	10/12/04	79.2	79.2	W	Franklin, NY	D	Willis 115 kV	NYPA	9	5/12/09	FES, SRIS	2006/09	2009-2011
161	Marble River, LLC	Marble River Wind Farm	12/7/04	84	84	W	Clinton, NY	D	Willis-Plattsburgh WP-1 230kV	NYPA	10	11/30/09	SRIS, FS	2006	2011/10
166	AES-Acciona Energy NY, LLC	St. Lawrence Wind Farm	2/8/05	79.5	79.5	W	Jefferson, NY	E	Lyme Substation 115kV	NM-NG	10	12/22/09	SRIS	2006/12	2011/12
168	Dairy Hills Wind Farm, LLC	Dairy Hills Wind Farm	2/8/05	120	120	W	Wyoming, NY	C	Stolle Rd.-Meyer 230kV	NYSEG	8	10/28/09	SRIS	2006/11	N/A
169	Alabama Ledge Wind Farm, LLC	Alabama Ledge Wind Farm	2/8/05	79.8	79.8	W	Genesee, NY	B	Oakfield-Lockport 115kV	NM-NG	9	12/22/09	FES, SRIS	2007/12-2009/12	2009-2011
171	Marble River, LLC	Marble River II Wind Farm	2/8/05	132.3	132.3	W	Clinton, NY	D	Willis-Plattsburgh WP-2 230kV	NYPA	10	11/30/09	SRIS, FS	2007/12	2011/10
178	Noble Allegany Windpark, LLC	Allegany Windpark	2/14/05	100.5	100.5	W	Cattaraugus, NY	A	Freedom Substation 115kV	Village of Arcade	9	10/29/08	SRIS	2007/10	2009/12
180A	Green Power	Cody Rd	3/17/05	10	10	W	Madison, NY	C	Fenner - Cortland 115kV	NM-NG	11	10/28/09	None	None	2010/10
182	Howard Wind, LLC	Howard Wind	3/21/05	62.5	62.5	W	Steuben, NY	C	Bennett-Bath 115kV	NYSEG	10	10/28/09	SRIS, FS	2007/10	2010/12
185	New York Power Authority	Blenheim Gilboa Storage	3/29/05	120	120	PS	Schoharie, NY	F	Valenti Rd., Gilboa 345kV	NYPA	12,14	11/30/09	SRIS	2010	2010/05
186	Jordanville Wind, LLC	Jordanville Wind	4/1/05	80	80	W	Herkimer, NY	E	Porter-Rotterdam 230kV	NM-NG	10	10/28/09	SRIS, FS	2006/12	2011/12
189	PPM Energy, Inc.	Clayton Wind	4/8/05	126	126	W	Jefferson, NY	E	Coffeen St-Thousand Island 115k	NM-NG	8	10/14/08	FES, SRIS	2006/12	2010/12
197	PPM Roaring Brook, LLC / PPM	Tug Hill	7/1/05	78	78	W	Lewis, NY	E	Boonville-Lowville 115kV	NM-NG	9	10/14/08	FES, SRIS	2009/12	2009/12
198	New Grange Wind Farm, LLC	Arkwright Summit Wind Farm	7/21/05	79.8	79.8	W	Chautauqua, NY	A	Dunkirk-Falconer 115kV	NM-NG	9	12/22/09	FES, SRIS	2008/12	2010
201	NRG Energy	Berrians GT	8/17/05	200	200	CC-NG	Queens, NY	J	Astoria West Substation 138kV	CONED	6	11/30/09	FES	2008/02	2012/06

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203	GenWy Wind, LLC	GenWy Wind Farm	10/21/05	478.5	478.5	W	Genesee, NY	A	Stolle Rd - Homer City 345kV	NYSEG	6	10/28/09	FES, SRIS	2008/10	N/A
204A	Duer's Patent Project, LLC	Beekmantown Windfarm	10/31/05	19.5	19.5	W	Clinton, NY	D	46kV	NYSEG	10	10/28/09	None	2008/06	N/A
205	National Grid	Luther Forest	11/2/05	40	40	L	Saratoga, NY	F	Round Lake 115kV	NM-NG	6	10/14/08	SIS	2007/08	N/A
206	Hudson Transmission Partners	Hudson Transmission	12/14/05	660	660	DC/AC	NY, NY - Bergen, N.	J	West 49th Street 345kV	CONED	9	10/28/09	FES, SRIS	2009/Q2	2011/Q4
207	BP Alternative Energy NA, Inc.	Cape Vincent	1/12/06	210	210	W	Jefferson, NY	E	Rockledge Substation 115kV	NM-NG	9	10/14/08	FES, SRIS	2009/Q4	2009/Q4
210	Canadian Niagara Power, Inc.	Fortran	3/14/06	150	150	AC	Niagara, NY	A	Huntley Station 115kV	NM-NG	6	11/30/09	FES	2008/Q1	2010/Q3
213	Noble Environmental Power, LLC	Ellenburg II Windfield	4/3/06	21	21	W	Clinton, NY	D	Willis-Plattsburgh WP-2 230kV	NYPA	10	11/30/09	SRIS, FS	2007/10	N/A
216	Nine Mile Point Nuclear, LLC	Nine Mile Point Uprate	5/5/06	168	168	NU	Oswego, NY	C	Scriba Station 345kV	NM-NG	9	11/30/09	SRIS	2010/Q3	2012/Q2
222	Noble Ball Hill Windpark, LLC	Ball Hill Windpark	7/21/06	90	90	W	Chautauqua, NY	A	Dunkirk-Gardenville 230kV	NM-NG	7	10/28/09	FES, SRIS	2008/10	2011/12
224	NRG Energy, Inc.	Berrians GT II	8/23/06	256	280	CT-NG	Queens , NY	J	Astoria West Substation 138kV	CONED	5	10/28/09	FES	2010/06	2012/06
225	New York State Electric & Gas	Ithaca Transmission	9/7/06	TBD	TBD	AC	Thompkins, NY	C	Oakdale - Lafayette 345kV	NYSEG	6	7/31/09	SIS	2009/12	2010/06
225A	Schenectady International, Inc.	SII Rotterdam Junction	9/8/06	9.3	9.3	Wo	Rotterdam, NY	F	69kV	NM-NG	10	10/28/09	None		N/A
227A	Laidlaw Energy Group Inc.	Laidlaw Energy & Env.	10/30/06	7	7	Wo	Cattaraugus, NY	A	13.2kV	NM-NG	7	10/28/09	None		N/A
231	Seneca Energy II, LLC	Seneca	11/2/06	6.4	6.4	M	Seneca, NY	C	Goulds Substation 34.5kV	NYSEG	9	10/28/09	SRIS	2009/07	2010/07
232	Bayonne Energy Center, LLC	Bayonne Energy Center	11/27/06	512.5	512.5	CT-D	Bayonne, NJ	J	Gowanus Substation 345kV	ConEd	7	9/1/09	FES, SRIS	2008/11	2011/06
233	Erie Boulevard Hydro Power, LP	Sherman Island Uprate	11/27/06	8.5	8.5	H	Warren, NY	F	Spier - Queensbury 115kV	NM-NG	9, 14	11/30/09	SRIS	2007/10	I/S
234	Steel Winds, LLC	Steel Winds II	12/8/06	45	45	W	Erie, NY	A	Substation 11A 115kV	NM-NG	9	10/14/08	SRIS	2007/12	2009/12
236	Gamesa Energy USA, LLC	Dean Wind	12/14/06	150	150	W	Tioga - Schuyler, NY	C	Watercure-Oakdale 345kV	NYSEG	5	12/22/09	FES	2009/12	2011/12
237	Allegany Wind, LLC	Allegany Wind	1/9/07	77.5	77.5	W	Cattaraugus, NY	A	Homer Hill – Dugan Rd. 115kV	NM-NG	5	12/22/09	FES	2009/10	2010/10
237A	Chautauqua County	Chautauqua Landfill	1/11/07	6.4	6.4	M	Chautauqua, NY	A	Hartfield – South Dow 34.5kV	NM-NG	10	10/28/09	None	2007/12	N/A
239	Western Door Wind, LLC	Western Door Wind	1/30/07	100	100	W	Yates, NY	C	Greenidge – Haley Rd. 115kV	NYSEG	5	12/22/08	FES	2010/10	2010/10
239A	Innovative Energy System, Inc.	Modern Innovative Plant	1/31/07	6.4	6.4	M	Niagara, NY	A	Youngstown – Sanborn 34.5kV	NM-NG	9	10/14/08	None	2007/12	2009/Q4
241	Noble Chateaugay Windpark II, LLC	Chateaugay II Windpark	3/15/07	19.5	19.5	W	Franklin, NY	E	Chateaugay Substation 115kV	NYSEG	5	10/28/09	None	2008/07	2011/07
243	Astoria Energy, LLC	Astoria Uprate	4/12/07	100	230	CC-NG	Queens, NY	J	Astoria East Substation 138kV	ConEd	5	11/30/09	None	2010/05	2010/05
245	Innovative Energy System, Inc.	Fulton County Landfill	4/17/07	3.2	3.2	M	Montgomary, NY	F	Ephratah – Amsterdam 69kV	NM-NG	7	10/14/08	None	2008/Q3	2009
246	PPM Energy, Inc	Dutch Gap Wind	6/1/07	250	250	W	Jefferson, NY	E	Indian River Substation 115kV	NM-NG	5	10/14/08	FES	2010/12	2010/12
247	RG&E	Russell Station	6/11/07	300	325	CC-NG	Monroe, NY	B	Russell Station 115kV	RG&E	5	10/28/09	None	2013/07	2013/03
250	Seneca Energy II, LLC	Ontario	7/2/07	6.4	6.4	M	Ontario, NY	B	Haley Rd. - Hall 34.5kV	NYSEG	9	10/28/09	None	2009/10	N/A
251	CPV Valley, LLC	CPV - Valley	7/5/07	630	630	CC-NG	Orange, NY	G	Coopers – Rock Tavern 345kV	NYPA	7	9/1/09	FES/SRIS	2012/05	2012/10
253	Marble River, LLC	Marble River SPS	8/13/07	TBD	TBD	AC	Clinton, NY	D	Moses-Willis-Plattsburgh 230kV	NYPA	5	10/28/09	None	2007/12	N/A
254	Ripley-Westfield Wind LLC	Ripley-Westfield Wind	8/14/07	124.8	124.8	W	Chautauqua, NY	A	Ripley - Dunkirk 230kV	NM-NG	6	10/28/09	FES	2007/12	N/A
256	Niagara Shore Winds, LLC	Niagara Shore Wind	9/4/07	70.5	70.5	W	Niagara, NY	A	Somerset Switch Yard 345kV	NYSEG	5	11/30/09	None	2010/11	2010/11
257	RG&E	Brown's Race Uprate	9/12/07	2	2	H	Monroe, NY	B	Beebee Station 34kV	RG&E	7	10/14/08	None	2008/12	2009/09-2010/10
260	Beacon Power Corporation	Stephentown	9/25/07	20	20	F	Rensselaer, NY	F	Greenbush - Stephentown 115kV	NYSEG	7	12/22/09	None	2008/10	2010/09
261	Astoria Generating Company	South Pier Improvement	10/2/07	100	100	CT-NG	Kings, NY	J	Gowanus Substation 345kV	ConEd	5	11/30/09	None	2010/06	2010/06
263	Stony Creek Wind Farm, LLC	Stony Creek Wind Farm	10/12/07	142.5	142.5	W	Wyoming, NY	C	Stolle Rd - Meyer 230kV	NYSEG	5	4/8/09	FES	2010/01	2010/01

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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	Z	Interconnection Point	Utility	S	Last Update	Availability of Studies	Proposed In-Service Original	Proposed In-Service Current
264	RG&E	Seth Green	10/23/07	2.8	2.8	H	Monroe, NY	B	11kV	RG&E	7	10/14/08	None	2008/04	2010/01
265	CityGreen Transmission	CityGreen	11/16/07	1100	1100	DC	Wsch'r/Bkln/Qns, NY	H, J	Millwood - Farragut/Rainey 345kV	ConEd	3	11/30/09	None	2012/Q3	2012/Q3
266	NRG Energy, Inc.	Berrians GT III	11/28/07	789	789	CC-NG	Queens, NY	J	Astoria 345kV	NYPA	6	6/24/09	FES	2010/06	2012/06
267	Winergy Power, LLC	Winergy NYC Wind Farm	11/30/07	601	601	W	New York, NY	J	E13th St. Substation 345kV	ConEd	3	12/22/08	None	2015/01	2015/01
270	Wind Development Contract Co LLC	Hounsfield Wind	12/13/07	268.8	268.8	W	Jefferson, NY	E	Fitzpatrick - Edic 345kV	NYPA	7	9/1/09	FES/SRIS	2010/09	2010/09
270A	National Grid	Luther Forest Transmission	12/18/07	N/A	N/A	AC	Saratoga, NY	F	Ngrid 115kV	NM-NG	6	10/28/09	SIS	2017	2017
271	State Line Wind Power LLC	State Line Wind	12/20/07	124.8	124.8	W	Chautauqua, NY	A	Ripley - Dunkirk 230kV	NM-NG	5	5/27/09	FES	2010/12	2010/12
276	Air Energie TCI, Inc.	Crown City Wind Farm	1/30/08	90	90	W	Cortland, NY	C	Cortland - Tully 115kV	NM-NG	5	6/24/09	FES	2011/12	2011/12
279	Riverbank Power Corporation	Riverbank Power D1	2/20/08	1000	1000	PS	St. Lawrence, NY	E	Massena 765kV	NYPA	3	1/21/09	None	2014/06	2014/06
281	Riverbank Power Corporation	Riverbank Power G	2/20/08	1000	1000	PS	Rockland, NY	G	West Haverstraw 345kV	ConEd	3	1/21/09	None	2014/06	2014/06
282	Concord Wind Power LLC	Concord Wind	2/28/08	101.2	101.2	W	Chautauqua, NY	A	Dunkirk - South Ripley 230kV	NM-NG	5	9/1/09	FES	2011/09	2011/09
284	Broome Energy Resources, LLC	Nanticoke Landfill	3/6/08	1.6	1.6	M	Broome, NY	C	Nanticoke Landfill Plant 34.5kV	NYSEG	10	11/30/09	None	2008/07	2010/05
285	Machias Wind Farm, LLC	Machias I	3/27/08	79.2	79.2	W	Cattaraugus, NY	A	Gardenville - Homer Hill 115kV	NM-NG	4	10/28/09	None	2010/12	2010/12
287	Horizon Wind Energy, LLC	Pomfret	3/27/08	73.5	73.5	W	Chautauqua, NY	A	Dunkirk - Falconer 115kV	NM-NG	3	12/22/08	None	2010/12	2010/12
289	New York State Electric & Gas	Corning Valley Trans.	4/1/08	N/A	N/A	AC	Steuben, NY	C	Avoca and Hillside 230kV	NYSEG	6	10/29/08	SIS	2010/12	2010/12
290	National Grid	Paradise	4/3/08	N/A	N/A	AC	Niagara, NY	A	Paradise Station 115kV	NM-NG	6	10/14/08	SIS	2010/12	2010/12
290A	Green Island Power Authority	Green Island Power	4/7/08	20	20	L	Albany, NY	F	Maplewood - Johnson Rd 115kV	NM-NG	5	10/14/08	None	2009/12	2009/12
291	Long Island Cable, LLC	LI Cable - Phase 1	4/14/08	440	440	W	Suffolk, NY	K	Ruland Road 138kV	LIPA	3	11/19/08	None	2013/01	2014/01
292	Long Island Cable, LLC	LI Cable - Phase 2a	4/14/08	220	220	W	Suffolk, NY	K	Ruland Road 138kV	LIPA	3	11/19/08	None	2013/06	2015/01
294	Orange & Rockland	Ramapo-Sugarloaf	4/29/08	N/A	N/A	AC	Orange/Rockland, NY	G	Ramapo - Sugarloaf 138kV	O&R	5	10/28/09	None	2009/06	N/A
295	CCH Holdings Group, LLC	Cross Hudson II	5/6/08	800	800	AC	New York, NY-NJ	J	West 49th St. Substation 345kV	ConEd	3	11/30/09	None	2011/06	2012/Q2
297	Ashford Wind Farm, LLC	Ashford Wind	5/16/08	19.9	19.9	W	Cattaraugus, NY	A	Otto-West Valley 34.5kV	NM-NG	7	11/30/09	None	2009/12	2012/12
298	Air Energie TCI, Inc.	Leicester Wind	5/22/08	57	57	W	Livingston, NY	A	Highbank - Mortimer 115kV	NYSEG	4	9/30/09	None	2011/12	2011/12
301	Hamlin Wind, LLC	Hamlin Wind Farm	7/15/08	80	80	W	Monroe, NY	A	West Hamlin 115kV	NM-NG	3	10/29/08	None	2011/12	2011/12
305	Transmission Developers Inc.	Transmission Developers NYC	7/18/08	1000	1000	DC	Quebec - NY, NY	J	Gowanus Substation 345kV	ConEd/NYPA	3	11/30/09	None	2014/Q1	2014/Q1
306	Transmission Developers Inc.	Clay HVDC	7/18/08	2000	2000	DC	Onondaga/New York, NY	C, J	Clay 345kV - Sherman Creek 138 kV	NM-NG/ConEd	3	9/30/09	None	2014/Q1	2014/Q1
307	New York Wire, LLC	New York Wire-Phase 1	7/29/08	550	550	DC	NJ - Kings, NY	J	Gowanus Substation 345kV	ConEd	3	11/30/09	None	2013/07	2013/12
308	Astoria Energy II, LLC	Astoria Energy II	8/20/08	550	650	CS-NG	Queens, NY	J	Astoria 345kV	NYPA	5	6/24/09	None	2011/05	2011/05
310	Advanced Power Services	AP Dutchess	9/22/08	1002	938.7	CC-NG	Dutchess, NY	G	Pleasant Valley - Long Mt. 345kV	ConEd	3	11/30/09	None	2014/12	2014/12
311	New York State Electric & Gas	Concord Casino	9/24/08	48.0	48.0	L	Sullivan, NY	E	Coopers Corner - Rock Hill	NYSEG	5	10/28/09	None	2009/09	N/A
313	Atlantic Wind, LLC	Stone Church Wind	9/30/08	150	150	W	St. Lawrence, NY	E	Mc Intyre Substation 115 kV	NM-NG	3	9/1/09	None	2011/12	2011/12
315	CRC Renewables, LLC	Onondaga Renewables	10/23/08	47	47	M	Onondaga, NY	C	Geres Lock 115kV	NM-NG	5	4/8/09	None	2011/03	2011/03
318	AES Energy Storage, LLC	Westover Energy Storage	12/3/08	20	20	ES	Broome, NY	C	Westover 115kV	NYSEG	5	11/30/09	None	2010/01	2010/01
319	AES Energy Storage, LLC	Cayuga Energy Storage	12/3/08	20	20	ES	Onondaga, NY	C	Milliken 115kV	NYSEG	5	6/24/09	None	2010/07	2010/07
320	AES Energy Storage, LLC	Somerset Energy Storage	12/3/08	20	20	ES	Niagara, NY	A	Somerset 69kV	NYSEG	5	11/30/09	None	2010/07	2010/07
322	Horizon Wind Energy, LLC	Stone's Throw Wind	1/13/09	59.4	59.4	W	Madison, NY	E	County Line - Brothertown 115kV	NYSEG	3	11/30/09	None	2012/12	2012/12

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- *Type / Fuel. Key: ST=Steam Turbine, CT=Combustion Turbine, CC=Combined Cycle, CS= Steam Turbine & Combustion Turbine, H=Hydro, PS=Pumped Storage, W=Wind, NU=Nuclear, NG=Natural Gas, M=Methane, ST-SW=Steam Turbine-Solid Waste, S=Solar, Wo=Wood, F=Flywheel ES=Energy Storage, O=Oil, C=Coal, D=Dual Fuel, AC=AC Transmission, DC=DC Transmission, L=Load*
- *The column labeled 'Z' refers to the zone*
- *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 quarte*

Queue Pos.	Owner/Developer	Project Name	Date of IR	SP (MW)	WP (MW)	Type/ Fuel	Location County/State	Z	Interconnection Point	Utility	S	Last Update	Availability of Studies	Proposed In-Service Original	Proposed In-Service Current
326	NYSEG/RG&E	Rochester SVC/PST Trans.	3/9/09	N/A	N/A	AC	Monroe, NY	B	Station 124 115kV	NYSEG	6	12/22/09	SIS	2011/12	2011/12
327	Con Edison	Offshore Wind	3/20/09	700	700	W	NY - Suffolk, NY	J, K	Far Rockaway 69kV	LIPA	3	9/30/09	None	2020/01	2015/01
330	BP Solar	Upton Solar Farms	4/7/09	32	32	S	Suffolk, NY	K	8ER Substation 69kV	LIPA	5	9/1/09	None	2011/05	2010/09-2011/05
331	National Grid	Northeast NY Reinforcement	4/22/09	N/A	N/A	AC	Saratoga, NY	F	NGrid 230kV	NM-NG	6	12/22/09	SIS	2010-2019	2010-2019
333	National Grid	Western NY Reinforcement	5/5/09	N/A	N/A	AC	Cattaraugus, NY	A	NGrid 115kV	NM-NG	5	7/31/09	None	2014/Q2	2014/Q2
335	NextEra Energy Resources, LLC	Cold Creek Spring Wind	6/9/09	150	150	W	Cattaraugus, NY	A	Salamanca - Falconer 115kV	NM-NG	2	9/30/09	None	2012/12	2012/12
336	Enfield Energy, LLC	Black Oak Wind	6/29/09	50	50	W	Thompkins, NY	C	Black Oak Rd 115kV	NYSEG	2	11/30/09	None	2010/10	2010/10
337	Long Island Power Authority	Northport Norwalk Harbor	7/14/09	N/A	N/A	AC	Suffolk, NY	K	Northport 138kV	LIPA	5	9/30/09	None	2016	2016
338	RG&E	Brown's Race II	8/11/09	8.3	8.3	H	Monroe, NY	B	Station 3 / Station 137 34.5kV	RG&E	2	11/30/09	None	2011/08	2011/08
339	RG&E	Transmission Reinforcement	8/17/09	N/A	N/A	AC	Monroe, NY	B	Niagara - Kintigh 345kV	RG&E	5	11/30/09	None	2015/09	2015/09
340	RG&E	Brown's Race III	9/2/09	2	2	H	Monroe, NY	B	Station 6 34.5 kV	RG&E	2	11/30/09	None	2010/12	2010/12
341	Covanta Energy	Hempstead Expansion	9/2/09	37	39	ST-SW	Nassau, NY	K	Hempstead 138kV	LIPA	4	11/30/09	None	2013/07	2013/07
342	Albany Energy, LLC	Albany Landfill	9/3/09	4.8	4.8	M	Albany, NY	F	34.5kV	NM-NG	4	12/22/09	None	2010/12	2010/12
343	Champlain Wind Link, LLC	Champlain Wind Link I	9/29/09	600	600	AC	Clinton, NY - VT	D	Plattsburgh - New Haven, VT 230kV	NYPA	4	12/22/09	None	2014/06	2014/06
344	Champlain Wind Link, LLC	Champlain Wind Link II	9/29/09	600	600	AC	Clinton, NY - VT	D	Plattsburgh - New Haven, VT 345kV	NYPA	4	12/22/09	None	2014/06	2014/06
346	Beacon Power	Scotia Industrial Park	11/24/09	20	20	F	Schenectady, NY	F	Spier - Rotterdam	NM-NG	1	12/22/09	None	2011/08	2011/08
347	Horizon Wind Energy, LLC	Franklin Wind	12/2/09	50.4	50.4	W	Delaware, NY	E	Sidney - Delhi 115kV	NYSEG	1	12/22/09	None	2012/12	2012/12
348	Casella Waste Systems	Hyland Landfill	12/2/09	8	8	M	Allegany, NY	B	Station 249	RG&E	1	12/22/09	None	2010/Q3	2010/Q3

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, CS= Steam Turbine & Combustion Turbine, H=Hydro, PS=Pumped Storage, W=Wind, NU=Nuclear, NG=Natural Gas, M=Methane, ST-SW=Steam Turbine-Solid Waste, S=Solar, Wo=Wood, F=Flywheel ES=Energy Storage, O=Oil, C=Coal, D=Dual Fuel, AC=AC Transmission, DC=DC Transmission, L=Load*
- *The column labeled 'Z' refers to the zone*
- *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.*

Section II – Attachment B

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

III. Installed Capacity Demand Curves Report

Capacity Market Report and Withholding Analysis

Executive Summary

This report reviews the outcomes in NYISO-administered capacity markets, assesses the effectiveness of the ICAP Demand Curves in attracting investment in new generation, and examines the issue of potential withholding activity in NYISO-administered capacity auctions in all capacity regions of New York State – New York City, Long Island, and Rest of State ("ROS") – from November 2008 through November 2009, covering the full 2008-2009 Winter and 2009 Summer Capability Periods, and the month of November of the 2009-2010 Winter Capability Period.[1] The NYISO conducted similar analyses through December 2008, which it reported to the Commission in filings on January 15, 2009[2] and July 27, 2009[3] (collectively, the "January 2009 Report"), as well as filings for earlier periods. The analysis conducted for this report was prepared using an enhanced methodology that is different from prior reports.[4] As described in the NYISO Updated Status Report, this report modifies the reporting structure and methodology from that utilized in prior reports, and it includes additional criteria in the analyses.

During the 2008-2009 Winter Capability Period, capacity prices followed a relatively stable pattern – albeit at lower levels relative to 2007-2008 Winter Capability Period – on a Statewide basis, as well as in the New York City and Long Island Localities with the exception of a price spike in the January 2009 spot auction. A large amount of unoffered MW from a single generator in the Rest of State region caused a spike in the NYCA Spot Auction clearing price for that month, so much so that the NYCA clearing price set the New York City and Long Island capacity prices.[5] Remaining months experienced dramatically decreasing capacity prices

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[1] *See* New York Independent System Operator, Inc.'s Updated Status Report on Stakeholder Discussions Regarding Annual Installed Capacity Demand Curve Reports and Plan for Future Reports ("NYISO Updated Status Report") at p. 4 (filed with the Commission in these dockets on November 12, 2009).

[2] The months of November and December 2008 are again reported in this filing because the months are within the periods analyzed using the new methodology outlined below.

[3] *See* Motion for Leave to Respond, and Response, of the New York Independent System Operator, Inc. filed with the Commission on July 27, 2009.

[4] NYISO Updated Status Report at pp. 3-4. *See* also Section III.C of this report for a description of the new methodology and the analytical framework employed to prepare this report.

[5] *See* explanatory note for that event in Section III.C.2 of this report.

in all regions, and in most of the months, the auction prices for the New York City and the Long Island Localities were set by the NYCA clearing price. The declining trend and the relative stability of prices in New York City were driven mainly by In-City mitigation measures, and in Long Island largely by the bilateral nature of the Long Island capacity market.

During the 2009 Summer Capability Period, capacity prices in New York City remained stable, however they were higher compared to the Summer 2008 Capability Period. The increase in price was driven primarily by a lower capacity surplus and higher generator derating factors. Capacity prices in Long Island and the Rest of State region were also higher than the prior summer; however, there was a declining trend in the last three months of the Summer 2009 Capability Period. In particular, the observed increases in capacity prices in the Rest of State region in June and July 2009 are chiefly attributable to the decrease in capacity imported from the PJM Control Area (nearly 870 MW). In all three NYISO capacity regions, capacity prices in November 2009 were lower than in November 2008.

For the 2009 reporting period, there was no change 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. In UCAP terms, in the 2007/2008 Winter Capability Period, 49.72% of LSE capacity requirements were met through bilateral purchases, while the remaining were met through the NYISO-administered auctions. The percentages of bilateral purchases were 52.80% in Summer 2008, 50.25% in Winter 2008/2009, and 50.58% in Summer 2009 Capability Periods.

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 unsold capacity resources for the month. In the overall NYCA market, the quantities of unsold and unoffered capacity do not exceed a few percent of available supplies (*see* Charts 7 and 8). In addition, capacity offered and purchased throughout the State consistently exceeded the minimum capacity requirements, and prices have been below the cost of new entry ("CONE") reflected on the ICAP Demand Curves. Thus, the results of the analysis in this report as well as the performance of the market do not raise concerns about withholding in the NYCA, New York City, or Long Island markets.

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 amount to satisfy reliability requirements.

The NYISO understands that developers will look to anticipated future revenues when making investment decisions in the near term. At this time, the current ICAP market structure provides sufficient market signals to anticipate future revenues. The NYISO's 2008 Reliability Needs Assessment ("RNA") process identified future reliability needs, and the NYISO requested and received market-based proposals to address those needs. The NYISO tracks the progress of these proposals.

For the purpose of evaluating possible further enhancements in the New York capacity markets, the NYISO spent considerable time in 2008 and 2009 working with stakeholders to evaluate the use of a forward capacity market. After extensive stakeholder meetings and input from a consultant, the NYISO decided not to pursue a forward capacity market at this time, and its stakeholders concurred.

The NYISO continues to believe that the ICAP Demand Curves remain sound. They are structured to provide a positive incentive to develop new capacity when and where it is needed, particularly when compared to the *de facto* vertical demand curves in place prior to the Summer 2003 Capability Period. Although the specific parameters of the ICAP Demand Curves, *i.e.* the slope and the height, likely will continue to be subject to debate 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 ameliorate the unstable prices resulting from the prior *de facto* vertical demand curves, provide market-driven compensation for capacity above the minimum capacity requirement, and reduce incentives for withholding.

Recent Installed Capacity Auction Results and Capacity Purchases

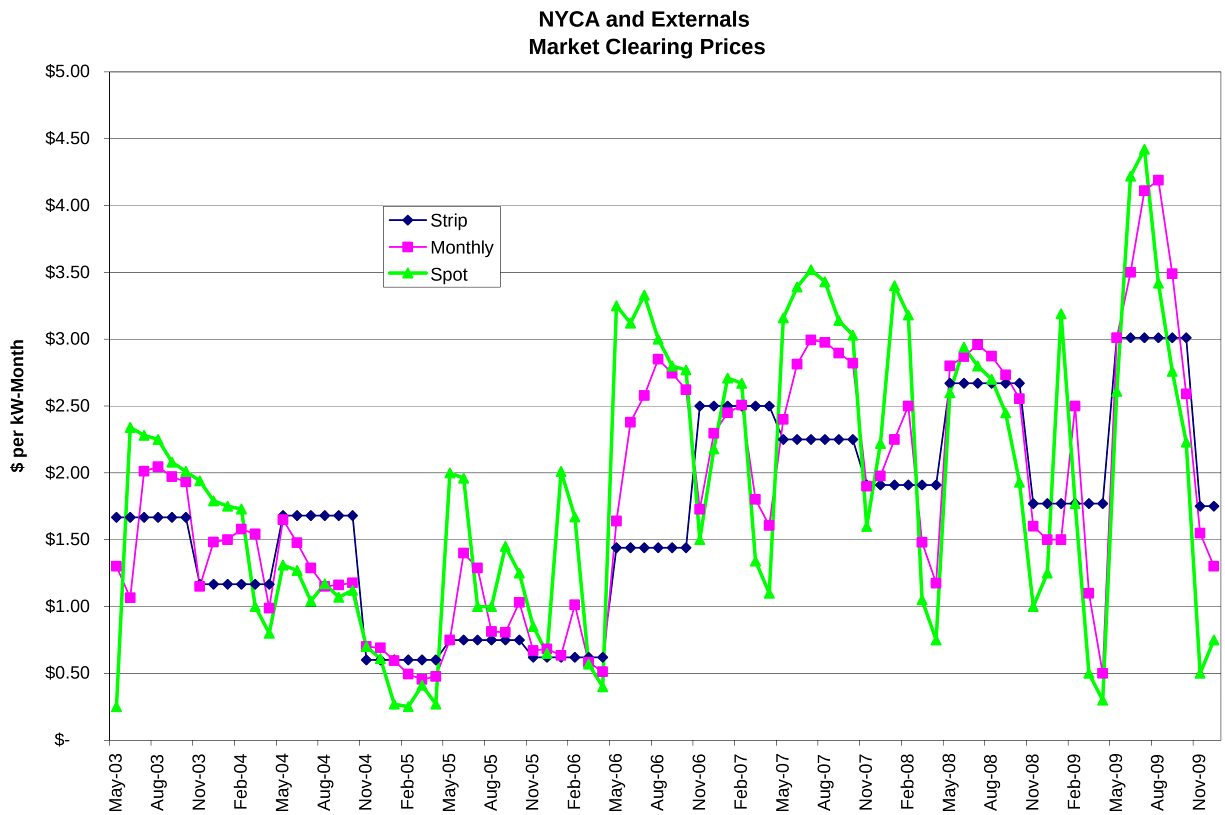
Committed capacity remains well in excess of minimum installed capacity requirements on a Statewide basis, as well as in the New York City and Long Island Localities.

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 increase and decrease seasonally. Further, the NYCA Demand Curve price declines to zero when supply exceeds the minimum capacity requirement in the NYCA by 12% or more. Accordingly, the NYCA auction clearing prices are consistently at or below half of the estimated net cost of entry for new peaking capacity.

The amount of capacity committed to the NYCA, including imports, continues to be high. The import levels were 1,414 MW in the 2008/2009 Winter Capability Period, which was lower than the approximately 1,760 MW of 2009 Summer Capability Period level. 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 2009 for the NYCA, New York City, and Long Island are shown in tabular form in Appendix A. Market clearing prices are depicted in graphic form in Charts 1, 3, and 5, and capacity commitment levels (including unsold MW) are depicted in Charts 2, 4, and 6, below. The NYCA Unsold MW depicted in Chart 2 includes unsold MW located in Rest of State, as well as the Unsold MW depicted in Charts 4 and 6 for the New York City, and Long Island localities, respectively.

Chart 1



NYCA and Externals
Market Clearing Prices
$ per kW-Month
$5.00
$4.50
$4.00
$3.50
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$-
Strip
Monthly
Spot
May-03
Aug-03
Nov-03
Feb-04
May-04
Aug-04
Nov-04
Feb-05
May-05
Aug-05
Nov-05
Feb-06
May-06
Aug-06
Nov-06
Feb-07
May-07
Aug-07
Nov-07
Feb-08
May-08
Aug-08
Nov-08
Feb-09
May-09
Aug-09
Nov-09

Chart 2

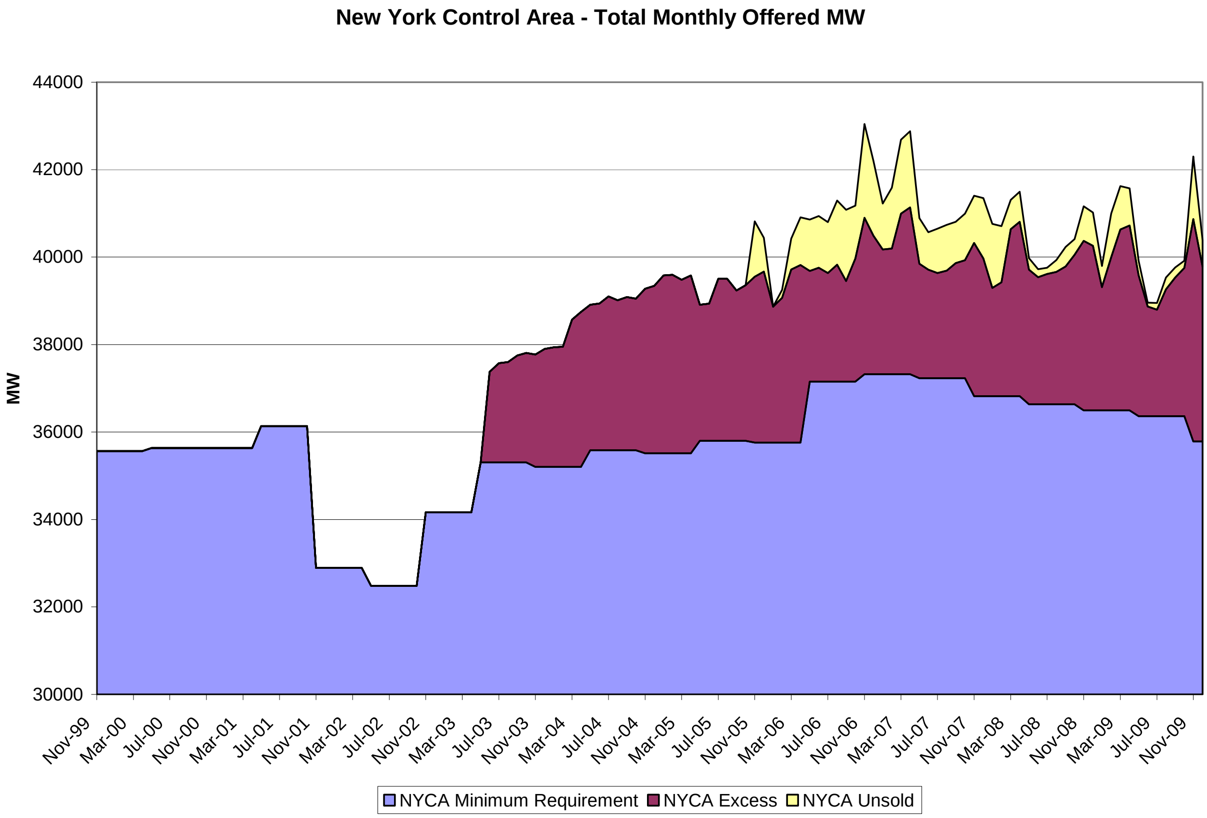

New York Control Area - Total Monthly Offered MW
MW
44000
42000
40000
38000
36000
34000
32000
30000
Nov-99
Mar-00
Jul-00
Nov-00
Mar-01
Jul-01
Nov-01
Mar-02
Jul-02
Nov-02
Mar-03
Jul-03
Nov-03
Mar-04
Jul-04
Nov-04
Mar-05
Jul-05
Nov-05
Mar-06
Jul-06
Nov-06
Mar-07
Jul-07
Nov-07
Mar-08
Jul-08
Nov-08
Mar-09
Jul-09
Nov-09
NYCA Minimum Requirement
NYCA Excess
NYCA Unsold

Chart 3

New York City
Market Clearing Prices

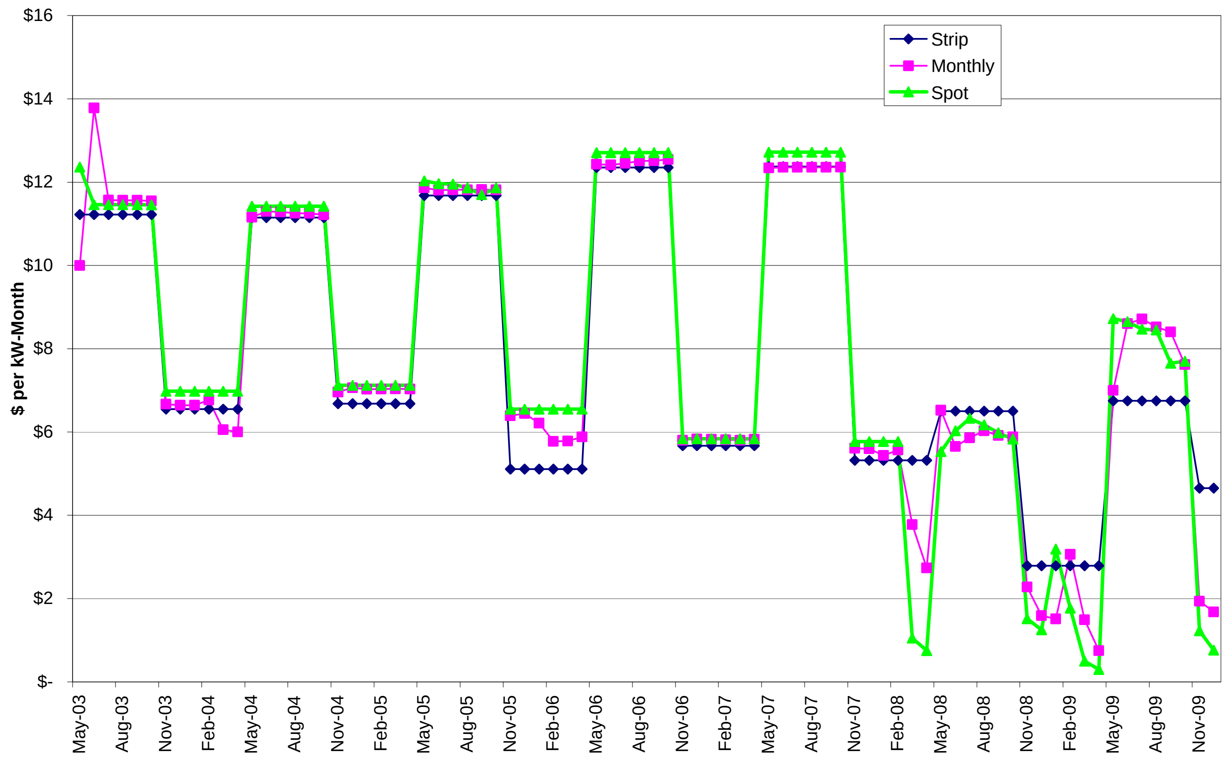


Chart 4

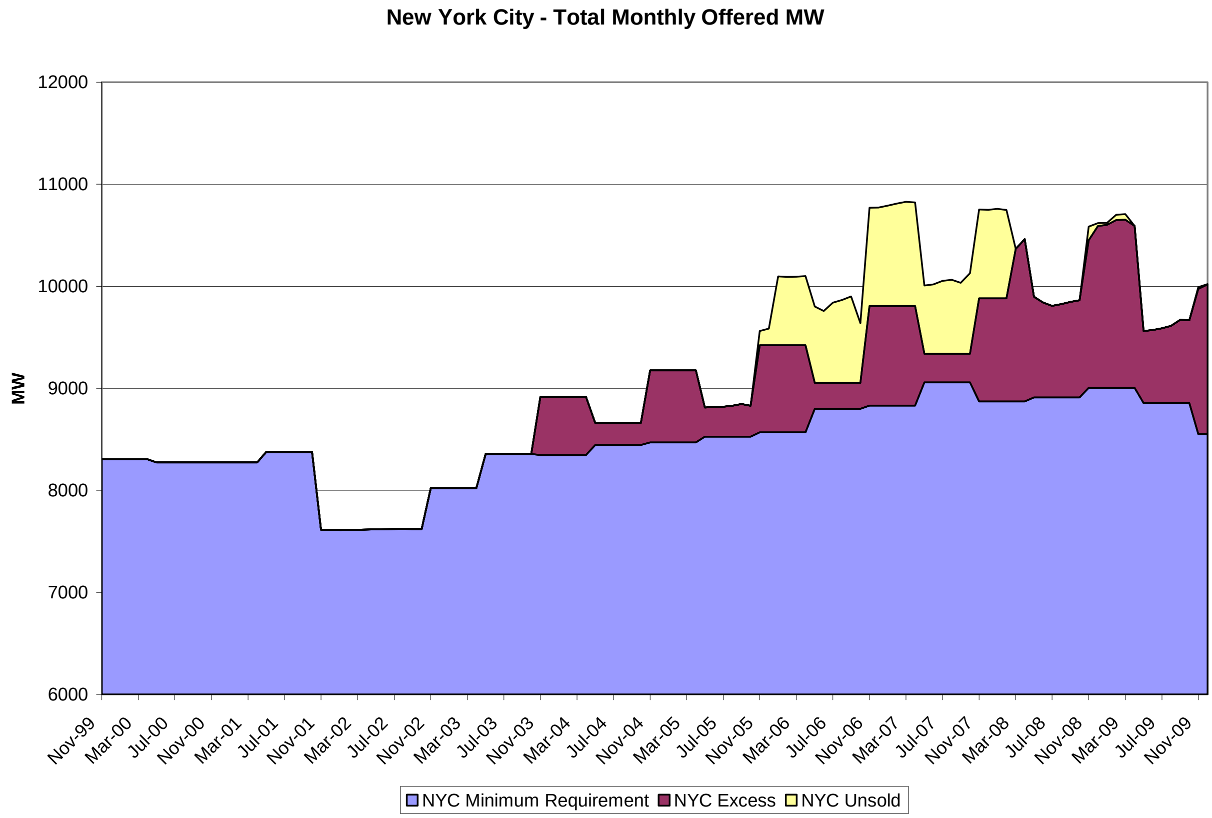
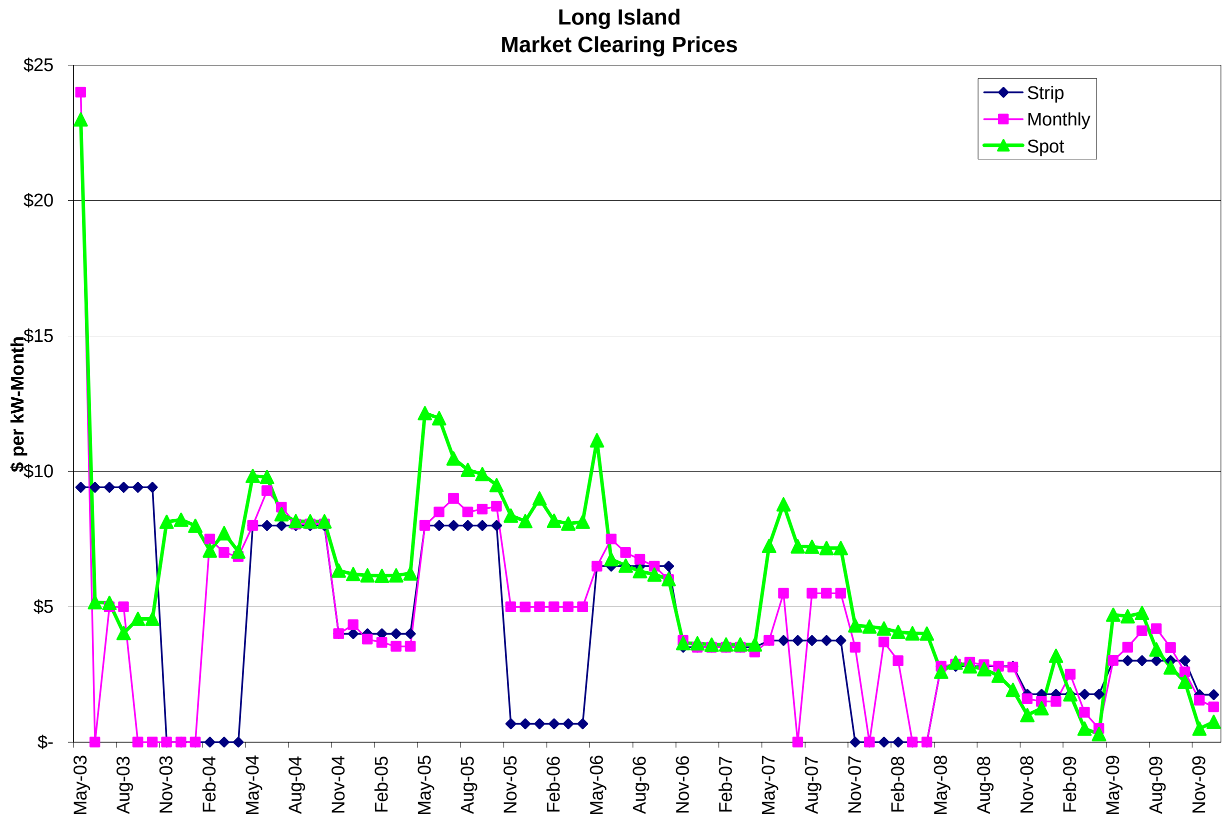
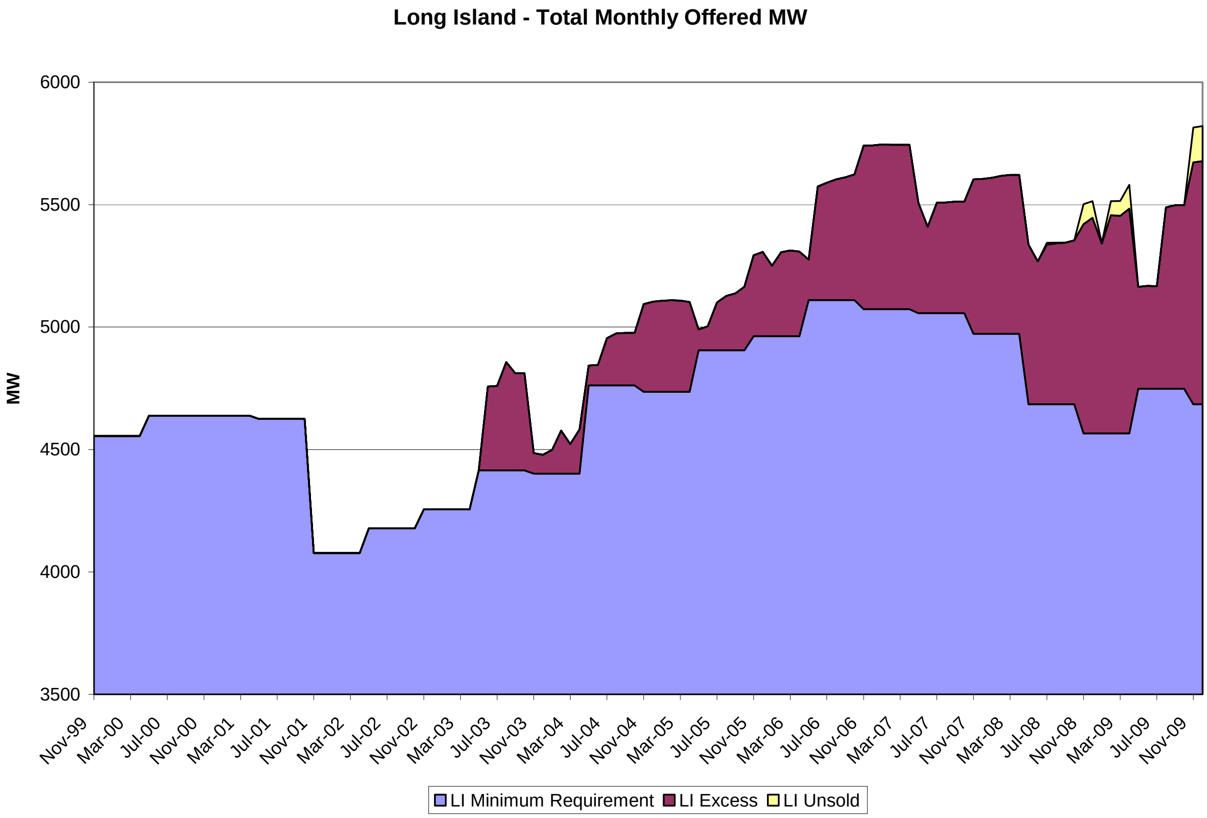

New York City - Total Monthly Offered MW
MW
12000
11000
10000
9000
8000
7000
6000
Nov-99
Mar-00
Jul-00
Nov-00
Mar-01
Jul-01
Nov-01
Mar-02
Jul-02
Nov-02
Mar-03
Jul-03
Nov-03
Mar-04
Jul-04
Nov-04
Mar-05
Jul-05
Nov-05
Mar-06
Jul-06
Nov-06
Mar-07
Jul-07
Nov-07
Mar-08
Jul-08
Nov-08
Mar-09
Jul-09
Nov-09
NYC Minimum Requirement
NYC Excess
NYC Unsold

Chart 5



Long Island
Market Clearing Prices
$ per kW-Month
$25
$20
$15
$10
$5
$-
Strip
Monthly
Spot
May-03
Aug-03
Nov-03
Feb-04
May-04
Aug-04
Nov-04
Feb-05
May-05
Aug-05
Nov-05
Feb-06
May-06
Aug-06
Nov-06
Feb-07
May-07
Aug-07
Nov-07
Feb-08
May-08
Aug-08
Nov-08
Feb-09
May-09
Aug-09
Nov-09

Chart 6



Long Island - Total Monthly Offered MW
6000
5500
5000
4500
4000
3500
MW
Nov-99
Mar-00
Jul-00
Nov-00
Mar-01
Jul-01
Nov-01
Mar-02
Jul-02
Nov-02
Mar-03
Jul-03
Nov-03
Mar-04
Jul-04
Nov-04
Mar-05
Jul-05
Nov-05
Mar-06
Jul-06
Nov-06
Mar-07
Jul-07
Nov-07
Mar-08
Jul-08
Nov-08
Mar-09
Jul-09
Nov-09
LI Minimum Requirement
LI Excess
LI Unsold

Potential Withholding in the Capacity Markets

A. All Regions of New York State

This section of the report addresses potential withholding in NYISO-administered capacity auctions in all regions of New York State from November 2008 through November 2009. It focuses on market outcomes and related behavior since May 2006.

In order to determine whether any potential withholding occurred, the NYISO analyzed the differences between available supply[6] and the supply committed through self-supply, bilateral transactions, and/or through NYISO administered auctions. In particular, the NYISO examined:

- the qualified NYCA capacity available but neither offered for sale nor certified as self-supply,
- qualified capacity offered for sale and not sold,
- unoffered capacity as a percentage of available capacity, and
- unsold capacity as a percentage of offered capacity.[7]

Examining the MW of capacity offered but not sold – as distinct from MW 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 that physical withholding may have occurred.

In New York City, units of a Pivotal Supplier (defined as ICAP Market Participants along with their Affiliated Entities that Control In-City capacity in excess of the pivotal control threshold[8]) are subject to mitigation measures and have a requirement to offer their capacity in the Spot Market Auction. There is not a "must-offer" requirement for capacity located in the Rest of State or on Long Island. On Long Island, the Locational Minimum Installed Capacity Requirement was 94% in Winter 2008-2009 and 97.5% in Summer 2009. If capacity located on Long Island is offered into the auctions, it is applied to the Locality market requirement before

[6] Available supply is defined as NYISO-accepted DMNC tested capacity with the effective forced outage rates applied.

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

[8] See Sections 2.1 and 4.5 of Attachment H of the Services Tariff.

the NYCA. The rights to almost all of the existing capacity on Long Island have been secured by bilateral contracts.

The existence of unoffered and/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. Extraneous market factors, including decisions that pre-date implementation of sloped demand curves[9] and the increasingly variable flows of capacity between Control Areas, must also be considered.

Since the NYISO's Demand Curves reports of January 2007, 2008 and 2009, patterns of unsold capacity relative to offered capacity have varied across the NYCA, and the New York City and Long Island Localities. For the entire NYCA, most of the capacity offered but not sold was unsold during winter months. Long Island experienced little to no unsold capacity during the past 3 years. In New York City, the rise in the amount of unsold capacity relative to offered capacity in New York City in 2006 coincided with the addition of 1,000 MW of new capacity in New York City. However, the amount of unsold capacity in New York City as percent of offered capacity declined significantly since 2006; it was 0% in Summer 2008, 0.21% in Winter 2008 - 2009, and 0% in Summer 2009 Capability Periods. For the NYCA as a whole, both the developments in New York City (*i.e.,* the addition of 1,000 MW of capacity in 2006 in conjunction with the offering behavior of market participants and the changes in mitigation measures) and the growing variability of exports and imports contributed to the observed fluctuations in unsold capacity when measured as a percentage of offered capacity.[10]

There are three types of auctions in each Capability Period: a Capability Period Auction (also referred to as the "six-month strip auction"), six 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

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9 References to Demand Curves herein mean the demand curves with a "sloped" line segment, originally approved by FERC in May 2003. Prior to the May 2003 ICAP Spot Market Auction, Deficiency Auctions used a "stepped" demand curve with a vertical line segment at the minimum requirement level. All NYISO Demand Curves have horizontal sections above and below these line segments, at $0 and a maximum price, respectively, as defined in the Tariff.

10 Capacity imported from neighboring control areas is subject to an overall limit that is currently at approximately 3,490 MW of ICAP, which translates into approximately 3,300 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.

City and on Long Island to procure minimum levels of capacity from facilities that are electrically located within their respective Load Zones. Such capacity is also credited toward each New York City and Long Island LSE's overall NYCA obligation. The NYISO establishes Locational Minimum Installed Capacity Requirements on an annual basis according to NYISO Procedures.[11]

With the exception of the New York City Locality, the Services Tariff does not require capacity suppliers to offer capacity into the ICAP markets. Until the implementation of the mitigation measures set forth in Attachment H of the Service Tariff, which were effectuated in May 2008, the majority of capacity in New York City – that of the Divested Generation Owners – had been subject to Commission-approved ICAP market mitigation measures that imposed bid caps and required the units' capacity to be offered into the ICAP auctions. Capacity resources constructed subsequent to the Commission's approval of the bid caps were not subject to bid caps or the mandate to offer into the auctions. That capacity and other capacity inside and outside of the New York City Locality could be sold in bilateral transactions or offered in one or more of the NYISO's ICAP auctions. The Commission's March 7, 2008 Order[12] removed the requirements unique to the Divested Generation Owners and approved mitigation measures applicable to all capacity, and effectuated new In-City mitigation measures based on Pivotal Supplier determinations combined with offering conduct and price impact thresholds, to determine whether an abuse of market power has occurred, as set forth in Attachment H of the Tariff (referred to herein as "Mitigation Measures").

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 October 31, 2007)
- Winter 2007-2008 (November 1, 2007 through April 30, 2008)
- Summer 2008 (May 1, 2008 through October 31, 2008)
- Winter 2008-2009 (November 1, 2008 through April 30, 2009)
- Summer 2009 (May 1, 2009 through October 31, 2008)
- Winter 2009-2010 (November 2009 only)

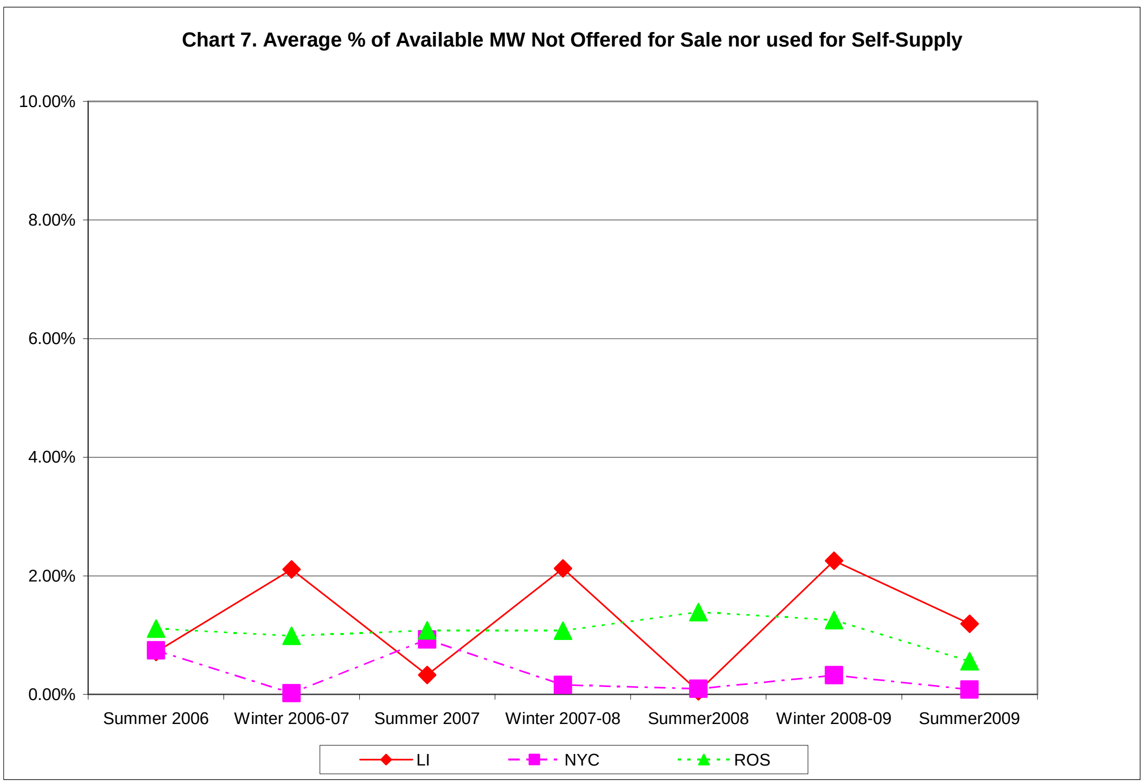
[11] *See* Section 2 and Attachment B of the NYISO Installed Capacity Manual.

[12] *New York Independent System Operator, In..*, Docket No. EL07-39-000, Order Conditionally Approving Proposal, 122 FERC ¶ 61,211.

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

1. Certification data, reflecting the certified MW of UCAP from all Resources within New York available to supply capacity to the NYCA. The analysis did not include resources physically located outside of the NYCA;
2. The amount of UCAP supplied (sold, certified as self-supplied against an LSE's capacity obligation, or committed through bilateral transactions) in all categories; and

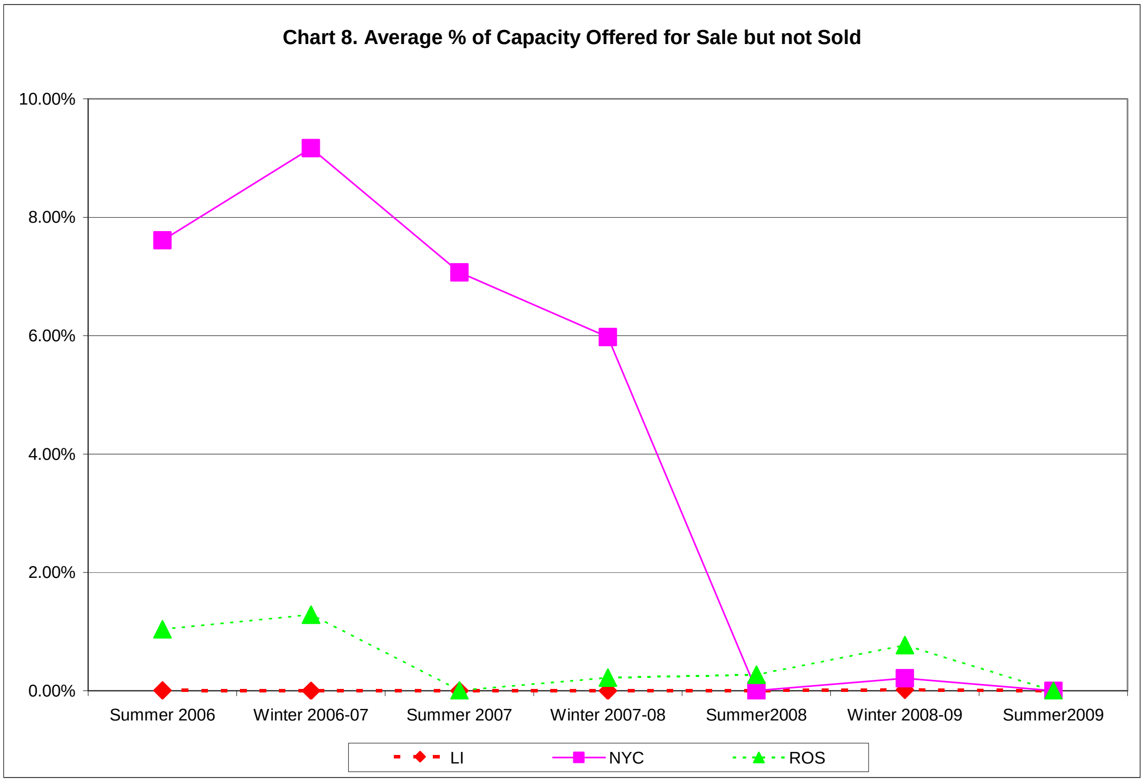
Chart 7 displays the percentage of available capacity in the NYCA that was neither offered for sale, certified against an LSE's capacity obligation, nor committed through bilateral transactions – *i.e.*, "unoffered capacity."



Given the relatively small amounts of available capacity that was not offered in each region, physical withholding is not a concern. A small but stable fraction of the unoffered capacity in each of the three regions is capacity from Special Case Resources. The Long Island Locality reveals seasonality in the amounts of unoffered capacity. The Long Island Locality is characterized by capacity procurement chiefly through bilateral transactions and self-supply. While it appears the amount of unoffered capacity on Long Island fluctuates between 0.05% and 2.26%, much of the unoffered capacity is not actually available. The majority of this unoffered capacity is associated with generation stations permitted for less than 80 MW, although the DMNC of the units at each station when aggregated exceeds 80 MW. For example, in four instances on Long Island, there are two units at a site, and each individual unit at that site can produce considerably more than 40 MW. In the event that one unit is out of service and the market participant wishes to run the other unit at output levels higher than 40 MW, the NYISO must have that higher (actual) DMNC value in its software system in order for the bid to pass validation. These units do not offer all of their available capacity because the site permit restrictions limit the combined output to below 80 MW. However, apart from that situation, a market participant in Long Island had approximately 112 MW of unoffered capacity in a month during the 2008/2009 Winter Capability Period. Prior to Summer 2008, in New York City, the low level of unoffered capacity was principally due to the must-offer requirement applicable to the Divested Generation Owners. Since the Summer 2008 Capability Period, the near absence of unoffered capacity can be attributed to the Mitigation Measures effectuated in 2008. The ROS region had insignificant amounts of unoffered capacity relative to available capacity, as evidenced by offers in excess of close to 99% of the available capacity.[13]

Chart 8, below, displays the offered but not sold capacity as a percent of total capacity offered (offered for sale in an auction, supplied to external Control Areas, certified against an LSE's capacity obligation, or committed in bilateral transactions) for each of the three regions.

[13] In November 2009, the amount of unoffered capacity was approximately 89 MW in Long Island, 17 MW in New York City, and 146 MW in ROS.



For all Capability Periods beginning with Summer 2006, nearly all Long Island capacity that was offered was sold. In New York City, the average amount of unsold capacity as percentage of offered capacity trended at near zero levels since the Summer 2008 Capability Period. Since the Summer 2007, nearly all the MW of Resources located in Rest of State that offered capacity into the ICAP auctions were sold despite a reduction in the NYCA Installed Reserve Margin from 18% to 16.5% for the 2007/2008 Capability Year, and from 16.5% to 15% for the 2008-2009 Capability Year. The NYCA Installed Reserve Margin for the 2009/2010 Capability Year is 16.5%. As discussed below in the Rest of State section, and also in the January 2009 Report, the amount of unsold capacity compared to the MW of Rest of State capacity offered under the NYCA Demand Curve generally was a small percentage of the total.[14]

B. The New York City Locality – Additional Details

The New York City capacity that was not sold, as a percent of the capacity offered, exhibited a sharp declining trend from the 9% level in Winter 2006/2007 Capability Period to 0.21% in Winter 2008/2009 Capability Period, with no unsold capacity in Summer 2008

[14] In November 2009, the amount of unsold capacity was approximately 12 MW in Long Island, 17 MW in New York City, and 329 MW in ROS.

Capability Period. This sharp decline can be explained by the implementation of the Mitigation Measures that became effective in the Summer 2008 Capability Period.[15] The Mitigation Measures require all Pivotal Suppliers to offer their capacity at or below the Demand Curve default reference price. This requirement in turn eliminated the effects of the behavior of the one In-City supplier that always offered its capacity at the price cap for Divested Generation Owners (*i.e.*, the Commission-approved price cap) prior to Mitigation Measures.

Chart 9, below, illustrates the effects of the ICAP In-City Mitigation Measures. As depicted in the chart, these measures include a Pivotal Supplier threshold determined by the number of MW controlled by an In-City supplier and its Affiliated Entities. If an Entity is Pivotal, it is subject to the default reference price cap. The default reference price $/kW-month (as shown in Chart 9) becomes the cap the Pivotal Supplier must offer at or below in the ICAP Spot Market Auction unless the Pivotal Supplier's Going Forward Costs ("GFCs"), as submitted to and accepted by the NYISO, are higher than the default reference price. To date, no market participant has submitted GFCs.

The level of unoffered and unsold MW can be inferred from Chart 9 by comparing the New York City spot price to the default reference price. The default reference price is the price on the demand curve if all available UCAP is offered and sold. The difference between the spot price and default reference price can be attributed to capacity that is either not offered or offered at a price above the default reference price. Note that the spot price may diverge from the New York City default reference price when the NYCA auction sets the New York City spot auction clearing price, which occurred in most months of Winter 2008/2009 Capability Period.

In November 2008, one market participant had 106 MW of unsold capacity, and another market participant did not offer approximately 55 MW. These two events explain the price divergence in November 2008. For all of the Winter 2008/2009 Capability Period, approximately 800 MW of additional UCAP was available in New York City as a result of higher output from generators that are capable of producing more MW in the winter months. The additional MW reduced the default reference price. Subsequently, the higher NYCA spot prices set the New York City prices for December 2008 through April 2009. The large divergence in January 2009 resulted from unoffered MW in Rest of State that raised the NYCA price, and subsequently, the New York City price. The January 2009 event is explained in the

[15] See earlier reports for the analysis of the New York City capacity area prior to the effectuation of the Mitigation Measures in accordance with the March 7, 2008 Order and removal of the bid-caps.

Rest of State section of this report. In the Summer 2009 Capability Period, there is very little divergence between the spot price and default reference price. There was no unsold capacity in New York City in Summer 2009, and very little unoffered capacity. In May 2009, a Responsible Interface Party *(i.e.*, the Installed Capacity Supplier for Special Case Resources) did not offer 6.3 MW, and in August 2009 a Responsible Interface Party did not offer 20 MW. Apart from these two situations, in the Summer 2009 Capability Period, the Installed Capacity Suppliers that did not offer MW each had less than approximately four MW per Installed Capacity Supplier. In November 2009, the New York City spot price was higher than the NYCA price. This price was only slightly higher than the default reference price due to 16.6 MW unoffered and 17 MW offered and unsold capacity.

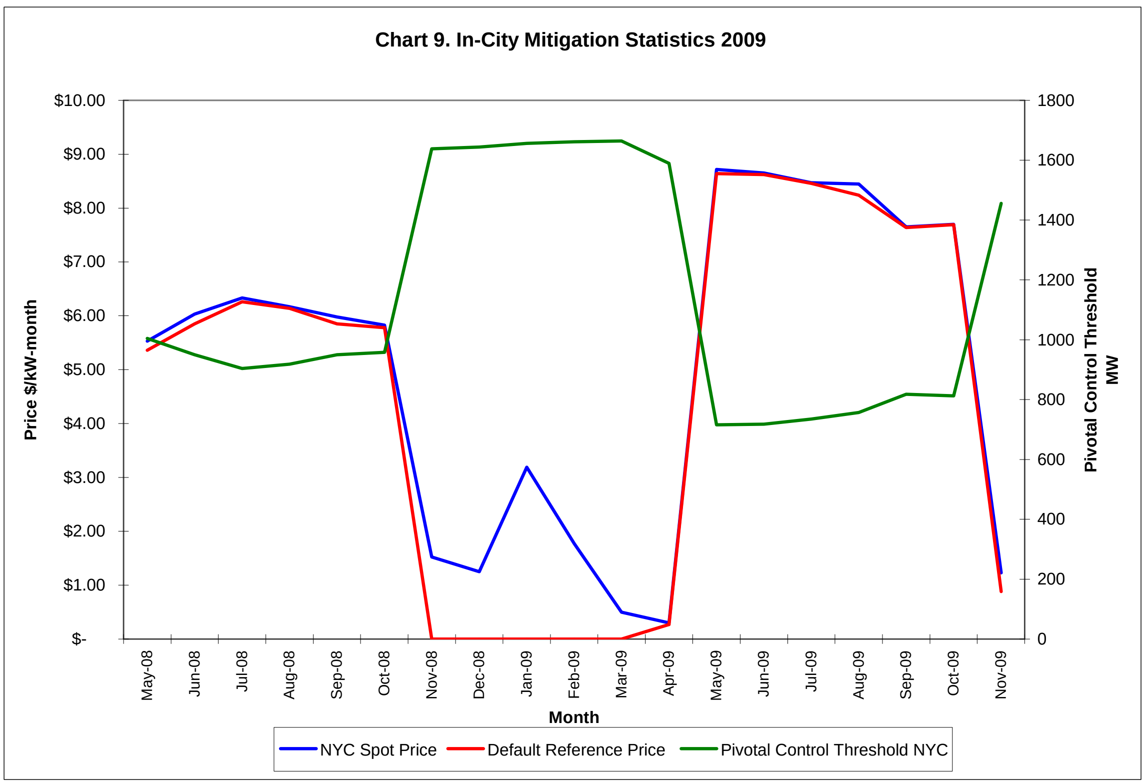
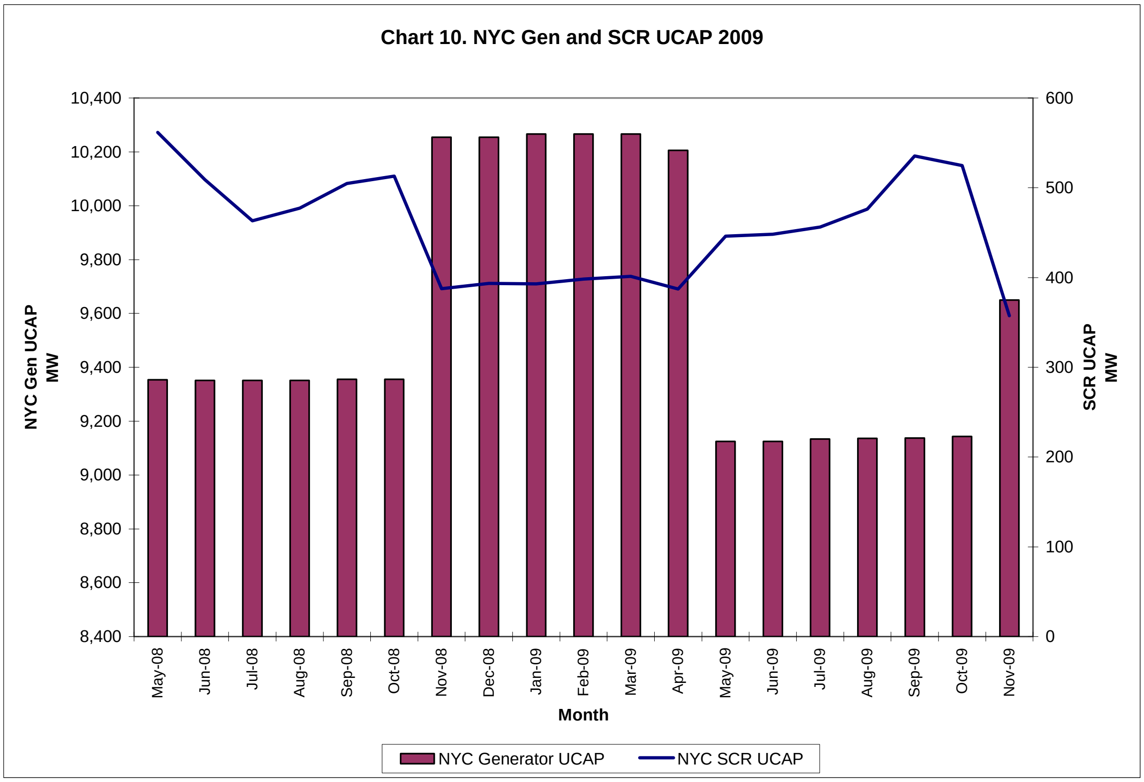


Chart 10 depicts the levels of available generator UCAP and SCR UCAP. The data show that the level of available generator UCAP remains stable within each Capability Period. The decreases in generator UCAP in Summer 2009 and partial period Winter 2009/2010 (the month of November, *i.e.*, the period for which data is available) Capability Periods result from higher derating factors for Resources in New York City. The Summer 2009 Capability Period derating factor was 8.14%, 1.24% higher than the Summer 2008 Capability Period. The Winter 2009/2010 derating factor was 11.29%, which is 5.36% higher than the previous 2008/2009

Winter Capability Period.[16] Special Case Resource UCAP values continue to fluctuate considerably. The largest Special Case Resource declines occur in the early months of the Winter Capability Periods, and the peaks appear in the months of September and October of Summer Capability Period.



C. The NYCA Capacity Market

1. Additional Details

This section of the report addresses possible withholding of capacity in the Rest of State region from November 2008 through November 2009. This analysis is based on resources located in the NYCA, including resources that export capacity, but excluding capacity located in New York City and on Long Island.

For this review, the NYISO conducted a detailed analysis of:

[16] The increase in equivalent forced outage rates was associated with more frequent forced outages over the past year for some generators and a change in the EFORd methodology to more accurately estimate the available capacity from run of the river hydro units. (*See* p. 54 of the Quarterly Report on the New York Electricity Market, Third Quarter 2009, Potomac Economics-Independent Market Advisor, November 16, 2009).

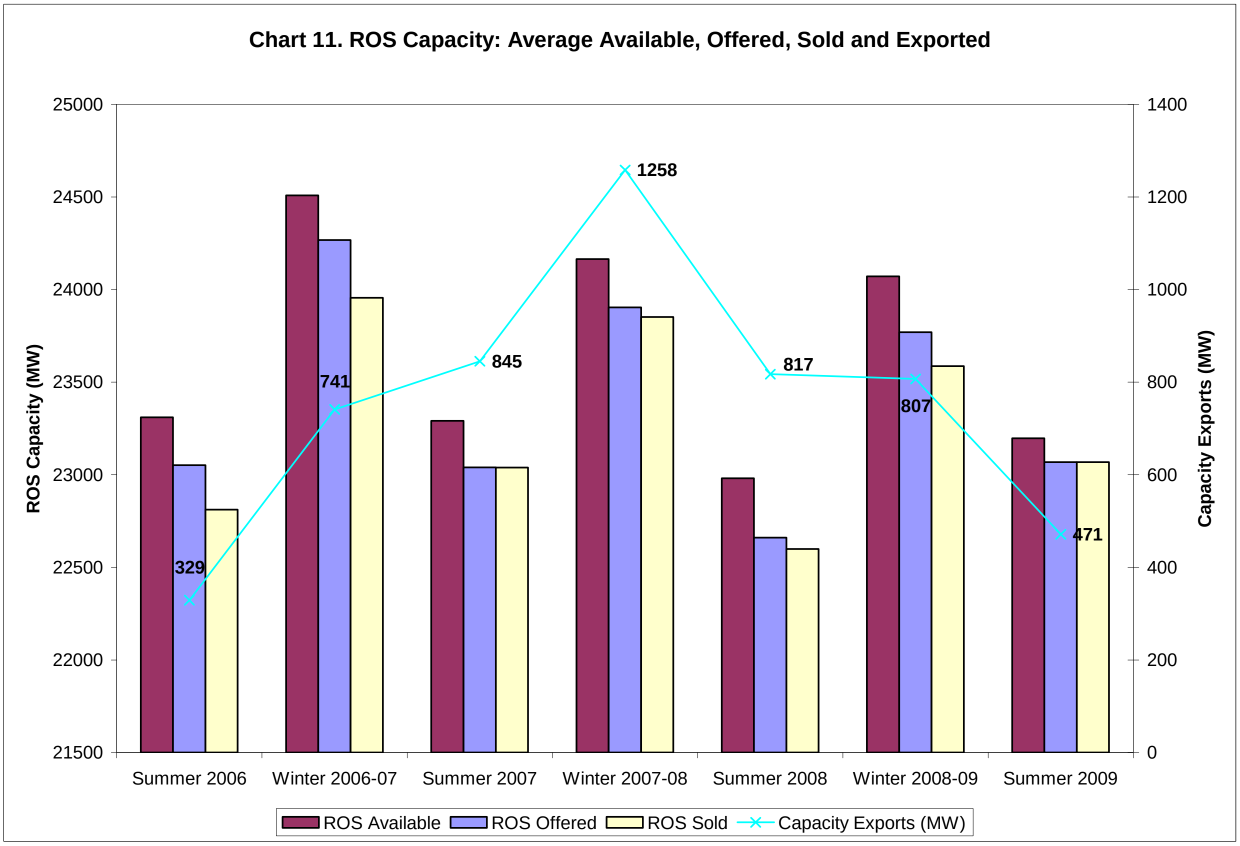
- the amount and the composition of Rest of State capacity[17] that was neither offered for sale, certified to meet an LSE's capacity obligation, nor committed in bilateral transactions in NYCA or to external control areas, *i.e.*, unoffered capacity, and
- the amount and composition of Rest of State capacity offers from resources located in Rest of State that were not accepted, *i.e.*, unsold capacity.

The NYISO conducted a detailed examination of the following data for the May 2006 through November 2009 period:

1. Monthly UCAP ratings of each unit of capacity, including Special Case Resources,
2. Monthly sales awards for each unit of capacity,
3. Spot auction offers and awards for each month, and
4. Monthly figures for Rest of State capacity committed to external control areas, (*i.e.*, exports).

Chart 11, below, shows the four broad Rest of State capacity aggregates – Available, Offered, Sold, and Exported.

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



Examination of Rest of State capacity data pertaining to individual market participants revealed general patterns in capacity that was not offered and capacity that was not sold. The patterns suggest a three-way classification of suppliers by market sector: All generation-owning Transmission Owners, five generation owners, and other suppliers which includes Special Case Resources (which participate in the NYISO's markets through Responsible Interface Parties). Note that these classification and, accordingly, the following three tables follow the same approach as that in the NYISO's July 27, 2009 filing in displaying the unoffered and unsold capacity in Rest of State area.[18] In other words, three versions of Table 1 are being submitted in this filing. Tables 1, 1A, and 1B of this Report Section III summarize the distribution of monthly averages for each Capability Period.

As originally compiled for the January 15, 2009 Filing and prior Demand Curve reports, Table 1 focused on the difference, if any, between the UCAP rating of ROS Capacity Resources and the MW sold from that Resource. In some instances during the period covered by Table 1, however, Rest of State entities purchased MW of capacity in a Capability Period Auction, a

[18] *See* ER01-3001, ER03-647, Motion for Leave to Respond, and Response, of the New York Independent System Operator, Inc. filed July 27, 2009.

Monthly Auction, or in a bilateral transaction, and did not certify all of this capacity against an ICAP requirement and did not offer the uncertified capacity into the ICAP Spot Market Auction, or it remained unsold in such auction.

In order to address this issue, the NYISO presented three versions of the Table 1 in its July 27, 2009 filing and in this report. Accordingly, Table 1 shows the combined results of the enhanced methodology and previously reported corrections described above, including combing all Rest of State generation-owning Transmission Owners in the first row. Table 1A shows the MW that were purchased in a Capability Period or Monthly Auction or in a bilateral transaction, but ultimately were neither certified against an LSE's ICAP requirement for a given month nor sold in the corresponding ICAP Spot Market Auction (either because it was not offered or remained unsold.) This set of data is also included in Table 1. Table 1B includes the change in the reporting of the data for the Rest of State generation-owning Transmission Owners as described above.

Table 1 - Breakout of Unoffered and Unsold Capacity MW by type of Market Participant

	Summer 2006		Winter 2006-2007		Summer 2007		Winter 2007-2008		Summer 2008		Winter 2008-2009		Summer 2009	
	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW
All ROS TOs	**132.8**	**0.0**	**127.2**	**0.0**	**139.6**	**0.0**	**175.6**	**0.0**	**204.5**	**0.0**	**64.1**	**0.0**	**69.2**	**0.0**
	44.48%	0.00%	44.88%	0.00%	49.85%	0.00%	61.43%	0.00%	60.11%	0.00%	21.22%	0.00%	56.79%	0.00%
5 ROS GenCos	**7.4**	**226.8**	**79.4**	**308.5**	**94.0**	**1.5**	**43.3**	**51.3**	**67.9**	**61.6**	**79.5**	**173.8**	**24.5**	**0.0**
	2.47%	94.45%	28.01%	98.85%	33.58%	100.00%	15.14%	97.44%	19.96%	100.00%	26.30%	95.00%	20.09%	0.00%
All Others incl. SCRs	**158.4**	**13.3**	**76.8**	**3.6**	**46.4**	**0.0**	**67.0**	**1.4**	**67.8**	**0.0**	**158.7**	**9.2**	**28.2**	**0.0**
	53.05%	5.55%	27.11%	1.15%	16.57%	0.00%	23.43%	2.56%	19.93%	0.00%	52.49%	5.00%	23.12%	0.00%
Total Unoffered/ Unsold	**298.6**	**240.1**	**283.5**	**312.1**	**280.0**	**1.5**	**285.9**	**52.6**	**340.2**	**61.6**	**302.3**	**183.0**	**122.0**	**0.0**
Total Available MW	23311		24509		23292		24164		22980		24071		23197	

Notes to Table 1:

(1) All Rest of State Transmission Owners ("TOs") category includes TOs' Special Case Resources.

(2) 5 Rest of State GenCos category kept as in original for data continuity.

Table 1 A - MW Purchased in Strip and Monthly Auctions or Bilaterally and Not Certified Against Load, Not Offered in Spot Auctions

	Summer 2006		Winter 2006-2007		Summer 2007		Winter 2007-2008		Summer 2008		Winter 2008-2009		Summer 2009	
	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW
All ROS TOs	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.48%	0.00%	0.00%	0.00%	0.00%	0.00%
5 ROS GenCos	**0.0**	**0.0**	**8.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
	0.00%	0.00%	21.63%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
All Others incl. SCRs	**26.2**	**13.3**	**30.2**	**3.3**	**28.4**	**0.0**	**25.7**	**0.0**	**20.7**	**0.0**	**1.0**	**0.0**	**2.1**	**0.0**
	100.00%	100.00%	78.37%	100.00%	100.00%	0.00%	100.00%	0.00%	99.52%	0.00%	100.00%	0.00%	100.00%	0.00%
Total Unoffered/ Unsold	**26.2**	**13.3**	**38.5**	**3.3**	**28.4**	**0.0**	**25.7**	**0.0**	**20.8**	**0.0**	**1.0**	**0.0**	**2.1**	**0.0**
Total Available MW	23311		24509		23292		24164		22980		24071		23197	

Notes to Table 1A:

(1) All Rest of State TOs category includes TOs' Special Case Resources.

(2) 5 Rest of State GenCos category kept as in original for data continuity.

Table 1B - ROS MW Difference Between Generator's Available UCAP and MW Unoffered and Unsold

	Summer 2006		Winter 2006-2007		Summer 2007		Winter 2007-2008		Summer 2008		Winter 2008-2009		Summer 2009	
	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW
All ROS TOs	**132.8**	**0.0**	**127.2**	**0.0**	**139.6**	**0.0**	**175.6**	**0.0**	**204.4**	**0.0**	**64.1**	**0.0**	**69.2**	**0.0**
	48.76%	0.00%	51.94%	0.00%	55.48%	0.00%	67.49%	0.00%	63.99%	0.00%	21.29%	0.00%	57.80%	0.00%
5 ROS GenCos	**7.4**	**226.8**	**71.1**	**308.5**	**94.0**	**1.5**	**43.3**	**51.3**	**67.9**	**61.6**	**79.5**	**173.8**	**24.5**	**0.0**
	2.70%	100.00%	29.02%	99.91%	37.37%	100.00%	16.64%	97.44%	21.26%	100.00%	26.39%	95.00%	20.45%	0.00%
All Others incl. SCRs	**132.2**	**0.0**	**46.6**	**0.3**	**18.0**	**0.0**	**41.3**	**1.4**	**47.1**	**0.0**	**157.7**	**9.2**	**26.1**	**0.0**
	48.53%	0.00%	19.04%	0.09%	7.15%	0.00%	15.87%	2.56%	14.75%	0.00%	52.33%	5.00%	21.76%	0.00%
Total Unoffered/ Unsold	**272.4**	**226.8**	**245.0**	**308.8**	**251.6**	**1.5**	**260.2**	**52.6**	**319.4**	**61.6**	**301.3**	**183.0**	**119.8**	**0.0**
Available MW	23311		24509		23292		24164		22980		24071		23197	

Notes to Table 1B:

(1) All Rest of State TOs category includes TOs' Special Case Resources.

(2) 5 Rest of State GenCos category kept as in original for data continuity.

Salient facts from the above tables for the last four capability periods are:

- The average levels of both unoffered and unsold (if any) capacity has remained approximately 1% of the available capacity.
- The group of all Rest of State generation-owning Transmission Owners consistently had unoffered capacity which ranged from 21% to 61% of total unoffered capacity for the period Winter 2007/2008 through Summer 2009.
- The group of all Rest of State generation-owning Transmission Owners had no unsold capacity for the period Winter 2007/2008 through Summer 2009.
- The group of five generation owners consistently had unoffered capacity which ranged from 15% to 26% of total unoffered capacity for the period Winter 2007/2008 through Summer 2009.
- The group of five generation owners had unsold capacity which accounted for 0% to 100% of total unsold capacity for the period Winter 2007/2008 through Summer 2009.
- The group of all others including Special Case Resources consistently had unoffered capacity that ranged from 20% to 52% of total unoffered capacity for the period Winter 2007/2008 through Summer 2009.
- The group of all others including Special Case Resources had unsold capacity that ranged from zero to 5% for the period Winter 2007/2008 through Summer 2009.

2. Analysis of Unoffered Capacity

As with previous reports, this section of the report includes a detailed analysis of the unoffered capacity in the Rest of State ICAP market by Capability Period and by market sector, and also presents the maximum price impact of the unoffered capacity, in each month and averaged over the six months of the Capability Period consistent with the filing on July 27, 2009. In addition, the NYISO contacted each ICAP supplier that had 15 MW or more of unoffered capacity in any one month in either the Winter 2008/09, Summer 2009, or (partial) Winter 2009/10 Capability Period for an explanation of its behavior. This information is reported in below.

In general, the findings support the view that for the vast majority of the capacity that was not offered, the Installed Capacity Suppliers' respective reasons for not offering the capacity were benign, and none of the instances evidences unequivocally demonstrates strategic behavior intended to artificially raise prices. The following information was provided to the NYSIO by ICAP suppliers that had 15 MW or more of unoffered capacity in any one month in a Capability Period:[19]

1. A generation-owning Transmission Owner routinely does not offer the full quantity from several of its resources, an amount that ranges, in aggregate, from approximately 19 MW to 123 MW in each month from November 2008 through November 2009. This action was explained to be primarily due to a conservative operating approach.
2. A generation-owning Transmission Owner keeps roughly 30 MW of aging gas-fueled generation out of operation during the Summer Capability Period (except the month of October) due to environmental restrictions.
3. A generation owner inadvertently failed to certify approximately 83 MW in the November 2008 Spot Market Auction that was sold in the Monthly Auction.
4. A generation owner inadvertently failed to certify approximately 62 MW in August 2009 Spot Market Auction that was sold in the Monthly Auction.
5. A generation owner inadvertently did not offer approximately 71 MW in the April 2009 Spot Market Auction.
6. A generation owner failed to offer approximately 20 MW in November 2009, 8 MW in the August 2009, and approximately 3 MW in each of the June, July, September and October 2009. The owner did not offer the capacity because the owner believed that it was prohibited from doing so.
7. Another generation owner inadvertently did not offer approximately 678 MW in the January 2009 Spot Market Auction. The NYISO met with the Market Participant and determined that the failure to offer was due to the Market Participant mistakenly omitting bids for the January 2009 Spot Market Auction. This conclusion was based

[19] Attachment 2 is filed as a confidential attachment, which provides Market Participant explanations for behavior with regard to unoffered and unsold capacity greater than 15 MW.

on the information provided by the Market Participant and the analysis conducted by the NYISO.[20]

8. A generation owner inadvertently did not offer approximately 64 MW in December 2008.

9. In August 2009, another generation owner inadvertently failed to certify capacity from two units totaling 62 MW, which resulted in unoffered capacity.

10. A generation owner has a PURPA contract that prohibits it from selling any capacity above the level of the bilateral contract. The amount of unoffered capacity ranges from 24.5 MW in Summer months to 69.5 MW in Winter months.

11. Several Responsible Interface Parties routinely did not offer all available MW in their portfolio. These MW are a minor share of both the available and offered capacity.

Table 2 below shows the maximum price impact of the unoffered capacity based on the slopes of the spot auction demand curves for the relevant capability periods. Maximum price impacts are calculated both on a monthly basis and on a seasonal average basis.

Table 2 – Total Maximum Price Impact of the Unoffered Capacity

<table>
<tr><th>Month</th><th>Total Unoffered MW</th><th>Maximum Monthly Price Impact</th><th>Maximum Seasonal Average Price Impact</th></tr>
<tr><td>Nov-08</td><td>242.4</td><td>$0.48</td><td rowspan="6">$0.60</td></tr>
<tr><td>Dec-08</td><td>219.2</td><td>$0.44</td></tr>
<tr><td>Jan-09</td><td>888.2</td><td>$1.77</td></tr>
<tr><td>Feb-09</td><td>181.3</td><td>$0.36</td></tr>
<tr><td>Mar-09</td><td>105.9</td><td>$0.21</td></tr>
<tr><td>Apr-09</td><td>177.2</td><td>$0.35</td></tr>
<tr><td>May-09</td><td>115.7</td><td>$0.26</td><td rowspan="6">$0.28</td></tr>
<tr><td>Jun-09</td><td>107.9</td><td>$0.25</td></tr>
<tr><td>Jul-09</td><td>96.3</td><td>$0.22</td></tr>
<tr><td>Aug-09</td><td>225.6</td><td>$0.51</td></tr>
<tr><td>Sep-09</td><td>107.9</td><td>$0.25</td></tr>
<tr><td>Oct-09</td><td>78.3</td><td>$0.18</td></tr>
<tr><td>Nov-09</td><td>145.9</td><td>$0.34</td><td>$0.34</td></tr>
</table>

The NYISO calculated the maximum price impact of the unoffered capacity, averaged over the six months of the Winter 2008/2009 and Summer 2009 Capability Periods as $0.60/kW-

[20] The NYISO met with the Market Participant and determined that the Market Participant's failure to offer was in the January 2009 Spot Market Auction was inadvertent. This conclusion was based on the information provided by the Market Participant and the analysis conducted by the NYISO.

month and $0.28/kW-month, respectively. For the month of November 2009, the maximum price impact of the unoffered capacity was $0.34/kW-month. The relatively high seasonal average price impact of $0.60/kW-month was primarily due to a generation owner that inadvertently omitted to offer approximately 678 MW in the January 2009 Spot Market Auction, which represents nearly three percent of the total available MW in the Rest of State region.

3. Analysis of Unsold Capacity

As with previous reports, this section of the report analyzes and reports on capacity that was offered but not sold ("unsold" capacity) in the ICAP Spot Market Auction by Capability Period and by market sector (*See* Tables 1, 1A and 1B above). It also presents the maximum price impact of the unsold capacity, in any one month and averaged over the six months of the Capability Period. In addition, the NYISO contacted each generator if (a) the class it was in had more than 15 MW of unsold capacity in a given month and (b) if the generator had a spot market offer that was greater than the generator's class average Net GFC with half net revenues ("GFCs with half net revenues", as described below) for an explanation of its behavior.

In addition to calculating the maximum monthly and maximum average price impacts, four metrics were calculated:

a. Class-based going forward costs ("GFCs") (with and without a risk adjustment);

b. Class-based GFCs with unit specific adjustments;

c. Amount of unsold capacity offered at prices above class-based GFCs with unit specific adjustments when performed (as described herein); and

d. Estimated monthly price impact of unsold capacity associated with offers above class-based GFCs (with unit-specific adjustments when performed).

i. Monthly Average Price Impact

The report includes the maximum price impact of average monthly unsold capacity for each Capability Period. The NYISO analyzed GFCs only if the monthly maximum price impact exceeded the price impact thresholds. The price impact thresholds were selected by considering the slopes of ICAP Demand Curves and the data for unsold capacity. The specific levels were chosen to identify when it is necessary to do a more in-depth analysis of unsold capacity with respect to the total capacity available.

The price impact thresholds are: $0.20/kW-month for the monthly average unsold capacity in a Capability Period, and $0.35/kW-month for the unsold capacity in any single month in that capability period. If either threshold was exceeded, the NYISO calculated the class average Net Going Forward Costs, as described in Section (ii) below. When the thresholds were not exceeded, the total maximum price impact was reported, and the analysis was concluded.

Price impacts due to errors by ICAP Suppliers, if documented, are included in the impact calculation but are not used as a basis for conducting GFC analyses, or included in the evaluations against the thresholds listed above.[21]

The NYISO calculated the maximum price impact of average monthly unsold capacity for Winter 2008/2009 and Summer 2009 Capability Periods, and the month of November 2009 (*See* Table 3 below). There was no unsold capacity in Rest of State for January 2009 and all of the 2009 Summer Capability Period. For the other six months covered by this analysis (November and December 2008, and February, March, April, and November 2009), the amount of unsold capacity ranged from 167.1 MW to 329.1 MW. The maximum price impact of the unsold capacity in any month ranged from $0.33/kW-month to $0.77/kW-month.[22] The maximum seasonal average price impact was $0.36/kW-month for the Winter 2008/2009 Capability Period.

[21] Two examples of the types of errors previously set forth in NYISO reports are a data entry error and an unintended failure to save offers in the NYISO system. The exclusion of unoffered, and offered but unsold, MW due to errors, as described here, is limited to instances in which there are circumstances that make it apparent to the NYISO that a mistake was involved; and that the circumstances do not indicate a reason for a conclusion other than an error (such as repeated conduct); and in which the generator provides the NYISO with a written explanation. The NYISO states the basis for its conclusion in such cases in the report.

[22] Note that $0.77/kW-month impact is for the month of November 2009 and does not reflect the maximum price impact for the entire 2009/2010 Winter Capability Period.

Table 3 – Maximum price Impact of Unsold MW

Month	Total Unsold MW	Maximum Monthly Price Impact	Maximum Seasonal Average Price Impact
Nov-08	306.5	$0.61	$0.36
Dec-08	190.7	$0.38	
Jan-09	0.0	$0.00	
Feb-09	180.1	$0.36	
Mar-09	253.5	$0.51	
Apr-09	167.1	$0.33	
May-09	0.0	$0.00	$0.00
Jun-09	0.0	$0.00	
Jul-09	0.0	$0.00	
Aug-09	0.0	$0.00	
Sep-09	0.0	$0.00	
Oct-09	0.0	$0.00	
Nov-09	329.1	$0.77	$0.77

ii. Class-based Going Forward Costs

Class-based GFCs for generators are defined for purposes of the report as costs (other than production costs) that could be reasonably expected to be avoided or deferred if the plant was mothballed for at least one year. (See table below for definitions.) GFCs may provide insight into why a generator offered its capacity at a non-zero offer price. The assumption is that an Installed Capacity Supplier would only want to sell capacity from a generator if the capacity revenues it receives cover the generator's net GFCs. In this analysis, GFCs will be calculated for the entire capacity of the plant.

The NYISO recognizes that generators face uncertainty about their expected net revenues, which may influence the prices at which they offer capacity. To account for this revenue uncertainty, the NYISO has constructed GFCs with and without certainty of net revenues. The GFCs with certainty of net revenues are calculated by subtracting the full amount of realized net revenues from the GFCs. Conversely, GFCs without certainty of net revenues have a zero value substituted for realized net revenues, which results in the highest possible GFC estimates.

Table 4 – Definitions

Going Forward Costs (GFCs)	Costs that would be avoided or deferred if a generator was mothballed for a year or more, but not including production costs, based on the calculation of the industry average cost data for the type of generator
Net energy and ancillary services revenues (net revenues)	Estimated energy plus ancillary services revenues minus estimated production costs, with a minimum value of zero
GFCs with full net revenues	GFCs minus net revenues. This value is used as a proxy for Net GFCs with certainty of net revenues
GFCs with no net revenues	GFCs. This value is used as a proxy for Net GFCs without certainty of net revenues
GFCs with half net revenues	GFCs minus 0.5 times net revenues. This value is used as a proxy for Net GFCs with some uncertainty
Unit Specific Net GFCs with Recognized Adjustments	GFCs plus unit-specific adjustments (i.e., the dollar amount identified by the generator for an adjustment that is readily recognizable as an appropriate adjustment (for example, a Payment in Lieu of Taxes agreement)), minus the unit specific revenues.
Unit Specific Net GFCs with all Adjustments	GFCs plus all unit-specific adjustments identified by the generator, minus the unit specific revenues.

If the price impact threshold was exceeded, the NYISO calculated GFCs for the generator classes that contributed to the price impact, provided that the class had more than 15 MW of unsold capacity. Specifically, if the $0.20/kW-month average threshold is exceeded, GFCs were calculated for classes with more than an average of 15 unsold MW over the Capability Period, and all months in that Capability Period are designated as "Analysis Months". If the $0.20/kW-month average threshold was not exceeded, but the $0.35/kW-month monthly threshold is exceeded for one or more months, the months in which the $0.35/kW-month monthly threshold is exceeded are designated as "Analysis Months," and GFCs are calculated only for classes that had more than 15 unsold MW in those Analysis Months. If both thresholds were exceeded, the respective rules of both tests apply for the selection of classes. In all instances, the NYISO reported the amount of unsold MW in each class. The NYISO estimated Net GFCs for generator classes that met the above-described criteria.

Based on the maximum price impact results shown in Table 3 above, the NYISO calculated class-based Net GFCs because the estimated maximum price impacts exceeded both of the established impact thresholds described above. The impact threshold for monthly average unsold capacity in a Capability Period of $0.20/kW-month was exceeded by the estimated 2008/2009 Winter Capability Period impact of $0.36/kW-month and the 2009/2010 Winter Capability Period[23] impact of $0.77/kW-month The monthly price impact threshold of $0.35/kW-month was exceeded in November 2008, December 2008, February 2009, March 2009 and November 2009 by the values shown in Table 3 above.

The methodology used to estimate going forward costs was the same as that used for the estimate of going-forward costs in ROS in support of previous NYISO filings.[24] The generating units whose capacity offers were not accepted (*i.e.*, unsold capacity) were natural gas combined cycle cogeneration units, No. 6 fuel oil steam turbine units, sub-critical coal steam turbine units, and coal-fired cogeneration units.

The NYISO reviewed a list of the principal generating units in ROS provided in the NYISO's Load and Capacity Data Report applicable to November 2008 through November 2009 (referred to as the "Gold Book"), and divided the units into classes based on primary fuel and technology. A number of units fell within the classes of units for which GFCs were estimated for ROS and NYC in the previous filings. These classes were: 1) Natural gas combined cycle (Class A); 2) Natural gas combined cycle cogeneration (Class B); 3) Natural gas simple cycle turbine (Class C); 4) No. 2 fuel oil simple cycle turbine (Class D); 5) Kerosene simple cycle turbine (Class E); 6) No. 6 fuel oil steam turbine (Class F); 7) Natural gas steam turbine (Class G); 8) Sub-critical coal steam turbine units (Class H); 9) Coal-fired co-generation unit (Class I).

All of the units whose capacity offers were not accepted in November 2008 through November 2009 fell into Classes B, F, H and I. Other classes could be formed for generating units in ROS because of the diversity of fuel and technologies in this region. These classes were not analyzed for this effort because no generating units whose capacity offers were not accepted in November 2008 through November 2009 were found in these classes.

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[23] Only November 2009 data were used for the 2009/2010 Winter Capability Period.

[24] The NYISO employed the same method for the estimation of going forward costs for the May 4, 2009 filing of "Response of the New York Independent System Operator, Inc. to Deficiency Letter Dated April 2, 2009," Docket Nos. ER01-3001-021, ER03-647-012, ER01-3001-022 and ER03-647-013; the July 25, 2008, "Compliance Filing of the New York Independent System Operator, Inc.," Docket Nos. ER01-3001-019, and ER03-647-011, and the October 4, 2007, "Compliance Filing of the New York Independent System Operator, Inc., Regarding the New York City ICAP Market Structure," Docket No. EL07-39-000.

Generator avoidable costs were estimated on an annual basis assuming that decisions to mothball a unit would be made for a period of at least one year, if not longer. Recovery of avoidable costs would not all have to occur in any one month. It is assumed that one-twelfth of those costs (seasonally adjusted as appropriate) can be recovered in a given month to permit a given unit to remain a capacity supplier for that month.

Net Energy and Ancillary Services revenues were estimated by NYISO for ROS generating units whose capacity offers were unsold for months in the period from November 2008 through November 2009. For these generating units, the net Energy and Ancillary Services revenues were estimated for the period from November 2008 through October 2009 because the revenue data were not available for the month of November 2009.[25] Net revenues were equal to estimated energy plus ancillary services revenues minus estimated production costs, with a minimum value of zero.[26] If production cost estimates exceed Energy and Ancillary Services revenues, a value of zero is used as the net revenue figure.

The net revenues were determined from the books and records of the NYISO. The net revenues were estimated based on actual energy and ancillary services revenues less the average cost-based reference price information for the relevant ROS ICAP Suppliers with capacity offered but not sold. To calculate the average cost-based information, the NYISO used monthly average spot natural gas prices.

The majority of the units with unsold capacity had negative net revenue estimates. The estimates are not unreasonable given the capacity factors of some of the units and the economic conditions in 2008 and 2009. Six of these generators showed slightly negative net revenues near break-even levels, two showed mild gains, three showed large losses, and two showed large gains. The three generators with large negative net revenues had capacity factors ranging from a very low six percent to fifty-seven percent. The NYISO's estimation method may have overestimated or underestimated production costs for units that have low capacity factors if these

[25] For those units that had unsold capacity in November 2009, their offer levels were compared to GFCs calculated for the 2008/2009 Winter Capability Period.

[26] The value of class average going-forward costs minus net revenues for ROS generating units whose capacity offers were not accepted in November 2008 through November 2009 is summarized in Attachment 4. The estimates are shown on a UCAP basis to allow direct comparison to capacity offers and market prices for capacity. Three estimates were prepared in accordance with Attachment A to the New York Independent System Operator, Inc.'s November 12, 2009, "Updated Status Report on Stakeholder Discussions Regarding Annual Installed Capacity Demand Curve Reports and Plan for Future Reports," Docket Nos. ER01-3001-021, ER01-3001-022, ER03-647-012, and ER03-647-013.

units operated on days when the price of natural gas was substantially different from the average price of natural gas. Another possible source of overestimation or underestimation in the NYISO's calculations comes from the use of average reference costs. Average reference costs are unbiased estimators for units that are frequently dispatched throughout their entire operating range, but may lead to overestimation or underestimation of net revenues if the unit is consistently dispatched at its lower or upper ranges. The estimation of net revenues is, by its very nature, an estimate and may not account entirely for the specific characteristics of a unit or its dispatch. Therefore, any resulting negative unit net revenue values are set to zero in the analysis. While the NYISO believes that the current analyses are informative, the NYISO is continuing to look at ways to refine the net revenue estimation methodology as part of future enhancements to the report.

GFCs are calculated from industry data, such as labor rates, expenses for contract services, administrative and general, and insurance. Energy and Ancillary Services revenues are estimated from NYISO billing information, and production costs are estimated from NYISO unit specific reference level data and inputs to the reference calculation(s). The production costs are intended to reflect the costs incurred by a generator to produce Energy or provide Ancillary Services that it would not have incurred if it had not produced that Energy or provided those Ancillary Services.

GFCs with full net revenues were calculated for use as a proxy for net going forward costs with certainty of net revenues. Annual going forward costs minus full net revenues for November 2008 through October 2009 vary from $(4.18)/kW-year for Class I to $38.77/kW-year for Class H. Summer values range from $(0.47)/kW-month to $4.35/kW-month. Winter values range from $(0.23)/kW-month to $2.11/kW-month.

GFCs with no net revenues were calculated for use as a proxy for net going forward costs without certainty of net revenues. Annual going forward costs with no net revenues for November 2008 through October 2009 vary from $18.79/kW-year for Class B to $80.97/kW-year for Class I. Summer values range from $2.11/kW-month to $9.09/kW-month. Winter values range from $1.02/kW-month to $4.40/kW-month.

GFCs with half net revenues was calculated for use as a proxy for net going forward costs with some uncertainty. Annual going forward costs minus half net revenues for November 2008 through October 2009 vary from $17.91/kW-year for Class B to $42.22/kW-year for Class H.

Summer values range from \$2.01/kW-month to \$4.74/kW-month. Winter values range from \$0.97/kW-month to \$2.30/kW-month.

Table 5 below shows the amount of capacity unsold by month for which class-based Net GFCs were calculated. Table 5 also shows the amount of capacity unsold for which class average Net GFCs were not calculated (*i.e.*, unsold capacity that belongs to classes with less than 15 MW). Class-based Net GFCs were calculated for four classes because the unsold capacity within each of the four classes exceeded 15 MW. Class-based Net GFCs were not calculated for one class because the class sum did not exceed 15MW.

Table 5 – Unsold MW used for GFC calculations

Month	Total Unsold MW	Total Unsold MW for which class average GFCs calculated (Unsold MW > 15)	Total Unsold MW for which class average GFCs not calculated (Unsold MW < 15)
Nov-08	306.5	306.0	0.5
Dec-08	190.7	188.3	2.4
Jan-09	0.0	0.0	0.0
Feb-09	180.1	180.1	0.0
Mar-09	253.5	241.0	12.5
Apr-09	167.1	147.5	19.6
May-09	0.0	0.0	0.0
Jun-09	0.0	0.0	0.0
Jul-09	0.0	0.0	0.0
Aug-09	0.0	0.0	0.0
Sep-09	0.0	0.0	0.0
Oct-09	0.0	0.0	0.0
Nov-09	329.1	308.2	20.9

iii. Class based Going Forward Costs with Unit Specific Adjustments

The NYISO contacted generator owners for unit-specific information if a generator's offer for unsold capacity exceeded the "GFCs with half net revenues". The responses were used to calculate unit-specific Net GFCs with adjustments. Reported costs (other than production costs) that the generator owner could reasonably expect to avoid by mothballing for a year or more (that were not already included in the class-based GFC estimates) would be used to construct the "Net GFC with Recognized Adjustments" for that unit. Any other avoided costs reported by the generator were used in the "Net GFC with all Adjustments". There was no need to describe unquantifiable responses because the responses provided were already quantified. This report also includes the basis for the NYISO's determination that any such adjustment was not reasonable. If none of the generators with unsold capacity identifies adjustments in their respective responses, the NYISO proceeded with its analysis without incorporating GFC adjustments.

For each Analysis Month, and in each of six GFC scenarios set forth in Table 4, the report includes (a) the total number of MW of unsold capacity in that Analysis Month that was offered at a price above the Unit Specific Net GFCs in that scenario (i.e., with or without certainty of Net Revenues and without Adjustments, with Recognized Adjustments, or with all Adjustments, as stated for that scenario); and (b) the estimated price impact of all generators offering unsold capacity at prices above their Unit Specific Net GFCs for that scenario, when the Unit Specific Net GFCs are below the Spot Market clearing price for the Analysis Month (i.e., the difference between the actual ROS ICAP price for the Analysis Month and the price that would have been calculated if all unsold capacity offered at a price above Unit Specific Net GFCs had instead been offered at Unit Specific Net GFCs). In each of these analyses for each scenario, if Unit Specific Net GFCs are not calculated for a given unit, the class average Net GFCs for that scenario are used if available. The NYISO did not analyze the impact on price of unsold capacity offered by units for which class averages were not calculated. To complete the analysis of unsold capacity, the NYISO additionally reports the total number of MW of unsold capacity offered at a price less than unit-specific Net GFCs but greater than the Spot Market clearing price.

It is presumed that unsold capacity offered at a price greater than the ICAP Spot Market Auction clearing price would have no effect on the clearing price because those MW would not have cleared in the auction. Therefore, if offer prices for unsold capacity are set equal to the Unit Specific Net GFC used in a given scenario (or the class average net GFCs for that scenario, when that is available and the Unit Specific Net GFC is not available), and this value is greater than the Spot Market clearing price, the offer would have no price impact and would, therefore, not be included in the calculation of estimated price impact.

Given the offer levels and estimates of Net GFCs with half net revenues, only three out of 13 generators' offers for unsold capacity exceeded the "GFCs with half net revenues". Accordingly, the NYISO contacted these three generator owners for further information about their capacity offers and for unit-specific cost information to calculate unit-specific Net GFCs with adjustments. The NYISO obtained the following information regarding the behavior of generators:[27]

1. One market participant had two units with unsold capacity. The first unit had unsold capacity for five months that ranged from 47.5 MW to 58.3 MW. The second unit had unsold capacity for two months, with amounts of 18.6 MW and 43.7 MW. The market participant stated that its offer prices reflected its cost of providing capacity.
2. Another market participant had a unit with 104 MW in November 2008, 9.9 MW in March 2009, and 100 MW in April 2009. The market participant stated that its offers were of a financial nature, and the market cleared lower than it was willing to accept.

When NYISO contacted generator owners for unit-specific cost information, one of the generators reported no such costs, and the other two generators submitted information for consideration of unit specific cost adjustments that were not recognized by the NYISO.[28] Therefore, the six scenarios discussed above effectively collapsed into the following four scenarios: [29] (1) GFCs with full Net Revenues and no adjustments, (2) GFCs with no Net Revenues and no adjustments, (3) GFCs with full Net Revenues and all Adjustments, (4) GFCs with no Net Revenues and all Adjustments. Hence, for each Analysis Month, for each of the four scenarios, the NYISO estimated the price impact of three generators offering unsold capacity at prices above their Unit Specific Net GFCs, when the Unit Specific Net GFCs were below the Spot Market Auction clearing price. The estimated price impacts were calculated by replacing the unsold capacity offer prices with prices equal to unit specific Net GFCs (since unit specific GFCs were available for all of the units analyzed).

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[27] *See* Confidential Attachment 2 for details.

[28] The reported costs are from generator owners in Class F and Class H. These costs were not production costs and not already included in the class average going forward costs, but were not costs that the generator owner could reasonably be expected to avoid by mothballing for a year or more and, hence, were not recognized cost adjustments. Consequently, the estimates of going forward costs minus net revenues with recognized adjustments are the same as the estimates of going forward costs minus net revenues with no adjustments. The reported costs were used to construct estimates of going forward costs minus net revenues with all adjustments. *See* Confidential Attachment 3 for details of this particular case.

[29] *See* GFC estimates in Attachment 4.

The summary of estimates of going forward costs minus net revenues and cost adjustments for Class F and Class H, is as follows:[30]

1. Going forward costs with full net revenues and no adjustments for November 2008 through October 2009 vary from 23.57/kW-year for Class F to $38.77/kW-year for Class H. Summer values range from $2.65/kW-month to $4.35/kW-month. Winter values range from $1.28/kW-month to $2.11/kW-month.
2. Going forward costs with full net revenues and all adjustments for November 2008 through October 2009 vary from $38.64/kW-year for Class F to $71.12/kW-year for Class H. Summer values range from $4.34/kW-month to $7.99/kW-month. Winter values range from $2.10/kW-month to $3.87/kW-month.
3. Going forward costs with no net revenues and no adjustments for November 2008 through October 2009 vary from $23.57/kW-year for Class F to $45.66/kW-year for Class H. Summer values range from $2.65/kW-month to $5.13/kW-month. Winter values range from $1.28/kW-month to $2.48/kW-month.
4. Going forward costs with no net revenues and all adjustments for November 2008 through October 2009 vary from $38.64/kW-year for Class F to $78.00/kW-year for Class H. Summer values range from $4.34/kW-month to $8.76/kW-month. Winter values range from $2.10/kW-month to $4.24/kW-month.

The three units mentioned above had offers greater than their unit specific Net GFCs under the four scenarios stated above in the months of December 2008, February 2009, March 2009, and November 2009. The NYISO ran simulations in these four months for the three generators. Among the outcomes of the simulations, only the February 2009 Spot Market Auction rerun yielded a change in market clearing price, a decline of $0.12/kW-month under two scenarios, while the other three months' Spot Auction clearing prices remained unchanged (*see* Table 6 below for price impact analysis results).[31]

[30] See Attachment 4.

[31] A confidential version of Table 6 is filed with this report as Attachment 5.

Table 6 – Price Impact Analysis Results

Month	Unit	Original Offer	S1	S2	S3	S4	Original Market Clearing Price (MCP)	Decision to run simulation	Change in MCP, S1	Change in MCP, S2	Change in MCP, S3	Change in MCP, S4
Nov-08	Unit_1	$1.25	$1.28	$1.28	$3.04	$3.04	$1.00	No				
Nov-08	Unit_2	$1.30	$1.28	$1.28	$3.04	$3.04		No				
Nov-08	Unit_3	$1.00	$2.11	$2.48	$3.87	$4.24		No				
Nov-08	Unit_8	$1.25	$1.02	$1.02	$1.02	$1.02		No				
Dec-08	Unit_2	$1.35	$1.28	$1.28	$3.04	$3.04	$1.25	No				
Dec-08	Unit_3	$1.25	$2.11	$2.48	$3.87	$4.24		No				
Dec-08	**Unit_6**	$1.35	**$1.01**	**$1.02**	**$1.01**	**$1.02**		**Yes**	**None**	**None**	**None**	**None**
Feb-09	**Unit_2**	$2.50	**$1.28**	**$1.28**	$3.04	$3.04	$1.77	**Yes**	**-$0.12**	**-$0.12**		
Feb-09	Unit_3	$2.00	$2.11	$2.48	$3.87	$4.24		No				
Mar-09	Unit_1	$0.85	$1.28	$1.28	$3.04	$3.04	$0.50	No				
Mar-09	Unit_2	$0.75	$1.28	$1.28	$3.04	$3.04		No				
Mar-09	Unit_3	$0.50	$2.11	$2.48	$3.87	$4.24		No				
Mar-09	Unit_5	$1.00	$1.28	$1.28	$2.80	$2.80		No				
Mar-09	Unit_8	$0.50	$1.02	$1.02	$1.02	$1.02		No				
Mar-09	**Unit_9***	$1.00	**-$0.23**	$4.40	**-$0.23**	$4.40		**Yes**	**None**		**None**	
Mar-09	Unit_6	$1.00	$1.01	$1.02	$1.01	$1.02		No				
Mar-09	Unit_7	$0.50	$1.01	$1.02	$1.01	$1.02		No				
Apr-09	Unit_2	$0.40	$1.28	$1.28	$3.04	$3.04	$0.30	No				
Apr-09	Unit_8	$0.46	$1.02	$1.02	$1.02	$1.02		No				
Nov-09	Unit_4**	$1.25	$2.11	$2.48	$3.87	$4.24	$0.50	No				
Nov-09	Unit_4**	$1.00	$2.11	$2.48	$3.87	$4.24		No				
Nov-09	Unit_4**	$0.75	$2.11	$2.48	$3.87	$4.24		No				
Nov-09	Unit_4**	$0.50	$2.11	$2.48	$3.87	$4.24		No				
Nov-09	**Unit_9****	$1.73	**-$0.23**	$4.40	**-$0.23**	$4.40		**Yes**	**None**		**None**	
Nov-09	**Unit_9****	$1.56	**-$0.23**	$4.40	**-$0.23**	$4.40		**Yes**	**None**		**None**	
Nov-09	**Unit_9****	$1.06	**-$0.23**	$4.40	**-$0.23**	$4.40		**Yes**	**None**		**None**	
Nov-09	Unit_10	$0.50	$1.02	$1.02	$1.02	$1.02		No				
Nov-09	Unit_11	$0.55	$0.65	$1.02	$0.65	$1.02		No				
Nov-09	Unit_12	$0.50	$1.28	$1.28	$1.28	$1.28		No				
Nov-09	Unit_13	$0.50	$1.28	$1.28	$1.28	$1.28		No				

Note: Bold font indicates that a simulation is run by replacing a generator's offer with an estimated GFC for the respective scenario
*In March and Nov. 2009, Unit_9 Net GFC w/ full NR -$0.23 was replaced by zero offer.
** In Nov. 2009 Unit_4 and Unit_9 had multiple offers.

Scenario 1: Unit Specific Net GFC with full Net Revenues and no adjustments
Scenario 2: Unit Specific Net GFC with zero Net Revenues and no adjustments
Scenario 3: Unit Specific Net GFC with full Net Revenues and All Adjustments
Scenario 4: Unit Specific Net GFC with zero Net Revenues and All Adjustments

Table 7 below shows the total unsold capacity in the Analysis Months that was offered at a price above the Unit Specific Net GFCs and Table 8 shows the total number of MW of unsold capacity offered at a price less than unit-specific Net GFCs but greater than the Spot Market clearing price.

Table 7 – Unsold Capacity (MW) Offered at a Price above Unit Specific Net GFCs

	Nov-08				Dec-08				Feb-09				Mar-09				Apr-09				Nov-09			
	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4
Class B	104.0	104.0	104.0	104.0	18.6	18.6	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Class F	58.3	58.3	0.0	0.0	58.3	58.3	0.0	0.0	56.5	56.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Class H	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Class I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	55.0	0.0	55.0	0.0
Total	162.3	162.3	104.0	104.0	76.9	76.9	18.6	18.6	56.5	56.5	0.0	0.0	20.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	55.0	0.0	55.0	0.0

Scenario 1: Unit Specific Net GFC with full Net Revenues and no adjustments
Scenario 2: Unit Specific Net GFC with zero Net Revenues and no adjustments
Scenario 3: Unit Specific Net GFC with full Net Revenues and All adjustments
Scenario 4: Unit Specific Net GFC with zero Net Revenues and All adjustments

Table 8 – Unsold Capacity (MW) Offered at a Price less than Unit Specific Net GFCs but Greater than the Spot Market Auction Clearing Price

	Nov-08				Dec-08				Feb-09				Mar-09				Apr-09				Nov-09			
	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4
Class B	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.7	43.7	43.7	43.7	100.0	100.0	100.0	100.0	71.0	71.0	71.0	71.0
Class F	64.1	64.1	122.4	122.4	0.0	0.0	58.3	58.3	0.0	0.0	56.5	56.5	128.0	128.0	128.0	128.0	47.5	47.5	47.5	47.5	0.0	0.0	0.0	0.0
Class H	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	123.6	123.6	123.6	123.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0	150.0	150.0	150.0
Class I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	55.0	0.0	55.0
Total	64.1	64.1	122.4	122.4	0.0	0.0	58.3	58.3	123.6	123.6	180.1	180.1	171.7	191.7	171.7	191.7	147.5	147.5	147.5	147.5	221.0	276.0	221.0	276.0

Scenario 1: Unit Specific Net GFC with full Net Revenues and no adjustments
Scenario 2: Unit Specific Net GFC with zero Net Revenues and no adjustments
Scenario 3: Unit Specific Net GFC with full Net Revenues and All adjustments
Scenario 4: Unit Specific Net GFC with zero Net Revenues and All adjustments

iv. Conclusions

As can be seen from Table 1 above, on average, 183 MW of capacity were offered but not sold in the 2008/2009 Winter Capability Period. During this period, the NYCA minimum capacity requirement was 36,493 MW, and the total amount of capacity sold or certified averaged 40,216 MW.[32] Thus, during the 2008/2009 Winter Capability Period, the amount of ROS capacity offered but not sold constituted 0.5% of the NYCA minimum capacity requirement, and 0.46% of the total amount of NYCA capacity sold. As indicated by the excess amount of capacity sold over the minimum requirement, the NYISO purchased, on average, 3,723.5 MW of capacity over the minimum requirement during each of the months of the

[32] All capacity figures in the following analysis are in UCAP terms.

2008/2009 Winter Capability Period. Finally, the average spot market price across each of these six months of the 2008/2009 Winter Capability Period was $1.34/kW-month, while the net CONE as determined in connection with establishing the ICAP Demand Curve for the twelve month period beginning in May 2008 was $8.19/kW-month.

During the 2009 Summer Capability Period, the average number of MW that went unsold was zero and the average spot market price realized as $3.28/kW-month The Net CONE for the twelve month period beginning in May 2009 was $9.13/kW-month.

During the period from November 2008 through November 2009, the estimated maximum price impact of these unsold capacity in any month ranged from $0.33/kW-month to $0.77/kW-month.[33] The maximum seasonal average price impact was $0.36/kW-month for the Winter 2008/2009 Capability Period.

These results show that the small amount of ROS capacity that was offered but not sold was very unlikely to constitute economic withholding. As the Commission has recognized, "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."[34] Given the NYISO's analysis of 2008/2009 Winter Capability Period, where the amount of offered but unsold capacity constituted less than eight tenths of one percent of the available supply, and the market cleared at an average price that is approximately one sixth of the Net CONE, it is unlikely that any supplier was engaging in a viable strategy of economic withholding.

Based on the analysis of unsold capacity presented in Section III.C.3 above, if all the offered but unsold capacity had cleared under the Demand Curve, the average spot auction prices would have been lower by, at most, $0.36/kW-month in for the 2008/2009 Winter Capability Period (*See* Table 3 above). Furthermore, approximately half of the ROS capacity that was offered but unsold was capacity from units that also sold a significant portion of their capacity. Such partial sales occur when several suppliers have competing offers at the market clearing price, in which case the MW awards are prorated across the equal offers since only the amount needed to meet the LSE Unforced Capacity Obligation as determined by the Demand Curve is

[33] *See* Table 3. Note that $0.77/kW-month impact is for the month of November 2009.

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

cleared in the spot auction. These facts further confirm that there is little or no basis to conclude that the relevant suppliers were engaged in a profitable withholding strategy.

The competitiveness of the NYCA capacity market in the 2008/2009 Winter Capability Period is confirmed by the analysis of estimated Going Forward Costs for ROS units presented in Section III.C.3 of this report.[35] The analysis shows that an estimation of Going Forward Costs did not indicate that significant economic withholding occurred in the 2008/2009 Winter Capability Period, during which an average of 183 MW of ROS capacity was offered but not sold. During this period, the ICAP Spot Market Auctions cleared well below the estimated Going-Forward Costs for majority of the units with unsold capacity, which indicates the absence of significant economic withholding.[36]

While the conclusions outlined here indicate that there is no evidence of economic withholding by ROS capacity, the NYISO continues to closely monitor activity and conditions in all of its ICAP markets and will impose, or if necessary, seek authority to impose, appropriate mitigation measures against any significant exercise of market power should it occur. Under the conditions in the market for ICAP from ROS suppliers during the period covered by this report, however, no action is warranted. Any regulatory intervention in the bidding of ROS ICAP suppliers would not be justified by the market's structure or performance, and would be inconsistent with the Commission's policy and precedent.

[35] *See* also Attachment 4 for GFC estimates.

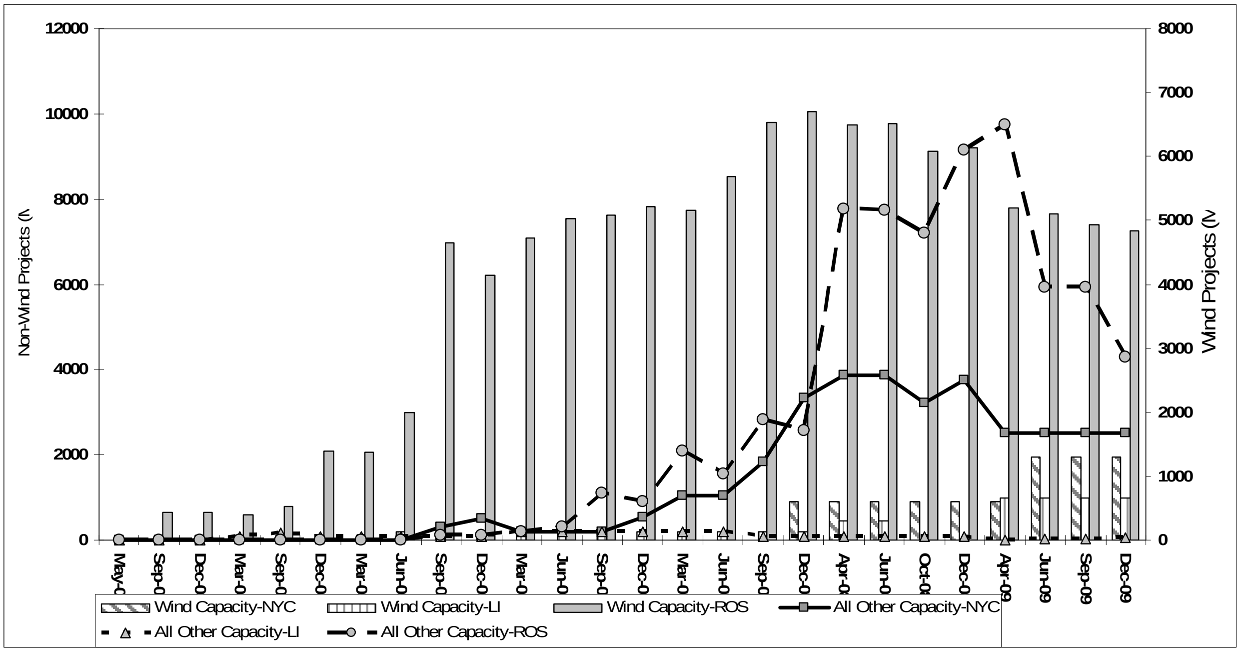
[36] Only 3 out of 13 units had their GFCs below the market clearing price in four months.

New Generation Projects and Net Revenue Analysis

The NYISO anticipated that the ICAP Demand Curves would increase the incentives to build new generation when it is needed. In past reports, the NYISO stated that it is difficult to relate the development of new generation to the ICAP Demand Curves given the lead time required to site, develop, and construct new generation, and the other barriers to new entry. Calendar year 2009 saw the addition of a 310 MW combined cycle facility on Long Island and 112 MW of new wind generation added in the Rest of State. In late 2009, the 300 MW Linden VFT controllable facility into New York City commenced commercial operation. The NYISO anticipates that within the next few years, new generation projects that have been planned since the NYISO implemented the ICAP Demand Curves will commence commercial operation. 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 in New York City, Long Island, and Rest of State – with wind projects depicted separately from generation projects with other fuel types.

Chart 13 – NYISO Interconnection Queue Projects



This analysis is based on periodically updated versions of the NYISO interconnection queue dating from May 2003 through December 2009.[37] For purposes of this analysis, only 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 2005 and beyond, status codes 0, 1, 12, 13, and 14 were omitted.

Generally, the amount of generation in the interconnection process has increased since the ICAP Demand Curves became effective in May 2003. The number of MW 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. The graph above shows that beginning with the

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

Winter 2007-2008 Capability Period, Rest of State has seen a sharply rising trend in the number of MW in the interconnection queue, particularly new non-wind projects. Since the January 2009 report, there has been a decrease in the total amount of Rest of State generation and New York City non-wind generation in the interconnection queue. This trend likely is due in part to the tight capital markets associated with the general economic downturn. There has been an increase in the amount of New York City and Long Island wind generation projects in the interconnection queue, including one 700 MW project between New York City and Long Island (shown in Chart 13 within the New York City totals). Chart 13 does not include a number of proposed HVDC connections into New York City, which currently total more than 5,300 MW -- an increase of roughly 3,000 MW from late 2008. The latter activity is significant and can be attributed in part to the expectation of higher capacity revenues in New York City than the revenues available in other locations.

Proposed Resource Additions

The January 2009 Report included a summary of the then-recently-completed Reliability Needs Assessment (RNA), which remains the most recent long-term assessment of reliability needs. The NYISO presently is in the fourth cycle of the CRPP process since the NYISO's planning process was approved by FERC in December 2004. The first CRP, which was approved by the NYISO Board of Directors in August 2006, identified 3,105 MW of resource additions needed through the 10-year Study Period ending in 2015. Market solutions totaled 1,200 MW, with the balance provided by updated Transmission Owners' plans. The second CRP, which was approved by the NYISO Board of Directors in September 2007, identified 1,800 MW of resource additions needed over the 10-year Study Period ending in 2016. Proposed market solutions totaled 3,007 MW, in addition to updated Transmission Owners' plans. The third CRP, which was approved by the NYISO Board of Directors in July 2008, identified 2,350 MW of resource additions needed through the 10-year Study period ending in 2017. Market solutions totaling 3,380 MW were submitted to meet these needs. The fourth CRP, which was approved by the NYISO Board on May 20, 2009, determined that there are no additional resource needs through the ten-year Study Period ending in 2018 under expected Bulk Power System conditions.

Although the 2009 CRP identified no additional resource needs, the market based projects that were submitted for the 2008 CRP continue to be tracked on a quarterly basis. Table 3 presents the market based projects and Transmission Owners' plans that were submitted in response to requests for solutions and were included in the 2008 CRP. The Table indicates that, as of September 30, 2009, 920 MW of solutions are still being reported to the NYISO as moving forward with development. There are a number of other projects in the NYISO interconnection queue that also are moving forward in the interconnection process, but which have not been offered as market based solutions in the CRPP process.

Table 3: September 30, 2009 Status of the 2008 CRP Market – Based Solutions and TOs' Plans

Project Type	Submitted	MW	Zone	Original In-Service Date	Current Status[1]
Resource Proposals					
Gas Turbine NRG Astoria Re-powering[2]	CRP 2005, CRP 2007, CRP 2008	520 MW	J	Jan - 2011	New Target June 2012 NYISO interconnection queue projects # 201 and # 224
Simple Cycle GT Indian Point	CRP 2007, CRP 2008	300	H	May - 2011	Withdrawn
DSM SCR EnerNOC	CRP 2008	125	G, H, J	2012 - 2017	Withdrawn
DSM SCR ECS	CRP 2008	300	F, G, H, I, J	Ramps up from 2008 through 2012	Withdrawn
Empire Generation Project	CRP 2008	635	F	Q1 2010	New Target July 2010 Under Construction NYISO interconnection queue project # 69
Transmission Proposals					
Controllable AC Transmission Linden VFT	CRP 2007, CRP 2008	300 (No specific capacity identified)	PJM - J	Q4 2009 PJM Queue G22	In-Service Nov., 2009 NYISO interconnection queue project #125
Back-to-Back HVDC, AC Line HTP	CRP 2007, CRP 2008 and was an alternative regulated proposal in CRP 2005	660 (500 MW specific capacity identified)	PJM - J	Q2/2011 PJM Queue O66	New Target Q4 2011 NYISO interconnection queue projects # 206
Back-to-Back HVDC, AC Line Harbor Cable	CRP 2007, CRP 2008 and was an alternative regulated proposal in CRP 2005	550 (550 MW specific capacity identified)	PJM - J	Jun - 2011	Withdrawn NYISO interconnection queue projects # 195 and # 253

Cross Hudson	CRP 2008	550	J	Jun - 2010	Withdrawn NYISO interconnection queue project # 255 Replaced with queue # 295
Cross Hudson II	CRP 2008	800	J	Jun - 2010	Project is Not Progressing NYISO interconnect queue project # 295
TOs' Plans					
ConEd M29 Project	CRP 2005	N/A	J	May - 2011	On Target Under Construction NYISO interconnection queue projects # 153
Caithness	CRP 2005	310	K	Jan - 2009	In-Service Aug, 2009 NYISO interconnection queue projects # 107
Millwood Cap Bank	CRP 2007	240 MVAr	H	Q1 2009	In-Service May, 2009

[1] Status as provided by Market Participant as of Sept. 30, 2009

[2] NRG submitted three proposals, one of which was withdrawn. For the purposes of the Market-Based solutions' evaluation NYISO assumed the lowest MW proposal. There is a retirement of 112 MW at this location reflected in the base case.

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 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.

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 an increased 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 4. Available Capacity vs. Required Capacity

		2004	2005	2006	2007	2008	2009
NYCA	Requirement (MW)	35585	35799	37154	37228	36633	36362
	Available Cap. (MW)	37,226	37,974	38,470	38,641	38192	38217
	Capacity margin %	**104.6%**	**106.1%**	**103.5%**	**103.8%**	**104.3%**	**105.1%**
NYC	Requirement (MW)	8,445	8,527	8,798	9,058	8911	8855
	Available Cap. (MW)	8,520	9,043	9,880	10,158	9858	9612
	Capacity margin %	**100.9%**	**106.1%**	**112.3%**	**112.1%**	**110.6%**	**108.5%**
LI	Requirement (MW)	4,762	4,905	5,110	5,056	4685	4749
	Available Cap. (MW)	4,946	5,100	5,279	5,192	5353	5331
	Capacity margin %	**103.9%**	**104.0%**	**103.3%**	**102.7%**	**114.3%**	**112.3%**

In Table 4, the required capacity is 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.[38] Statewide, the capacity margin has been stable (at around 104.5%) for the past few years despite declines in the Installed Reserve Margin – from 18% for the 2006-2007 capability year to 16.5% in 2007-2008, 15% in 2008-2009, and returning to 16.5% in 2009-2010. For New York City, the capacity margin dipped for the second year in a row, to 108.5%. The corresponding figure for Long Island, which had a mildly declining capacity margin until the 2008-2009 Capability Year, dipped slightly below the 2008-2009 figure due to an increase in the Locational Installed Reserve Margin from 94% to 97.5% of forecasted peak load and the addition of some generation.

[38] In contrast to the prospective figures used in the NYISO's annual Load & Capacity Reports, these charts reflect data based on realized outcomes.

Measure of Revenues

The NYISO assumed a revenue requirement based on the ICAP Demand Curves, which use a levelized annual revenue requirement for a given capability year (May – April) 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 from 2005 through 2009.

Table 5, below, shows the annual revenue requirements for a hypothetical new entry based on the assumptions reflected in ICAP Demand Curve parameters. Note that the ICAP Demand Curves were updated in 2008, and, consequently, the 2008 and 2009 figures are based on a revised model that incorporates updated financial assumptions and different benchmark technologies for each capacity zone. For example, the notional figures for New York City over the 2005-2007 period were based on a pair of LM 6000 Combustion Turbines, and the 2008 and 2009 Demand Curves assume a more efficient LMS 100 unit.

Table 5. Annual Revenue Requirements ($/MW)

	2005	**2006**	**2007**	**2008**	**2009**
NYCA	$93,697	$96,670	$98,964	$103,835	$103,312
NYC	$198,766	$204,437	$208,650	$209,747	$213,943
LI	$174,512	$177,122	$186,021	$180,914	$194,743

Table 6 below 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.[39]

Table 6. Benchmark Annual Revenues in UCAP terms ($/MW)

[39] 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%.

		Revenue Elements in $					Revenue Elements as % of Total				
		2005	2006	2007	2008	2009	2005	2006	2007	2008	2009
NYCA[40]	Energy	$4,238	$4,327	$6,220	$6,251	$5,291	16%	9%	11%	11%	10%
	A/S	$11,662	$19,044	$19,567	$24,584	$18,467	43%	38%	34%	43%	36%
	Capacity	$11,360	$26,600	$31,310	$26,050	$27,920	42%	53%	55%	46%	54%
	Total	$27,260	$49,972	$57,096	$56,885	$51,678	100%	100%	100%	100%	100%
NYC	Energy	$45,393	$38,582	$32,575	$41,243	$24,221	27%	23%	21%	37%	25%
	A/S	$8,632	$11,807	$13,002	$17,894	$14,155	5%	7%	8%	16%	15%
	Capacity	$112,940	$114,140	$111,220	$51,980	$58,640	68%	69%	71%	47%	60%
	Total	$166,965	$164,529	$156,797	$111,117	$97,016	100%	100%	100%	100%	100%
Long Island	Energy	$46,678	$87,372	$58,548	$48,229	$48,229	29%	49%	43%	49%	50%
	A/S	$8,498	$8,158	$9,804	$16,998	$16,998	5%	5%	7%	17%	18%
	Capacity	$105,260	$83,650	$67,830	$33,970	$30,800	66%	47%	50%	34%	32%
	Total	$160,436	$179,180	$136,182	$99,197	$96,027	100%	100%	100%	100%	100%

In order to assess 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 7. Revenue Margins

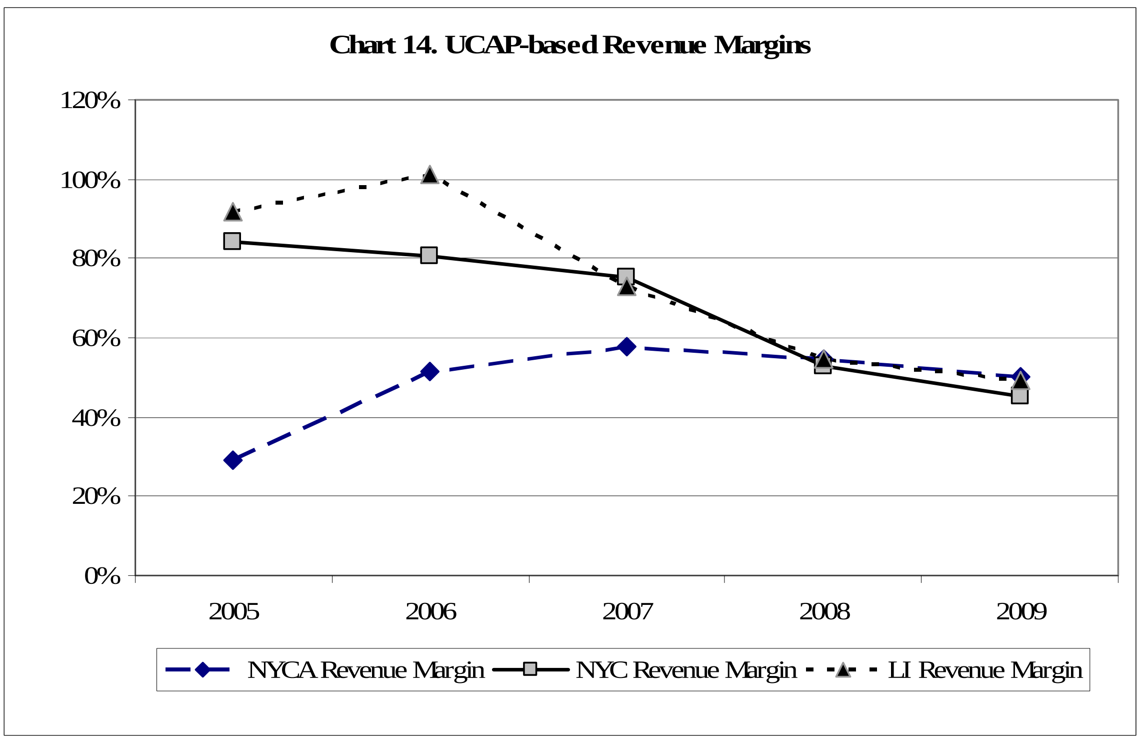
	2005	**2006**	**2007**	**2008**	**2009**
NYCA	29%	52%	58%	55%	50%
NYC	84%	80%	75%	53%	45%
LI	92%	101%	73%	55%	49%

Even though revenues remain well below what is necessary to attract new entry of a hypothetical benchmark GT in all three capacity zones, there is a disparity in the trends. Rest of State has seen stabilization in the percentage of revenue needed to attract new entry. Both New York City and Long Island, however, have experienced a steady decline in the revenues earned by a hypothetical unit relative to the respective CONE. The significant drop in ICAP Spot

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

Market prices explains acceleration in the decline in revenue margins for New York City and Long Island.

To assess whether revenue streams are adequate given the degree of need for new capacity, data from Tables 4 and 7 are graphed below, showing revenue (Chart 14) and capacity (Chart 15) margins. Chart 16 plots the installed capacity revenue component of the total net revenue as a percentage of the net cost of new entry in each region/locality. In Chart 15, the high levels of excess capacity in 2008 and 2009 do not lead to corresponding precipitous declines in capacity revenue due to the interaction of the Long Island and NYCA demand curves, where Long Island capacity will be valued at the greater of the NYCA or LI clearing price. All three areas exhibit declining trends in revenue margins. If such conditions persist for an extended period, it is reasonable to expect levels of excess capacity to decline, as is the case for New York City and Long Island. However, the decline in revenue margin is ameliorated in part by the market signals provided by the Demand Curves, which is apparent from the increased capacity market revenue relative to CONE for New York City and NYCA shown in Chart 16.



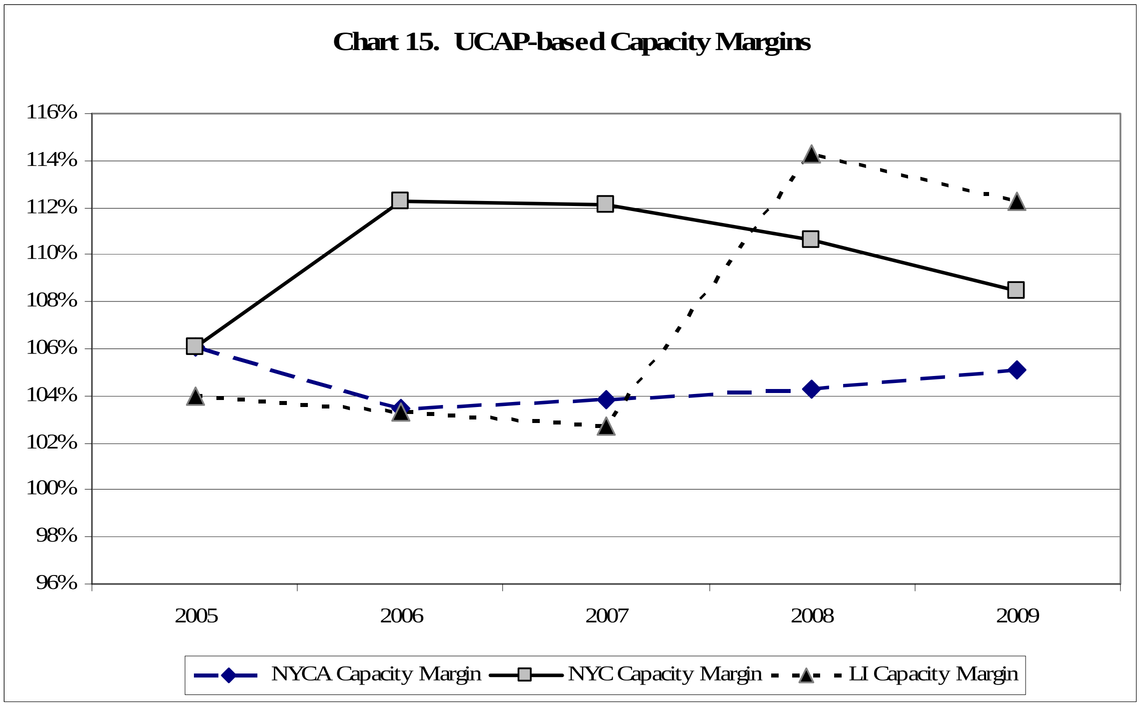


Chart 15. UCAP-based Capacity Margins
116%
114%
112%
110%
108%
106%
104%
102%
100%
98%
96%
2005
2006
2007
2008
2009
NYCA Capacity Margin
NYC Capacity Margin
LI Capacity Margin

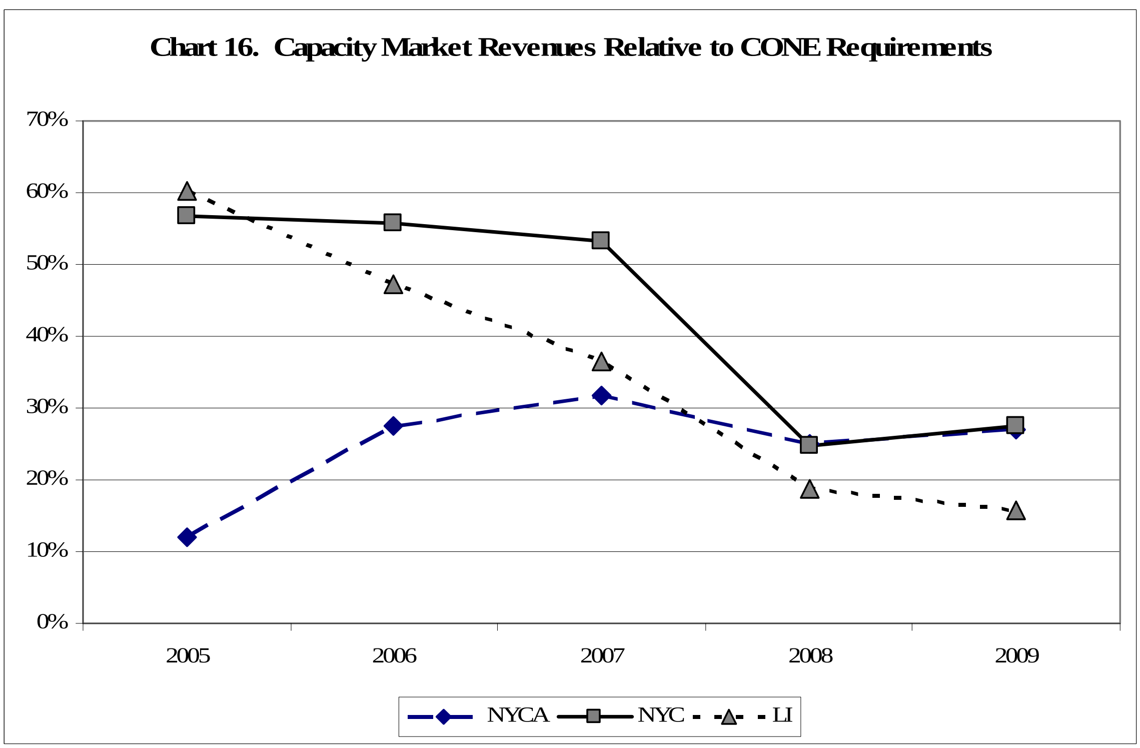


Chart 16. Capacity Market Revenues Relative to CONE Requirements
70%
60%
50%
40%
30%
20%
10%
0%
2005
2006
2007
2008
2009
NYCA
NYC
LI

Appendix A

Figure 1.a.

November 1999 – December 2009
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.

November 1999 – December 2009
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)

November 1999 – December 2009
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
January-08	3064.4	$1.91	3753.2	$2.25	7053.4	$3.40	36819.2	2477.3
February-08	3064.4	$1.91	3065.0	$2.50	6848.0	$3.18	36819.2	2602.7
March-08	3064.4	$1.91	4215.1	$1.48	8288.3	$1.05	36819.2	3818.1
April-08	3064.4	$1.91	4308.8	$1.17	7759.5	$0.75	36819.2	3989.6
May-08	2994.7	$2.67	1851.8	$2.80	8294.8	$2.60	36632.5	3080.6
June-08	2994.7	$2.67	2460.9	$2.87	7684.7	$2.94	36632.5	2909.9
July-08	2994.7	$2.67	1972.8	$2.96	8324.1	$2.80	36632.5	2981.6
August-08	2994.7	$2.67	2542.7	$2.87	7451.6	$2.70	36632.5	3030.1
September-08	2994.7	$2.67	3494.7	$2.73	6766.6	$2.45	36632.5	3156.4
October-08	2994.7	$2.67	3526.1	$2.55	6944.8	$1.93	36632.5	3418.3
November-08	2810.1	$1.77	2596.0	$1.60	9114.6	$1.00	36492.6	3879.7
December-08	2810.1	$1.77	2200.1	$1.50	9113.9	$1.25	36492.6	3766.6

Figure 1.a. (cont'd)

November 1999 – December 2009
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-09	2810.1	$1.77	2987.3	$1.50	6134.4	$3.19	36492.6	2816.8
February-09	2810.1	$1.77	3863.7	$2.50	5837.4	$1.77	36492.6	3505.6
March-09	2810.1	$1.77	3574.6	$1.10	5781.5	$0.50	36492.6	4142
April-09	2810.1	$1.77	3691.3	$0.50	5849.7	$0.30	36492.6	4230.3
May-09	2371.1	$3.01	2500.2	$3.01	7374.3	$2.61	36362.4	3222.7
June-09	2371.1	$3.01	2989.3	$3.50	7545.3	$4.22	36362.4	2509.4
July-09	2371.1	$3.01	3810.6	$4.11	6357.9	$4.42	36362.4	2435.6
August-09	2371.1	$3.01	4354.5	$4.19	5789.5	$3.42	36362.4	2901.2
September-09	2371.1	$3.01	4298.0	$3.49	5838.0	$2.76	36362.4	3169.6
October-09	2371.1	$3.01	4777.6	$2.59	5533.5	$2.23	36362.4	3387.2
November-09	3201.1	$1.75	2375.5	$1.55	6845.8	$0.50	35785.3	5083.7
December-09	3201.1	$1.75	2908.1	$1.30	6162.9	$0.75	35785.3	3990.6

Figure 2.a.

November 1999 – December 2009
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYC	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. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYC	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)

November 1999 – December 2009
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYC	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
January-08	908.2	$5.32	1551.7	$5.43	4662.5	$5.77	8870.8	1009.5
February-08	908.2	$5.32	1388.9	$5.57	4442.2	$5.77	8870.8	1009.5
March-08	908.2	$5.32	3039.2	$3.78	3348.7	$1.05	8870.8	1494.9
April-08	908.2	$5.32	3696.4	$2.74	2964.9	$0.75	8870.8	1591.6
May-08	494.9	$6.50	903.4	$6.52	4987.2	$5.53	8910.6	985.9
June-08	494.9	$6.50	2100.2	$5.65	3745.8	$6.03	8910.6	930.1
July-08	494.9	$6.50	2071.5	$5.86	3758.3	$6.33	8910.6	896.9
August-08	494.9	$6.50	2490.8	$6.03	3349.2	$6.17	8910.6	914.8
September-08	494.9	$6.50	2790.4	$5.92	3083.4	$5.98	8910.6	935.7
October-08	494.9	$6.50	2652.6	$5.88	3230.1	$5.83	8910.6	951.9
November-08	1260.8	$2.79	1378.2	$2.28	3974.3	$1.52	9003.4	1447.5
December-08	1260.8	$2.79	1234.1	$1.59	4186.0	$1.25	9003.4	1586.8

Figure 2.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYC	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess
								Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-09	1260.8	$2.79	1559.5	$1.51	4151.0	$3.19	9003.4	1599.3
February-09	1260.8	$2.79	2094.1	$3.06	3729.9	$1.77	9003.4	1644.8
March-09	1260.8	$2.79	1867.6	$1.49	3622.8	$0.50	9003.4	1647.2
April-09	1260.8	$2.79	1706.0	$0.75	3755.6	$0.30	9003.4	1586.9
May-09	436.7	$6.75	757.9	$7.00	4976.3	$8.72	8855.3	707.3
June-09	436.7	$6.75	1782.7	$8.60	3854.3	$8.65	8855.3	714.2
July-09	436.7	$6.75	2593.8	$8.71	2930.4	$8.47	8855.3	733.1
August-09	436.7	$6.75	2509	$8.52	2960.2	$8.45	8855.3	755.1
September-09	436.7	$6.75	2162.5	$8.40	3403.2	$7.65	8855.3	816.4
October-09	436.7	$6.75	2495.1	$7.62	2926.6	$7.70	8855.3	811.1
November-09	825.2	$4.65	2274.7	$1.94	3124.0	$1.23	8551.6	1422.3
December-09	825.2	$4.65	1757.6	$1.68	3607	$0.76	8551.6	1467.4

Figure 3.a.

November 1999 – December 2009
Installed Capacity Auction Activity
Long Island Locality (LI) Capacity

LI	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 3.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
Long Island Locality (LI) Capacity

LI	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 3.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
Long Island Locality (LI) Capacity

LI	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	$0.00	2.0	$3.50	631.5	$4.31	4972.5	630.6
December-07	0.0	$0.00	0.0	$0.00	635.9	$4.27	4972.5	633.0
January-08	0.0	$0.00	1.9	$3.70	640.3	$4.20	4972.5	637.4
February-08	0.0	$0.00	7.2	$3.00	645.1	$4.07	4972.5	645.1
March-08	0.0	$0.00	2.8	$0.00	648.5	$4.02	4972.5	648.5
April-08	0.0	$0.00	2.8	$0.00	648.8	$4.01	4972.5	648.8
May-08	0.0	$2.80	21.8	$2.80	652.1	$2.60	4684.9	650.8
June-08	0.0	$2.80	130.5	$2.88	644.9	$2.94	4684.9	583.3
July-08	0.0	$2.80	168.2	$2.94	653.4	$2.80	4684.9	650.8
August-08	0.0	$2.80	165.7	$2.86	657.4	$2.70	4684.9	656.3
September-08	0.0	$2.80	102.0	$2.80	659.4	$2.45	4684.9	658.9
October-08	0.0	$2.80	108.2	$2.77	668.7	$1.93	4684.9	668.7
November-08	0.3	$1.77	1.8	$1.60	772.8	$1.00	4566.1	854.3
December-08	0.3	$1.77	10.0	$1.50	802.4	$1.25	4566.1	880.0

Figure 3.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
Long Island Locality (LI) Capacity

LI	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess
								Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-09	0.3	$1.77	210.8	$1.50	847.0	$3.19	4566.1	774.6
February-09	0.3	$1.77	135.6	$2.50	821.1	$1.77	4566.1	891.1
March-09	0.3	$1.77	117.7	$1.10	849.1	$0.50	4566.1	887.9
April-09	0.3	$1.77	88.5	$0.50	821.1	$0.30	4566.1	917.7
May-09	53.3	$3.01	69.5	$3.01	414.8	$4.71	4748.5	416.3
June-09	53.3	$3.01	46.5	$3.50	415.8	$4.65	4748.5	419.7
July-09	53.3	$3.01	75.9	$4.11	404.9	$4.77	4748.5	419.2
August-09	53.3	$3.01	72.9	$4.19	717.8	$3.42	4748.5	740.6
September-09	53.3	$3.01	73.5	$3.49	742.9	$2.76	4748.5	749.0
October-09	53.3	$3.01	48.9	$2.59	749.3	$2.23	4748.5	749.7
November-09	35.0	$1.75	31.0	$1.55	843.5	$0.50	4685.0	986.9
December-09	35.0	$1.75	124.0	$1.30	875.3	$0.75	4685.0	992.1

Section III - Attachment 1
Public

AUCTION_	AUCTION_MONTH	LOCATION	OFFER_CAPACITY	OFFER_PRICE	PTID_NAME	AWARDED_CAPACITY	MARKET_CLEARING_PRICE	UNSOLD
Spot	11/1/2008	ROS	64.1	1.25	Unit_1	0	1	64.1
Spot	11/1/2008	ROS	58.3	1.3	Unit_2	0	1	58.3
Spot	11/1/2008	ROS	123.6	1	Unit_3	44.037	1	79.563
Spot	11/1/2008	ROS	104	1.25	Unit_8	0	1	104
Spot	11/1/2008	ROS	0.5	1.3	Unit_14	0	1	0.5
		Offered	350.5		Awarded	44.0		
					Unsold	306.5		

AUCTION_	AUCTION_	LOCATION	OFFER_CAPACITY	OFFER_PRICE	PTID_NAME	AWARDED_CAPACITY	MARKET_CLEARING_PRICE	UNSOLD
Spot	12/1/2008	ROS	123.6	1.25	Unit_3	12.179	1.25	111.421
Spot	12/1/2008	ROS	58.3	1.35	Unit_2	0	1.25	58.3
Spot	12/1/2008	ROS	18.6	1.35	Unit_6	0	1.25	18.6
Spot	12/1/2008	ROS	2.4	1.3	Unit_14	0	1.25	2.4
		Offered	202.9		Awarded	12.2		
					Unsold	190.7		

AUCTION_	AUCTION_MONTH	LOCATION	OFFER_CAPACITY	OFFER_PRICE	PTID_NAME	AWARDED_CAPACITY	MARKET_CLEARING_PRICE	UNSOLD
Spot	2/1/2009	ROS	123.6	2	Unit_3	0	1.77	123.6
Spot	2/1/2009	ROS	56.5	2.5	Unit_2	0	1.77	56.5
		Offered	180.1		Awarded	0		
					Unsold	180.1		

AUCTION_	AUCTION_	LOCATION	OFFER_CAPACITY	OFFER_PRICE	PTID_NAME	AWARDED_CAPACITY	MARKET_CLEARING_PRICE	UNSOLD
Spot	3/1/2009	ROS	123.6	0.5	Unit_3	111.366	0.5	12.234
Spot	3/1/2009	ROS	58.3	0.75	Unit_2	0	0.5	58.3
Spot	3/1/2009	ROS	64.1	0.85	Unit_1	0	0.5	64.1
Spot	3/1/2009	ROS	5.6	1	Unit_5	0	0.5	5.6
Spot	3/1/2009	ROS	100	0.5	Unit_8	90.102	0.5	9.898
Spot	3/1/2009	ROS	43.7	1	Unit_6	0	0.5	43.7
Spot	3/1/2009	ROS	274.7	0.5	Unit_7	247.51	0.5	27.19
Spot	3/1/2009	ROS	20	1	Unit_9	0	0.5	20
Spot	3/1/2009	ROS	10.2	0.6	Unir_15	0	0.5	10.2
Spot	3/1/2009	ROS	1.5	0.64	Unit_16	0	0.5	1.5
Spot	3/1/2009	ROS	0.2	1	Unit_17	0	0.5	0.2
Spot	3/1/2009	ROS	0.9	0.5	Unit_18	0.811	0.5	0.089
Spot	3/1/2009	ROS	0.5	0.5	Unit_19	0.45	0.5	0.05
Spot	3/1/2009	ROS	2.2	0.5	Unit_20	1.982	0.5	0.218
Spot	3/1/2009	ROS	2.1	0.5	Unit_21	1.892	0.5	0.208
		Offered	707.6		Awarded	454.1		
					Unsold	253.5		

AUCTION_	AUCTION_	LOCATION	OFFER_CAPACITY	OFFER_PRICE	PTID_NAME	AWARDED_CAPACITY	MARKET_CLEARING_PRICE	UNSOLD
Spot	4/1/2009	ROS	47.5	0.4	Unit_2	0	0.3	47.5
Spot	4/1/2009	ROS	100	0.46	Unit_8	0	0.3	100
Spot	4/1/2009	ROS	18.5	0.3	Unit_32	9.349	0.3	9.151
Spot	4/1/2009	ROS	10.2	0.6	Unit_15	0	0.3	10.2
Spot	4/1/2009	ROS	0.2	1	Unit_17	0	0.3	0.2
		Offered	176.4		Awarded	9.3		
					Unsold	167.1		

AUCTION_	AUCTION_	LOCATION	OFFER_CAPACITY	OFFER_PRICE	PTID_NAME	AWARDED_CAPACITY	MARKET_CLEARING_PRICE	UNSOLD
Spot	11/1/2009	ROS	50	1.25	Unit_4	0	0.5	50
Spot	11/1/2009	ROS	50	1	Unit_4	0	0.5	50
Spot	11/1/2009	ROS	50	0.75	Unit_4	0	0.5	50
Spot	11/1/2009	ROS	50	0.5	Unit_4	48.208	0.5	1.792
Spot	11/1/2009	ROS	1	1.73	Unit_9	0	0.5	1
Spot	11/1/2009	ROS	1	1.56	Unit_9	0	0.5	1
Spot	11/1/2009	ROS	53	1.06	Unit_9	0	0.5	53
Spot	11/1/2009	ROS	42.2	0.5	Unit_10	40.688	0.5	1.512
Spot	11/1/2009	ROS	71	0.55	Unit_11	0	0.5	71
Spot	11/1/2009	ROS	806.7	0.5	Unit_12	777.79	0.5	28.91
Spot	11/1/2009	ROS	1.7	0.5	Unit_13	1.639	0.5	0.061
Spot	11/1/2009	ROS	14	0.6	Unit_15	0	0.5	14
Spot	11/1/2009	ROS	15	0.5	Unit_22	14.462	0.5	0.538
Spot	11/1/2009	ROS	0.3	1	Unit_23	0	0.5	0.3
Spot	11/1/2009	ROS	0.8	1	Unit_24	0	0.5	0.8
Spot	11/1/2009	ROS	0.1	1	Unit_25	0	0.5	0.1
Spot	11/1/2009	ROS	3.6	1	Unit_26	0	0.5	3.6
Spot	11/1/2009	ROS	0.2	1	Unit_27	0	0.5	0.2
Spot	11/1/2009	ROS	0.6	1	Unit_28	0	0.5	0.6
Spot	11/1/2009	ROS	0.6	1	Unit_29	0	0.5	0.6
Spot	11/1/2009	ROS	0.9	0.5	Unit_30	0.868	0.5	0.032
Spot	11/1/2009	ROS	1.2	0.5	Unit_31	1.157	0.5	0.043
			1213.9		Awarded	884.8		
					Unsold	329.1		

Annual Avoidable Costs for a Mothballed Unit	November 2008 - October 2009 (2009$)			
	Class B ROS	**Class F ROS**	**Class H ROS**	**Class I ROS**
Technology	Combined Cycle Cogeneration	Steam Electric	Steam Electric	Steam Electric Cogeneration
Primary Fuel	Natural Gas	#6 Fuel Oil	Coal	Coal
Total Units in Group	22	7	15	4
Dual-Fueled Units in Group	5	4	3	1
Average Capacity Factor	19.5%	2.1%	78.2%	75.1%
Average In-Service Date	19-Nov-1992	18-Dec-1968	8-Sep-1957	24-Apr-1975
Average Plant Performance				
Net Plant Capacity - Summer (MW)	113	432	170	42
Net Plant Capacity - Winter (MW)	130	437	170	42
Net Plant Capacity - Summer/Winter Avg. (MW)	122	435	170	42
Fixed O&M Assumptions				
Average Labor Rate, incl. Benefits ($/hour)	54.34	54.34	54.34	54.34
Number of Operating and Maintenance Staff (full-time equi	9.0	32.0	41.0	19.0
Labor - Routine O&M ($/year)	1,017,250	3,616,889	4,634,139	2,147,528
Materials and Contract Services - Routine ($/yea	978,788	6,307,744	2,325,165	976,613
Administrative and General ($/year)	206,633	587,273	775,418	325,175
Other Fixed Cost Assumptions				
Insurance Rate	0.30%	0.30%	0.30%	0.30%
Market value of plant ($/kW)	1,474	761	870	1,088
Insurance ($/year)	607,972	1,054,872	459,534	150,652
Avoidable Cost Percentages - Mothball				
Labor - Routine O&M	73.4%	75.4%	88.7%	88.7%
Materials and Contract Services - Routine	90.0%	90.0%	90.0%	90.0%
Administrative and General	61.4%	80.1%	90.2%	90.2%
Insurance	60.0%	60.0%	60.0%	60.0%
PJM Category for Percent Avoidable	Combined Cycle Cogeneration Frame B or E	Oil and Gas Steam	Subcritical Coal	Subcritical Coal
Avoidable Costs - Mothball ($/year)				
Labor - Routine O&M	746,356	2,727,906	4,111,015	1,905,072
Materials and Contract Services - Routine	880,909	5,676,970	2,092,648	878,952
Administrative and General	126,893	470,156	699,151	293,178
Insurance	364,783	632,923	275,721	90,391
Total	2,118,942	9,507,956	7,178,535	3,167,592
$/kW-year	**17.43**	**21.86**	**42.34**	**75.08**

Going Forward Costs with Revenue Uncertainty and Owner-Identified Adjustments	November 2008 - October 2009 (2009$)			
	Class B ROS	**Class F ROS**	**Class H ROS**	**Class I ROS**
Technology	Combined Cycle Cogeneration	Steam Electric	Steam Electric	Steam Electric Cogeneratio
Primary Fuel	Natural Gas	#6 Fuel Oil	Coal	Coal
Avoidable Costs - Mothball ($/kW-yr) - ***from Exhibit B***	**17.43**	**21.86**	**42.34**	**75.08**
Avoidable Costs - Mothball ($/kW-yr) - UCAP basis[1]	**18.79**	**23.57**	**45.66**	**80.97**
Net Revenues ($/kW-yr) - Actual	**1.75**	**0.00**	**6.88**	**85.15**
Going Forward Cost with Revenue Uncertainty				
G oing Forward costs minus full Net Revenue ($/kW-yr)	**17.04**	**23.57**	**38.77**	**(4.18)**
Summer ($/kW-mon)	1.91	2.65	4.35	(0.47)
Winter ($/kW-mon)	0.93	1.28	2.11	(0.23)
Going Forward costs minus half Net Revenue ($/kW-yr)	**17.91**	**23.57**	**42.22**	**38.39**
Summer ($/kW-mon)	2.01	2.65	4.74	4.31
Winter ($/kW-mon)	0.97	1.28	2.30	2.09
Going Forward costs minus zero Net Revenue ($/kW-yr)	**18.79**	**23.57**	**45.66**	**80.97**
Summer ($/kW-mon)	2.11	2.65	5.13	9.09
Winter ($/kW-mon)	1.02	1.28	2.48	4.40
Going Forward Costs with Revenue Uncertainty and Owner Adjustments[2]				
Going Forward Costs minus full or zero Net Revenue and no adjustments or recognized adjustments are the same as above				
Going Forward Costs minus full Net Revenues with All Adjustments ($/kW-yr)		**38.64**	**71.12**	
Summer ($/kW-mon)		4.34	7.99	
Winter ($/kW-mon)		2.10	3.87	
Going Forward Costs minus zero Net Revenues with All Adjustments ($/kW-yr)		**38.64**	**78.00**	
Summer ($/kW-mon)		4.34	8.76	
Winter ($/kW-mon)		2.10	4.24	

Notes

1. All remaining values in Exhibit D also are on a UCAP basis
2. Only owners of generating units in Class F and Class H reported additional going forward costs.

EXISTING GENERATING FACILITIES

REF. NO.	Owner Operator and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YYYY-MM-DD	Name Plate Rating (KW)	2007 Capability (kilowatts) SUM 2007	WIN 2007	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Fuel Type 2	Fuel Type 3	2006 Net Energy MWh	Capacity Factor
	2009 Capability Year																				
1082	Carr Street Generating Station LP	Carr St.-E. Syr		C	24060	Dewitt	067	36	1993-08-01	122,600	86,000	102,600	Y	CC			NG			28,663	3.47%
1126	Dynegy Power Marketing, Inc.	Independence		C	23800	Scriba	075	36	1994-11-01	1,254,000	954,400	1,105,600	Y	CC			NG			1,201,196	13.31%
1129	Energy Systems North East LLC	Energy Systems North East		A	23901	North East	049	42	1992-08-01	88,200	74,500	83,700	Y	CC			NG			10,077	1.45%
1136	EPCOR Energy Marketing (US) Inc.	Fort Orange		F	23900	Castleton	083	36	1992-01-01	72,000	62,100	70,900	Y	CC			NG			84,787	14.55%
1312	Hess Corporation	Binghamton Cogen		C	23790	Binghamton	007	36	2001-03-01	47,700	40,900	49,400	Y	CC			NG	FO2		1,744	0.44%
1313	Indeck Energy Services of Silver Sprin	Indeck-Silver Springs		C	23768	Silver Springs	121	36	1991-04-01	56,600	50,100	64,200	Y	CC			NG	FO2		6,662	1.33%
1314	Indeck-Corinth LP	Indeck-Corinth		F	23802	Corinth	091	36	1995-07-01	147,000	129,300	132,000	Y	CC		Y	NG	FO2		810,701	70.83%
1315	Indeck-Olean LP	Indeck-Olean		A	23982	Olean	009	36	1993-12-01	90,600	77,800	86,000	Y	CC			NG			288,683	40.24%
1316	Indeck-Oswego LP	Indeck-Oswego		C	23783	Oswego	075	36	1990-05-01	57,400	51,100	63,000	Y	CC			NG			11,341	2.27%
1317	Indeck-Yerkes LP	Indeck-Yerkes		A	23781	Tonawanda	029	36	1990-02-01	59,900	49,700	57,900	Y	CC			NG			6,695	1.42%
1322	Integrys Energy Services, Inc.	Beaver Falls		E	23983	Beaver Falls	049	36	1995-03-01	107,800	80,200	86,200	Y	CC			NG			11,224	1.54%
1324	Integrys Energy Services, Inc.	Syracuse		C	23985	Syracuse	067	36	1993-09-01	102,700	85,800	92,500	Y	CC			NG			23,405	3.00%
1509	Niagara Mohawk Power Corp.	Fortistar - N.Tonawanda		A	24026	N Tonawanda	029	36	1993-06-01	55,300	52,000	62,100	Y	CC			NG			12,618	2.52%
1510	Niagara Mohawk Power Corp.	General Mills Inc		A	23808		029	36	1988-12-01	3,800	3,800	3,800	Y	CC			NG			2,305	6.92%
1576	Niagara Mohawk Power Corp.	Nottingham High School		C	23634		067	36	1988-06-01	200	200	200	Y	CC			NG			0	0.00%
1641	NYSEG Solutions, Inc.	Carthage Energy		E	23857	Carthage	045	36	1991-08-01	62,900	56,900	66,800	Y	CC			NG			4,779	0.88%
1647	Power City Partners, L.P.	Massena		D	23902	Massena	089	36	1992-07-01	101,800	81,400	92,000	Y	CC			NG	FO2		3,611	0.48%
1677	Selkirk Cogen Partners, L.P.	Selkirk-I		F	23801	Selkirk	001	36	1992-03-01	95,000	77,600	107,000	Y	CC			NG			457,754	56.61%
1678	Selkirk Cogen Partners, L.P.	Selkirk-II		F	23799	Selkirk	001	36	1994-09-01	262,600	291,300	332,400	Y	CC			NG	FO2		1,578,349	57.78%
1682	Seneca Power Partners, L.P.	Batavia		B	24024	Batavia	037	36	1992-06-01	67,300	50,100	62,100	Y	CC			NG			5,220	1.06%
1700	Shell Energy North America (US), L.P.	Rensselaer Cogen		F	23796	Rensselaer	083	36	1993-12-01	103,700	79,000	81,300	Y	CC			NG			4,924	0.70%
1701	Sterling Power Partners, L.P.	Sterling		E	23777	Sherrill	065	36	1991-06-01	65,300	50,600	63,900	Y	CC			NG			4,093	0.82%
	Class B Averages								**1992-11-19**	**137,473**	**112,945**	**130,255**								**207,220**	**19.45%**
1120	Dynegy Power Marketing, Inc.	Danskammer 1		G	23586	Newburgh	071	36	1951-12-01	72,000	67,000	66,700	N	ST	T	A	FO6	NG	FO2	5,903	1.01%
1127	Dynegy Power Marketing, Inc.	Roseton 1		G	23587	Newburgh	071	36	1974-12-01	621,000	614,500	618,500	N	ST	T	A	FO6	NG	FO2	145,620	2.70%
1128	Dynegy Power Marketing, Inc.	Roseton 2		G	23588	Newburgh	071	36	1974-09-01	621,000	605,700	610,500	N	ST	T	A	FO6	NG	FO2	300,963	5.65%
1121	Dynegy Power Marketing, Inc.	Danskammer 2		G	23589	Newburgh	071	36	1954-09-01	73,500	61,700	63,200	N	ST	T	A	FO6	NG	FO2	6,920	1.26%
1636	NRG Power Marketing LLC	Oswego 5		C	23606	Oswego	075	36	1976-02-01	901,800	837,700	851,700	N	ST	W	A	FO6			42,957	0.58%
1637	NRG Power Marketing LLC	Oswego 6		C	23613	Oswego	075	36	1980-07-01	901,800	833,200	843,500	N	ST	W	A	FO6			48,941	0.67%
1325	International Paper Company	Ticonderoga Mill		F	23804	Ticonderoga	031	36	1970-01-01	42,100	7,600	7,700	Y	ST			FO6			100	0.15%
	Class F Averages								**1968-12-18**	**461,886**	**432,486**	**437,400**								**78,772**	**2.07%**

EXISTING GENERATING FACILITIES

REF. NO.	Owner Operator and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YYYY-MM-DD	Name Plate Rating (KW)	2007 Capability (kilowatts) SUM 2007	WIN 2007	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Fuel Type 2	Fuel Type 3	2006 Net Energy MWh	Capacity Factor
	2009 Capability Year																				
1007	AES Eastern Energy, LP	Somerset		A	23543	Somerset	063	36	1984-08-01	655,100	682,800	682,600	N	ST	W	A	BIT			5,232,866	87.50%
1633	NRG Power Marketing LLC	Huntley 67		A	23561	Tonawanda	029	36	1957-12-01	218,000	187,200	190,000	N	ST	T	A	BIT			1,233,783	74.68%
1634	NRG Power Marketing LLC	Huntley 68		A	23562	Tonawanda	029	36	1958-12-01	218,000	188,000	190,000	N	ST	T	A	BIT			1,192,950	72.05%
1628	NRG Power Marketing LLC	Dunkirk 1		A	23563	Dunkirk	013	36	1950-11-01	80,000	78,400	77,000	N	ST	T	A	BIT			555,102	81.55%
1629	NRG Power Marketing LLC	Dunkirk 2		A	23564	Dunkirk	013	36	1950-12-01	80,000	78,400	75,600	N	ST	T	A	BIT			591,196	87.65%
1630	NRG Power Marketing LLC	Dunkirk 3		A	23565	Dunkirk	013	36	1959-09-01	200,000	189,600	186,500	N	ST	T	A	BIT			1,274,208	77.35%
1631	NRG Power Marketing LLC	Dunkirk 4		A	23566	Dunkirk	013	36	1960-08-01	200,000	188,400	186,800	N	ST	T	A	BIT			1,282,763	78.06%
1008	AES Eastern Energy, LP	Westover 7		C	23579	Union	007	36	1944-01-01	75,000	40,200	40,900	N	ST	W	A	BIT			5,515	1.55%
1009	AES Eastern Energy, LP	Westover 8		C	23580	Union	007	36	1951-12-01	43,800	80,900	82,200	N	ST	T	A	BIT			492,424	68.93%
1005	AES Eastern Energy, LP	Greenidge 3		C	23582	Torrey	123	36	1950-04-01	50,000	52,000	48,200	N	ST	W	A	BIT			36,867	8.40%
1006	AES Eastern Energy, LP	Greenidge 4		C	23583	Torrey	123	36	1953-12-01	112,000	103,500	104,100	N	ST	T	A	BIT	WD	NG	671,519	73.85%
1001	AES Eastern Energy, LP	Cayuga 1		C	23584	Lansing	109	36	1955-09-01	167,200	152,300	154,200	N	ST	T	A	BIT			1,090,337	81.22%
1002	AES Eastern Energy, LP	Cayuga 2		C	23585	Lansing	109	36	1958-10-01	155,300	153,800	155,200	N	ST	T	A	BIT			1,087,990	80.39%
1122	Dynegy Power Marketing, Inc.	Danskammer 3		G	23590	Newburgh	071	36	1959-10-01	147,100	132,000	134,200	N	ST	T	A	BIT	NG	FO2	1,002,316	85.97%
1123	Dynegy Power Marketing, Inc.	Danskammer 4		G	23591	Newburgh	071	36	1967-09-01	239,400	235,200	236,500	N	ST	T	A	BIT	NG	FO2	1,664,222	80.55%
	Class H Averages								**1957-09-08**	**176,060**	**169,513**	**169,600**								**1,160,937**	**78.16%**
1326	Jamestown Board of Public Utilitie	Jamestown 5		A	1658	Jamestown	013	36	1951-08-01	28,700	22,820	23,300	Y	ST			BIT			121,659	60.2%
1327	Jamestown Board of Public Utilitie	Jamestown 6		A	1658	Jamestown	013	36	1968-08-01	25,000	19,880	20,300	Y	ST			BIT				0.0%
1692	Shell Energy North America (US),	Fort Drum		E	23780	Watertown	045	36	1989-07-01	58,000	55,600	56,200	Y	ST			BIT			459,978	93.9%
1723	Trigen-Syracuse Energy Corp.	Syracuse Energy ST1		C	323597	Syracuse	067	36	1991-08-01	73,000	69,900	69,500	Y	ST			BIT	FO2		250,753	41.1%
	Class I Averages								1975-04-24	46,175	42,050	42,325								277,463	75.1%