NEW YORK INDEPENDENT SYSTEM OPERATOR

290 Washington Avenue Extension, Albany, New York 12203

December 1, 2003

E-FILED

The Honorable Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

New York Independent System Operator, Inc.
Bi-Annual Compliance Report on Demand Response Programs and the Addition of New Generation in Docket No. ER01-3001-00_

Dear Ms. Salas:

Pursuant to Ordering Paragraph "(B)" of the October 25, 2001 Order in this proceeding (the "Initial Order"),[1] Ordering Paragraph "(C)" of the July 19, 2002 Order in this proceeding (the "July 19, 2002 Order"),[2] paragraph 5 of the September 3, 2002 letter order in this proceeding (the "September 3, 2002 Order"),[3] and paragraph 7 of the October 24, 2003 Order in this Proceeding (the "October 24, 2003 Order),[4] the New York Independent System Operator, Inc. ("NYISO"), by counsel, hereby submits this report. The report addresses: (i) the NYISO's existing demand response programs, the status of real-time demand response mechanisms, and the effects of demand response programs on wholesale prices; and (ii) the status of new generation resources in the New York Control Area ("NYCA").[5] This submittal represents the NYISO's fifth report in compliance with the Initial Order and the subsequent orders listed above.

I. List of Documents Submitted

The NYISO submits the following documents:

1. This filing letter;

---

1 *New York Independent System Operator, Inc.*, 97 FERC ¶ 61, 095 (2001).

2 *New York Independent System Operator, Inc.*, 100 FERC ¶ 61, 081 (2002).

3 *New York Independent System Operator, Inc.*, 100 FERC ¶ 61,243 (2002).

4 *New York Independent System Operator, Inc.*, 105 FERC ¶ 61,115 (2003).

5 Capitalized terms not otherwise defined herein shall have the meaning set forth in Article 2 of the NYISO's Market Administration and Control Area Services Tariff.

2. A report entitled "NYISO 2003 Demand Response Programs" ("Attachment I");

3. Tables summarizing the load and capacity outlook for the entire NYCA, New York City and Long Island ("Attachment II");

4. A table listing proposed new interconnections in the NYCA ("Attachment III");

5. A table, prepared by the New York State Department of Public Service, listing proposed new power plant projects that have been reviewed pursuant to New York State's "Article X" process ("Attachment IV");

6. A presentation version of the NYISO's *Power Alert III* (Attachment V); and,

7. A form of *Federal Register* Notice ("Attachment VI").

II. Copies of Correspondence

Copies of correspondence concerning this filing should be served on:

Robert E. Fernandez, General Counsel and Secretary
Belinda F. Thornton, Director of Regulatory Affairs
Gerald R. Deaver, Senior Attorney
New York Independent System Operator, Inc.
3890 Carman Road, Schenectady, NY 12303
Tel: (518) 356-6153
Fax: (518) 356-4702
rfernandez@nyiso.com
bthornton@nyiso.com
gdeaver@nyiso.com

III. Service List

Copies of this filing are being served on all parties designated on the official service list for this proceeding maintained by the Secretary of the Commission. The NYISO has also mailed a copy of this filing to all parties who have executed Service Agreements under the NYISO's Open-Access Transmission Tariff or its Market Administration and Control Area Services Tariff, and to the electric utility regulatory agencies in New York, New Jersey, and Pennsylvania.

IV. Compliance Report

In the Initial Order in this proceeding, the Commission extended the effectiveness of the NYISO's Temporary Extraordinary Procedures Authority ("TEP") and the $1,000 MWh bid cap on certain types of bids into the NYISO-administered energy markets ("Bid Cap") until certain market conditions were met. Among the reasons for extending the TEP and the Bid Cap, the Commission found that the electric energy supply situation in New York remained tight. The Commission further noted that loads remain unable to reduce purchases in response to dramatic price increases and that experience with the NYISO's demand response programs was insufficient to justify lifting the Bid Caps.[6] Accordingly, the NYISO was directed to file bi-annual reports, beginning December 1, 2001, on the progress of the NYISO's demand response programs, the development of real-time demand response mechanisms, and on the progress of generation additions in New York.[7]

The NYISO's initial report was accepted by the July 19, 2002 Order with the further requirement that the NYISO include information on the effects of demand response programs on wholesale prices in future reports.[8] The September 3, 2002 Order directed the NYISO to indicate which proposed generation projects it regards as likely to enter service at the times indicated in subsequent reports.[9] The October 24, 2003 Order directed the NYISO to include more current publicly available information from other NYISO documents regarding the progress of generation development in New York.[10]

A. Status of NYISO Demand Response Programs for 2003

As in 2002, the NYISO's three demand response programs for the Summer 2003 Capability Period included three specific programs: the Emergency Demand Response Program ("EDRP"), the Day-Ahead Demand Response Program ("DADRP"), and Installed Capacity/ Special Case Resources (ICAP/SCR).

Established under the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff"), the EDRP provides for payments to Curtailment Service Providers that voluntarily reduce their Loads at the NYISO's request to reduce peak demands in the NYCA during an Emergency condition.[11] Also established under the Services Tariff, the

---

6 97 FERC ¶ 61,095 at 8. [Initial Order]

7 *Id.* at 9. [Initial Order]

8 100 FERC ¶ 61,081 at 8. [July 19, 2002 Order]

9 100 FERC ¶ 61,243 at 3. [September 3, 2002 Order]

10 105 FERC ¶ 61,115 at 4. [October 24, 2003 Order]

11 Under the EDRP, qualified demand resources are paid for reducing their energy consumption when the NYISO declares that an operating reserves deficiency or major

DADRP allows Demand Side Resources that are qualified to participate in the competitive Energy markets to bid Load reductions into the Day-Ahead Energy Markets as if such reductions are a competing supply resource.[12] Special Case Resources are the distributed "behind the meter" generators through which some Demand Reduction Providers achieve the Load reductions that are made available to the NYISO.[13] Special Case Resources may also qualify to provide Installed Capacity ("ICAP") in the NYISO's Unforced Capacity markets pursuant to the ICAP provisions of the Services Tariff.

In compliance with the Commission's prior orders in this proceeding, the semi-annual reporting information regarding these demand response programs is provided in Attachment I to this filing. Attachment I is a report analyzing participation in all three programs, response to reserve deficiency/emergency events, program benefits and impact on LBMP, and proposed changes to the EDRP/SCR programs.

In an additional development during 2003 that is not included in Attachment I, the New York Public Service Commission ("NYPSC") instituted a proceeding to evaluate the need for changes in the existing voluntary real-time pricing ("RTP") programs that are currently offered by five of the six major electric utilities operating in New York State. The changes under consideration included implementing mandatory RTP programs for certain customer classes. Anticipating the benefits of increased participation in its own demand response programs, the NYISO had recommended in its comments to the NYPSC that mandatory programs would be appropriate for some customer classes. The NYPSC issued an order on October 30, 2003, however, that directed utilities to place increased emphasis on promoting voluntary RTP programs, but did not expand the use of mandatory RTP programs at this time.

---

emergency exists. There is no obligation to respond to the NYISO's declaration. Participation in the program occurs through "Curtailment Services Providers," which are paid $500/MWh for verified load reductions.

12 The DADRP permits demand resources to submit demand reduction bids in the DAM. These bids are treated the same as suppliers' bids and can set the market clearing price

13 Under the ICAP/SCR, retail electricity customers are paid for making their load reduction capability available over a specified contract period. Thus, ICAP/SCR participants are paid in advance for agreeing in advance to curtail usage during times when the grid could be jeopardized. Unlike, EDRP participants, ICAP/SCR participants are subject to penalties if they fail to curtail on the NYISO's request.

B. Status of Addition of New Generation Resources

The NYISO's semi-annual compliance report regarding the status and progress of the development of new generation resources in New York includes: (i) the three tables of data contained in Attachments II, III, and IV to this filing and discussed in more detail below; (ii) a narrative description of the significant issues currently facing the development of new generation resources; and, Attachment V consisting of a "presentation" version of "Power Alert III," which was released by the NYISO in May of this year and is the third in a series of its annual assessments of energy issues facing New York. The full text of this report is also posted on the NYISO's web site – www.nyiso.com.

1. Attachment II – Forecasted Load and Capacity Data

Attachment II to this filing presents, in the first table of data, the most recent forecasted load and capacity data for New York State as a whole, and for the New York City and Long Island Load Zones, for the Summer 2004 Capability Period.[14] The second, third, and fourth tables in Attachment II identify new generating resources that are currently expected to be on line and available by June 2004 for upstate New York, New York City, and Long Island, respectively.

As the first table indicates, the statewide need for external resources to balance available supplies with forecasted demands for Summer 2004 has increased to 931 MW from the prior report's figure of 703 MW. New York City's deficiency for its locational In-City capacity requirement has increased slightly from the last report to 260 MW. Long Island's available supplies, however, continue to slightly exceed its locational capacity requirements.

With respect to changes from the NYISO's previous semi-annual report, the addition of the Athens Generating Plant, located in Greene County, New York, represents the first instance of the addition of a new generating resource outside of the constrained New York City and Long Island Load Zones in these reports to the Commission. Located in Load Zone F, Athens is a 1,080 MW generating unit that is currently in testing and is expected to be in-service in early 2004.

As of the date of this report, the NYISO is anticipating a planned 250 MW unit at the KeySpan Ravenswood facility to be the only addition of new generation in the New York City Load Zone for Summer 2004. The three gas turbine units that were indicated in the June 2003 report as being expected for the Summer 2003 period did not, in fact, come into service and have been delayed, principally as a result of transmission interconnection limitations. These

---

[14] Summer Capability Periods are the six-month period from May 1 through October 31 of each year. The highest peak demands in the New York Control Area typically occur at some point during a Summer Capability Period.

previously reported units were indicated as "KIAC @JKF", Bay Energy @ Gowanus", and NYC Energy @ Kent."

Four new gas turbines are expected to be in service by June 2004, as indicated in Attachment II. The KeySpan @ Freeport turbine, previously reported as being available for the Summer 2003 period, was delayed to 2004, and the previously reported "PSEG @ North Bellport" unit has been delayed beyond 2004.

2. Attachment III – Proposed Transmission Interconnection Projects

Attachment III is a four-page table of the most current proposed transmission system enhancements in the NYCA. The data presented in this table has not changed from the NYISO's June 2003 report to the Commission. While the proposed enhancements in Attachment III include some that are proposed transmission upgrades for reasons other than new generation, the majority of the proposed projects, in fact, represent new interconnections for proposed generation additions.

As indicated on the last page of Attachment III, 25,392 MW of the interconnection projects under review for New York are related to potential in-state additions of new generation. This table also indicates, however, that only 6,000 MWs of this planned new generation has received the necessary certifications from the New York Public Service Commission ("NYPSC"). Moreover, while the Athens project is anticipated to be in service in early 2004, the proposed in-service dates for the other certified projects are in a range of one to eight years after 2004.

3. Attachment IV – Table of NYPSC Article X Proceedings

As in prior reports, for the Commission's information, the NYISO has also included, as Attachment IV to this filing, a four-page table of applications for siting authority for new generation currently pending before the New York Department of Public Service ("NYPSC"). This table is reproduced from the NYPSC's website and a link to this table is included on the home page of the NYISO's website. This table indicates that approximately 3,100 MWs of already certified Article X projects are under construction, with in-service date estimates ranging from the third quarter of 2003 to 2006. According to the NYPSC's table, the eleven certified projects either under construction or pending construction represent an increase of one project from the NYISO's June 2003 report.

The Commission's September 3, 2002 Order directed the NYISO, in subsequent filings, to indicate which proposed generation projects it regards as "likely" to enter service at the times indicated in the NYISO's report.[15] The projected in-service dates indicated in Attachment IV to this report do not differ at this time from the NYISO's best estimate of when proposed projects will be complete based on all publicly available information. Among other things, the NYISO does not have the information about developers' business strategies, or corporate finances, that would be needed to make an informed prediction independent of the predictions reflected in Attachment IV. Consequently, with the limited information available to it, the NYISO anticipates that the listed projects will achieve their forecasted in-service dates.

4. Significant Issues Facing the Development of Generation Resources

A. Barriers to Development

Under the best of circumstances, the development of a new generating resource in New York State is a challenging undertaking. Several recent circumstances, however, have the potential for creating additional barriers to generation developers and are a concern to the NYISO. These potential barriers, and the NYISO's response to them, encompass both regulatory, business and market issues, and transmission grid operation issues.

(i) Regulatory Uncertainties

As noted in *Power Alert III*, power plant siting was governed largely by local zoning restrictions prior to New York's adoption of Article X of its Public Service Law. Article X was intended, and has proven to be, a means for expediting the siting process by providing a "one-stop" avenue for reviewing and approving power plant site proposals. This law, however, expired on December 31, 2002, and, as yet, has not been renewed by the New York State legislature. Consequently, while the NYPSC will continue its reviews of those projects that submitted applications prior to the expiration of the law, it is uncertain whether a similar expedited licensing process will be available to future generating project proposals.

Creating additional regulatory uncertainties, which, in turn, discourage investment in new generation are the, the unresolved United States Congressional debate over the Commission's Standard Market Design ("SMD") and the continuing tension over jurisdictional issues between Federal and State regulators. Consequently, the NYISO supports the Commission's efforts to develop standard market rules and anticipates the implementation of its own similar SMD 2.0 in the near future.

---

[15] 100 FERC ¶ 61,243 at p. 2. [September 3, 2002 Order]

(ii) Business and Market Issues

In addition to the necessary licenses and permits, new generating projects require significant amounts of capital, the availability of which continues to be a concern to both developers and the NYISO. In *Power Alert* III, the NYISO previously noted that the effects of the disclosures of the corporate accounting and financial scandals in the energy and other industries and the subsequent severe financial problems of some merchant generation companies has impacted the near-term financing for new merchant generation projects.

The New York energy markets reflect an extremely high level of divestiture of generation ownership from traditional operators. These markets, including the competitive markets in neighboring control areas to New York, now govern the entry of new generation in New York State. To ensure that potential developers can, indeed, secure financing and construct new generation resources in New York, the NYISO is endeavoring to develop market rules that produce effective long-term price signals. Such price signals will indicate market revenues, over the long-run equilibrium, sufficient to cover both the market entry costs of new development projects and the ongoing costs of already existing generation units.

The NYISO is concerned, therefore, that in his recently presented Summer 2003 review of the New York electricity markets, the NYISO's Independent Market Advisor, Dr. David B. Patton concluded that net revenues, defined as market revenues net of operating costs, have increased only slightly from 2002 to 2003 for all New York Load Zones. Moreover, capacity revenues have slightly declined in 2003 in all Load Zones. Dr. Patton's analysis also concluded that current market revenues do not provide an adequate economic incentive to construct a new gas turbine generator either within or outside of New York City at this first-year stage of the three-year phase-in of a new ICAP Demand Curve, discussed further below.[16] The expectation, however, is that market revenues would be sufficient with the completion of the Demand Curve phase-in period.

Accordingly, a significant portion of the NYISO's organization resources have and will continue to be devoted to developing and implementing market rules and structures that will provide economically efficient price signals that will provide opportunities for market revenues sufficient to sustain existing generation and attract new generation development. For example, as referenced above, the implementation of the NYISO's SMD 2.0, which includes a new Real-Time Scheduling component, will not only move New York closer to the Commission's vision of standardized markets, but is designed to provide more efficient price signals. Existing generators have been concerned that price signals during supply scarcity conditions in New York have not consistently reflected those scarcity conditions, and both

---

[16] *Summer 2003 Review of the New York Electricity Markets*, presented to October 21, 2003, Joint NYISO Board of Directors and Management Committee Meeting, by Dr. David B. Patton, Independent Market Advisor.

SMD 2.0 and earlier discrete market rule changes already implemented by the NYISO are intended to provide peak demand price signals that adequately reflect the resulting scarcity of energy supplies.

The Commission's approval earlier this year of demand pricing curves for New York's Installed Capacity markets is another example of an effort to develop market rules that will provide market revenues that reflect workable competition while providing economic incentives for new investment.[17] The Commission specifically found that an ICAP Demand Curve will provide better price signals to investors for the construction of new generation, encourage the formation of long-term bilateral transactions (which should further encourage investors), and reduce incentives to withhold capacity.[18] Unforced Capacity Deliverability Rights ("UDRs"), designed within the NYISO's governance process and also approved by the Commission earlier this year, will provide another tool for Installed Capacity suppliers, both current and future, to make their capacity available in the NYISO's historically constrained and, thus, higher-revenue Load Zones.

(iii) Transmission Grid Issues

As the NYISO has noted in numerous venues including *Power Alert III*, an efficient transmission grid is a necessary component of competitive wholesale markets. Thus, the NYISO noted with concern in *Power Alert III* that transmission expansion in New York is still being driven primarily by reliability needs and the interconnection of new generation resources. Conversely, no major proposals for upgrades to the bulk power high-voltage alternating current network to enhance market efficiency and reduce congestion are currently in the licensing or construction process in New York.

In *Power Alert III*, the NYISO included numerous recommendations with respect to transmission issues, including developing increased transmission capability for congested zones, implementing a transmission expansion planning process that facilitates new transmission investment, and addressing cost allocation formulas and cost recovery mechanisms in appropriate forums.

Currently, the NYISO has undertaken or is participating in specific efforts impacting each of the earlier recommendations. The NYISO is encouraging and, where possible, facilitating the development and operation of new high-voltage direct current transmission projects that are designed to provide additional capacity in the congested New York City and Long Island Load Zones. With the full participation of Market Participants through its governance process, the NYISO is presently developing changes to the transmission

---

17 103 FERC ¶ 61,201 (May 20, 2003.)

18 *Id.* at 1.

expansion planning process to facilitate the expansion of New York's transmission grid. Likewise, transmission expansion cost allocation formulas are being reviewed and amended in that process. The NYISO is conducting an extensive stakeholder consultation process during the course of developing its compliance filing with the Commission's generic Transmission Interconnection Order. Finally, the NYISO is endeavoring to provide the Commission with a sound basis for resolving specific disputes in the transmission planning and cost allocation arena, such as in the current proceeding before the Commission regarding transmission cost allocation issues during 2001.[19]

Specific generator concerns with respect to transmission expansion and interconnection have also been noted to the NYISO. For example, during the course of a NYISO analysis of selected bulk power substations that may require increases in circuit breaker capacities based on the Summer 2003 Capability Period, referred to as a "Short Circuit Assessment," numerous issues of dispute have arisen between Transmission Owners and generators in the relevant working groups and committees. Generators were also concerned during 2003 with delays in the completion of the transmission enhancements necessary to accommodate the interconnection of new generators, which resulted in the NYISO's Operating Committee being required to establish system operation protocols that deviate from Day-Ahead Schedules for certain generators in the event of transmission constraints.

5. Status of New Generation Development – Conclusion

The NYISO noted in *Power Alert III* that New York should set a goal of bringing an additional 5,000 to 7,000 MW of new generation on-line by 2008 to enhance reliability, increase competition, and deliver environmental benefits through the retirement of older, more polluting generating units. The NYISO noted at the same time, however, that after the completion of the current "bubble" of approximately 2,500 to 3,500 of generating projects that will likely be constructed, there is little evidence that serious consideration is being given to developing other additional new generation in New York. This continuing shortfall will continue to be the principal driver behind the NYISO's efforts to enhance its demand response programs and to develop and implement market rules that encourage new investment.

[19] See, *KeySpan Energy Development Corporation, et. al. v. New York Independent System Operator, Inc.,* FERC Docket No. EL02-125-000.

V. *Federal Register* Notice

A form of *Federal Register* Notice is provided herewith. A diskette of the Notice is also provided in WordPerfect format.

Respectfully submitted,

/s/ Robert E. Fernandez
Counsel for
New York Independent System Operator, Inc.

Robert E. Fernandez, General Counsel and Secretary
Gerald R. Deaver, Senior Attorney
New York Independent System Operator, Inc.
3890 Carman Road
Schenectady, NY 12303

cc: Daniel L. Larcamp, Director Office of Markets, Tariffs and Rates, Room 8A-01, Tel. (202) 502-6700
Alice M. Fernandez, Director Office of Markets, Tariffs and Rates -- East Division, Room 71-31, Tel. (202) 502-8284
Robert E. Pease, Acting Director of Division of Enforcement, Office of Market Oversight and Enforcement, Room 52-41, Tel. (202) 502-8131
Michael A. Bardee, Lead Counsel for Markets, Tariffs and Rates, Room 101-09, Tel. (202) 502-8068
Stanley P. Wolf, Office of the General Counsel, Room 101-03, Tel. (202) 502-8891

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person that has executed a Service Agreement under the NYISO's Open Access Transmission Tariff or Market Administration and Control Area Services Tariff, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010 (20001).

Dated at Washington, D.C. this 1st day of December, 2003.

/s/ Ted J. Murphy
Ted J. Murphy
Hunton & Williams
1900 K Street, N.W.
Washington, DC 20006-1109
(202) 955-1588

ATTACHMENT I

New York Independent System Operator, Inc.
Semi-Annual Compliance Report on Demand Response Programs and the Addition of New Generation
<u>FERC Docket No. ER-3001-00</u>

NYISO 2003 Demand Response Programs

I. Emergency Demand Response and Special Case Resource Installed Capacity Programs

The NYISO's Emergency Demand Response Program (EDRP) provides participants an opportunity to earn the greater of $500/MWh or the prevailing LBMP for curtailments provided when the NYISO calls upon them. There are no consequences for enrolled participants that fail to curtail. EDRP curtailments, until this year, were called in conjunction with the dispatch of Special Case Resource (SCR) curtailments.

The Installed Capacity/Special Case Resources program allows customers that can meet certification requirements to offer unforced capacity (UCAP) to Load Serving Entities (LSEs) and to the six-month strip and the monthly reconfiguration auctions that are administered by the NYISO. Participants are obligated to curtail when called upon to do so with two or more hour's notice, provided that they were notified the day ahead of the possibility of such a call. Failure to curtail could result in penalties administered under the ICAP program that can exceed the amount the participant received initially as an ICAP payment. Curtailments were called when reserve shortages were anticipated, and, until this year, all participants were expected to comply.

A. Participation

A total of thirty Curtailment Service Providers (CSPs) offer programs that deliver the NYISO's Emergency Demand Response Program (EDRP) and Special Case Resource ICAP program (SCR) to retail customers, comprised of:

- Eight transmission owners
- Eight load serving entities unaffiliated with transmission owners
- Eight aggregators
- Six EDRP/SCR direct customers

Non-Transmission Owner providers currently sponsor 55.8 percent of the total EDRP/SCR registered megawatts.

The NYISO has incorporated the small customer aggregation requirements into EDRP. To date, two Transmission Owner (TO) direct load control programs (Long

Island Power Authority and Consolidated Edison) are enrolled and both participated in the August 15 EDRP call (discussed further below).

B. EDRP and SCR Events in 2003

1. August 15, 2003

The New York Control Area was still in the restoration process following the August 14 Northeast Blackout. As discussed in greater detail in the Program Impacts section, below, NYISO Operators were continuing the process of restoring load in portions of New York City and southeastern New York. As the bulk power system was still maintaining a precarious balance between load and generation, Operators continued to believe that efforts to keep load as low as possible remained a prudent approach. Public officials were asked to continue public appeals for residents and businesses across the state to avoid all non-essential use of electricity. As part of this effort, all EDRP and SCR customers across the state were notified at 7:31 a.m. on August 15 that all of their registered capability would be needed beginning at 10:00 a.m. and continuing until 11:00 p.m. of August 15. This notification allowed customers the two hours advance notice provided under EDRP and SCR program rules.

With load beginning to pick up, all EDRP and SCR customers were notified at 9. a.m. that they should respond immediately with their maximum performance until 11:00 p.m. Although this immediate activation did not provide the customary two-hour advance notice stipulated in the EDRP and SCR program rules, since SCR resources had not been provided with the 22-hour notice required to make performance mandatory, all performance on August 15 was fully voluntary.

Customer responses through the Notification Manager system (see discussion below) indicated an expected response of 593.9 MW. This is very close to the 563 MW peak response achieved by the same companies that responded to the notice, and compares favorably to the same companies' 497 MW average response.

At 1:22 p.m., all EDRP and SCR customers were notified that all of their registered capacity was likely to be needed the following day (August 16) from 10:00 a.m. through 11:59 p.m. This notice provided SCR resources with the requisite 21-hour advance notice required to make performance mandatory.

As shown in Table 1, EDRP response rates were comparable with those seen in past years (~48%). However, August 15 SCR response rates were well below the ~80% averages seen historically. Deeper investigation of the data suggests that the chaotic situation surrounding the blackout is likely responsible. For example, while the average EDRP response rate appears typical, it masks the fact that many resources provided little or no reduction, while others provided many times their registered amounts. The operations of the former were likely still disrupted by the lingering effects of the blackout and, not focused on shedding load they may only have restored a few hours before. Meanwhile, the over-performers were likely those who had not yet resumed normal operation following restoration of service.

August 15, 2003			Actual MWh Reduction - Hour Beginning:														
Program	Zone	MW Registered	9	10	11	12	13	14	15	16	17	18	19	20	21	22	Payment
EDRP	A	152.2	97.7	99.7	104.6	105.0	104.6	110.7	112.9	110.0	107.3	107.2	105.4	104.5	107.5	103.0	$739,973
EDRP	B	33.1	18.2	23.1	25.5	26.9	27.5	27.5	28.5	28.1	28.4	28.4	29.4	28.6	28.0	27.9	$188,066
EDRP	C	38.7	13.2	17.6	20.1	20.3	20.0	19.8	19.3	18.2	17.7	16.4	16.4	15.6	15.2	14.6	$122,278
EDRP	D	219.4	7.7	6.5	5.4	5.6	83.2	4.1	4.3	7.4	6.0	6.7	6.8	7.2	7.7	6.9	$82,705
EDRP	E	71.6	22.0	22.9	24.6	31.7	31.2	31.6	31.6	30.8	29.6	28.9	28.4	28.3	28.3	27.7	$198,792
EDRP	F	72.3	48.9	56.8	57.5	50.7	54.9	60.0	60.8	58.6	53.4	50.5	48.6	49.0	55.5	52.5	$378,902
EDRP	G	55.4	34.5	37.4	36.2	34.4	29.0	25.5	22.9	22.1	20.1	18.9	21.7	22.7	19.9	18.4	$181,805
EDRP	H	7.2	3.8	2.7	3.0	3.1	3.3	3.6	3.2	2.8	2.7	2.4	2.8	2.9	2.9	3.6	$21,419
EDRP	I	17.9	12.8	13.4	13.8	14.6	14.6	15.1	15.3	14.4	11.8	10.6	10.0	6.2	4.3	20.3	$88,612
EDRP	J	106.8	64.8	61.2	53.9	54.6	69.5	93.9	97.0	94.4	120.5	135.0	162.7	175.9	167.2	154.2	$752,439
EDRP	K	179.7	46.9	52.2	65.0	74.5	82.9	92.1	94.7	72.0	74.4	61.4	53.1	48.4	43.1	37.2	$449,022
		954.2	370.4	393.6	409.8	421.4	520.6	484.0	490.5	458.7	472.0	466.4	485.3	489.3	479.6	466.3	$3,204,014
SCR	A	333.0	146.8	183.3	188.4	191.8	192.8	195.7	195.2	192.6	190.0	189.0	188.4	187.3	187.4	184.8	$1,221,598
SCR	B	30.2	1.9	2.8	3.7	8.0	8.8	7.1	7.7	7.7	7.7	7.4	7.6	5.8	5.1	4.2	$42,742
SCR	C	75.6	37.6	38.1	36.2	42.8	43.3	40.7	47.9	47.1	46.7	45.9	43.0	42.2	50.8	51.9	$303,506
SCR	D	108.6	0.0	0.2	0.3	0.9	2.1	2.1	1.5	1.4	1.5	1.7	1.8	1.7	1.0	0.4	$8,254
SCR	E	12.0	2.7	5.2	5.5	5.8	8.6	8.5	6.4	5.3	4.5	4.5	4.3	4.9	4.8	4.9	$35,775
SCR	F	53.5	31.6	34.4	33.5	34.1	33.0	31.6	30.4	25.5	26.7	27.2	29.6	30.7	29.4	25.8	$204,240
SCR	H	2.4	1.3	1.9	2.0	2.0	2.1	2.1	2.2	1.6	1.2	1.2	1.1	1.1	1.1	1.0	$7,548
SCR	I	8.0	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.6	0.5	0.5	0.5	0.4	$2,847
SCR	J	126.7	64.8	66.6	68.7	73.9	71.6	71.0	69.5	76.6	74.0	62.5	59.3	57.9	57.5	50.6	$428,840
SCR	K	7.1	3.6	3.7	4.2	5.2	6.3	6.8	6.8	6.5	6.4	6.4	6.8	7.3	7.2	7.2	$42,157
		757.1	290.6	336.5	342.9	364.9	368.9	366.0	368.1	364.6	359.1	346.4	342.5	339.5	344.8	331.3	$2,297,508
TOTAL NYCA		1,711.3	661.0	730.0	752.7	786.2	889.5	850.0	858.6	823.3	831.1	812.8	827.9	828.8	824.4	797.6	$5,501,522

Table 1 – EDRP Response by Zone, August 15, 2002 Event

The same observation with respect to over- and under-performers applies to SCR resources as well. However, in this case the significant decline in response from these normally very reliable resources may more clearly indicate the disruptive effect that the blackout had on participants' ability to respond, particularly given the fact that, due to the immediate activation with less than two hours advance notice, the response of SCR resources was voluntary.

15-Aug	Real-Time Hourly Integrated Hourly Price - Hour Beginning:													
Zone	9	10	11	12	13	14	15	16	17	18	19	20	21	22
A	56.77	56.71	58.4	60.82	71.02	75.97	64.61	65.37	66.05	58.4	56.26	59.66	50.26	49.45
B	58.63	58.87	60.49	62.36	73.3	78.86	66.5	67.65	68.91	61.13	58.53	61.96	51.76	50.86
C	58.37	58.97	60.64	62.79	73.52	78.47	67.14	67.94	69.27	62.15	59.21	62.9	52.35	51
D	56.64	57.42	58.02	59.26	70.12	75.3	63.51	64.47	67.38	60.5	58.46	61.86	51.01	49.34
E	59.61	60.13	60.94	62.51	73.76	79.18	66.71	67.62	70.29	63.02	60.85	64.52	53.1	51.8
F	62.27	61.96	62.4	63.83	76.29	82.51	67.75	68.85	73.96	69.46	63.7	67.25	54.66	54.41
G	65.11	74.18	84.84	95.46	100.33	99.21	101.93	101.21	84.8	82.36	68.66	77.32	68.76	57.12
H	65.69	76	88.29	99.1	103.7	102.31	106.02	105.14	99.31	83.56	69.21	78.23	70.24	57.57
I	66.69	77.22	89.88	100.59	105.42	104.12	107.88	106.98	100.74	84.8	70.23	79.39	71.33	58.44
J	108.7	126.16	148.25	134.49	150.77	159.23	151.84	151.04	137.71	110.27	107.54	109.79	108.11	94.82
K	76.39	88.81	97.49	102.97	110.39	111.31	110.45	111.48	106.17	92.04	87.58	91.85	90.93	80.3

Table 2 – Real-Time LBMP During August 15, 2003 EDRP Event

Figures 1 and 3 show that the sources of verified and paid demand reduction during the August 15 and 16 events, respectively. They indicate that within EDRP, on-site generation continues to make up a significant proportion of the overall resource mix. However, Figures 2 and 4, indicate the extent to which on-site generation is becoming more concentrated in the Upstate region.

2. August 16, 2003

By the morning of August 16, service had been fully restored to essentially all loads in the state. However, the NYISO was still operating in Major Emergency mode, Real-Time markets were still suspended and system restoration in Ontario was not yet complete. As a result, system operators and government officials continued to call for customers to curtail unnecessary demand.

All EDRP and SCR customers across the state were notified at 11:19 a.m. that all of their registered capability would be needed immediately and continuing until 10:00 p.m. This notification did not provide customers the two hours advance notice provided under EDRP and SCR program rules.

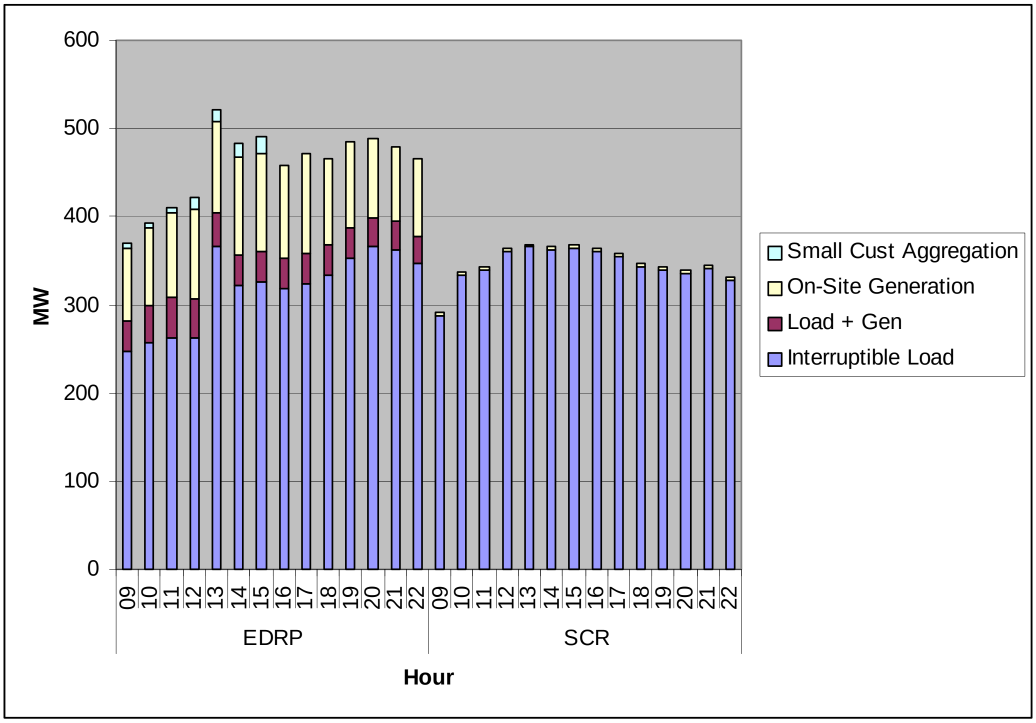


Figure 1 – August 15 EDRP/SCR Participation by Load Reduction Type

At 11:20 a.m., all EDRP and SCR customers were notified that all of their registered capacity was likely to be needed the following day (August 17) from 12:00 p.m. until 10:00 p.m. This notice provided SCR resources with the requisite 21-hour advance notice required for mandatory performance. Due to improved system conditions and moderate weather, the program was not activated on August 17.

Customer responses through the Notification Manager system (see discussion below) indicated an expected response of 589.6 MW. In this case, unlike August 15, the actual peak response of the responding companies was significantly lower – on the order of 400 MW. Their average response was only 351 MW.

It appears that this relatively low response can be attributed to a number of factors. First, this was the first time that the programs had ever been activated on a weekend day and it is likely for a variety of reasons that weekend responses are likely to be lower than weekday responses. Second, based on the immediate activation, without the requisite two-hour notice, responses for SCR resources were again voluntary, muting incentives to respond. Third, it is likely that many participants were simply fatigued from the trials of the previous two days.

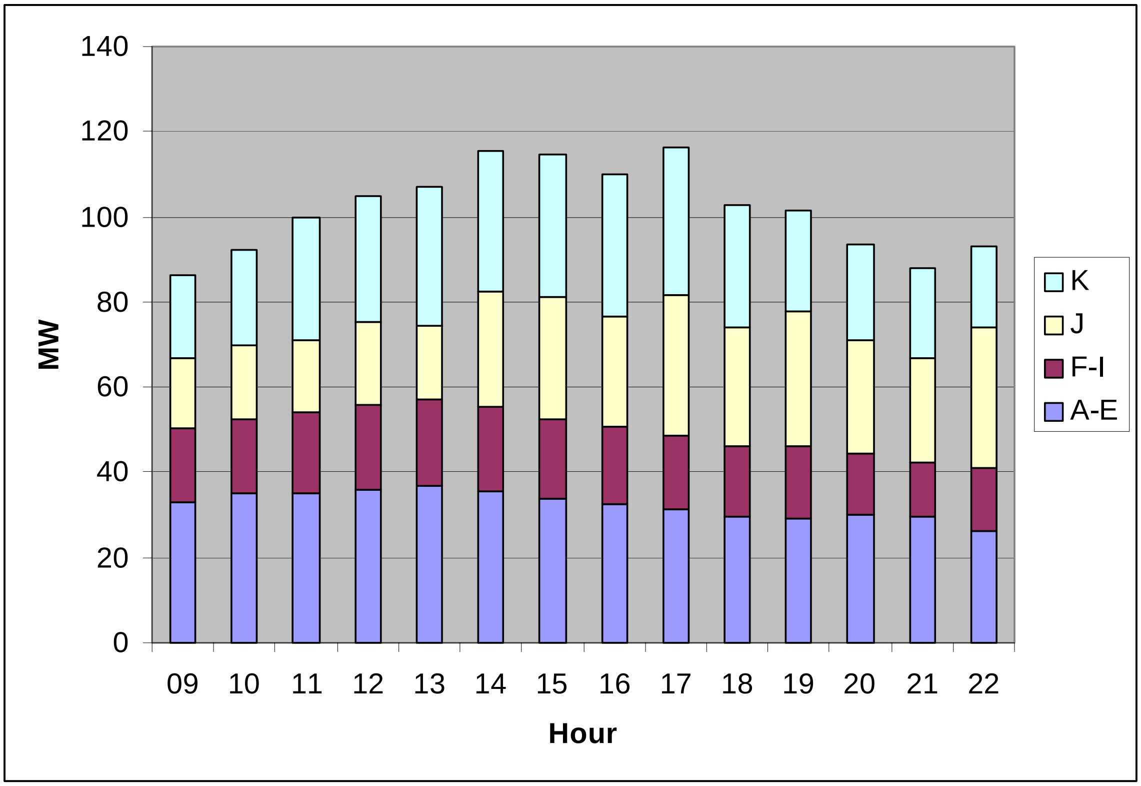


Figure 2 – On-Site Generation Participating in August 15 Event, by Zone

August 16, 2003			Actual MWh Reduction - Hour Beginning:								
Program	Zone	MW Registered	12	13	14	15	16	17	18	19	Payment
EDRP	A	152.2	69.2	69.8	69.4	69.0	69.0	68.5	67.2	66.0	$274,053
EDRP	B	33.1	26.3	27.3	28.1	27.3	26.4	26.5	27.2	26.6	$107,800
EDRP	C	38.7	4.2	4.9	5.8	6.1	6.9	7.0	6.0	5.7	$23,319
EDRP	D	219.4	4.1	40.1	3.0	0.9	1.2	0.7	0.7	0.9	$25,789
EDRP	E	71.6	7.1	8.6	8.2	11.8	8.7	7.4	7.9	8.3	$66,714
EDRP	F	72.3	30.3	29.8	29.3	29.5	26.0	27.2	25.0	27.1	$112,106
EDRP	G	55.4	10.2	14.2	14.8	13.4	16.0	15.4	12.2	12.5	$54,385
EDRP	H	7.2	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	$425
EDRP	I	17.9	0.5	0.5	0.3	0.4	0.3	0.3	0.3	0.3	$1,460
EDRP	J	106.8	16.2	14.8	14.2	13.7	14.0	11.1	9.3	9.2	$51,179
EDRP	K	179.7	1.9	2.5	6.3	8.7	9.1	9.3	7.3	6.2	$25,640
		954.2	170.0	212.5	179.5	180.8	177.7	173.5	163.4	163.0	$742,872
SCR	A	333.0	191.7	199.8	198.5	181.3	175.8	173.4	171.7	170.6	$678,706
SCR	B	30.2	1.4	1.2	1.2	1.2	1.2	1.2	1.4	1.2	$4,955
SCR	C	75.6	38.6	36.5	27.7	29.4	39.2	41.4	36.9	35.9	$142,261
SCR	D	108.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	$18
SCR	E	12.0	0.8	1.3	1.4	1.6	0.9	0.8	0.9	1.1	$4,164
SCR	F	53.5	31.6	33.9	33.6	33.7	33.1	34.4	34.6	33.9	$132,418
SCR	H	2.4	0.2	0.9	0.9	0.9	0.9	0.9	0.9	0.9	$1,812
SCR	I	8.0	0.4	1.0	3.4	3.4	2.0	0.4	0.4	0.4	$3,820
SCR	J	126.7	26.7	29.0	30.2	32.5	32.8	32.6	32.0	30.7	$108,285
SCR	K	7.1	1.2	5.3	6.9	6.9	6.8	6.8	6.7	6.6	$23,544
		757.1	292.7	308.8	303.7	290.9	292.7	291.9	285.4	281.3	$1,099,983
TOTAL NYCA		1,711.3	462.7	521.3	483.2	471.7	470.3	465.4	448.8	444.3	$1,842,855

Table 3 – EDRP and SCR Response by Zone, August 16, 2003 Event

16-Aug	Real-Time Integrated Hourly Price - Hour Beginning:							
Zone	12	13	14	15	16	17	18	19
A	83.31	85.43	85.42	85.41	85.42	80.02	71	64.43
B	89.67	91.93	92.15	92.11	92.15	86	76.92	69.74
C	88.79	91.15	91.33	91.33	91.36	85.2	76.17	69.16
D	86.89	89.27	89.45	89.37	89.36	83.15	74.75	67.93
E	90.24	92.7	92.71	92.73	92.72	86.31	77.41	70.34
F	93.05	95.64	95.87	95.91	95.93	89.28	80.09	72.82
G	98.46	101.18	101.42	101.41	101.41	94.29	84.56	76.8
H	97.47	100.12	100.38	100.38	100.34	93.25	83.68	75.98
I	98.88	101.57	101.79	101.79	101.79	94.56	84.85	77.05
J	104.51	106.35	106.52	106.52	106.49	101.44	94.99	89.48
K	100.05	102.4	102.72	102.39	102.61	94.61	85.15	76.77

Table 4 – Real-Time LBMP During August 16, 2003 EDRP Event

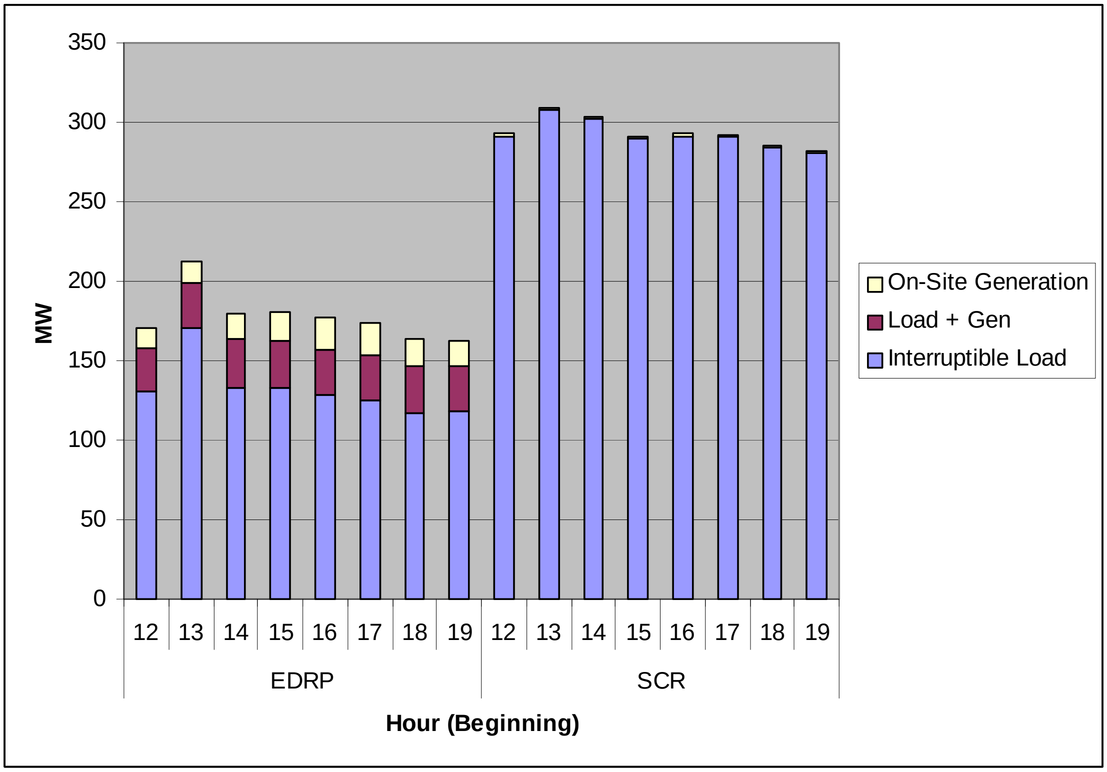


Figure 3 – August 16 EDRP/SCR Participation by Load Reduction Type

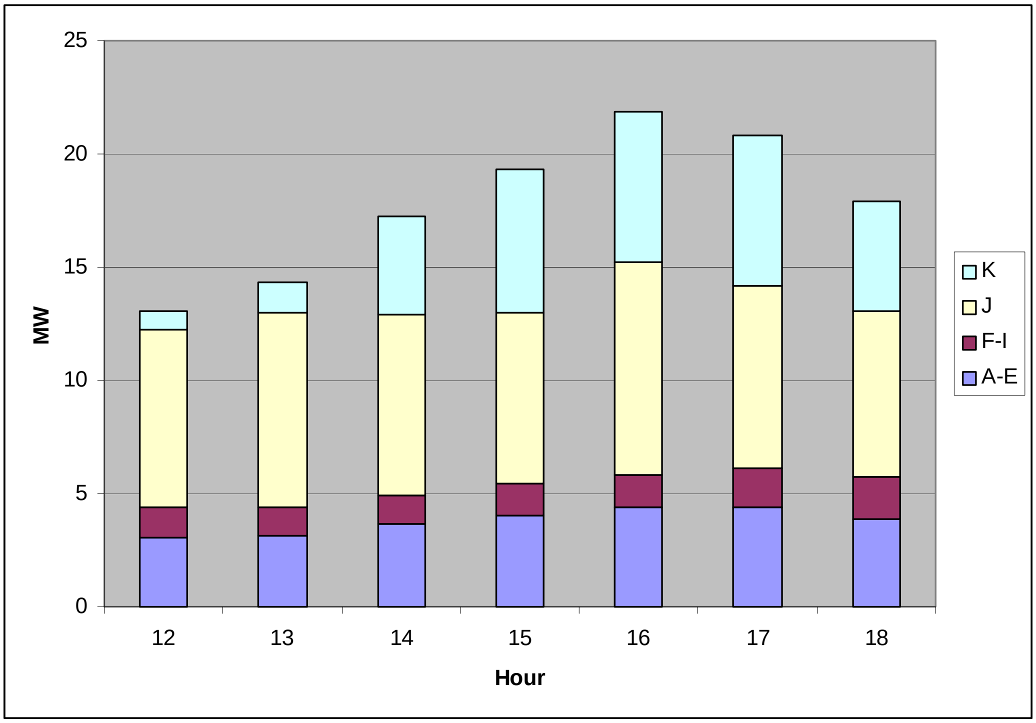


Figure 4 – On-Site Generation Participating in August 16 Event, by Zone

3. Program Payment Rules Applicable to the Blackout

During August 15 and 16 EDRP/SCR events, the NYISO Real-Time markets that normally apply to the pricing of EDRP and SCR resources were suspended. The NYISO Day-Ahead markets continued to run normally. Under the special financial settlement rules for the restoration period that were developed by the NYISO and reviewed with Commission Staff, it was decided that the Real-Time prices applicable to NYISO settlements would be set equal to the corresponding Day-Ahead prices that had been established prior to the event, as these were deemed to be most indicative of what competitive market prices would have been but for the system disturbance. Accordingly, the NYISO's scarcity pricing rules were not invoked and prices during the two events averaged approximately $100/MWh as shown in Tables 2 and 4, above.

EDRP resources are guaranteed to receive the higher of real-time LBMP or $500/MWh payment for their reductions. However, under the new program rules for 2003, SCR resources are guaranteed to receive the higher of real-time LBMP or their strike price, measured over the duration of the event. Because scarcity-pricing rules were not invoked, including those that would normally set real-time prices at $500/MWh whenever EDRP is invoked, SCR resources with strike prices below $500/MWh were paid less than EDRP resources. Those whose strike prices were below LBMP received the LBMP for their reduction.

In addition to the direct pricing effects of the blackout settlement rules, another requirement was deemed to be necessary to protect the integrity and intent of the EDRP and SCR programs. This requirement stemmed from the fact that most loads in New York State lost power and many were still without power during the period covered by the August 15 EDRP/SCR activation.

It was determined that EDRP and SCR resources should be paid for actual performance, that is taking affirmative steps to curtail demand (whether through demand reduction or the operation of generation) to reduce load on the system. However, where a participant's load was zero simply because service in their area had not yet been restored, it was determined that there was no actual performance and that energy payments under the programs would be inappropriate.

Accordingly, where a participant's event report indicated a zero metered load during any event hour on August 15 or 16, the reporting CSP was required to provide evidence acceptable to the NYISO that service had been restored. Where such evidence was not provided, reported performance was adjusted to zero. The response and payment figures presented in Tables 1 and 3, reflect the application of this policy.

C. The RETX Notification System

2003 was the first year in which the NYISO used the RETX automated notification system to alert EDRP and SCR customers that the programs would be needed the following day and to communicate the actual activation notices to customers on a two-hour ahead basis and, in this case, an immediate basis as well.

Previously, NYISO staff was required to phone and email the program instructions to customers, a time-consuming and inefficient process. The "RETX Notification Manager" allows NYISO program administrators or system operators to issue program notifications and activations via both email and automated telephonic means.

As program participants are registered, the Notification Manager, a secure web-based application hosted by RETX, is pre-loaded with the size, location, program association, and strike price of each of more than 1,500 resources. When program activation is expected to be required, NYISO users are able to input the amount and location of demand reduction desired. To the extent that the NYISO is seeking less than the full amount of EDRP and/or SCR in a given zone, the program is capable of dispatching less than the full amount of SCR in a given zone, based upon the strike prices submitted (lowest strike prices are dispatched first). The amount of curtailment requested from CSPs is communicated to each CSP via automated emails and phone calls to designated contacts. In the latter case, the message indicating the requested MW reductions in each zone is converted into a computerized voice message. Customers are then asked to click on a hyperlink in their notification email that takes them to a secure website where they input their expected demand response. This information is then made available to NYISO staff via a secure web page.

Following the August EDRP/SCR events, participants indicated that the system worked as planned and very rapidly communicated the NYISO's needs out to the curtailment service providers (CSPs) and in turn allowed the CSPs to communicate their expected demand response back to the NYISO.

D. Market Impacts

In past EDRP evaluations, the focus has been on estimating the value of curtailments by imputing a cost to what might have transpired otherwise; i.e., what would have happened if these customers had not been curtailed? Specifically, the analysis sought to isolate the improvement to system reliability, measured in the reduction of the loss of load probability, associated with the EDRP-induced curtailments. Because of the nonlinear relationship between operating reserves and the likelihood that demand can not be served, the lower the level of reserves, the greater the improvement in loss-of-load-probability (LOLP) for a given amount of load curtailments. The change in the measure of LOLP establishes an expectation regarding the reliability all consumers realized.

The value of un-served energy is used as a measure of the benefits provided by EDRP/SCR resources during the restoration period, and is given by the product of:

- The change in LOLP due to the use of EDRP/SCR,
- The amount of load that would otherwise have been subject to an outage, and
- The value of lost load (in $/kWh)

The latter is a measure of the cost consumers incur when their service is curtailed under such circumstances. This methodology utilizes time-honored methods for valuing reliability. In past practice, it's application has been feasible and compelling since EDRP curtailment events corresponded to times when reserves were short, and therefore of marginal value.

In addition to the reliability benefits, past evaluations of EDRP performance have estimated the impact of curtailments on prevailing Real-Time Market (RTM) LBMPs. In some instances, and this was the case quite often in 2002, the dispatch of the entire stock of EDRP resources was more than needed. The method described above takes that explicitly into account in establishing the LOLP improvement.

E. A new Challenge: the 2003 Blackout

The method described above, however, is not directly applicable when assessing the value of EDRP and ICAP/SCR curtailments undertaken on August 15 and 16. On August 15, system operators declared an EDRP and SCR emergency event as part of their effort to restore the bulk power grid in the wake the loss of power to most of the NYCA grid. On August 16th, the NYISO system was completely "re-energized," but system operators, so as to have more comfortable reserves available in the face of still uncertain and less than normal operating circumstances, again invoked the EDRP and SCR programs. While the valuation method utilized in previous year was applicable to the second day's circumstances, it was not amenable to valuing curtailments when customers were still without power.

Under conditions when load is being restored step by step, the value of curtailments undertaken by EDRP and SCR customers is that they allow other customers to get back online faster; it moves them from a situation of no power, where LOLP is equal to one, to a more, if not completely normal state where they enjoy reliable electric service. In this case, each curtailed MWh corresponds to moving another MWh from the state where its LOLP is one and the expected unserved energy is equal to the load it would use, if it could. In other words, there is a one-to-one correlation between DADRP and ICAP/SCR curtailments and the corresponding expected unserved energy. With this unique relationship established, valuing these curtailments can then be accomplished by invoking the usual practice of multiplying this quantity by the value of lost load.

In past analyses, a range of value-of-lost-load (VOLL) values has been used to reflect the wide variance in the estimates of the cost to customers of forced outages. The literature seems to suggest that in cases where such outages are of relatively short duration, for example achieved by rolling blackouts that move across the population, on average, customers can adapt in ways that mitigate the costs somewhat. In such circumstances, using the lower range of values that have been proposed, or VOLL, is appropriate. Where the outage is widespread and of an extended duration, in which case customers have little recourse except to withstand the hardships, higher VOLL would seem to be applicable.

F. Estimates of the Value of EDRP and ICAP/SCR Curtailments

To quantify the benefits of curtailments undertaken by EDRP and ICAP/SCR participants on August 15 and 16, the days were treated as separate system states. On August 15, when the system was being rebuilt, curtailments were credited with a one-for-one improvement in expected un-served energy and the LOLP was set at $5.00/kWh. One the second day, the conventional partial improvement in LOLP methodology was employed. Curtailments were compared to reserve needs for each hour, and only those that were needed to maintain typical reserve requirements were considered as needed and valued. Measuring the hour-by-hour contribution to LOLP improvement was not practical given the state of the system. Given the state of the bulk power system on August 16th, a more conservative estimate for the amount of expected un-served energy is used and assumes the change in LOLP to be 0.20 and the load at risk of an outage was set at 3% of real-time system load in each event hour. Moreover, because the system was still considered to be less than robust, the same $5.00/kWh VOLL value was applied to the expected calculated change in expected un-served energy.

Table 5: Estimated Reliability Benefits during 2003 EDRP & ICAP SCR Events–Value of Estimated Unused Energy(VEUE)			
Date	VEUE ($M)	Energy Payments ($M)	Benefit Cost Ratio
August 15	50.8	5.9	8.7
August 16	3.5	1.7	1.7

Table 5 displays the estimated EDRP and ICAP/SCR benefits for the two days. The table also displays the payments made to those that curtailed, and the ration of benefits to costs. On the second day, net benefits were positive, but the benefit/cost ratio is more modest. Very conservative assumptions were employed in the second day valuation, especially with regard to determining what amount of the curtailments was needed. In some hours, the needed reserves standard employed resulted in only a small fraction of the curtailed loads being assigned a value. Those more familiar with the state of the system might argue that any reserves were welcomed and were used and useful, and customers weary of coping without power might have been inclined to pay several times more to avoid yet another outage.

G. Impact of EDRP and SCR Program Changes on Participation

The NYISO implemented several EDRP and SCR program changes in 2003, including:

1. EDRP and SCR were uncoupled requiring that customers be enrolled in only one in any time period[1];
2. The SCR curtailment capability, in a zone or system-wide, could be partially deployed during an event, either by calling all of the capability in some zones but not others, or by calling only part of the capability within certain zones. This change could result in only some participants being called to curtail;
3. To implement a partial dispatch, SCR customers were required to nominate a strike price at which they would be dispatched during those events where not all-

[1] Sequencing protocols determined under which program a participant was paid when a day-ahead DADRP scheduled curtailment became coincident with a same-day invoked EDRP or ICAP/SCR event and the participant was jointly registered. Participants' performance was first credited to DADRP obligations, with any remaining performance being credited to EDRP or SCR.

available curtailment capability was needed. That price was capped at $500/MWH; and

4. During SCR curtailments, those called upon to curtail were eligible for an energy payment that is the higher of their nominated strike price to the prevailing LBMP, measured over the duration of the event.

In addition, changes in market operating protocols had implications for demand response program participation and performance, specifically:

1. SCR and EDRP resources could set LBMP when dispatched. Consequently, the SCR dispatch strike price (which could be as high as $500/MWH) or the EDRP floor price ($500/MWH) could set the real-time LBMP. This protocol could result in higher prices during those periods when EDRP and SCR are dispatched than was the case in previous years.
2. The ICAP spot market auction created a more robust monthly spot market that was expected to raise the clearing prices that SCR resources are paid when they sell into that auction. This was expected to make SCR participation more attractive.

To evaluate the impact of program changes on participation in 2003, two initiatives were undertaken. First, a survey was administered to the entities that recruit customers to participate in demand response programs to characterize how the changes impacted their recruiting efforts and program administration. Second, a detailed retention and migration study tracked changes in program participation from previous years to establish any patterns that might be attributable to the program changes. While no effort was made to sort out the separate impacts of the general protocol changes, their influence can be implied by some of the behaviors observed.

To assess how the program changes implemented in 2003 would impact participation, it was hypothesized that the changes in EDRP and SCR would have at least three distinct impacts, specifically:

a. Uncoupling would result in the migration of EDRP participants to SCR because of the greater benefit/risk ratio created by the combination of the SCR first and as needed dispatch rule and the implementation of energy payments for SCR curtailments;
b. The requirement that SCR participants nominate a curtailment strike price would complicate recruitment and possibly act as deterrent to participation; and,
c. SCR participant strike price nominations would be clustered around very low (near zero) and very high (close to the $500/MWH bid cap) levels, the former from customers that are sure they can comply and want to be asked to curtail so they are paid the energy payment and the latter reflecting some customers' efforts to limit their curtailment exposure.

H. Survey of Demand Response Providers

To assess the impact of the new demand response program provisions on recruitment, a survey was administered to the entities that market the NYISO's demand response programs; regulated and competitive load serving entities (LSEs) and curtailment service providers. The survey was administered in the fall of 2003 so that the summer's program history would be factored into respondents' assessment of the program provisions.

I. The Survey Respondents

There were 13 survey respondents, including five (5) LSEs (two regulated and three competitive), six (6) demand response providers, and one (1) retail customer and one (1) institutional respondent. All but two indicated that they had recruited customers to participate in at least one of the NYISO demand response programs available in 2003. Some are also active in similar programs offered by PJM Interconnection and ISO-NE. Most (83%) reported enrolling customers in SCR, and half sponsored customer participation in EDRP.

J. EDRP Experiences

Seven of the survey 12 respondents that are active in promoting some aspect of the NYISO's demand response program indicated that they recruited customers to participate in EDRP in 2003. Most indicated that they expected that the benefits of participation would be lower in 2003 than they were in 2002. It is not surprising that these entities expected lower EDRP benefits in 2003. One important change in the EDRP program was that as a consequence of decoupling SCR, the dispatch rules were changed so that if the situation allowed, SCR resources would be called first, and EDRP curtailments only if they were needed.

When asked about how the EDRP uncoupling affected their marketing efforts in 2003, five answered that they experienced no change as a result, one said that it made its marketing efforts easier, and two reported that it made it more difficult to market participation in EDRP. Most of the EDRP marketers said that customers that had participated in EDRP previous to 2003 were satisfied with the 2003 offering. One said that such customers were highly satisfied and one reported that its customers were very dissatisfied.

K. SCR Experiences

Ten of twelve respondents reported that they recruited customers to SCR, half of them being demand response providers. Eight respondents reported that customers found nominating a curtailment strike price either not difficult at all, or only somewhat difficult, while two said that customers found it difficult. Most felt that if the new energy payment provisions of SCR were eliminated, that participation would decrease, with estimates of that reduction ranging from 50 to 75% of the amount that enrolled in 2003.

Respondents were asked to indicate how they arranged to achieve SCR curtailments in the case where not all of the available curtailments were needed. Two said they adopted a round-robin dispatch and two reported that they had adopted the alternative offered, prorating the curtailment proportionally to all participants. Four others responded that they had adopted neither method. Most (eight of 10 responses) said they liked the existing practice, which is to have each individual LSE and demand response provider decide how to achieve its curtailment quota, when the entire available amount is not needed.

L. Summary

Half of the respondents said they recruited customers to EDRP, and over 80% enrolled customers in SCR. For the most part, the uncoupling of the two programs, which required that customers elect one or the other, seems to have not adversely impacted LSEs' and demand response providers' ability to market participation successfully. The requirement that SCR participants nominate a curtailment strike price seems to have not been unduly complicated or a barrier to participation. However, the bidding behavior is itself of interest, as discussed below.

The provision for allocating curtailments under SCR was not put to the test. Nonetheless, most respondents want to keep the protocol implemented in 2003 whereby the NYISO determines the level of curtailment each LSE and demand response provider must achieve, and leave it to them to decide how to meet that requirement.

M. Program Retention and Migration

Overall, the number of participants in all demand response programs declined in 2003 by 10%.[2] Table 6 provides a detailed accounting of how participation changed from 2002 to 2003. The first column lists 2002 participation by program option: EDRP had

[2] A participant is defined as a single customer or an aggregation of customers.

1535 participants, SCR had 226, and DADRP had 24.[3] The next six columns of Table 6 account for the difference from 2002 to 2003 participation by tracking 1) re-subscriptions in the same program option, 2) migration to another program option, 3) dropouts from the program option altogether, and 4) new subscribers to the program option.

	Total 2002 (count)	2003 (count) EDRP	DADRP	ICAP	Dropped	New	Total 2003
EDRP	1535	1021	0	7	507	269	**1323**
ICAP	226	33	0	117	76	89	**213**
DADRP	24	0	24	0	0	3	**27**
sub	1785	1054	24	124			
	NEW 2003	*269*	*3*	*89*			
		1323	**27**	**213**			

Table 6: Program Participation Summary

Consider the EDRP accounting provided in the first row of Table 6. Tracking 2002 to 2003 changes shows that 1021 of the 2002 EDRP participants reenrolled in 2003, none migrated to DADRP, seven migrated to SCR, 507 dropped out, and 269 new customers enrolled in EDRP in 2003. EDRP enrolled curtailable load decreased by 10% (95 MW), as illustrated in Table 7, which employs the same accounting structure to compare 2002 to 2003 curtailed load registrations. The load of new participants (148 MW) canceled out that of dropouts (142), so the net EDRP curtailable reduction is due to migration of SCR (53 MW) and changes in the amount subscribed by re-enrollments. Overall, the change in EDRP participation is quite small, despite a substantial amount of churn, changes to other programs and dropouts. The dropouts and new entrants will be studied more closely in the future to determine if there is any discernable pattern.

[3] Participation data for 2002 represent enrolments over the summer months and correspond to the values reported in the NYISO's evaluation of 2002 program performance, as described in Neenan Associates and CERTS, January 2003.

	Total 2002 (MW)	2003 (MW)						
		EDRP	**DADRP**	**ICAP**	**Dropped**	**New**	**Re-enrolled changes to subscription**	**Total 2003**
EDRP	949.13	753.92	0.00	52.80	142.41	147.96	-76.39	**853.99**
ICAP	659.50	28.50	0.00	476.40	154.60	332.70	-11.60	**850.30**
DADRP	393.80	0.00	393.80	0.00	0.00	22.50	-5.00	**411.30**
sub	2002.43	782.42	393.80	529.20				
	NEW 2003	*147.96*	22.50	332.70				
	Re-enrolled changes to subscription	-76.39	-5.00	-11.60				
		853.99	**411.30**	**850.30**				

Table 7: Program Participation Summary - MW

Using Table 6 and 7 in the same manner reveals that SCR participation decreased by 10% (13 participants) but enrolled curtailable load increased by 29% (190 MW): the average curtailable load per participant increased. As Table 6 shows, the drop in participation occurred in spite of 89 new enrollments, the result of 76 dropouts and 33 migrations to EDRP. But, as Table 7 illustrates, the new participants brought in more load than was lost through attrition. Customers pledging greater curtailments replaced customers with smaller curtailment obligations. The average curtailment of new participants was 3.8 MW, while that of dropouts was only 2.0. It appears that SCR participation is more attractive to customers with larger curtailment capability. However, some of the participants represent aggregations comprised of several, or in some cases many, customers.

Load subscribed to DADRP increased slightly (5%), proportionally less than the increase in enrollment (15%). The added participants were new to this program option.

Table 8 illustrates program participation by zone.

	EDRP		**DADRP**		**ICAP**	
Zone	**#**	**MW**	**#**	**MW**	**#**	**MW**
A	54	53.38	9	162.40	39	399.00
B	16	62.59	0	0.00	17	30.20
C	145	36.78	4	40.40	31	75.90
D	9	219.43	0	0.00	5	108.60
E	46	55.67	3	114.00	9	14.10
F	66	68.98	9	91.00	14	68.80
G	42	58.97	0	0.00	1	0.40
H	8	7.20	1	1.00	4	2.40
I	25	13.04	0	0.00	14	12.00
J	107	98.72	1	2.50	67	130.30
K	805	179.24	0	0.00	12	8.60
Total	***1323***	***853.994***	***27***	***411.30***	***213***	***850.30***

Table 8: Program Participation by Zone

	EDRP		DADRP		ICAP	
	2001 to 2002	2002 to 2003	2001 to 2002	2002 to 2003	2001 to 2002	2002 to 2003
Dropped	117	507	6	0	34	76
New	1497	269	4	3	91	89
Transfers		33				7
Renewals	190	1021	20	24	117	117
	1687	1323	24	27	208	213

Table 9: Participation Changes 2001 - 2003

To recap, participation numbers for EDRP fell from 2002 to 2003, as did the load available for curtailment. Table 9 provides tracking data for the period 2001 to 2002 and the corresponding data for 2002 to 2003. 2002 was a big growth year for EDRP, as there were 1,497 new participants and only 117 dropouts from 2001.

There was a net reduction in participation in 2003, which is not necessarily an indication that the program has reached it apex and is now in decline. To the contrary, it seems that the EDRP program is maturing. Examination of the 507 2003 EDRP dropouts reveals that 40% (208) of them did not provide any curtailed load during the 11 hours of EDRP events in 2002.

The 89 SCR participants classified as new in 2003 are so because they were not registered in SCR in 2002. But, they could have participated previously, and just took a year off. An examination for 2001 records reveals that only three of the new 2003 participants had participated in SCR in 2001. The rest are new to the program, an indication that LSEs and demand response providers are actively working new accounts to increase participation, a sign of a robust program.

Enrollment records were examined to characterize SCR participants' strike price nominations. While the ICAP Demand Curve is a new provision in 2003, one might postulate that first-time participants would have a different motivation. Specifically, they might hope to be able to avoid some or all curtailments by submitting a high bid, and thereby earn ICAP payments with minimum curtailment costs. Consequently, Figure 5 illustrates the bid curve for three segments for the population of SCR participants, associated with the number of year's experience with program participation.

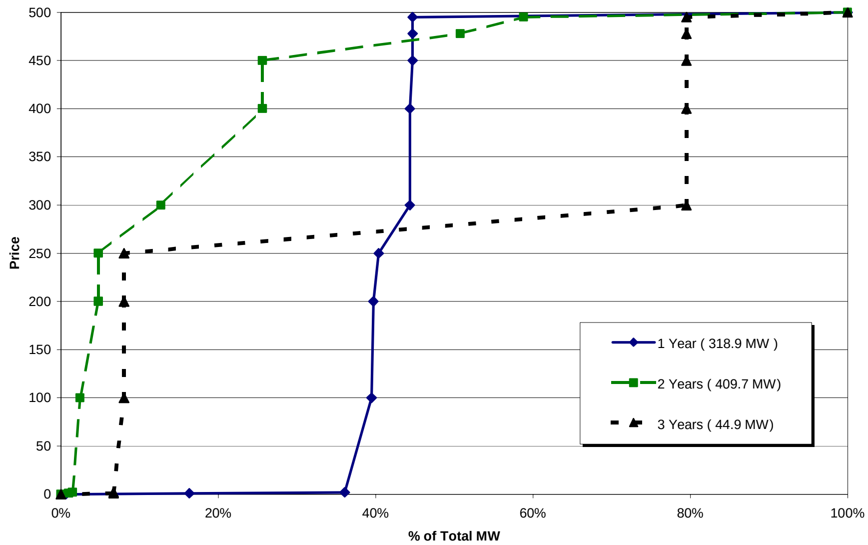


Figure 5: SCR Strike Price Curves

All three of the bid curves are characterized by a substantial clustering of bids around the extremes, but the most extreme is for the 2-year and 3-year participants. The first year participants' bid curve has two distinct clusters, and one very steep but narrow segment. This outcome can represent a variety of behaviors. It supports the maintained hypothesis that some customers would want to be curtailed and other would like to avoid curtailments, as extreme bid clustering is apparent. But the defining factor for which extreme is favored is not the number of years of experience, as all three curves show the same clustering, to some extent.

N. Conclusions

Regarding the hypothesis constructed to characterize the EDRP and SCR 2003 program changes, the analyses of tracking data suggest the following conclusions:

1. Participation in SCR did increase dramatically, but not due to migration from EDRP, but from (primarily large) new subscribers.
2. LSEs and demand response providers report that most SCR customers were able to nominate a strike price with little difficulty, which comports with the large increase in SCR participation in 2003. However, there were 76 dropouts; was the nomination provision a contributing factor? No primary data are available to refute that contention. But, the fact that dropouts (by definition) did not even participate in EDRP, which does not require any nomination and imposes no

penalty for failure to comply, suggests that these customers in general found curtailing loads infeasible for business reasons, and not as a result of program provision changes.

3. Curtailment bids by SCR participants are indeed highly clustered around very low and very high values. While there is nothing inherently inconsistent or questionable about that outcome, it does complicate implementing a curtailment that requires only a fraction of the available curtailable loads.

II. Day-Ahead Demand Response Program

The Day-Ahead Demand Response Program (DADRP) allows customer to submit curtailment bids into the day-ahead market (DAM) and if the bid, which is treated as a generation resource, is scheduled, the participant is paid the market clearing DAM LBMP. Real-time market (RTM) curtailment imbalances (shortfalls) resulting the customer buying-back that position at the higher of the DAM LBMP at which the curtailment was scheduled, or the RTM LBMP, and until 2003 plus an additional 10% penalty.

Two changes in Day-Ahead Demand Response Program (DADRP) protocols went into effect in 2003: a bid floor of $50/MWH was imposed, and the 10% penalty previously assessed when curtailment obligations were not met was removed. The former was implemented to discourage the submission of bids when a facility shutdown was already scheduled for that period. As a result of the latter change, participants settle curtailment imbalances at the higher of the DAM LBMP, at which they were scheduled, or the RTM LBMP that corresponds to the curtailment shortfall. The impact of these changes on participation in DADRP is discussed in the next section, while the following sections discuss program participation and the impact of scheduled DADRP bids on NYISO market prices.

A. Participation

Registration in DADRP increased to 27 customers in 2003, compared to the 24 that were registered in 2002. The amount of bids scheduled in the summer months was up 20% from 2002, to 1,752 MWH. The scheduled bids and LBMP are illustrated in Figure 6. The increase in accepted bids is likely, in part, due to the lower prices that characterized the upstate zones where most of the bids were submitted. Declining price volatility in the DAM and RTM reduces the number of opportunities for scheduling DADRP bids, especially upstate where participation is highest. In addition to reducing the number of bid scheduled, reduced price volatility affects the impacts of those bids on market prices, as discussed below.

Figure 7 plots the MWh offered and MWh accepted in DADRP since program inception. In 2003, total offered MWh was less than previous years, but a greater percentage of offers were accepted.

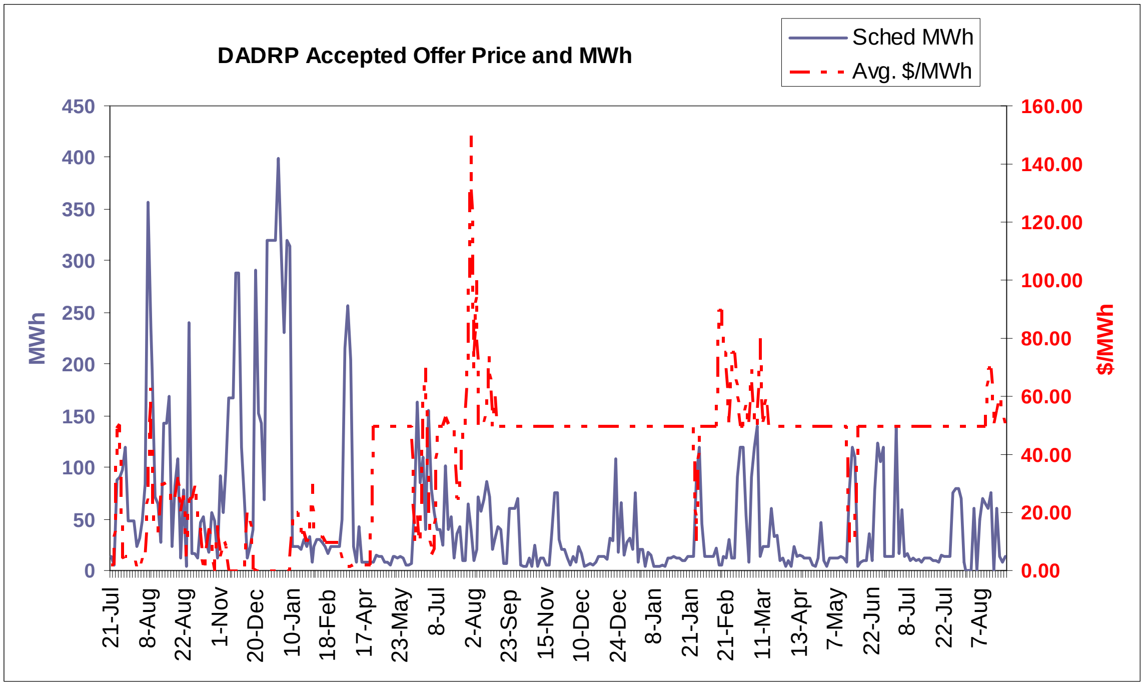


Figure 6- DADRP Accepted Offer Price and MWh

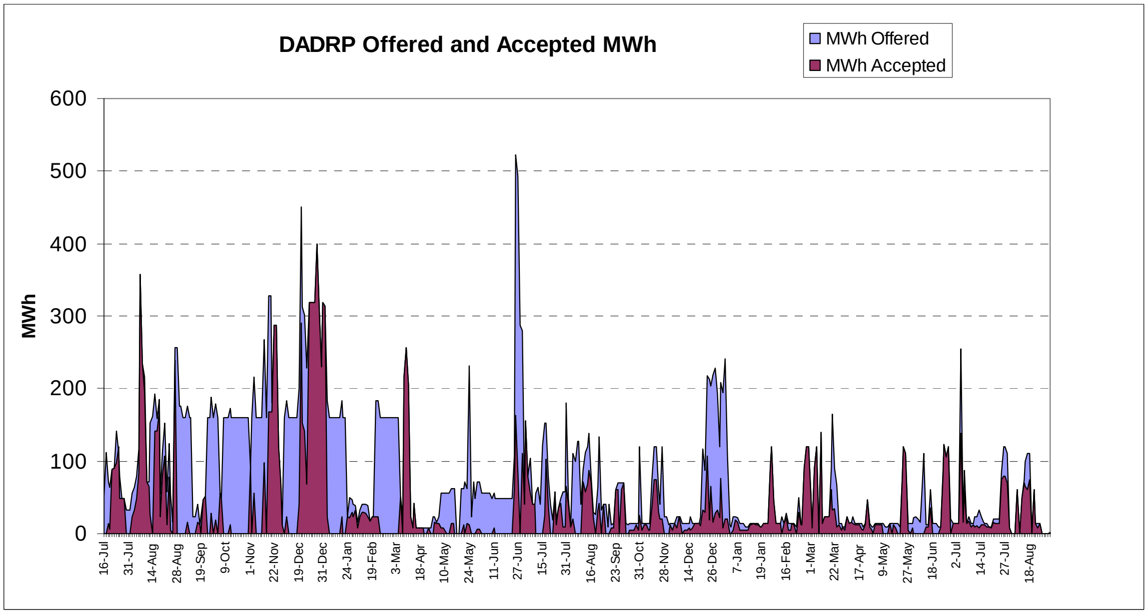
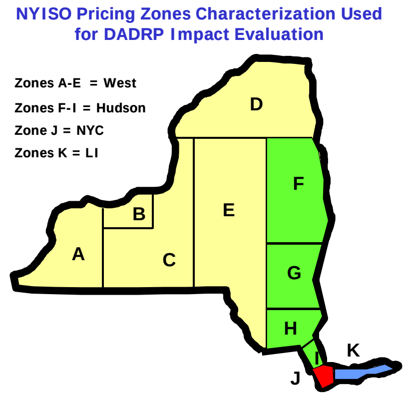


Figure 7 – DADRP Offered and Accepted MWh

B. Market Impacts

Market price impacts for the summer months (June – August) 2003 were estimated using the methods developed in previous year's assessments[4]. Supply flexibilities were developed for the two aggregate regions, Upstate and Hudson-Capital, and two NYISO zones, New York City and Long Island. Supply flexibilities, defined as the percentage change in LBMP resulting from a one percent change in the load served, characterize the nature of the resource supply curve. The greater the price flexibility, the greater the reduction in the calculated DAM LBMP due to the scheduling of a DADRP curtailment bid. High supply flexibilities over a narrow range of load levels are indicative of a pronounced "hockey-stick" shaped supply curve.



Price flexibilities in the DAM and RTM are much lower in 2003 than they were in previous years, as illustrated in Table 10 and Table 11, respectively. The reduction in the DAM supply flexibilities (Table 10) is particularly pronounced in the West and Hudson/Capital regions, and results in lower market impacts from the scheduling of DADRP curtailment bids.

Table 10. DAM Price Flexibilities

	2001	2002	2003
West	**9.4**	**4.2**	**1.4**
Hudson/Capital	**5.1 / 11.8**	**3.9 / 5.0**	**1.9**
New York City	**9.4**	**3.6**	**3.5**
Long Island	**5.1**	**6.5**	**1.2**

Price flexibility = % change in LBMP resulting from a 1% change in load served

Table 11. Real Time Market Price Flexibilities

	2001	2002	2003
West	6.4	6.7	3.4
Hudson/Capital	8.6 / 8.4	4.7 / 6.0	2.5
New York City	14.5	12.8	5.9
Long Island	10.4	5.2	6.0

Price flexibility = % change in LBMP resulting from a 1% change in load served

[4] This analysis is confined to the summer months to accommodate comparing 2003 with prior years' analyses that included only these months. DADRP impacts for the first five months of 2003 were reported previously.

Market impacts for 2003 are compared to those for 2002 and 2001 in Table 12. Despite the 20% increase in scheduled MWh, the market impacts, measured as collateral and reduced hedge costs, were down by over 50%, to $207,331 (Table 12, Total Price Impact). Collateral impacts measure the reduction in the cost of DAM purchases by LSEs resulting from the scheduled DADRP curtailment. Hedge cost impacts estimate the ripple effect lower prices in the DAM during curtailment hours are postulated to have on bilateral contract supply costs.

Table 12. DADRP Market Impact

	Scheduled DADRP MWHs	Collateral Savings	Reduction in Hedge Cost	Total Price Impact	Program Payments
2001	2,694	$892,140	$682,358	$1,574,498	$217,487
2002	1,468	$236,745	$202,349	$439,094	$110,216
2003					
West	**176**	**$3,529**	**$72,613**	**$76,142**	**$9,844**
Hudson-Capital	**1,576**	**$42,244**	**$88,945**	**$131,189**	**$111,300**
2003 Total	**1,752**	**$45,773**	**$161,558**	**$207,331**	**$121,144**

The lower market impacts in 2003 reflect the relatively flat nature of the resources supply curve during the summer months. Low supply flexibilities mean that scheduled curtailments have a lower impact on the DAM LBMP. Program costs however are based on the price at which the DADRP curtailment was scheduled, and they are up from 2003, but under 10%, despite the 20% increase in scheduled MWh. The ratio of market impacts to DADRP curtailment payments in 2003 was 1.7, compared to 4.0 and 7.2 in 2002 and 2001, respectively. In general, the low impact ratio in 2003 is attributable in part to loads that were scheduled at LBMPs close to the $50/MWH floor, periods when the supply flexibility was low. Consequently, the market price impacts are low compared to prior years when supply flexibilities were higher.

C. Impact of DADRP Program Changes on Participation

The NYISO implemented several program changes in 2003, including:

1. A $50/MWH floor price was imposed in DADRP bids; and
2. The 10% penalty applied to curtailment imbalances was eliminated.

To assess how the program changes implemented in 2003 would impact participation, it was hypothesized that the changes in DADRP would have distinct and opposite effects, as follows:

a. The elimination of the 10% penalty on DADRP imbalances would have a negligible impact on participation, and

b. The imposition of a $50/MWH bid floor would act as a deterrent to DADRP participation.

D. Survey of Demand Response Providers

To assess the impact of the new demand response program provisions on recruitment, a survey was administered to the entities that market the NYISO's demand response programs: regulated and competitive load serving entities (LSEs) and curtailment service providers. The survey was administered in the fall of 2003 so that the summer's program history would be factored in respondents' assessment of the program provisions.

E. The Survey Respondents

The 13 survey respondents included five LSEs (2 regulated and three competitive), six demand service providers, and one retail customer and one institutional respondent. All but the institutional respondent and one competitive LSE reported that it recruited customers to participate in at least one of the NYISO demand response programs available in 2003. Most of them had done so in prior years.

Only 15% (2 respondents, one regulated LSE and one demand response provider) of those customers participating in the survey enrolled a customer in DADRP. When asked what actions they undertook to recruit customers to DADRP, most (7 of 13) reported that they did not actively promote participation. Another two said that they responded only when the customer asked about participation, and three (one regulated LSE and two demand response providers) reported that they actively promoted DADRP. These results are consistent with previous evaluations of the DADRP program that found that awareness of DADRP was low in general, and even among those customers participating in ICAP/SCR or EDRP.

F. DADRP Experiences

The active DADRP marketers reported that the removal of the 10% penalty for curtailment noncompliance either created interest but not participation (3) or it had no influence (2). The penalty may have been perceived by some customers as being more severe than it really was, and its removal only highlighted other features that are seen as barriers to participation.[5]

When asked what they perceived as the biggest barrier to customer participation in DADRP, 40% (2) of those that promoted participation said it was the requirement that bids be submitted in one MW increments, and an equal number said the biggest barrier

[5] Previous evaluations asked customers what they saw as the barriers to participation in DADRP. Few answered that they saw the penalty a barrier. More common were that customers cannot curtail usage under the program circumstances, or they could, but the perceived benefits were not sufficient for them to do so.

was the recently instituted $50/MWH bid floor. The one MW bid increment requirement has been cited before as a deterrent because it forces the LSEs or demand service provider to manage the risks if customers bids do not meet that standard, or force customers to undertake the consequential market risk.

Given that most customers pay a commodity rate that is at least $50/MWH, it is difficult to construct a situation where a customer would curtail at a DADRP price lower than it would otherwise have consumed, except in case where the customer can dispatch on-site generation with a lower fuel cost, and such action is not allowed under DADRP protocols. One explanation for favoring a lower (or no) bid floor is that some customers want to bid curtailments coincident with planned shutdowns, either partial or total facility. Such behaviors are contrary to the objectives of offering DADRP, which is to induce curtailments that otherwise not have occurred at times when the result is a lower DAM price, and forestalling such biding behaviors was the primary motivation for establishing the floor price.

The active DADRP marketers were also asked to choose from among four program features changes based on which they felt would have the largest beneficial impact with respect to promoting participation. None chose the provision whereby participants with scheduled bids would be paid for additional curtailments, beyond what was scheduled. Two chose lowering the bid increment to 100 kW and two chose lowering the bid floor. One said that settling scheduled curtailment shortfalls at the RTM LBMP, rather than the higher of it or the DAM LBMP at which it was scheduled, would be most helpful.[6]

[6] On average, DAM prices are 3-5% higher than RTM LBMPs, which might appear to offer an arbitrage opportunity for participants who could settle at the RTM LBMP. However, when prices are most volatile, RTM prices tend to be higher, which would foreclose the arbitrage opportunity. Perhaps the best argument for settling DADRP imbalances at the RTM LBMP is that it would further reduce deadweight losses that DADRP is intended to mitigate.