A Study of NYISO

2003 PRL Program Performance

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Prepared for

New York Independent System Operator

Prepared by

Bernie Neenan, Donna Pratt, Peter Cappers, James Doane, Jeremey Anderson,
Lydia Scholle-Cotton, Kim Butkins and Richard Boisvert
Neenan Associates
Syracuse, NY

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Executive Summary

Background

The NYISO has undertaken extensive reviews and evaluations of the performance of its demand response programs since their inception in the summer of 2001. This year's evaluation was focused on analyzing the effects of the changes to the program protocols instituted in 2003, and gauging interest in a new, real-time demand response program option. As is customary, the evaluation quantified the level and distribution of benefits from the demand response (DR) program curtailments, including a new feature of the valuation methodology, the calculation of the net social welfare implications of the DADRP program.

NYISO Demand Response Program Overview

The NYISO offers three different DR programs that meet specific market needs. Participants in the Emergency Demand Response Program (EDRP) are asked to curtail with two or more hours notice when emergency system conditions are anticipated, and are guaranteed a minimum price of $500/MWh for verified load reductions during such events. The Installed Capacity, Special Case Resource (ICAP/SCR) program allows participants to sell their load reduction capability as installed capacity in exchange for a guarantee to curtail when called upon. Events can be declared with two-hours notice, at any time of the year or day, provided that participants were given notice of the possibility of an event the previous day. The Day-Ahead Demand Response Program (DADRP) allows end-use customers to offer demand reduction bids into New York ISO's day-ahead electricity market as supply resources, and receive market-clearing prices for scheduled curtailments. Curtailment under the latter two programs is compulsory, and the penalties for curtailment shortfalls can exceed the payments made for committing to curtail.

Summary of Demand Response Program Changes

Substantial changes were made to the ICAP/SCR and EDRP programs in 2003. First, customers were required, starting in 2003, to subscribe to one program or the other. Previously, joint participation was allowed, which resulted in ICAP/SCR participants receiving the same

$500/MWh minimum curtailment payment as their EDRP counterparts, which supplemented the up-front capacity payment ICAP/SCR participants received.[1] Second, ICAP/SCR subscribers are now required to specify a strike price, which will be used by NYISO dispatchers to determine which resources are dispatched in the case where not all available ICAP/SCR resources are required. Third, those strike prices will be used to determine the level of the energy payment received by those that are called upon to curtail. Each was assured of receiving a payment at least as large as its strike price. Finally, ICAP/SCR resources will be called upon first when operating reserve shortfalls are anticipated. An EDRP event, applicable to all subscribers to the program, will be called only if the ICAP/SCR curtailments are deemed to be insufficient to meet exigent circumstances. In addition, the NYISO's pricing algorithm has been modified to allow resources from either of these two reliability programs to set the market price.

Two changes were made to the DADRP program. First, a $50/MWh bid floor was instituted to deter opportunistic bidding, defined as low bids submitted when the customer's load was well below normal, such as on holidays or during scheduled plant maintenance.[2] Second, the 10% incremental penalty was eliminated so that non-compliance results in a penalty equal to the higher of the scheduled day-ahead price, or the real-time price.

Because these changes were substantial in nature, and therefore may have impacted program participation or performance, two surveys of the entities that market participation to retail customers were undertaken to both characterize the effects these program changes had on their recruitment efforts and to gauge interest in new ones. In addition, an analysis of the migration patterns from one program to another was performed to provide insight into how these changes affected actual enrollment.

[1] Once subscribed to ICAP/SCR, participants may sell their qualified capacity to Load-Serving Entities, or commit it to the six-month capability or monthly auctions administered by the NYISO.

[2] Compliance is determined by the difference between the level of usage the participant is otherwise deemed to have used, called a CBL, and its actual hourly usage during the event. The CBL for each event hour is the average usage of the corresponding hours in the five highest usage days of the ten days prior to the scheduling of the DADRP curtailment.

Satisfaction with Program Changes

To characterize how the program changes affected recruiting efforts and program administration, a survey was administered during the fall of 2003 to regulated and competitive load serving entities (LSEs) and curtailment service providers (CSPs) that market program participation to retail customers, as well as to customers that subscribe to programs directly. Respondents were asked to indicate which programs they promoted, and how the program changes impacted those efforts. Surveys were completed by entities that represent hundreds of MWs of load subscribed to the programs.

Almost three-quarters of the respondents reported that they had enrolled customers in ICAP/SCR in 2003, and nearly half sponsored customer participation in EDRP. However, only two reported promoting DADRP, and only one of them actually enrolled a customer in the day-ahead program. These results generally square with previous evaluations of the DADRP program that found that the entities marketing EDRP and ICAP/SCR do not promote participation in DADRP. Consequently, the program changes enacted in 2003 likely had little impact on 2003 participation.

Most of the respondents indicated that the changes in the EDRP program had little impact on their recruitment success, despite the fact that half indicated that they expected benefits from participation would be lower in 2003. This is based on the view that while previously ICAP/SCR and EDRP curtailments were called simultaneously, under the new protocols in some cases only ICAP/SCR resources would be needed to restore reliability, and therefore an EDRP event would not be declared.

Most survey respondents were satisfied with the separation of ICAP/SCR from EDRP, and reported that it was not particularly detrimental to their marketing initiatives, despite the fact that participants were no longer guaranteed an energy payment of $500/MWh when they curtailed. Most indicated that customers found nominating a strike price to be not very difficult. Overall, the changes in the program EDRP and ICAP/SCR protocols were not viewed as having an adverse affect on participation, at least by survey respondents. However, as is discussed below, there were important changes in the distribution of participants between EDRP and ICAP/SCR, as befits the change in expectations for benefits from participation.

Interest in Participation in Real-Time Energy and Ancillary Services Markets

To gauge interest in participation in the proposed Real-Time Demand Response Program (RTDRP), wherein customers would bid to supply reserves in real-time, the NYISO conducted workshops that included end-use customers, potential program providers (LSEs and CSPs) and other stakeholders, such as enabling technology providers. The protocols of the proposed RTDRP were described to attendees, supplemented by examples of the potential benefits from participation in each program.

The important protocols in the proposed program were that bids to supply reserves that were accepted would result in a reservation payment to the customer, but it would receive no additional energy payment if called upon to curtail. Moreover, a bid could be rejected for supplying reserves, but later called upon to supply balancing energy, in which case the customer received no payment at all for its curtailment. Participants could avoid such adverse outcomes by bidding a high supply price, but doing so would reduce the likelihood of being selected to provide reserves and thereby defeat the purpose of participation. Clearly, participation in this market would require a sound understanding of market fundamentals to devise and execute even a simple bidding strategy.

When asked about their interest in participation, more than half of the LSEs/CSPs/Other Stakeholders, entities that recruit and represent retail customers, indicated that they were at least somewhat interested in promoting the RTDRP program, despite its obvious drawbacks. But, most of the end-use customers indicated that they were not interested. Customers and their representatives also expressed different views on what would be required to induce participation. End-use customers indicated that higher benefits would be required, while the LSEs/CSPs were more concerned with standardization of the NYISO service with those offered by the other northeast ISOs. Both, however, agreed that the high costs of the required five-minute measurement telemetry were a significant barrier to participation.

To provide a frame of reference, workshop attendees were also provided comparable information about alternative market participation options: a Day-Ahead Ancillary Services bidding program, which would allow end-use customers to bid to provide ancillary services in the Day-Ahead Market to meet the reliability needs of the NYISO and an LSE-sponsored day-ahead bidding program, whereby the LSEs incorporates customer bids into its day-ahead bidding activities and shares the proceeds with the customers.[3] The main advantage of these options is that the curtailment commitment is made the day-ahead at posted market prices. In addition, because the estimated benefits of RTDRP based only on a reserve payment were so low, a variation on the RTDRP was offered whereby participants received an energy payment in addition to a reservation payment, to ascertain if short notice of the level of payment was the biggest barrier to participation, since such payments are inconsistent with the NYISO's vision for this program.

Among the choices offered, customers selected RTDRP with energy payments as their favorite, and the base RTDRP design as their last choice, which is not surprising since the energy payments increased the expected benefits of RTDRP participation ten-fold. For at least some customers, managing load in near real-time is apparently feasible, if the rewards are sufficient. However, many also expressed interest in the day-ahead ancillary service-bidding program, involving less risky bidding circumstances, which suggests such a program would be worth evaluating. The program provider respondents indicated either that they wanted none of the programs implemented, or if they had a strong preference, it was for the RTDRP with energy payments.

2003 Demand Response Program Enrollment

Table E-1 provides a detailed accounting of how participation in the demand response programs has changed from 2002 to 2003. The rows in the table represent the program options, which are defined in

	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 E-1. Change in Participation 2002 to 2003

[3] This can be accomplished by a customer submitting a price above which designated load is not committed to NYISO day-ahead clearing prices.

the first column. The second column indicates 2002 participation (number of subscribers) by program option. The next five columns of the table categorize changes in participation from 2002 to 2003 participation according to: a) re-subscriptions to the same option or migration to another program option (the third, fourth and fifth columns), b) those that left the program altogether (the sixth column), and c) new subscribers to the program option (the seventh column). The final column shows the net result – 2003 subscription to the program option.

In 2003, the number of participants in all demand response programs declined by about 10%.[4] Moreover, there was a substantial amount of churn in program participation. For example, 507 of the 2002 EDRP participants failed to re-subscribe in 2003. The loss of these participants, however, had little effect on the performance of EDRP load as a resource, since 41% of the EDRP dropouts in 2003 provided no load curtailment in any of the 11 EDRP event hours in 2002.

EDRP, which imposes no penalty for failure to curtail during events, was envisioned from its inception as providing customers with a low-risk way to get experience with participation in demand response. In designing the program, the NYISO anticipated that some would discover that their curtailment costs exceed their market value and drop out, but that others would realize that they could accommodate curtailments linked to system conditions, and migrate to the ICAP/SCR and DADRP programs to realize greater benefits. However, only seven of the 2002 EDRP participants switched to ICAP/SCR and none elected to participate in DADRP. It appears that EDRP is considered by most customers to be an end-state product, and not a stepping-stone to potentially more lucrative, but riskier, involvement in the NYISO's capacity and energy markets.

Table E-2 describes 2003 demand response participation by program option and NYISO pricing zone. Zones J (New York City) and K (Long Island) account for 69% of EDRP participants, but only 33% of curtailable load. These zones have an even greater disparity in ICAP/SCR; they account for 37% of participants but only 16% of total load enrolled. The difference is due, in large measure, to the large number of residential customers and small businesses in these zones that are aggregated for program purposes. Due to the relatively small curtailment per capita that characterizes participants in this area, and the high churn rate, building

[4] A single customer or an aggregation of customers defines a participant.

up the stock of curtailable load downstate, where the resources are most needed, will require the ongoing recruitment of new customers.

Zone	EDRP		DADRP		ICAP	
	#	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 E-2. 2003 Program Participation by Zone

The data in Table E-3 show the changes in participation in all three programs from 2001- 2003. In 2002, overall participation increased dramatically, by 1,570 customers, over the 2001 level. As discussed above, in 2003 there was a 10% reduction in participation, but the load pledged for curtailment remained about the same. While participation in ICAP/SCR declined slightly in 2003, the amount of load pledged for curtailment increased by over 20%. The new subscribers offered more of curtailable load per capita (3.7 MW) than what had been provided by the dropouts (2.0 MW), resulting in an increase in the average curtailable MW/participant. Curiously, almost none of the ICAP/SCR dropouts migrated to the more accommodating provisions of EDRP.

	EDRP		DADRP		ICAP	
	2001 to 2002	**2002 to 2003**	**2001 to 2002**	**2002 to 2003**	**2001 to 2002**	**2002 to 2003**
Dropped	117	508	6	0	34	76
New	1497	269	4	3	91	90
Transfers		33				7
Renewals	190	1021	20	24	117	116
	1687	1323	24	27	208	213

Table E-3. Participation Changes 2001-2003 (Number of Participants)

Strike Price Nominations for ICAP/SCR

As noted above, program providers indicated that nominating a strike price under ICAP/SCR was not perceived as difficult. But, do the nominations reflect differences in customers' outage costs, yielding, as one might expect a fairly uniform distribution of prices? Or, do other factors result in clusters of bids that make this resource lumpy and less divisible, and therefore more difficult to dispatch precisely?

Prior program experience seems to have influenced the bidding strategies undertaken by participants. Figure E-1 displays three bid curves comprised of the strike prices ICAP/SCR participants nominated, grouped according to the number of years they have participated in the program. First-year participant bids exhibit a bimodal distribution, with 40% bidding zero and over 50% bidding $500/MWh, the price cap. This suggests that these customers either wanted to be assured of being called, and submitted a very low strike price, or sought to avoid that result by submitting a high strike price. Second-year participants' bids were somewhat less clustered, 20% lying between zero and $450/MWh. Third-year participants' are quite diverse, and characterized by more low bids; about 80% of strike prices were less than $300/MWh. Perhaps these customers have learned that they should bid their outage cost, so that they get paid at least their direct cost of curtailing, and that way they will not regret the outcome of any individual event. An important consequence is that such bidding results in diversity that makes the resources more valuable to dispatchers.

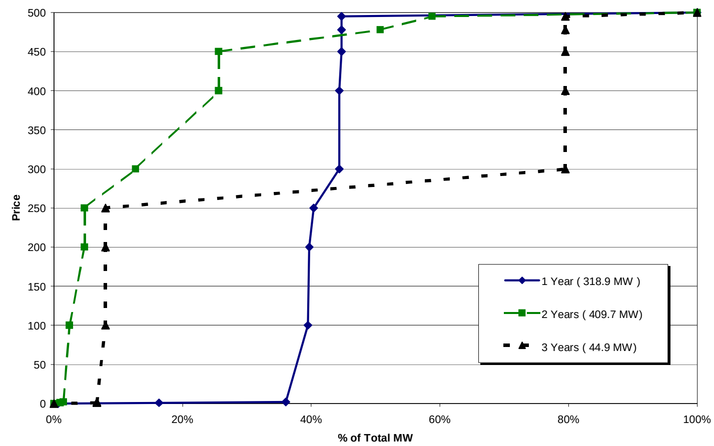

Figure E-1. ICAP/SCR Curtailment Bid Curves by Years of Experience

The Benefits of Demand Response

Curtailments undertaken under the auspices of EDRP and ICAP/SCR improve the reliability of the bulk transmission grid, but are now eligible to set market prices, thus if the curtailment payment level exceeds the marginal generation bid, the result of calling such events can be that real-time market-clearing prices are higher.

Conversely, DADRP curtailments scheduled in the day-ahead market and delivered in the real-time market, exert downward pressure on market prices that produce savings to buyers purchasing energy from the NYISO spot markets during those times.[5] Moreover, all customers realize benefits over the long run. By lowering price volatility, DADRP curtailments act to reduce the premiums that buyers of hedged supply pay because the alternative, purchasing from the spot market, is less risky. Finally, curtailments undertaken by DADRP participants can reduce the dead-weight losses that arise from the gap between the retail rate that customers pay and the cost of supplying their needs.

EDRP and ICAP/SCR Evaluation Results

In 2003, the EDRP and ICAP/SCR curtailment events were declared only during the period following the August 14th blackout. Because real-time market operations were suspended during part of this period, EDRP and ICAP/SCR curtailments had no explicit impact on market prices. Moreover, all available resources were called, so the new provision for partial dispatch based on nominated strike prices was not tested.

On August 15th, curtailments by EDRP and ICAP/SCR participants in effect allowed other customers, whose service had not been restored, to come on line faster. Service had been fully restored by the 16th, but reserves were at times deficit, and the inter-connections to other systems tentative. Program curtailments provided operators with more flexibility in dispatching generation units, and thereby contributed to maintaining reliability of New York's electricity system.

The value of improved reliability, established in previous program analyses, is calculated as the product of the change in the expected loss of load probability (LOLP) attributed to the curtailments, times the percentage of load deemed to be at risk, the product of which is the expected unserved energy, times the value of lost load. For August 15, the explicit unserved energy was identically equal to load curtailment, since for each MW curtailed, a MW of load was restored. On the subsequent day, the change in LOLP was set at .20 and the load at risk at .05%,

[5] In order for a DADRP curtailment bid to be scheduled, it must lower overall supply cost that would result from scheduling a generation (or DADRP) alternative.

the product of which is multiplied times the actual load during hour of the event to establish the expected unserved energy. The same VOLL value, $5.00/kWh, was used both days.

On August 15, 2003, the average hourly load reduction was 803 MWh, with 56% coming from EDRP participants, and the rest from ICAP/SCR participants, resulting in curtailment payments to participants of just over $5.9 million. The curtailment payment rate was $500/MWh for EDRP, and averaged $460/MWh for ICAP/SCR.[6] On August 16, 2003, a Saturday, the hourly average load reduction was 473 MWh, with 37% coming from EDRP participants, and almost two–thirds from ICAP/SCR participants, with curtailment payments of about $1.7 million.

The value attributed to these curtailments is described in Figure E-2. On August 15th, the programs are credited with providing over $50 million in reliability benefits, and an additional $3.5 million were generated on August 16. Overall, the ratio of benefits to program payments was almost 7:1, indicating that the curtailments dispatched by the NYISO were very cost effective in terms of delivered reliability improvements to consumers.

Outage cost = $5,000/MW

Date	System State	Benefits (million)
August 15	Recovering	$50.8
August 16	Fully Recovered	$3.5
Total Blackout Value of DR Resources =		$54.3

Total August event curtailment payments

August 15	$5.9 million	Total =	$7.6
August 16	$1.7 million		

Ratio Reliability Benefits to Curtailment Payments:
August 15 = 8.6
August 16 = 201
Overall = 6.7

Figure E-2. Estimates of Reliability Benefits August 15 and 16, 2003

DADRP Evaluation Results

Average prices in New York State have been increasing since 2001 in both the Real-Time and Day-Ahead markets, while price volatility has been on the decline. As Figure E-3 illustrates, the supply curve in 2003 is dramatically flatter at high loads compared to 2001. The price flexibility of the estimated supply curves, the curve's slope at its steepest segment, is three times less in 2003. Consequently, DADRP curtailments had a much lower impact on market prices in 2003.

[6] The lower average ICAP/SCR payment rate reflects the influence of the nominated strike price.

The total scheduled DADRP load reduction during the summer months of 2003 was 1,752 MWh, down slightly from that of 2002. All curtailments were in the Capital (90%) and Western (10%) zones, where prices are generally lower than downstate, especially compared to those of New York City or Long Island.[7] The average scheduled DADRP load reduction was 3 MW in the Capital Zone and over three times higher, 10 MW, in Western New York. Scheduled curtailments were on average about one-tenth of one percent of the corresponding day-ahead load, and the estimated reduction in the DAM LBMP was $0.03/MWh in the Capital zone and $0.05/MWh in the Western NY, substantially lower than in previous years.

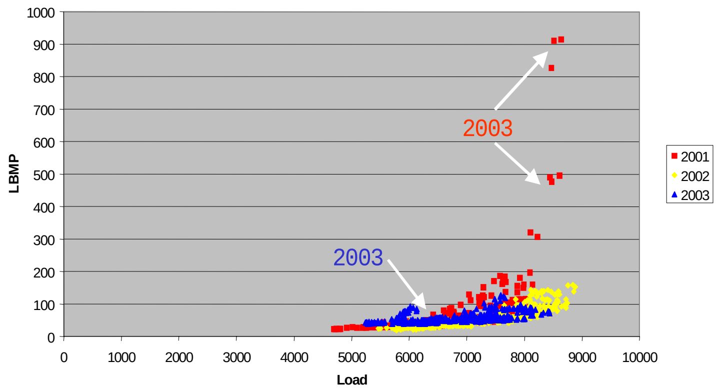

Figure E-3. Declining Day-Ahead Market Price Volatility
(Load vs. LBMP in the DAM, by Year, Western New York)

The effect of DADRP curtailments on 2003 market prices was very small compared to those of previous years (Figure E-4), and barely larger than the incentives paid out for curtailments. This is primarily the result of the majority of these bids being scheduled at relatively low prices, when the supply flexibility is nearly equal to one.

	Scheduled DADRP (MWH)	Collateral Savings ($ Mil.)	Reduced Hedge Cost ($ Mil.)	Total Benefits (Mil.)	Curtailment Payments (Mil.)
2001	2,694	$1.5.	$0.7	$2.2	$0.2
2002	1,468	$0.2.	$0.2	$.4	$0.1
2003	1,752	$0.05	$0.16	$.21	$0.2

Benefits measure savings by purchasers of electricity

Figure E-4. Market Price Impacts for DADRP Summer 2001-2003

Change in Net Social Welfare

When the price consumers pay are below the cost to supply those goods or services, both consumers and producers suffer from the less than optimal utilization of resources. In New York,

[7] No participants were enrolled in DADRP in any zones except the Capital and Western zones.

most electricity consumers are served under a rate that does not vary with the hourly supply cost, as measured by NYISO spot market clearing prices, resulting in lower net social welfare. By inducing customers to respond to marginal prices, especially when they are high, DADRP closes the gap between actual and optimal market performance.

However, at low prices and low supply flexibilities, the DADRP payments to curtail may not exceed the corresponding reduction in deadweight losses, and as a result the net social benefits of the program may be low, or even negative.[8] Estimates of net social welfare changes were developed for each year that DADRP has been in existence to compare the current year's results with those of previous years, where market price volatility was higher. The change in net social welfare attributed to DADRP scheduled curtailments was positive in 2001, when the supply curve exhibited the eponymous hockey stick shape. But, in 2002 and 2003, with a relatively flat supply curve, the net social change was negative. In other words, the payments made to participants to curtail were greater than the improvement in resource usage they provided.

Table E-4. Net Social Welfare Impacts of the DADRP Program

Summer of	Curtailment Payments	Reduction in Deadweight Loss		Change Net Social Welfare
		Day-Ahead	Real-Time	
2001	$213,944	$129,567	$127,365	$42,737
2002	$110,294	$59,109	$27,266	($23,919)
2003	$121,144	$30,371	$18,502	($72,271)

These negative benefit contributions are small in comparison to market transaction volumes. Nonetheless, the prospect of such an outcome militates for changes in the program that reduce the incidence of negative welfare contributions, but in a way that does not abate incentive to bid curtailments when prices are high.

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[8] When the supply curve is flat, the variance of an average price rate from the marginal supply cost is small. That difference defines deadweight loss. For there to be an increase in net social welfare, the rate/price difference, on a unit basis, must exceed the incentive paid to the participant to curtail, the spot market price. A complete graphic discussion is provided in the report.

Chapter 1 – Report Overview

Background

The potential improvements to electricity market performance from exposing wholesale transactions to retail price responsiveness have been well documented. This is especially true in situations where the possibility for capacity shortfalls, and resulting high prices, is uncomfortably large. A price topology that only periodically exhibits high prices is conducive to programs that direct customers to curtail or shift load under very specific conditions. To ensure that the maximum market benefits are realized, the New York Independent System Operator (NYISO) has, for the past three years, operated programs to induce retail customers to adjust their consumption according to prevailing wholesale market conditions. Accordingly, these price-responsive load (PRL) programs have been designed to integrate, to the extent possible, load management actions by customers into NYISO operations.[1] Customers can participate in any program for which they qualify by registering with the NYISO, and curtailing their electricity usage under the program provisions and protocols. Some programs also allow customers to operate distributed generation (DG) during curtailment events to reduce the net load taken from the system, and mimic a load curtailment.[2]

PRL programs are offered in three of the five markets the NYISO oversees. Two of these PRL programs provide capacity that can be dispatched to the market, while the third provides scheduled energy service.

By utilizing load management capabilities to augment the supply of generation used by the NYISO as standing reserves, the **Installed Capacity Program/Special Case Resources (ICAP/SCR)** program (first implemented in 2000) can be critically important in capacity-

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[1] The provisions of the PRL programs are authoritatively described in the program manuals available from the NYISO.

[2] The NYS Department of Environmental Conservation regulates the operation of small, noncommercial electrical generation units, limiting the conditions under which many such units can operate and thereby limiting participation in NYISO PRL programs.

deficient regions of the State. Customers that qualify their load curtailment capability can sell their ICAP/SCR capacity, which generates a stream of payments that the other two PRL programs do not, a feature appealing to many customers in spite of the penalties assessed for non-compliance.[3] The NYISO exercises its demand call on ICAP/SCR during periods of reserve shortfalls.[4] In addition, an ICAP/SCR participant receives an energy payment when they curtail, equal to the higher of the prevailing locational-based marginal price (LBMP) or the strike price it nominated upon enrollment.[5]

The **Emergency Demand Response Program (EDRP)**, implemented initially in 2001, creates a unique category of ancillary services that are valuable in maintaining short-term system reliability.[6] The NYISO notifies participants at least two hours in advance of when curtailments are needed to supplement conventional generation resources. Customers that curtail during the specified periods are paid either the LBMP or $500/MWH, whichever is higher. As the result of a 2003 program change to reflect scarcity pricing, the $500/MW floor price can set the real-time LBMPs during EDRP events.

In part to help ensure competitive bidding behavior, the **Day-Ahead Demand Response Program (DADRP)**, also implemented in 2001, allows load curtailment resources to compete directly against generation in the NYISO's day-ahead auction. Participants submit demand reduction bids that are treated as comparable to supply bids of generators. If scheduled, they receive market prices for load reductions that are scheduled for the next day. By bidding directly with generators, prices in the day-ahead market can be set by scheduled DADRP demand reduction bids. If a participant fails to fully deliver a scheduled demand reduction bid, any shortfall is settled at the higher of the day-ahead or real-time market price. During the first two years of DADRP operation, there was also an additional 10% penalty.

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[3] Customers that sell their ICAP/SCR through the NYISO deficiency auction receive monthly payments.

[4] Customers are no longer able to participate in both ICAP/SCR and EDRP programs, but they could do so in both 2001and 2002, in which case they received PRL benefits only when the NYISO coincidently call for curtailments under both programs.

[5] Participants nominate a strike price from $0-$500/MWH, which are used to dispatch curtailments when the amount of load relief needed is less than the amount enrolled. The strike price can be changed monthly

[6] The NYISO is currently working to expand participation of PRL resources both in the real-time market and in ancillary service markets.

Overview of Program Performance

During the first three years of operation, these PRL programs have met with considerable success. For example, in the first year of EDRP operation (2001), 292 participants supplied over 400 MW of sustained load reduction, over a total of 17 hours on three consecutive summer days, when system reserves were short.

Enrollment in EDRP increased dramatically in 2002, to 1,711 customers (some of whom were enrolled in both EDRP and ICAP/SCR). Moreover, EDRP participants in 2002 subscribed more load for curtailment, 1481 MW, representing a more than three-fold increase from 2001. Approximately 58% of 2001 EDRP participants re-enrolled in the 2002 programs, an indication of high program satisfaction.[7]

In 2002, curtailments under EDRP were called on two consecutive days in April, and one day in each of the months of July and August. In the April events, curtailments were called for only in the downstate pricing zones. EDRP curtailments on those days were modest, about 70 MW on average, due to the early date on which they occurred. Few of the previous summer's participants were prepared to curtail so early in the season, and recruitment for the summer of 2002 had just begun. The July and August events were declared statewide. For these events, average hourly curtailment performance over the 10 curtailment hours was about 668 MW, ranging from an hourly low of 550 MW to a high of over 800 MW.[8]

As a result of the program changes, customers were no longer able to enroll in both EDRP and ICAP/SCR programs in 2003. By summer's end, there were 1,321 customers enrolled in EDRP, somewhat below the high of 1,534 customers that were in EDRP only in 2002.

In 2003, EDRP events were called only for the two days following the blackout of August 14, 2003. Since these EDRP customers were asked to remain off the system during those days, they, along with participants in ICAP/SCR gave NYISO the opportunity to pick up additional non-interruptible load of 800-900 MW at a total payout of between $6 and $8 million.

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[7] See Neenan Associates (2002) for a detailed evaluation of the 2001 programs.

[8] See Neenan Associates and CERTS (2003) for a detailed evaluation of the 2002 programs.

However, according to the system operators, there is no unambiguous way to estimate how much longer restoration would have taken without the EDRP and ICAP/SCR programs.

Over the past three years, participation in the Day-Ahead Demand Response Program (DADRP) has been modest in comparison to the other two programs. In 2001, over a dozen customers subscribed to this adaptation of the real-time pricing principle to wholesale energy markets, providing over 25 MW of load reduction coincident with peak summer prices.[9] Despite an increase in customer enrollment, from 16 to 24 customers, customer-bidding activity in the 2002 DADRP decreased compared to 2001; during the summer of 2002, scheduled bids accounted for only 55% of the MWs scheduled in 2001.[10] In 2003, 27 customers enrolled in DADRP, and the scheduled load reduction during the summer months was about 70% of the 2001 level.

Purpose of the Report

In each of the three years of PRL program operation, the NYISO has undertaken an extensive review and evaluation of both EDRP and DADRP. This report contains the third in that series of yearly evaluations of the performance of the New York Independent System Operator's (NYISO) price responsive load (PRL) programs. We assess the performance of both EDRP and DADRP for the year 2003.[11] The evaluation is based on data collected to populate a project database designed for that purpose.

There are several important aspects to the evaluation of the PRL programs. The effects of PRL program performance on electricity markets are among the most important. These major **market effects** include:

- Estimated changes in electricity prices;

[9] In conventional retail real-time pricing programs, customers respond to posted market-clearing prices, which do not directly take into account the possible price response. DADRP curtailment bids by end-use customers are offered in advance and fully integrated in the price setting mechanics, thereby insuring that they exercise influence over the level of prices all customers face.

[10] See Neenan Associates (2002) and Neenan Associates and CERTS (2003) for a detailed evaluation of the 2001 and 2002 programs.

[11] See the NYISO December 1, 2003 filing with FERC for a summary of the results presented herein.

- Estimated collateral benefits—redistribution of payments from generators to customers, or vice versa;
- Program payments by NYISO to participants ; and
- Estimated reduction in the risk of an outage.

An additional cost is the payments made by LSEs to ICAP/SCR participants, which is not included in this analysis.[12] Another major component of this year's evaluation is an examination of the implications of changes, introduced in 2003, to PRL provisions and protocols.[13]

In the evaluation of PRL programs, it is also critical to estimate the effects of EDRP load reduction on system security and its value in terms of reducing the expected value of unserved energy. These effects of EDRP have been addressed in previous evaluations. In contrast, since DADRP is designed to improve market efficiency, it is important to know the effect of DADRP load reductions on the size of the deadweight social losses in the day-ahead market.[14]

In 2003, the EDRP and ICAP/SCR programs were called only during the recovery from the August 14th blackout. Also, there was a decision not to attempt to run a "live" real-time market, and instead to set hourly prices in the real-time market at the corresponding day-ahead prices. Because real-time prices were set administratively, there are no 2003 **price effects** to estimate in the real-time market. However, it is critical to estimate the value of these resources to **system reliability**, as the system was re-built after the blackout. This part of the evaluation has required some modifications to the methodology for valuing these resources when system-wide

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[12] Customers that sell ICAP/SCR directly to LSEs do so under bilateral contracts, the terms of which are not publicly available.

[13] These include: a) uncoupling of EDRP and ICAP/SCR programs (after the substantial growth in EDRP enrollment and load subscription during 2002); b) establishment of a bid curve for ICAP/SCR resources and the imposition of a $500/Megawatt-hour (MWh) bid cap; c) imposition of a $50/Mwh bid floor price for DADRP; d) extension of participation in DADRP bidding to demand resource providers, e) removal of the 10% non-compliance penalty for DADRP; and f) impact of scarcity pricing rules, if adopted, during PRL events. Given the post-blackout-only invocation of EDRP in 2003, much of this part of the evaluation must be in terms of examining the potential effects, using information about participation and price response from the two previous years' evaluations.

[14] A complete explanation of the application of welfare theory to these PRL programs is provided in Appendix 3-A.

reserves are short of required levels. Another issue of importance in this regard is the extent to which the value of these resources is location specific.

For purposes of the 2003 evaluation, market effects can only be estimated in the DAM due to the scheduling of DADRP bids, but as suggested above, this year's evaluation is the first to focus also on estimating DADRP's contribution to market efficiency by calculating reductions in social deadweight welfare losses resulting from scheduled DADRP bids. Such an analysis is a critical component in the examination of the long-term efficacy of DADRP. Since this part of the evaluation of DADRP was not conducted previously, we also report similar calculations for 2001 and 2002, to put the discussion of the long-term efficacy of DADRP into a proper 3-year perspective.

To place the DADRP analysis and evaluation in proper perspective, we begin with some descriptive data to characterize the nature of load and LBMPs in the DAM and RTM. The data cover several major zones or groups of zones for which separate hourly prices are determined. These data are compared with similar data for 2001 and 2002, to see if there are any major differences from previous years in the general level and variability in prices and demand. These observations help determine how best to re-calibrate the electricity supply models needed to estimate the market effects of DADRP.[15] We estimate these supply models for the spring and summer months of 2003.[16]

We go on to characterize the changes in LBMP due to changes in load served in percentage terms by using the price flexibility of supply: the percentage change in price due to a one percent change in load served. We then provide the results of the analysis designed to estimate the value of EDRP resources during and immediately after the system blackout. This

[15] This re-calibration is designed to exploit ways to improve the methodology by: a) examining planning and operational data that better characterize the impact of dispatched PRL resources on system reliability; b) re-specifying real-time supply models to reflect the impact of new pricing rules invoked when PRL resources are dispatched; and c) re-specifying the day-ahead supply flexibility model to capture contemporaneous market supply conditions. In an effort to test formally for any systematic changes in the NY electricity markets, we made an attempt to pool the data for the past three summers and estimate price flexibilities for each of the past three years, see Appendix 2-C.

[16] A complete explanation of the application of welfare theory to these PRL programs is provided in Appendix 3-A.

discussion is followed by the evaluation of DADRP, including the extended social welfare implications. In keeping with our attempt to identify any emerging trends in the markets or the performance of these PRL programs, we make every attempt to compare the finding in this year's evaluation with those of the past two years.

Chapter 2 – Electricity Demand and Prices in New York

To place the evaluation into proper perspective, it is helpful to examine some summary statistics for hourly prices (LBMPs) and demand for the three summer months of June, July, and August. Our discussion focuses on 2003 data for the afternoon hours (12:00 noon through 7:00 p.m.), since it is during these periods that most curtailment events occur.[1] Some comparisons with the data for both 2001 and 2002 also set the stage for better understanding of the nature of the 2003 short-run supply curves in both the DAM and the RTM.

In the discussion of the price and demand data, and in the supply analysis below, the NYISO pricing zones for New York City and Long Island are treated separately. Because it is the NYISO's policy not to report load separately for New York City and Long Island, we report prices separately, but aggregate those two zones for purposes of presenting summary load data. However, for evaluation purposes, separate supply models are estimated for New York and Long Island.[2] For both modeling and discussion purposes, the remaining nine zones are aggregated into two "super" zones. The Capital Zone and three zones in the Hudson Valley between the Capital Zone and New York City, are combined into a single region (Capital-Hudson "super" zone or region).[3] The five zones west of the Total East transmission corridor are combined into the

[1]There are two reasons for focusing on these hours. First, this is the period of the day during which demand across the State peaks; thus one would expect prices to be highest during the afternoon hours. As is seen in the report by Neenan Associates (2002) prices generally rise from early to mid-afternoon and then fall in each of the pricing zones. The same is true of load in both the day-ahead and real-time markets. There are isolated instances of high prices at other hours during the day, but they do not occur frequently enough to attempt modeling these morning hours along with the afternoon. These circumstances would suggest that EDRP would most likely be called during this time of the day. The second reason for the focus on these hours is that careful examination of the data has revealed that the structure of the short-run supply relationship during this period is distinct from that during other times of the day. It was also apparent in 2003 that the hour from noon to 1:00 p.m. should be added to the data set for analysis. For comparison with previous years, we included summary data for this additional hour. Thus, the summary data for 2001 and 2002 reported here are slightly different than what is found in Neenan Associates (2002) and in Neenan Associates and CERTS (2003).

[2] Therefore, throughout this report loads in these two zones are either added together or are merely indexed in some fashion for reporting purposes to reflect loads relative to the mean or maximum load.

[3] This aggregation is slightly different from that used in the past two years in which the Capital zone was treated separately (Neenan Associates, 2002 and Neenan Associates and CERTS, 2003).

Western New York "super" zone or region. By combining zones in which prices seem to be similar, we facilitate the analysis by improving the estimates of the short-run supply relationships. Figure 2.1 contains the boundaries of these aggregate zones in relation to the boundaries of the 11 individual pricing zones.[4]

For these aggregate pricing zones, Charts 2.1 through 2.4 contain average load and load-weighted LBMPs, for both the DAM and RTM for the three summer months of 2001, 2002, and 2003.[5] The data used to construct these charts are reported in Appendix 2A, Tables 2-1A through 2-3A.[6] To facilitate comparisons, the price and demand data for all three years in each aggregate zone and market are also plotted in Figures 2-1B through 2-8B of Appendix 2B.

A Comparison of Electricity Demand and Prices in New York, 2001, 2002, and 2003

For the afternoon hours of summer 2003, fixed bid load in the DAM averaged 19,039 MW statewide (Table 2-1A, Zones A-K, Mean DAM Load).[7] In real-time, load served averaged 21,820 MW (Table 2-1A, Zones A-K, Mean RT Load), nearly 15% higher than in the DAM. The Capital-Hudson super zone displayed the most dramatic instance of this tendency – with an average RTM load for the specified hours that was 127% of corresponding DAM loads. In Western New York, the difference was only 7%, while in the downstate zones average load in real time exceeded that scheduled in the DAM by about 21%.

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[4] To create these "super" zones, loads for the individual component zones are simply added together. In contrast, LBMPs for these aggregate zones are calculated as load weighted averages of LBMPs for the individual component zones. This weighted averaging process is the logical way to calculate these aggregate zonal prices because the 11 individual zonal LBMPs are currently constructed as a load weighted average of the individual bus prices within a zone.

[5] Fixed bid load is the load bid into the DAM that the LSEs or other market participants scheduled in the DAM regardless of the market-clearing price. It also includes load that is scheduled in the DAM, but is hedged under bilateral contract.

[6] This section makes multiple references to the data in Table 2-1A. The panels of this table refer to different zones or collections of zones. Within a panel, the rows report various statistical measures of the data. The columns refer to load and LBMP, for the DAM and the RTM. We will refer to specific items in Table 2-1A as follows: "(Table 2-1A,Zones A-K, Mean DAM Load)" refers to the value (19,039) in the "Mean" row, the "DAM Bid Load" column, of the "New York State (Zones A – K)" panel of Table 2-1A.

[7] Fixed bid loads are requests by LSEs to buy specified amount of energy in the day-ahead market at the market-clearing LBMP.

The statewide variability in RTM load served during these summer hours, measured either by the standard deviation or the coefficient of variation (e.g., the standard deviation divided by the mean), was substantially larger than the variability in DAM load - with standard deviations of 3,161 vs. 2,354, respectively (compare Table 2-1A, Zones A-K, Std Dev RT Load with Table 2-1A, Zones A-K, Std Dev DAM Load). This is true for the aggregate zones as well, with the smallest difference in variability in Western New York.

Statewide, average summer prices for these afternoon hours were rather modest, both in the DAM and in real time. Statewide, the load weighted average prices were (coincidentally) $70/MW in both the DAM and the RTM (Charts 2.3 and 2.4 and the appropriate columns of Table 2-1A, Zones A-K). Downstate average prices were somewhat higher. In the DAM, prices averaged $79/MW on Long Island and $84/MW in the City (Chart 2.3 and Table 2-1A, Zone K, Mean DAM LBMP, and Table 2-1A, Zone J, Mean DAM LBMP). In the RTM, prices were somewhat larger still, averaging $81/MW on Long Island and $85/MW in the New York City (Chart 2.4 and Table 2-1A, Zone K, Mean RT LBMP and Table 2-1A, Zone J, Mean RT LBMP). For the Capital-Hudson Region, average prices were $65/MW in both markets (Charts 2.3 and 2.4 and the respective columns of Table 2-1A, Zones F, G, H, and I), while in Western New York average prices were lower: $55/MW in the DAM and $51/MW in the RTM (Charts 2.3 and 2.4 and the respective columns of Table 2-1A, Zones A,B,C,D and E).

It is interesting to contrast these values for 2003 loads and LBMPs with the corresponding values in earlier years. Compared to 2001, statewide summer-hour load-weighted average LBMPs in both the DAM and RTM were higher in 2003 (by $2/MW and $4/MW, respectively). This increase occurred despite the fact that statewide average loads were slightly lower (91% and 99% of the 2001 levels for the DAM and RTM, respectively). These conclusions come from comparing data in Charts 2.3 and 2.4, and in the respective columns for Zones A-K of Tables 2-1A and 2-2A. These differences can be explained in part by activity in downstate markets, where average load served in 2003 in the DAM was only 82% of that in 2001, but was nearly identical in the RTM across both years. Weighted average prices for New York City and Long Island combined were higher in 2003 by $6/MW in the DAM and $3/MW in the RTM.

Most of this difference, however, was due to the fact that prices in New York City for these summer afternoon hours averaged $10/MW higher in 2003 than in 2001.

In contrasting the 2003 values to those of 2002, (see Charts 2.3 and 2.4 and Tables 2-1A and 2-2A), it is also true that the 2003 weighted average statewide prices are somewhat higher in both markets ($70/MW vs. $66/MW in the DAM and $70/MW vs. $60/MW in the RTM). However, in comparing these years, it is in the RTM that average demand statewide is slightly lower in 2003 than in 2002 (96% of that in 2002). Average load served in the DAM statewide is about 1% higher in 2003.

Given that available ICAP statewide during these months was on average about 12% higher in 2003 than in 2001 (unpublished NYISO data), one might have expected somewhat lower prices in 2003, if one could assume that the availability of additional capacity statewide would lead to a more competition among suppliers, and lower spot market price.[8] However, this seemed not to be the case. Again, much of the source of the slightly higher statewide average prices comes from differences in average price in New York City. Average LBMP in the DAM for afternoon summer hours in New York City was $84/MW, compared with $74/MW in 2001 (Charts 2.3 and 2.4 and the DAM LBMP columns for Zones A-K of Tables 2-1A and 2-2A). In the RTM, average LBMP for afternoon summer hours in New York City was $85/MW in 2003, but only $75/MW in 2001 (Charts 2.3 and 2.4 and the RT LBMP columns of Tables 2-1A and 2-2A). Thus, either this additional statewide ICAP capacity was not available to New York City, or generator bids were consistently somewhat higher, perhaps due to increases in fuel prices over the two years.

With respect to the higher **average** prices in 2003, without having access to actual bid data, it is difficult to attempt any further explanation. Another interesting contrast of 2003 with earlier years focuses on price **variability**. While the relative variation in load across all three years is about the same, as measured by the coefficients of variation (see the DAM and RT Load

[8] The increase in ICAP is due to adoption of new protocols under which the NYISO purchases ICAP in addition to the 15% standard in the monthly deficiency auction if the offer prices are below the value to consumes, as indicated by the ICAP demand curve.

columns of the Coeff of Var rows of Tables 2-1A through 2-3A), the relative variation in prices in the RTM fell dramatically. In 2002, for example, the statewide coefficient of variation for LBMP in the RTM was 1.08, and it ranged from 1.38 in the West to a low of 0.92 on Long Island (Chart 2.6). In 2001, the coefficient of variation was 1.11 statewide, while it ranged from 1.34 in New York to 1.02 on Long Island (Chart 2.6). Put differently, in these two years, the standard deviation in prices was larger than average prices statewide, and larger or nearly so in the aggregate pricing zones. In contrast, 2003 saw the relative variability in prices drop dramatically; the standard deviation in RTM prices statewide was only 0.36 as large as mean prices, and in no aggregate zone did the coefficient of variation in prices exceed 0.45 (Chart 2.6). The three-year trend is for average prices to increase while price volatility decreases.

In the DAM, the relative variation in **statewide** weighted average prices was nearly identical in all three years (coefficients of variation of 0.45, 0.46, and 0.43, in 2001, 2002, and 2003, respectively, Chart 2.5). In 2003, the relative volatility in prices was lower for the individual zones than for the statewide average (Chart 2.5). In contrast, the zonal prices were much more volatile than the statewide average in both 2001 and 2002 (compare coefficients variation for LBMP in the DAM across years in Chart 2.5). This contrast (volatility of the statewide average less than that of its component zones) means that prices in at least some zones were negatively correlated (i.e. moved in opposite directions) during 2001 and 2002.

Again, without more detailed information about the bids, etc., it is not possible to sort out the reasons for the differences in price variability in both the DAM and the RTM across years. What is clear, however, is that many of the volatility-producing price spikes that occurred in the various super zones, in both the DAM and the RTM, in 2001 and 2002 were absent in 2003. For visual evidence of this difference in price spiking, see the plots of load vs. LBMP in the Figures 2-1B through 2-8B in Appendix 2B. Put differently, the “hockey stick” nature of the short run supply curves found in both 2001and 2002 is largely absent in 2003. As is seen in the next sections, this clearly has important implications for modeling supply, and for the size of the estimated price flexibilities of supply that relate the percentage change hourly LBMP to a one percent change in demand. These flexibilities in turn affect the size of the market effects of the PRL programs.

Characteristics of the Short-Run Electricity Supply Curves

To assess the price-mitigating effects of either DADRP or EDRP on the DAM and the RTM for electricity in New York, we must quantify the change in the market-clearing price due to changes in the amount of load reduction by these PRL programs.[9] This task requires knowledge of the supply side of the market. A detailed discussion of the specification of our supply modeling methodology is in Neenan Associates (2002). For completeness here, this methodology is outlined below geometrically, and the detailed algebra is reported in some detail in Appendix 2C.

The general underlying nature of these short-run supply functions is captured by the stylistic "hockey stick" shape—being relatively flat at low and moderate loads, but then rising, perhaps sharply, as load nears system capacity (e.g., Figure 2.2). The curves are so much steeper at loads near capacity that they appear to have separate regimes – to represent a different market structure. (Figures 2.3 and 2.4). In fact, these regimes reflect a market characterized by points of discontinuity due to the underlying indivisibilities in supply. In practice, these separate regimes are estimated as piece-wise "spline" functions with different intercepts between the regimes (see Figure 2.4). There may also be data points associated with high loads but low prices (see Figure 2.5), which seem at odds with the general nature of supply. We capture these effects, when they exist, by including variables, such as measures of transmission congestion, that shift the slope of the supply curve. These shifts are illustrated in Figure 2.6.

In turn, it is the supply price flexibilities, derived from these estimated supply curves, that are used to estimate the market impacts of PRL load reduction. These supply price flexibilities, defined as the percentage change in price due to one percent change in load, are used to calculate the change in prices due to a change in load.

The estimated supply curves for the DAM and the RTM for the two specific NYISO pricing zones and the two "super" zones described above are reported and discussed in detail in

[9] The programs allow customers to operate certain on-site generation units to reduce the net load they take from the system can claim the unit output as a curtailment.

Appendix 2D. For purposes here, it is sufficient to discuss the supply flexibilities for that part of the "spline" formulation associated with the highest levels of load served. It is these segments of the supply functions that are most relevant to estimating the market effects of PRL programs, since it is primarily at times when load served and/or prices are highest that PRL load reduction is scheduled or called.

These average price flexibilities of supply in the DAM and the RTM are reported in Charts 2.7 and 2.8 and in Appendix 2A, Tables 2-4A and 2-5A, respectively. As noted during the discussion of load served and LBMPs above, it appears that the supply relationships for 2003 are quite different from those in previous years.[10] Thus, for purposes of comparison, the corresponding price flexibilities of supply for both 2001 and 2002 (found in Neenan Associates, 2002 and 2003, respectively) are also reported in the charts and tables.[11]

Price Flexibilities in the DAM

There are a number of important conclusions one can draw about the short-run supply of electricity in New York by examining these price flexibilities of supply. Perhaps the most striking conclusion is that, for the highest loads served, LBMPs in the DAM in 2003 are much less responsive to the changes in load than in previous years (Chart 2.7 and Table 2-4A). The ranges in the price flexibilities in the previous two years were much larger as well. These results are

[10] These substantial differences became apparent in the supply modeling which is described in greater detail in Appendix 2D. It is clear that in all three years, there are substantial "regime" changes in supply when moving from points of low load to high load. There were, however, apparent regime changes across years as well. We were unable to capture these yearly differences by dividing load by capacity as we thought might be the case initially. Therefore, as explained in Appendix 2D, the data were not pooled. Separate supply curves were estimated using only 2003 data.

[11] The supply price flexibilities in the DAM will also be used in one of the new components in this year's evaluation--the three-year assessment of the welfare effects of DADRP. It becomes clear below that because bids in DADRP were accepted when fixed bid load was relatively low, price flexibility in the first part of the "spline" function are also used in the DADRP evaluation. While not discussed in this section above, they are reported in Appendix 2D. Reference will be made to them appropriately in some sections below.

consistent with the general lack of price spikes in 2003 that would otherwise give the supply curve a dramatic "hockey stick" appearance.[12]

For 2003 in New York City, for example, a 1% increase in load would increase LBMP in the DAM by an average of 3.53%, which is nearly identical to the value for 2002 of 3.55%. In 2001, however, a 1% increase in load would have led to a price increase of 9.42% (Chart 2.7 and Table 2-4A, Zone J, Average column).

The next most price responsive region is the aggregate zone consisting of the Capital Zone and the three zones in the Hudson River Valley (Capital-Hudson Region). In this area of the state, LBMP in the DAM would increase by 1.86% for every 1% increase in fixed bid load (Chart 2.7 and Table 2-4A, Zones F, G, H, and I, Average column). This result is not directly comparable to those in previous years where a separate supply function was estimated for the Capital Zone. However, in both the Capital Zone and the Hudson River Region for 2002, the average supply price flexibilities were more than twice the combined 2003 estimate (Chart 2.7). In these two regions for 2001, the price flexibilities were substantially higher still, averaging nearly 8.50 (Chart 2.7).

In Western New York, the supply price flexibility in the DAM averaged 1.38 during the summer of 2003, compared with 4.21 and 9.38 in 2002 and 2001, respectively (Chart 2.7 and Table 2-4A, Zones A, B, C, D, and E, Average column). Further, there was virtually no variation in this price flexibility in 2003, while over the past two summers, the supply price flexibility ranged from a low of 1.46 in 2002 to a high of 18.08 in 2001 (Table 2-4A, Zones A, B, C, D, and E, Min and Max columns).

The results for Long Island are very similar to those in Western New York. In 2003, a 1% increase in fixed bid load in the DAM would lead to an average 1.24% increase in the DAM LBMP. In contrast, the price responsiveness averaged 6.52 and 5.05 in 2002 and 2001, respectively (Chart 2.7 and Table 2-4A, Zone K, Average column). Again, there was almost no

[12] From a modeling perspective, it is also significant that in 2003, all but one of the supply models (Long Island in the RTM) required only one knot, indicating only two pricing regimes were needed to represent the market.

variation in the supply price flexibility around the means this year and in 2001, but it ranged from a low of 1.46 to a high of 11.68 in 2002 (Table 2-4A, Zone K, Min and Max columns).

Price Flexibilities in the RTM

As one might expect, the average price flexibilities in the RTM in all four regions are higher in 2003 than they are in the DAM (compare Charts 2.7 and 2.8 and Average columns of Tables 2.4A and 2.5A). This is consistent with the results from the past two years as well. Furthermore, since there were also few if any dramatic price spikes in the RTM, it is not surprising that the average supply price flexibilities in the RTM for 2003 are significantly lower than in previous years as well. With the exception of Long Island, there is little variation about the means for RT LBMP for this year, as is the case of the DAM. There was considerable variation about the means in all regions in previous years.

Perhaps the best way to characterize these differences is that in two of the areas, the average price flexibilities in 2003 were less than half their values in previous years. For New York City, the average price flexibilities were 5.86, 12.82, and 14.52 in 2003, 2002, and 2001, respectively (Chart 2.8 and Table 2-5A, Zone J, Average column). In Western New York, the average price flexibility for the highest loads served were 3.40, 6.67 and 6.44, in 2003, 2002, and 2001, respectively (Chart 2.8). On Long Island, the average supply flexibilities were similar for 2003 and 2002 (5.96 and 5.16, respectively), but in 2001, a 1% change in load would have led to nearly double the change in price (10.40%). Price volatility has reduced substantially over the past three years.

Consistent with these results, the average price flexibility in the new Capital-Hudson Region averaged 2.54 in 2003 (Chart 2.8 and Table 2-5A, Zones A, B, C, D, and E, Average column). This is half of the average value for the average of the two separate estimates for the Capital and Hudson River Regions for 2002 (5.33), and only a third of the average value for 2001 of 8.52 (Chart 2.8).

Some Conclusions

There are some important conclusions to be drawn from this comparative analysis of supply price flexibilities for the past three years. First, it is true that the average price flexibilities of supply are substantially smaller than in the previous two years, in both the DAM and the RTM. It follows from these empirical results that some of the market effects of the demand reduction programs will likely be less dramatic than in previous years. However, in all zones modeled, the flexibilities remain larger than unity. Thus, when load is relatively high, a one percent change in load does lead to a larger change in LBMP, in both markets and all regions.

Further, it might be tempting to conclude from both the summary data and these modest flexibility estimates that problems with electricity price variability in the New York markets are substantially under control. However, the 2003 summer in New York was relatively cool, and such a conclusion would be premature indeed.

Figure 2.1: Estimated Price Flexibility Zones

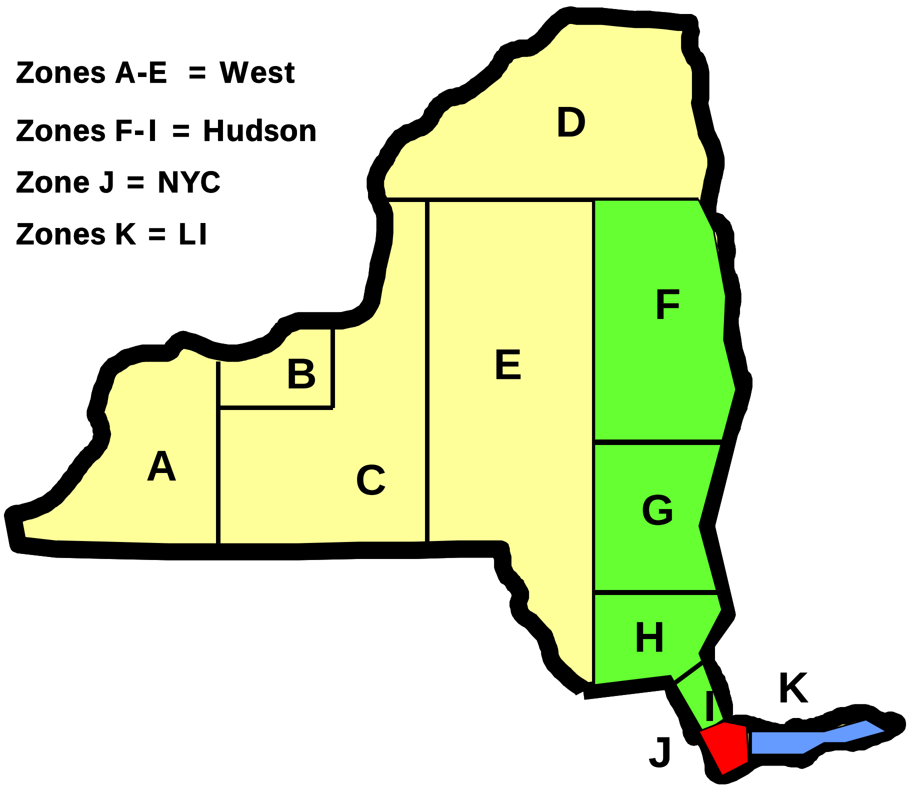


Figure 2.2: Scatter Diagram of LBMP vs. Load

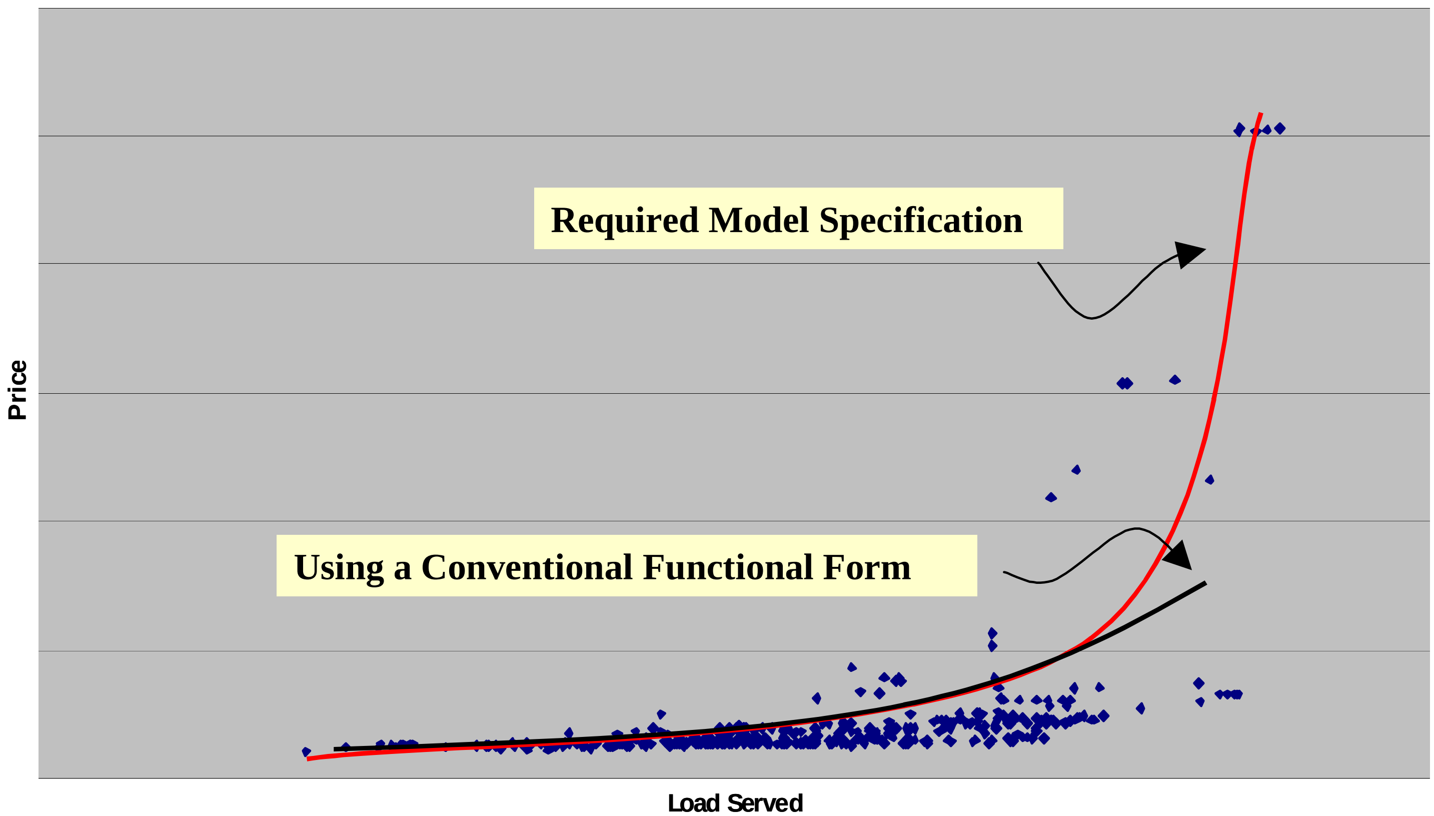
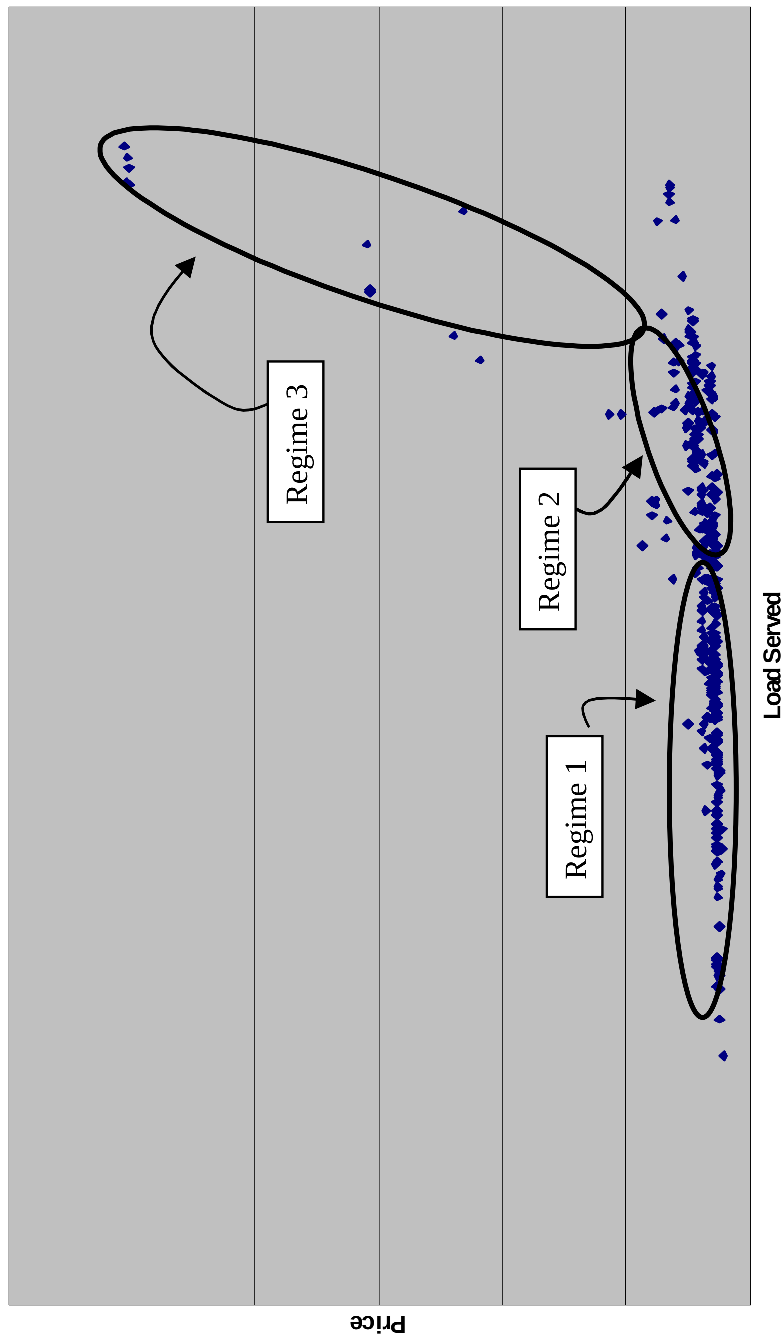


Figure 2.3: Different Supply Regimes



Neenan

Figure 2.4: "Spline" Model Specification

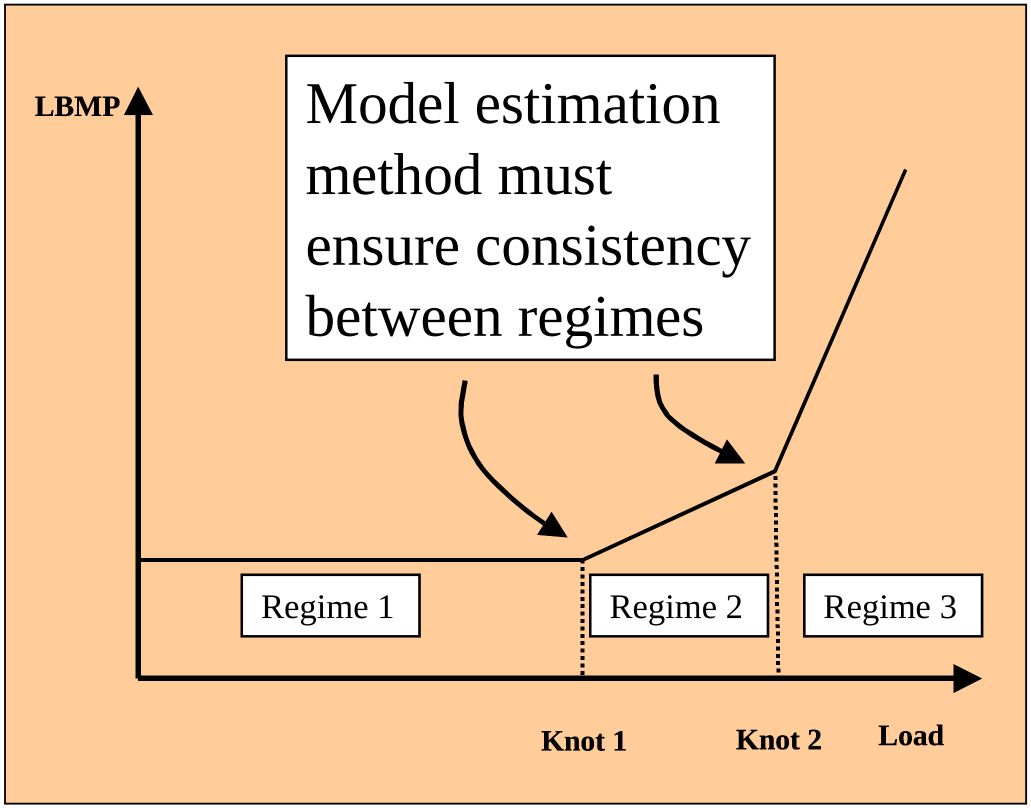


Figure 2.5: Modeling Apparent Outliers

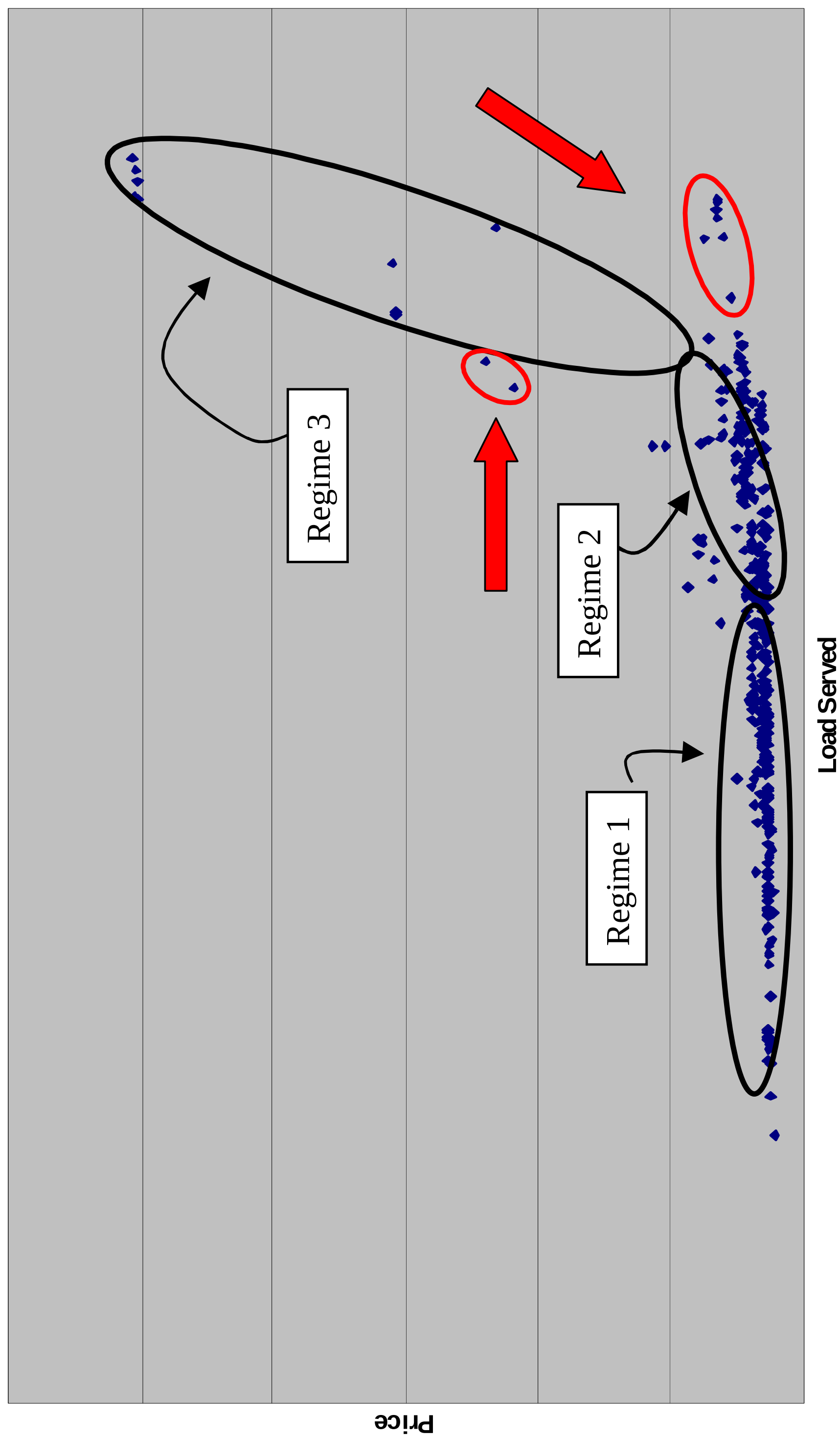
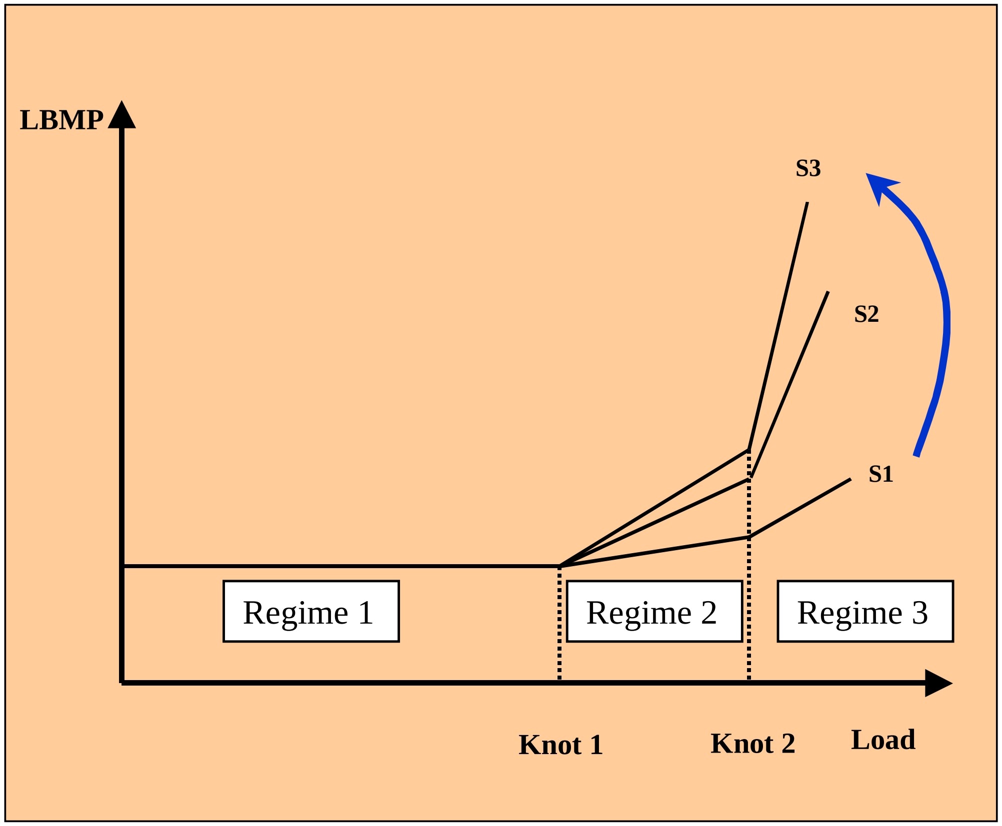


Figure 2.6: Final Model Specification



Supply Shift due to:

- Transmission Constraints,
- Generator Availability,
- Demand in Adjacent Zones,
- Others

Chart 2.1: Average Load in New York's Day-Ahead Electricity Market, by Region and Year (Summer Months, noon through 7:00pm)

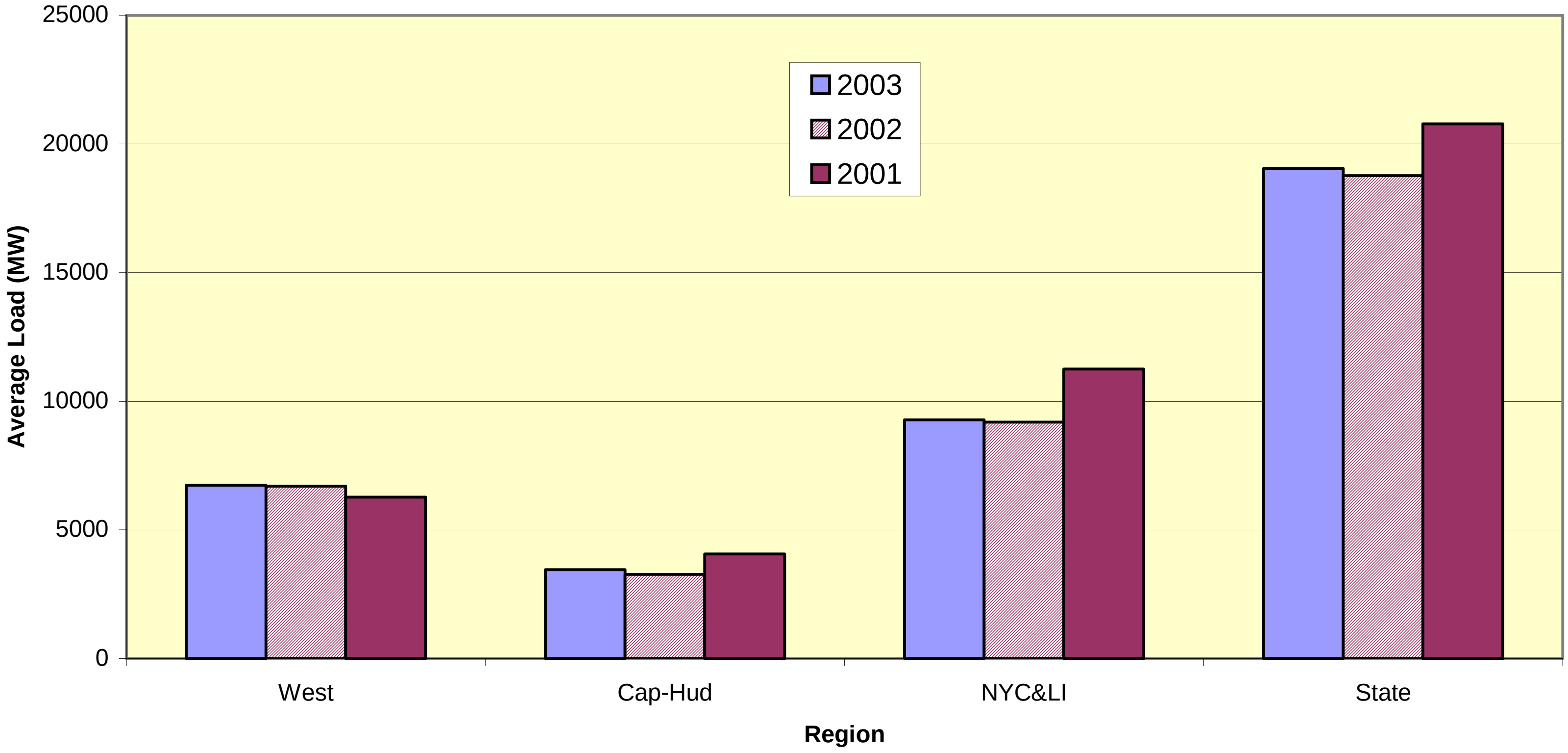


Chart 2.2: Average Load in New York's Real Time Electricity Market, by Region and Year (Summer Months, noon through 7:00pm)

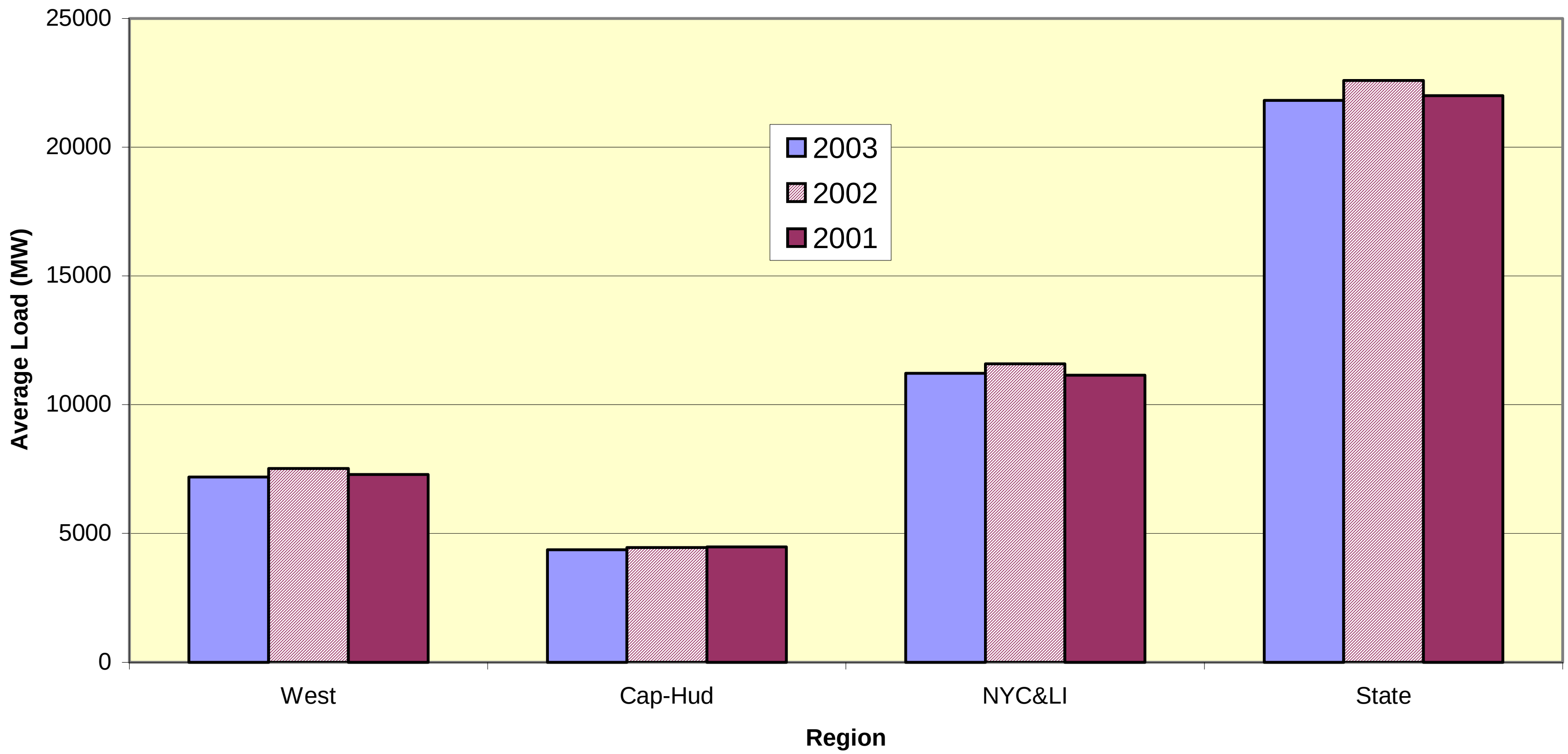


Chart 2.3: Average LBMPs in New York's Day-Ahead Electricity Market, by Region and Year
(Summer Months, noon through 7:00pm)

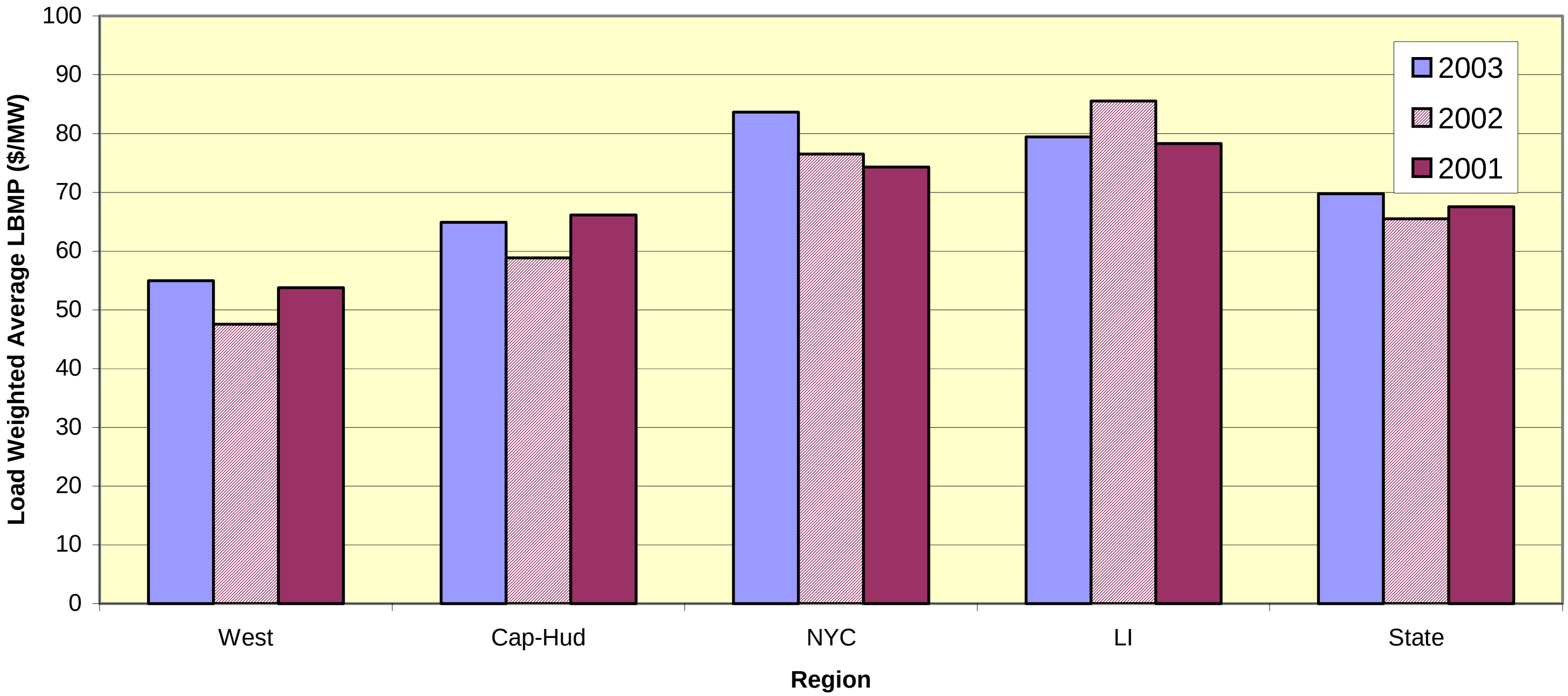


Chart 2.4: Average LBMPs in New York's Real Time Electricity Market, by Region and Year (Summer Months, noon through 7:00pm)

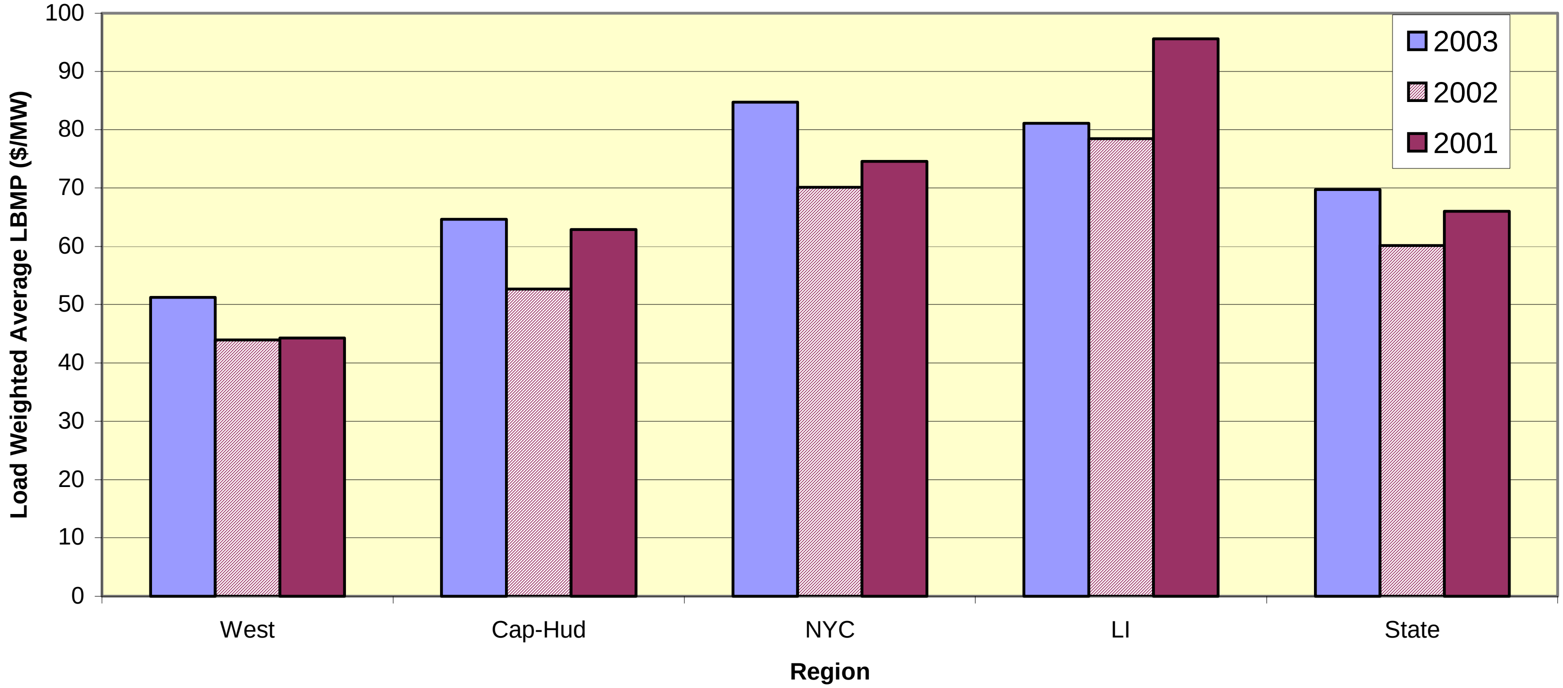


Chart 2.5: Relative Variability in LBMPs in New York's Day-Ahead Electricity Market, by Region and Year (Summer Months, noon through 7:00pm)

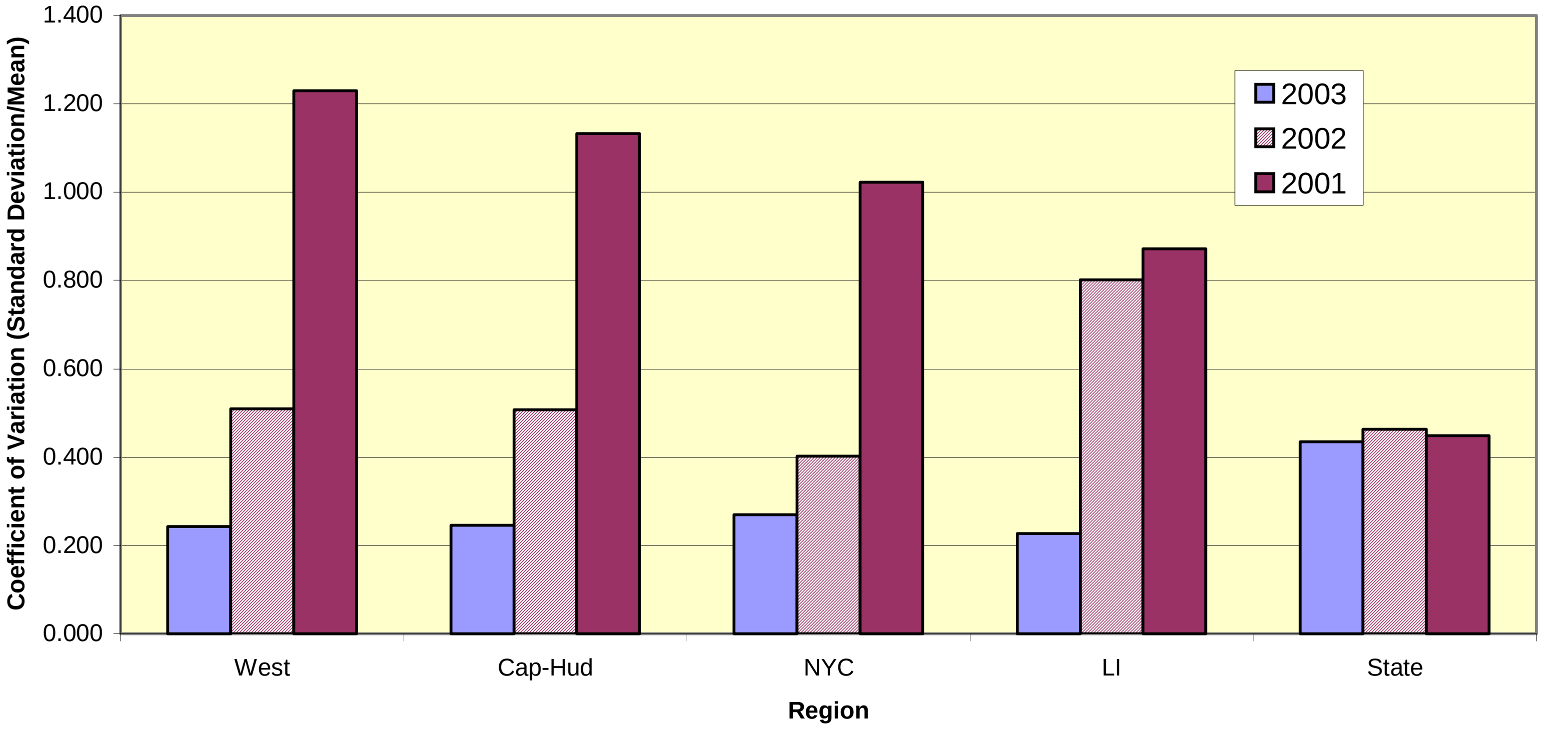


Chart 2.6: Relative Variability in LBMPs in New York's Real Time Electricity Market, by Region and Year (Summer Months, noon through 7:00pm)

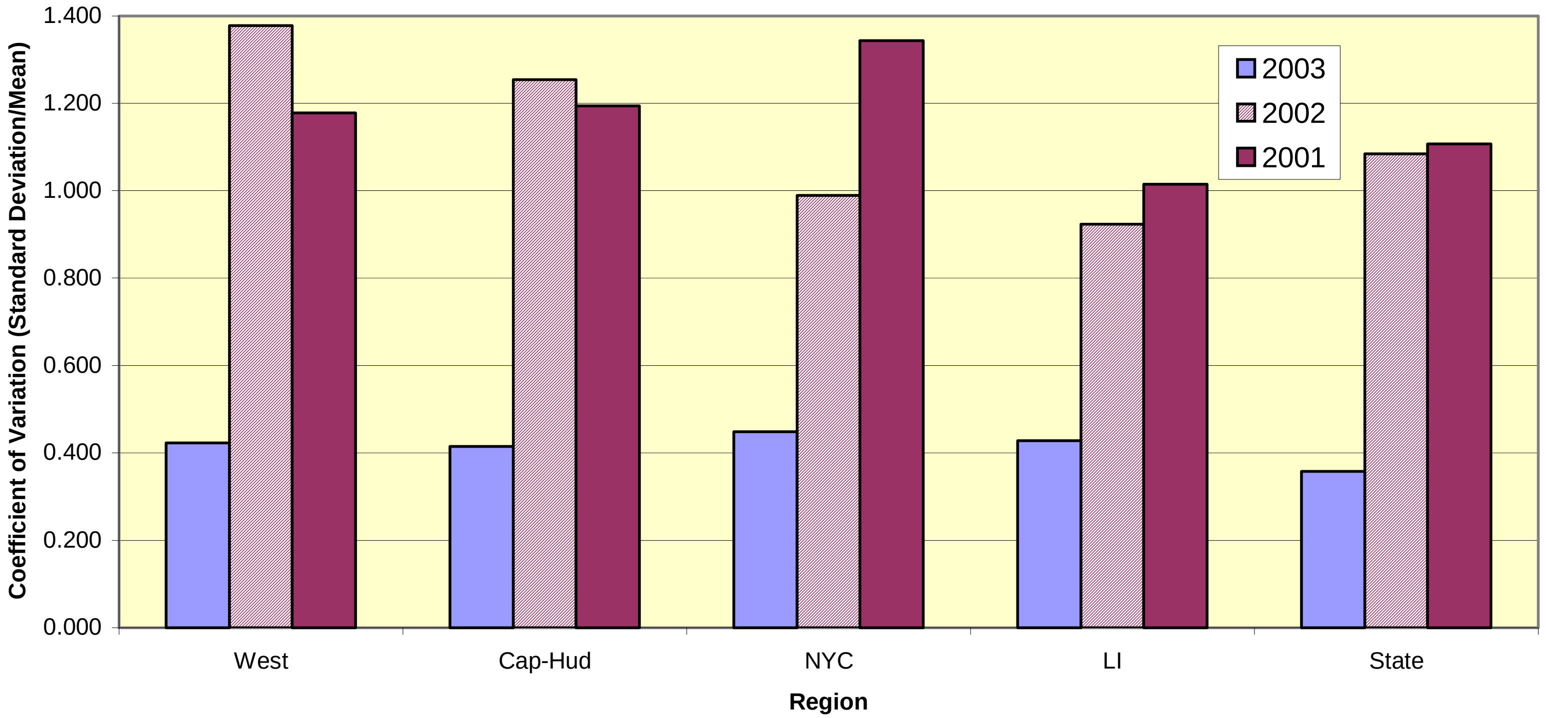


Chart 2.7: Supply Price Flexibilities in the New York Day-Ahead Market for Electricity, by Region and Year

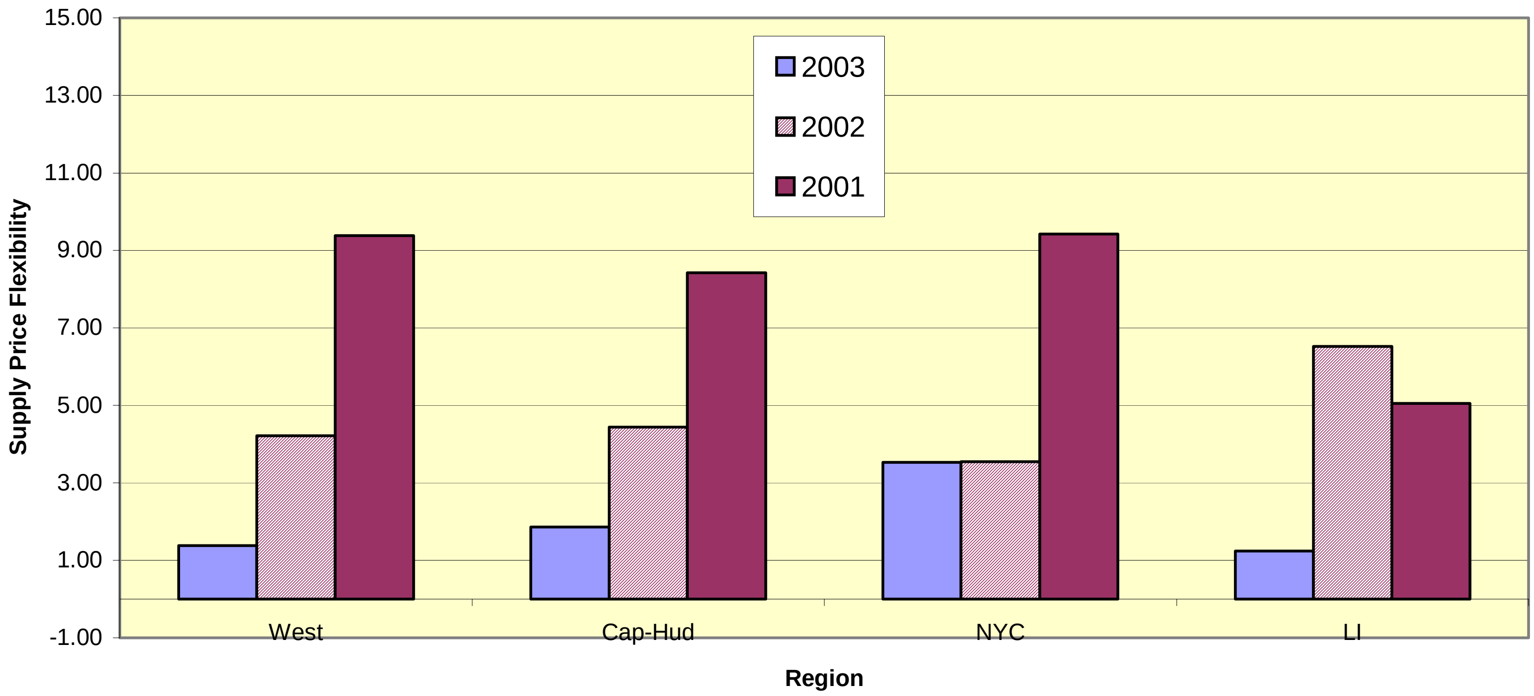


Chart 2.8: Supply Price Flexibilities in the New York Real-Time Market for Electricity, by Region and Year

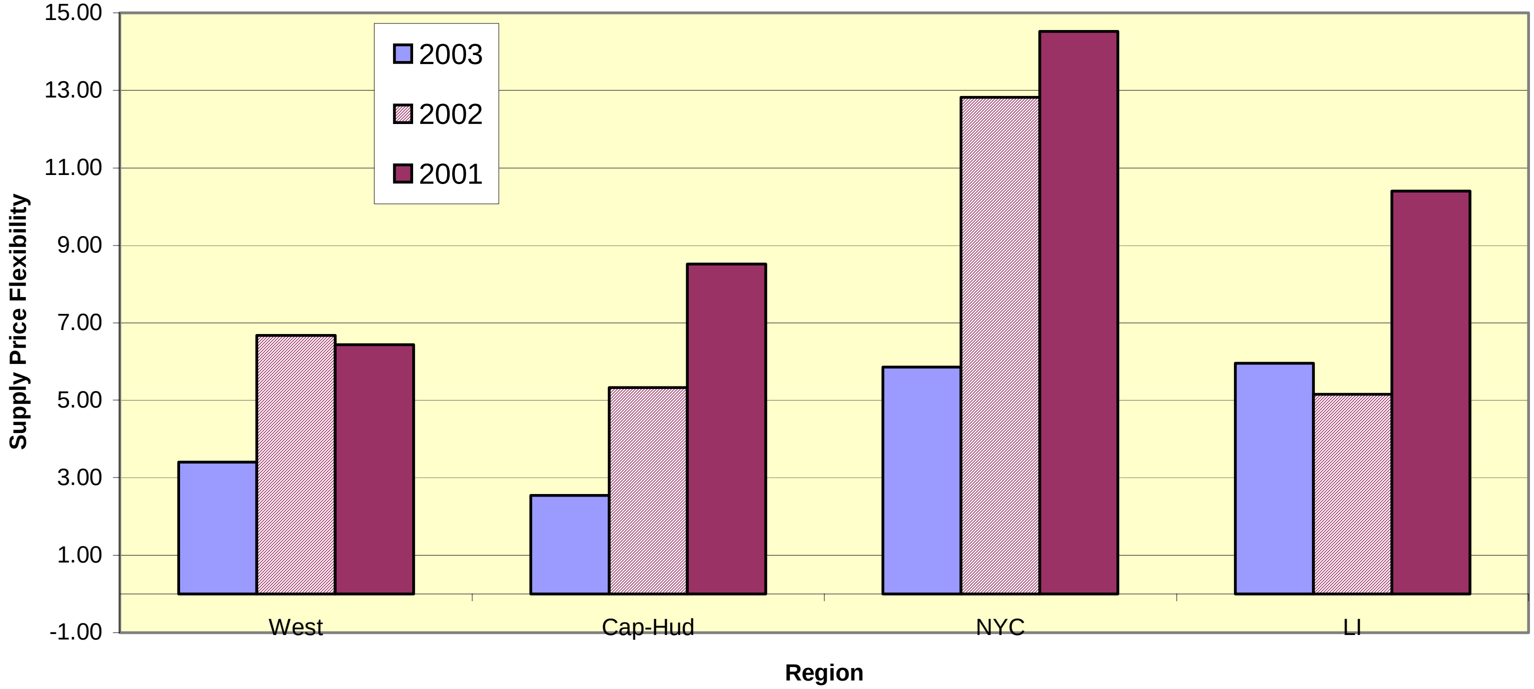


Table 2-1A. Summary Data for Hourly LBMP and Load by Zonal Aggregates for Which Separate Supply Functions are Estimated (Summer 2003, Afternoon Hours) *

West of Total East (Zones A, B, C, D & E)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	8,436	$127	8,943	$242
Mean	6,735	$55	7,185	$51
Minimum	5,071	$35	4,041	$0
Standard Deviation	780	$13	829	$22
Coefficient of Variation	0.12	0.24	0.12	0.42

Hudson River (Zones F, G, H & I)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	5,340	$165	6,202	$309
Mean	3,455	$65	4,371	$65
Minimum	2,472	$39	636	$17
Standard Deviation	489	$16	704	$27
Coefficient of Variation	0.14	0.25	0.16	0.41

New York City (Zone J)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum		$196		$428
Mean		$84		$85
Minimum		$49		$22
Standard Deviation		$23		$38
Coefficient of Variation		0.27		0.45

Long Island (Zone K)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum		$189		$427
Mean		$79		$81
Minimum		$55		$17
Standard Deviation		$18		$35
Coefficient of Variation		0.23		0.43

New York City & Long Island (Zones J & K)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	13,960	$187	15,233	$428
Mean	9,274	$82	11,207	$84
Minimum	6,528	$53	196	$26
Standard Deviation	1,205	$72	1,925	$35
Coefficient of Variation	0.13	0.88	0.17	0.42

New York State (Zones A - K)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	26,796	$150	28,938	$260
Mean	19,039	$70	21,820	$70
Minimum	13,994	$44	4,974	$21
Standard Deviation	2,354	$30	3,161	$25
Coefficient of Variation	0.12	0.43	0.14	0.36

* Afternoon hours correspond to 12:00 noon through 7:00 p.m. Prices in zonal aggregates are load weighted averages.

Table 2-2A. Summary Data for Hourly LBMP and Load by Zonal Aggregates for Which Separate Supply Functions are Estimated (Summer 2001, Afternoon Hours) *

		West of Total East (Zones A, B, C, D & E)		
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	8,637	$915	9,328	$937
Mean	6,263	$54	7,283	$44
Minimum	4,514	$23	5,527	-$41
Standard Deviation	872	$66	902	$52
Coefficient of Variation	0.14	1.23	0.12	1.18

		Hudson River (Zones F, G, H & I)		
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	5,748	$1,002	6,349	$1,013
Mean	4,057	$66	4,476	$63
Minimum	2,778	$27	3,073	$16
Standard Deviation	623	$75	738	$75
Coefficient of Variation	0.15	1.13	0.16	1.19

		New York City (Zones J)		
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum		$1,025		$1,071
Mean		$74		$75
Minimum		$35		$16
Standard Deviation		$76		$100
Coefficient of Variation		1.02		1.34

		Long Island (Zone K)		
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum		$831		$1,060
Mean		$78		$96
Minimum		$36		$19
Standard Deviation		$68		$97
Coefficient of Variation		0.87		1.02

		New York City & Long Island (Zones J & K)		
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	15,378	$966	15,502	$1,068
Mean	11,248	$76	11,141	$81
Minimum	7,138	$36	7,361	$19
Standard Deviation	1,865	$72	1,731	$98
Coefficient of Variation	0.17	0.95	0.16	1.20

		New York State (Zones A - K)		
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	28,423	$956	29,635	$1,016
Mean	20,769	$68	22,003	$66
Minimum	14,161	$32	15,566	$18
Standard Deviation	3,109	$30	3,112	$73
Coefficient of Variation	0.15	0.45	0.14	1.11

* Afternoon hours correspond to 12:00 noon through 7:00 p.m. Prices in zonal aggregates are load weighted averages. Summary data are slightly different from the 2001 evaluation which did not include noon to 1:00pm. (Neenan, 2002). This facilitates comparisons across years, since the additional hour was included in the supply models for 2003.

Table 2-3A. Summary Data for Hourly LBMP and Load by Zonal Aggregates for Which Separate Supply Functions are Estimated (Summer 2002, Afternoon Hours) *

West of Total East (Zones A, B, C, D & E)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	8,882	$158	9,506	$996
Mean	6,697	$48	7,518	$44
Minimum	4,701	$17	5,345	$12
Standard Deviation	930	$24	928	$61
Coefficient of Variation	0.14	0.51	0.12	1.38

Hudson River (Zones F, G, H & I)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	4,626	$204	6,073	$1,072
Mean	3,266	$59	4,449	$53
Minimum	2,132	$25	3,054	$15
Standard Deviation	610	$30	783	$66
Coefficient of Variation	0.19	0.51	0.18	1.25

New York City (Zone J)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum		$199		$1,123
Mean		$77		$70
Minimum		$29		$21
Standard Deviation		$31		$69
Coefficient of Variation		0.40		0.99

Long Island (Zone K)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum		$601		$1,109
Mean		$86		$78
Minimum		$38		$21
Standard Deviation		$69		$72
Coefficient of Variation		0.80		0.92

New York City & Long Island (Zones J & K)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	11,384	$375	15,443	$1,118
Mean	9,187	$81	11,586	$73
Minimum	6,386	$32	7,336	$24
Standard Deviation	1,161	$72	2,080	$70
Coefficient of Variation	0.13	0.89	0.18	0.95

New York State (Zones A - K)

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	23,599	$232	29,329	$1,070
Mean	18,758	$66	22,595	$60
Minimum	13,114	$29	15,496	$22
Standard Deviation	2,482	$30	3,509	$65
Coefficient of Variation	0.13	0.46	0.16	1.08

* Afternoon hours correspond to 12:00 noon through 7:00 p.m. Prices in zonal aggregates are load weighted averages. Summary data are slightly different from the 2002 evaluation which did not include noon to 1:00pm. (Neenan, 2003). This facilitates comparisons across years, since the additional hour was included in the supply models for 2003.

Table 2-4A. Supply Flexibilities for the Day-Ahead Electricity Market in New York

Year	2nd Knot (% of Maximum Load)	Average	Minimum	Maximum
Western New York (Zones A, B, C, D, and E)				
2003+	90.0	1.38	1.38	1.38
2002	60.0	4.21	1.46	7.10
2001	88.6	9.38	7.82	18.08
Capital and Hudson Region (Zones F, G, H, and I)*				
2003+	85.0	1.86	1.86	1.86
Capital (Zone F)*				
2002	75.0	4.96	1.95	7.79
2001	84.9	11.77	5.31	20.92
Hudson River Region (Zones G, H, and I)*				
2002	80.0	3.91	-3.66	9.11
2001	83.5	5.08	1.46	7.49
New York City (Zone J)				
2003+	75.0	3.53	3.51	3.56
2002	40.0	3.55	-0.01	6.49
2001	78.0	9.42	-5.15	18.47
Long Island (Zone K)				
2003+	90.0	1.24	1.24	1.25
2002	80.0	6.52	1.46	11.68
2001+	80.0	5.05	5.04	5.06

* In both 2001 and 2002, a supply curve for the Capital Zone was estimated. separately. In 2003, it was combined with the Hudson Super Zone.
+ There is only one knot in these supply models.
Note: Supply flexibilities for 2001 and 2002 are from Neenan Associates (2002, 2003).

Table 2-5A. Supply Flexibilities for the Real Time Electricity Market in New York

Year	2nd Knot (% of Maximum Load)	Average	Minimum	Maximum
Western New York (Zones A, B, C, D, and E)				
2003+	67.5	3.40	3.39	3.41
2002	75.0	6.67	-11.10	15.39
2001+	93.0	6.44	6.43	6.45
Capital and Hudson Region (Zones F, G, H, and I)*				
2003	90.0	2.54	2.53	2.55
Capital (Zone F)*				
2002	80.0	5.97	-4.30	10.94
2001	87.7	8.41	8.33	8.49
Hudson River Region (Zones G, H, and I)*				
2002	75.0	4.69	-8.47	10.66
2001+	84.6	8.62	8.62	8.62
New York City (Zone J)				
2003+	85.0	5.86	5.85	5.90
2002	90.0	12.82	12.76	12.79?
2001	65.0	14.52	6.26	27.57
Long Island (Zone K)				
2003	90.0	5.96	4.26	16.98
2002	87.5	5.16	-7.39	8.12
2001	78.0	10.40	10.33	10.48

* In both 2001 and 2002, a supply curve for the Capital Zone was estimated.
separately. In 2003, it was combined with the Hudson Super Zone.
\+ There is only one knot in these supply models.
Note: Supply flexibilities for 2001 and 2002 are from Neenan Associates (2002, 2003).

Figure 2-1B. Load vs. LBMP in the DAM, by Year, Western New York

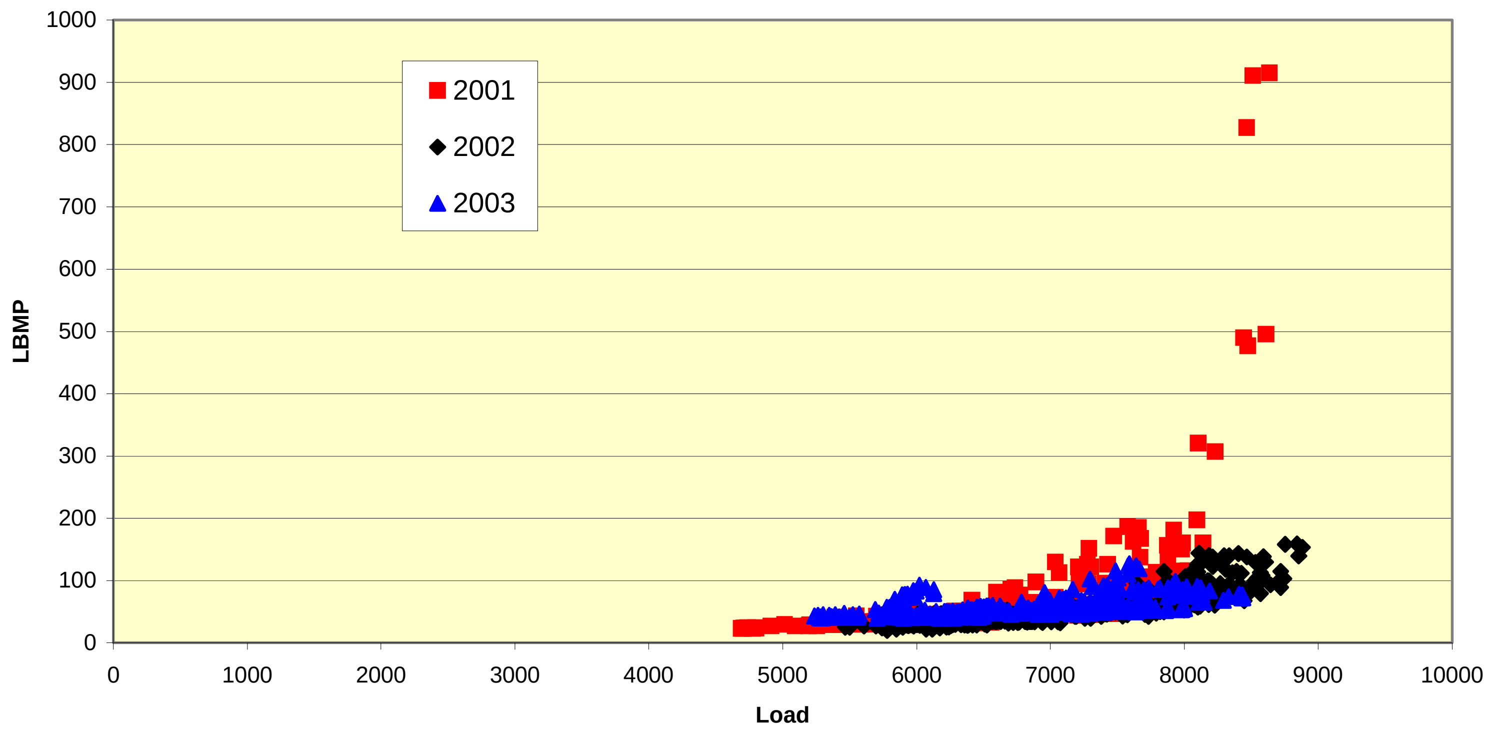


Figure 2-2B. Load vs. LBMP in the DAM, by Year, Capital and Hudson Region

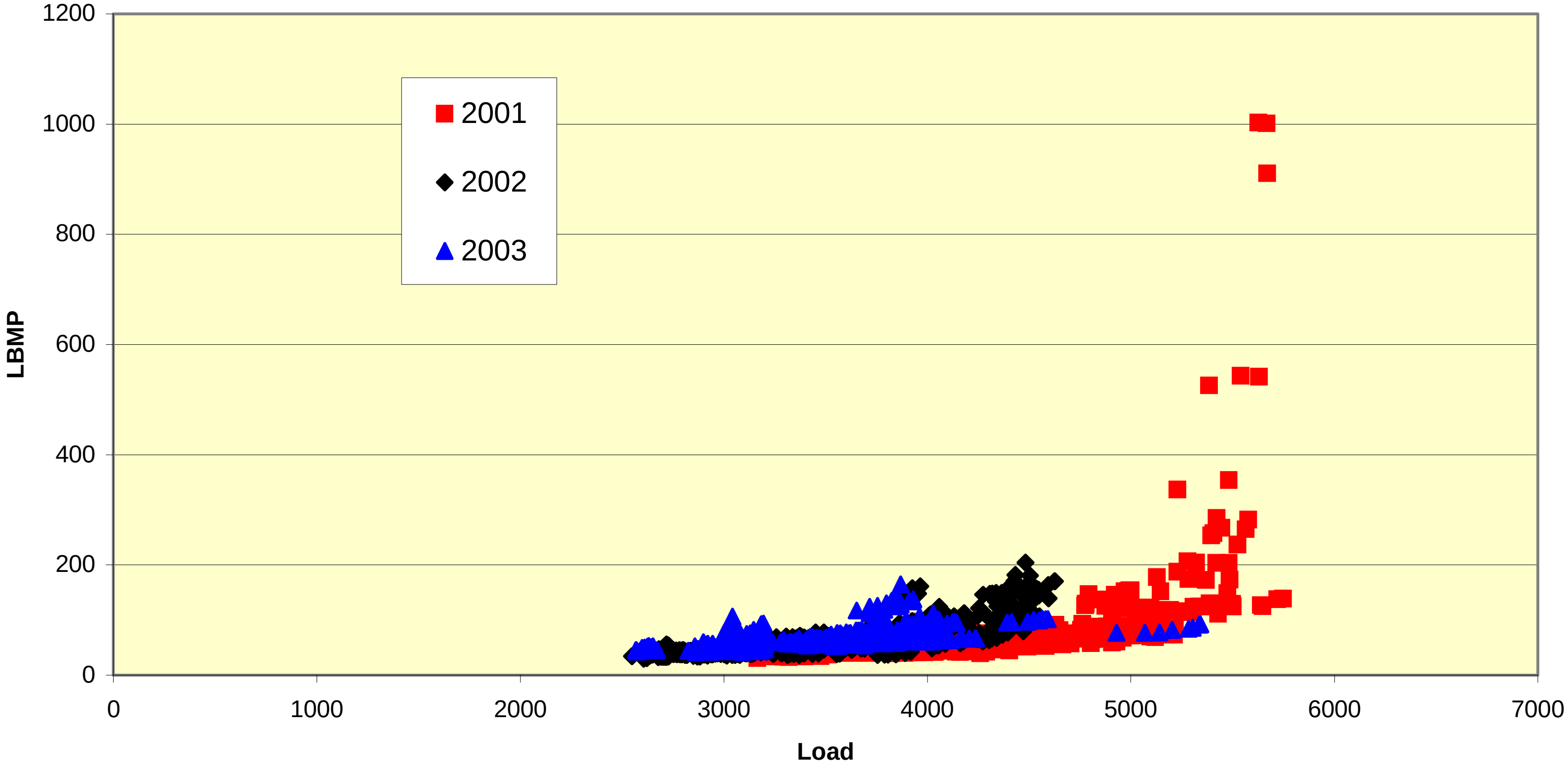


Figure 2-3B. Load vs. LBMP in the DAM, by Year, New York City

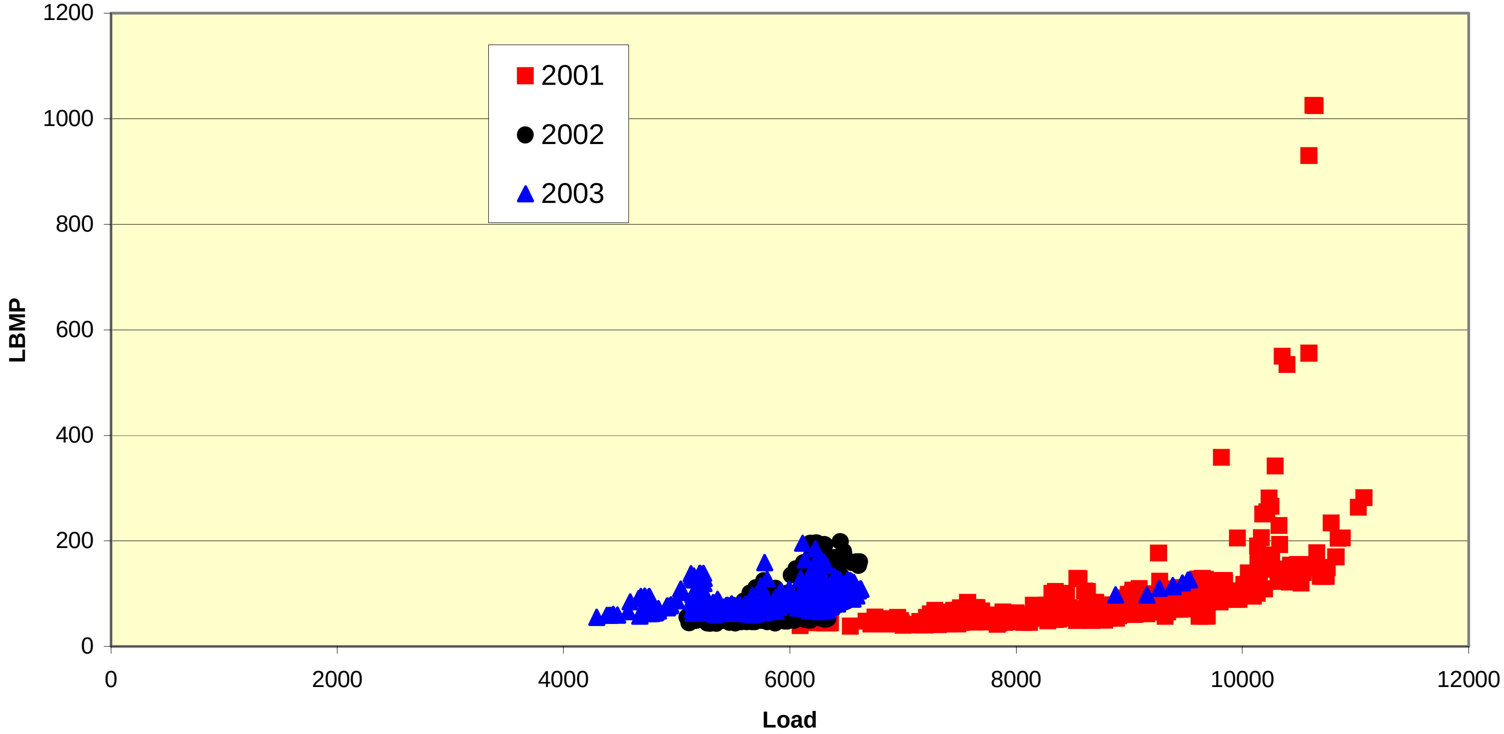


Figure 2-4B. Load vs. LBMP in the DAM, by Year, Long Island

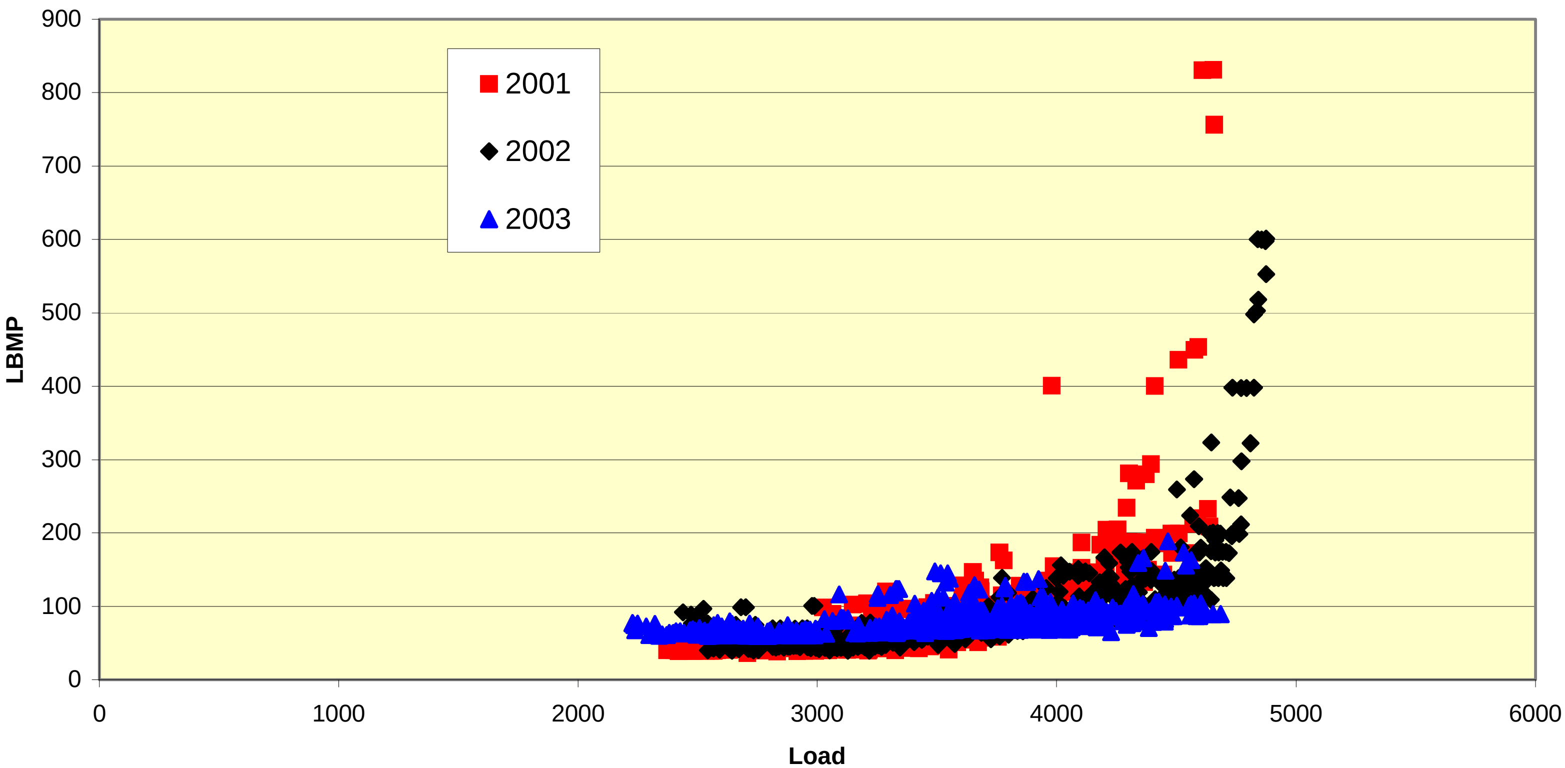


Figure 2-5B. Load vs. LBMP in the RTM, by Year, Western New York

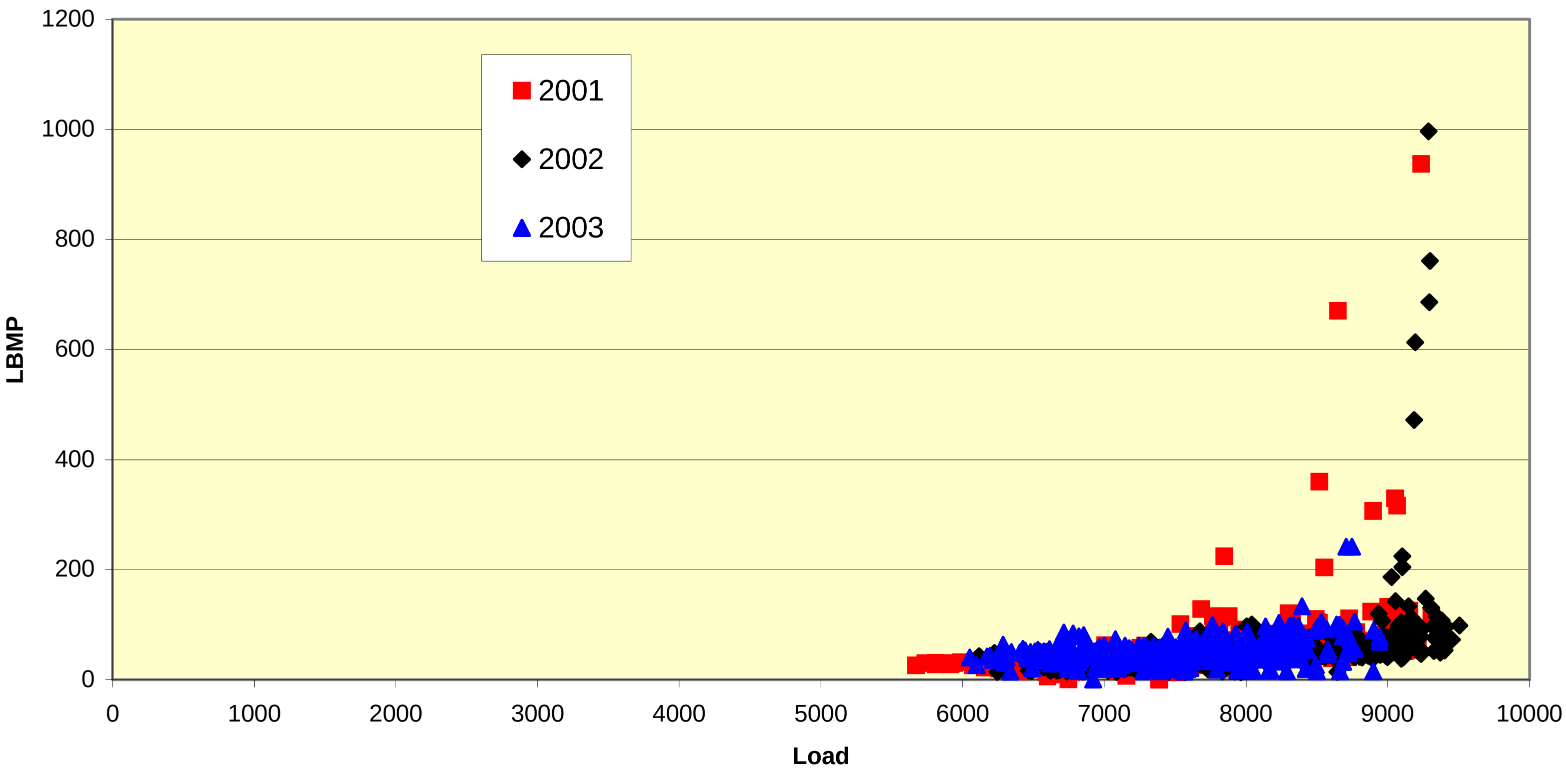


Figure 2-6B. Load vs. LBMP in the RTM, by Year, Capital and Hudson Region

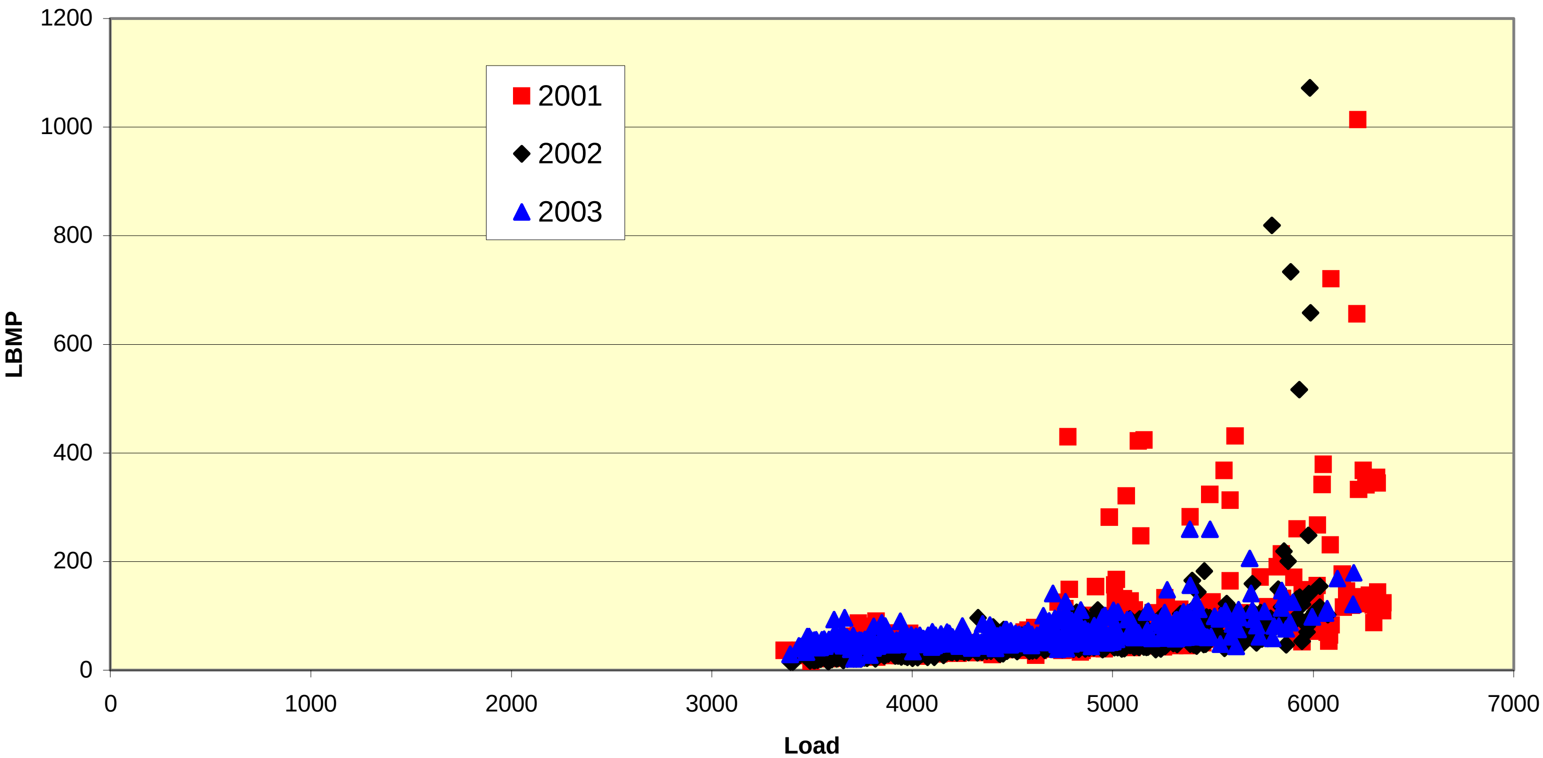


Figure 2-7B. Load vs. LBMP in the RTM, by Year, New York City

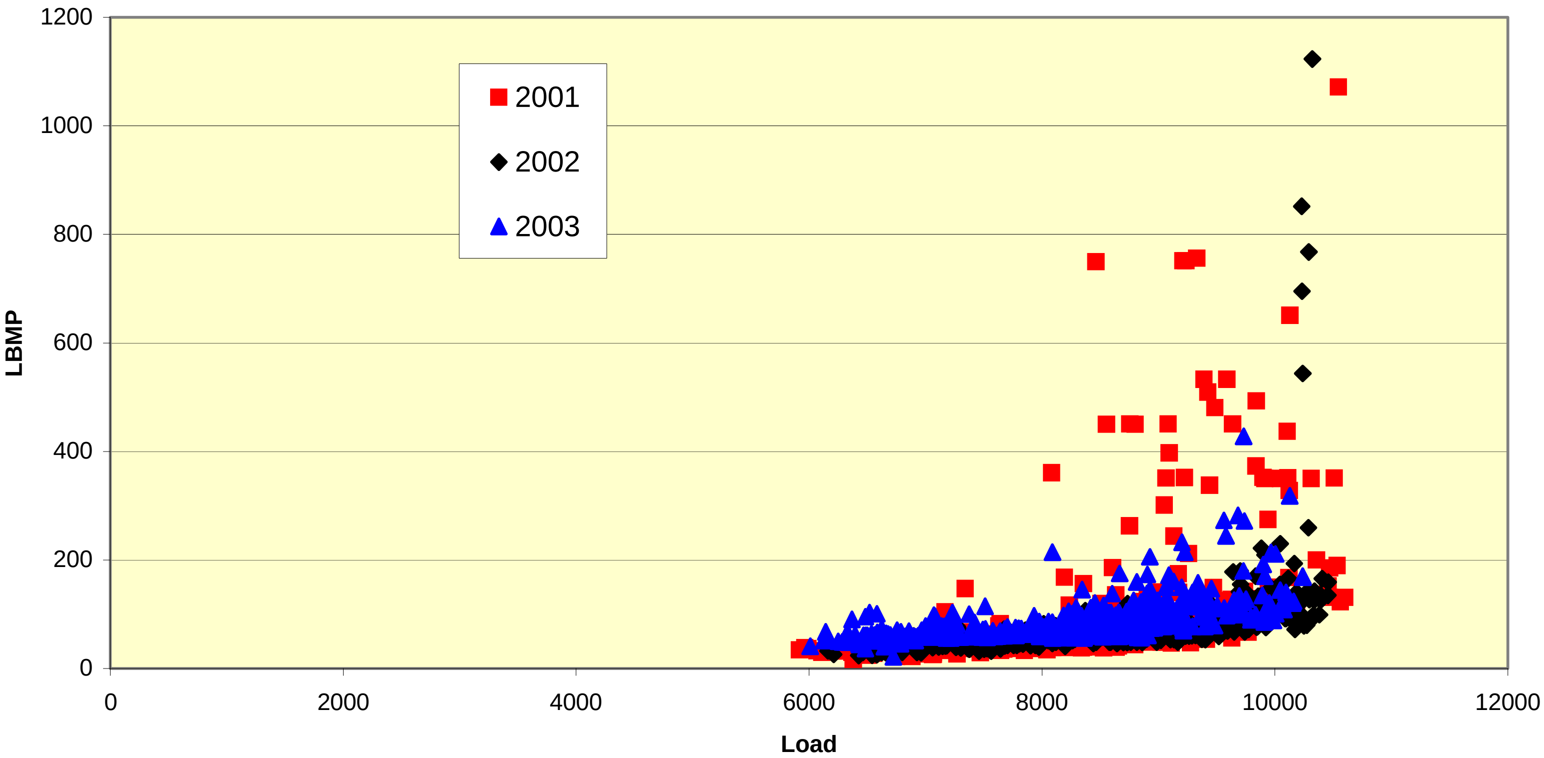
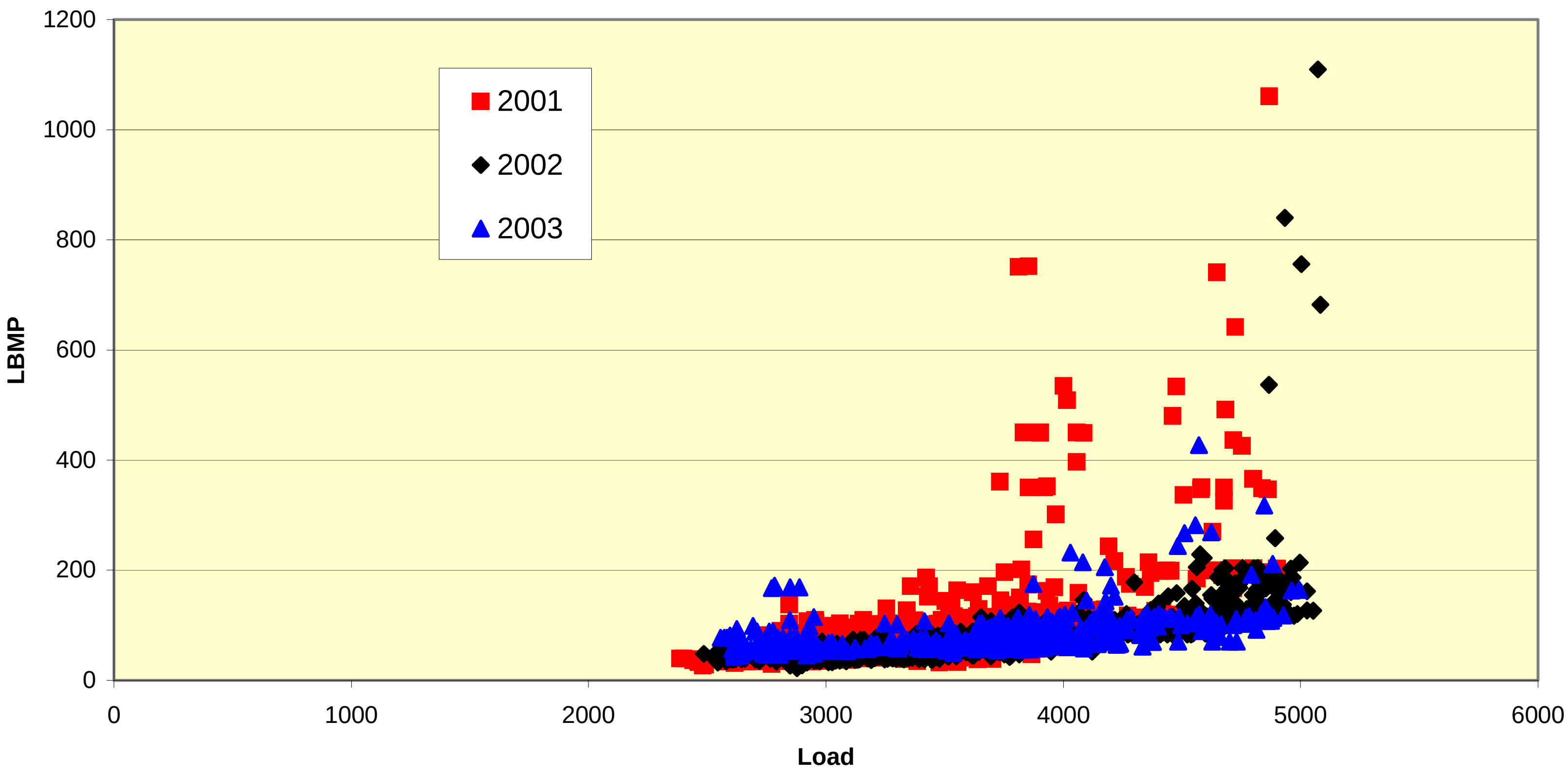


Figure 2-8B. Load vs. LBMP in the RTM, by Year, Long Island



Appendix 2C – The Econometric Model of Supply

Introduction

To assess the effects of the three PRL programs (DADRP, EDRP, and ICAP/SCR) on the day-ahead and/or real-time electricity market in New York, we must quantify the change in price due to changes in the amount of PRL load or on site generation scheduled. This is the supply side of the market. A detailed discussion of the specification of the supply models is in Neenan Associates (2002), and only the highlights are repeated in this appendix.

In most research of this kind, the strategy used to identify the price response is to collect actual market price and quantity data, along with other relevant information affecting the supply/demand relationships, and then to estimate econometrically the supply and demand functions simultaneously using a variety of regression techniques. Economic theory provides the structural basis for selecting which influences to include (e.g., Chambers, 1988; Diewert, 1974; Preckel and Hertel, 1988; and Griffin, 1977). The form of the empirical econometric models also depends on the nature of the markets, but is influenced by pragmatic considerations such as data availability. In this application, the estimated coefficients on the variables in the models provide the basis for calculating price response to changes in demand, and since that is the primary objective of the evaluation of PRL programs, it is particularly important to have precise estimates for these coefficients.

The New York electricity market has been in operation for just over 4 years. For this analysis, we have access to the hourly price and load data for both the DAM and the RTM since the inception of market operations.[1] Our task is complicated by the fact that we are unable to employ data on generator bids or their bid curves. However, for the RTM, we do have access to data on transmission constraints and net imports of electricity which proved to be essential in identifying the supply function in the RTM. More is said about the data below.

In determining the appropriate specification for the short-run supply functions in the DAM or the RTM we had to pay particular attention to: a) the way in which equilibrium prices and quantities are determined; and b) a strategy for capturing the "hockey stick" shape of the supply function. Each of these issues is discussed in turn below.

Equilibrium Price Determination

Tomek and Robinson (1981) demonstrate that the form of the econometric specification of supply models depends importantly on how the particular markets of interest function. Because of the unique nature of electricity as a commodity and the overriding need to maintain system reliability, wholesale prices for electricity in New York's two competitive markets, the DAM and the RTM, are determined "analytically" by the operation of the NYISO's SCUC and SCD scheduling and dispatch programs. This feature *clearly distinguishes* wholesale markets for electricity from those of other commodities. We know of no other markets that must function in this way. The implications for modeling the supply relationships are significant.

The Econometric Model Specification for Short-Run Electricity Supply Relationships

Although there are important differences in the structure and purposes for which SCUC and SCD models are used, LBMPs in the DAM and the RTM are determined as part of the solutions to these algorithms. Either in the day ahead or real time market, these algorithms use generators' bids and availability to minimize the cost of meeting, what is essentially for each hour, a fixed demand bid that LSEs have committed to purchase at what ever prices clear the

[1] Price data are publicly available on the NYISO web-site. Load data by zone are similarly available, but with New York City and Long Island reported in aggregate. For this analysis, the NYISO made some

market. Thus, once the bids have been submitted in the DAM, or load is observed in real time, electricity demand is essentially exogenous to the system for purposes of determining LBMP by the scheduling and dispatch algorithms. For modeling purposes, the practical implication is that rather than estimating quantity-dependent supply functions as is done for many commodities, we must instead specify price-dependent supply functions.

Put differently, following the theoretical discussion of the short-run supply function in the DAM or the RTM (see Neenan Associates, 2000), it should be possible to identify the envelope supply curves by examining primarily bid load, actual load, and price data. As bid loads or actual loads differ by hour and day, the demand curves, which are essentially vertical, slide up and down along a supply curve. The observations on bid load, actual load, and prices thus effectively trace out a number of supply curves in the DAM and the RTM. In these specifications, price is the dependent variable in the regressions and bid loads, or load served in real time are the independent variables.[2]

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confidential load data available.

[2] Estimating these electricity supply relationships is nearly identical to the pseudo-data methods developed by Griffin (1977) and Preckel and Hertel (1988) to generate summary, smooth cost and output supply response relations based on many repeated solutions to linear programming (LP) models. Griffin, for example, used pseudo-data arising from LP solutions to estimate a summary electricity cost function for later incorporation into the Wharton econometric model. In Preckel and Hertel's application, a complete system of output supply and input demand functions for agricultural commodities and inputs was estimated. The observations on quantities were the optimal output levels of several products determined by the successive solutions to the programming model. The prices were those assumed for each of the corresponding programming solutions. To map out the entire supply surface, the authors developed a complex sampling design to generate a wide range of relative input and output price differentials. In turn, these simulated data were used to estimate econometrically a smooth supply and input demand surface assuming a translog flexible functional form.

Viewed from a very practical perspective, this pseudo-data exercise is strictly a convenient way to summarize the relationships between the input data and the solutions to complex programming models. This is accomplished by regressing the solutions of the programming models on the input data to the programming models themselves. In a very real sense, the LBMPs from the DAM and the RTM are generated in exactly the same way as the data used in these "pseudo-data" exercises. The major difference is that the supply and demand quantities are used as input data in the SCUC and SCD models, and it is the prices that are determined by the solution to the model. Because of the way in which the data are generated, we identify the price-dependent supply curve.

If there were no shifts in supply due to different generator availability or general level of prices bid, there would be no need for generator bid data to identify the supply response flexibilities. However, these factors, and others, such as loads in adjacent regions and hours of the day, are extremely important as well. For these reasons, our econometric specification is zonal specific and includes explanatory variables other than load.

Some Modeling Issues

Further, the general underlying nature of these short-run supply functions is captured by the stylistic “hockey stick” shape—being relatively flat at low and moderate loads, but then rising sharply as load nears system capacity (e.g., Figure 2.2 of main text). It is as though the curves had separate regimes (Figures 2.3 and 2.4 of main text). These regimes were captured as piece-wise “spline” functions with different intercepts between the regimes (Neenan Associates, 2002). The points in Figure 2.5 (of main text) with high loads and low prices seem at odds with the general nature of supply. We capture these effects by including variables, such as measures of congestion, that shift the slope of the supply curve. These shifts are illustrated in Figure 2.6 (of main text). The supply flexibilities, defined as the percentage change in price due to a percentage change in load, are used to estimate the change in prices due to a change in load.

In this year’s evaluation, the task is complicated a bit because of our desire to pool the data for the past three years to estimate supply curves that formally can test for significant differences in supply flexibilities by year and aggregate pricing zone. This strategy, if successful, could be important to the overall market evaluation by providing evidence of the extent to which the markets are maturing. In we can capture this inter-year market complexity by so doing, our estimates should be improved through the additional information embodied in the pooled data. We also will have consistent supply models to estimate the market and welfare effects of DADRP from its inception three years ago. Because load, as well as capacity, has changed in some pricing zones, the spline models must be modified slightly to accommodate the pooled data.

The "Spline" Formulation of the Supply Curve

To capture the "hockey stick" nature of electricity supply, it is necessary to use a "spline" formulation of supply in which we identify points (often called knots) at which the supply relationship changes its structure. For our purposes, these "knots" are defined to isolate the ranges in load for which the supply envelope is functionally different. We hypothesize that three regimes should be sufficient, and as is seen in Neenan Associates (2002, 2003), there may be cases in which two regimes are sufficient. Assuming a log-linear specification, we begin as in the past evaluations by defining three zero-one variables, one for each segment of load (e.g., fixed bid load or actual load depending on which market is being estimated). These dummy variables are thus defined as:

(C-1) $D_1 = 1$ if $\ln L \le \ln L_1^*$, otherwise $D_1 = 0$;

(C-2) $D_2 = 1$ if $\ln L_1^* < \ln L \le \ln L_2^*$, otherwise $D_2 = 0$;

(C-3) $D_3 = 1$ if $\ln L > \ln L_2^*$, otherwise $D_3 = 0$.

Where L = normalized fixed bid load or real time load and the subscripts indicate specific MW loads. To accommodate the pooled data we normalize load in each year by capacity (ICAP). Thus, if we define load by Y and capacity by ICAP, then $L = Y/ICAP$ and $\ln L = \ln (Y/ICAP) = \ln Y - \ln ICAP$. This is an important definition of normalized load and is one way in which the method differs from that used in the past year's evaluations. However, as is seen below, the interpretation of the model's coefficients in terms of supply flexibilities is left unchanged.

The Linear "Spline" Function

Now, for a linear "spline" specification, the inverse supply relation is given by:[3]

(C-4) $\ln LBMP = \alpha_1 D_1 + \alpha_2 D_2 + \alpha_3 D_3 + \beta_1 D_1 \ln L + \beta_2 D_2 \ln L + \beta_3 D_3 \ln L.$

This specification is a simple dummy variable regression. But in its unconstrained form, there is no guarantee that the value of the fitted function coming into a "knot" is equal to the value of the function coming out of the "knot". We impose constraints to ensure that this requirement is met for internal consistency of the piece-wise function. Thus, to rule out jumps in the fitted values of the dependent variable, we must constrain the function (C-4) in the following way (Ando, 1997 and Neenan Associates, 2002):

(C-5) $\alpha_1 + \beta_1 \ln L_1^* = \alpha_2 + \beta_2 \ln L_1^*$ or $\alpha_1 = -\beta_1 \ln L_1^* + \alpha_2 + \beta_2 \ln L_1^*$.

(C-6) $\alpha_2 + \beta_2 \ln L_2^* = \alpha_3 + \beta_3 \ln L_2^*$ or $\alpha_3 = -\beta_3 \ln L_2^* + \alpha_2 + \beta_2 \ln L_2^*$.

The resulting constrained regression (equation (C-4) subject to equations (C-5) and (C-6)) can be estimated by ordinary least squares (OLS), through simple variable transformations made possible by solving equations (C-5) and (C-6) for α_1 and α_3, and then substituting the results into equation (C-4). In this way, we eliminate all of the intercept terms except α_2, and we are left with the following specification:

(C-7) $\ln LBMP = \alpha_2 \{ D_1 + D_2 + D_3 \} + \beta_1 \{ D_1 [\ln L - \ln L_1^*] \}$

$+ \beta_2 \{ D_1 \ln L_1^* + D_2 \ln L + D_3 \ln L_2^* \}$

$+ \beta_3 \{ D_3 [\ln L - \ln L_2^*] \}.$

[3] For computational convenience and additional flexibility in the model, this function is actually specified to be linear in logarithms. The subscripts for zone and time of day have been suppressed for notational simplicity.

In the data, the three zero-one variables add to a vector of ones. Thus, the first term in equation (C-7) reduces to a standard intercept term in OLS. All parameters of the original model are identified from this regression, except for α_1 and α_3. These parameters are identified after the fact by using equations (C-5) and (C-6).

Once equation (C-7) is estimated and the remaining parameters are identified, we can use equation (C-4) to calculate the supply price flexibilities. These flexibilities will differ in each regime of the spline function. That is, the partial logarithmic derivatives of equation (C-7) with respect to the logarithm of L are:

(C-8) $\partial \ln LBMP / \partial \ln L = \beta_1$, if $\ln Y \leq \ln L_1^*$;

(C-9) $\partial \ln LBMP / \partial \ln L = \beta_2$, if $\ln Y_1^* < \ln L \leq \ln L_2^*$;

(C-10) $\partial \ln LBMP / \partial \ln L = \beta_3$, if $\ln Y > \ln L_2^*$.

Thus, while these supply price flexibilities are constant over the corresponding ranges in load defined by the knots, this model allows them to differ across the intervals. These supply price flexibilities are in terms of normalized load, but it is easy to see that that they are equivalent to the flexibilities for actual load as well. The effect of the normalization on these supply price flexibilities is apparent at this point by substituting L = Y/ICAP and ln L = ln (Y/ICAP) = ln Y - ln ICAP into equation (C-7). By making this substitution, it is clear that –ln ICAP is multiplied by the β coefficients, but falls out of the partial logarithmic derivatives because it is a constant. Thus, we know that the two flexibilities are equal, e.g., $\partial \ln LBMP / \partial \ln L = \partial \ln LBMP / \partial \ln Y$.

Our principle hypothesis is that the price flexibilities will be positive and will rise as load rises—that is $\beta_1 < \beta_2 < \beta_3$. We constrain the calculated value of lnLBMP at the three “knots” to be equal in approaching the "knot" from either direction; it is these constraints that allow the flexibilities to differ. From equation (C-5) we see that $\beta_1 < \beta_2$, as long as $\alpha_1 > \alpha_2$. Likewise, $\beta_2 < \beta_3$ as long as $\alpha_2 > \alpha_3$.

A More Complex "Spline" Formulation

This linear "spline" formulation adds tremendous flexibility to the supply model, but it still requires that the price flexibility is constant within a particular interval of L. To relax this restriction, we need only make this formulation non-linear in the logarithm of L. Further, if there are other factors that affect supply, we can capture them by incorporating variables that shift the supply curve. Each of these refinements in the model is discussed in detail in Neenan Associates (2002), but they can be summarized in the following way. The model now includes a variable X that shifts all segments of the function in the same fashion and an interaction term, X lnL (e.g, X multiplied by lnL), whose slope differs between the "knots".[4] The "spline" equation becomes:[5]

$$\text{(C-11)}\quad \ln LBMP = a_1D_1 + b_1D_1X + c_1D_1 \ln L + d_1D_1 X \ln L$$

$$+ a_2D_2 + b_2D_2X + c_2D_2 \ln L + d_2D_2 X \ln L$$

$$+ a_3D_3 + b_3D_3X + c_3D_3 \ln L + d_3D_3 X \ln L$$

The constraints to assure that the function has the same value coming into and going out of the knots are given by:

$$\text{(C-12)}\quad a_1 + b_1X + c_1 \ln L_1^* + d_1X \ln L_1^* = a_2 + b_2X + c_2 \ln L_1^* + d_2X \ln L_1^*$$

$$\text{(C-13)}\quad a_3 + b_3X + c_3 \ln L_2^* + d_3X \ln L_2^* = a_2 + b_2X + c_2 \ln L_2^* + d_2X \ln L_2^* .$$

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[4] By allowing for interactions between the variable over which the "spline" is defined and other continuous or discrete variables, not only can we accommodate factors that shift supply for a given quantity, but we can also accommodate a specification that is non-linear in the logarithm of load by setting the shifter variable equal to the logarithm of load.

[5] When X = lnL, the model becomes quadratic in lnL.

By placing these constraints on the function at these "knots", we force the values of lnLBMP to be equal regardless of the direction from which we approach the "knot" without the corresponding parameters all being equal to one another. Suppose, for example, that we want the marginal effect of a change in lnL on lnLBMP to be higher for values of lnL across successive knots. A sufficient, but certainly not a necessary condition, for this to happen is for $c_3 > c_2 > c_1$; $d_3 > d_2 > d_1$; and $a_1 > a_2 > a_3$. If this were merely a linear "spline" function in lnL, the b's, and d's would all be zero, and the sufficient condition above would involve only the c's and the a's.

To estimate this model using OLS, we must again solve the two equations above for a_1 and a_3:

(C-14) $a_1 = a_2 + b_2X + c_2 \ln L_1^* + d_2X \ln L_1^* - [b_1X + c_1 \ln L_1^* + d_1X \ln L_1^*]$; and

(C-15) $a_3 = a_2 + b_2X + c_2 \ln L_2^* + d_2 \ln L_2X^* - [b_3X + c_3 \ln L_2^* + d_3X \ln L_2^*]$.

Substituting these expressions into equation (C-11), we have;

(C-16) $\ln LBMP = D_1 \{a_2 + b_2X + c_2 \ln L_1^* + d_2X \ln L_1^* \ [b_1X + c_1 \ln L_1^* + d_1X \ln L_1^*]\}+$

$b_1D_1X + c_1D_1 \ln L + d_1XD_1 \ln L + a_2D_2 + b_2D_2X + c_2D_2 \ln L + d_2D_2X \ln L$

$+ D_3 \{ a_2 + b_2X + c_2 \ln L_2^* + d_2X \ln L_2^* - [b_3X + c_3 \ln L_2^* + d_3X \ln L_2^*]\}+ b_3D_3X$

$+ c_3D_3 \ln L + d_3D_3X \ln L$.

Combining those terms for which there is a common parameter, we have:

(C-17) $\ln LBMP = a_2 [D_1+ D_2+ D_3]+b_1 [D_1 X–D_1X]+b_2 [D_1X+ D_2X+D_3X]+b_3 [D_3X-D_3X]$

$+ c_1 [D_1 \ln L – D_1 \ln L_1^*] + c_2 [D_1 \ln L_1^* + D_2 \ln L + D_3 \ln L_2^*]$

$+ c_3 [D_3 \ln L – D_3 \ln L_2^*] + d_1 [D_1X \ln L – D_1X \ln L_1^*]$

$+ d_2 [D_1X \ln L_1^* + D_2X \ln L + D_3X \ln L_2^*] + d_3 [D_3 \ln L – D_3 \ln L_2^*]$.

Again, since the sum of the zero-one variables, $[D_1+ D_2+ D_3]$ is unity, and the terms associated with b_1 and b_3 are zero, a_2 becomes an intercept term, and X, the variable that shifts the function in the same way across "knots", becomes a standard level term in the regression. This means that a_2, the intercept for the second segment, is identified directly in the regression along with the other coefficients, but a_1 and a_3 must be evaluated using equations (C-14) and (C-15). We cannot identify b_1 and b_3, but that is as it should be because we have assumed that X shifts the function identically regardless of the value of lnL, and this shift is captured by b_2. This is not true for the slope of the function, because of the interaction between X and lnL.

The marginal effects of the independent variables on the value of lnLBMP are of most interest in this model. That is, we want to identify from equation (C-11) the marginal effects of lnL and X on lnLBMP. Taking the partial derivatives of lnLBMP with respect to lnL for the three segments, we have:[6]

(C-18) $\partial \ln LBMP / \partial \ln L = c_1 + [d_1X]$, if $\ln L \leq \ln L_1^*$;

(C-19) $\partial \ln LBMP / \partial \ln L = c_2 + [d_2X]$, if $\ln L_1^* < \ln L \leq \ln L_2^*$;

(C-20) $\partial \ln LBMP / \partial \ln L = c_3 + [d_3X]$, if $\ln L > \ln L_2^*$.

These marginal effects differ by segment and are now functions of X. In the special case where X is a zero-one dummy variable for a specific year, then in the year for which X = 1, the supply flexibilities would be equal to $c_i + d_i$, rather than c_i for the i^{th} part of the spline. Thus, if this model is estimated based on pooled data, then one can test for differences in supply flexibilities across years in the i^{th} part of the using a simple t-test on the significance of the coefficients d_i. By including only one zero-one dummy variable one can test for differences in

[6] As above, we know that $\partial \ln LBMP / \partial \ln L = \partial \ln LBMP / \partial \ln Y$, except in the special case where X = lnL,and the model becomes quadratic in lnL

one year relative to all other years. If there are n years of data, then by including n-1 yearly dummy variables, one can test for differences in flexibilities across all years.

In this general formulation, the marginal effects of X on lnLBMP would be equal to b_2 for all values of lnL if it were not for the interaction terms between X and lnL. Because of the interaction, the partial derivatives of lnLBMP with respect to X are:

(C-21) $\partial \ln LBMP / \partial X = b_2 + d_1[\ln L]$, if $\ln L \leq \ln L_1^*$;

(C-22) $\partial \ln LBMP / \partial X = b_2 + d_2[\ln L]$, if $\ln L_1^* < \ln L \leq \ln L_2^*$;

(C-23) $\partial \ln LBMP / \partial X = b_2 + d_3[\ln L]$, if $\ln L > \ln L_2^*$.

These effects now differ by segment, and they are functions of lnL.

Appendix 2D – Estimates of the Short-Term Electricity Supply Curves in New York

Introduction

The purpose of this appendix is to describe in detail the estimated short-run supply curves for electricity in New York's day-ahead market (DAM) and real time market (RTM). As discussed in the text, these supply models apply to the hours noon to 7:00pm for the winter, spring and summer months of 2003. Separate models are estimated for each market in New York City and Long Island, while the remaining nine pricing zones are aggregated into two "super" zones (Western New York and the Capital-Hudson Region).[1] These supply models are needed to assess the market effects of DADRP, ICAP-SCR, and EDRP.

Estimates of the Short-Run Electricity Supply Curves

The estimated supply models for the summer months are reported in Tables 2-1D through 2-4D for the DAM and 2-6D through 2-9D for the RTM. Two models for the Capital/Hudson Region for the winter and spring months combined are reported in Tables 2-5D (the DAM) and 2-10D (the RTM). These two additional supply models for the DAM are needed to estimate the market and welfare effects of DADRP scheduled bids for the first several winter and spring months of 2003. The definitions of the variables used as shifters in the models are given in Table 2-11D.

In the table corresponding to each supply model, the estimated coefficients for the explanatory variables are reported, along with the t-ratios.[2] For the most part, the supply models

[1] See Figure 2.1 in the text for the definitions of the regions.

[2] As a result of the different regimes in each supply function, there is reason to believe that the model's error terms are not constant across observations. If this is true, the assumptions of the ordinary regression model are violated, and the OLS estimators remain unbiased, but they are no longer consistent (e.g. no longer the minimum variance estimators). The practical implication is that the standard errors could be

are specified entirely in logarithmic form so that the supply flexibilities are calculated according to equations (C-18 through C-20 of Appendix 2C). In the cases where there are no interaction terms with load, or if load squared is not in the model, then the supply price flexibilities are constant.[3]

Before discussing the specific results in detail, some general comments are in order. The first observation relates to an attempt to test for systematic yearly differences in the markets by pooling the data for 2001, 2002, and 2003. This effort met with little success. As is evidenced from the plots in Appendix 2B, the markets are simply too different across years to model them jointly. Our efforts to accommodate these differences by normalizing load by system capacity

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over- or underestimated—thus affecting the level of significance associated with the t-statistics (Gujarati, 1995).

It is advisable to test for the existence of heteroscedasticity (the error terms are correlated with load), but this was problematic given the need to transform the variables for the "spline" formulation. General tests of heteroscedasticity, such as the White test which regresses the estimated squared error on a quadratic expression in all the explanatory variables, led to estimates of the variance-covariance matrix that were not of full rank. This was most likely due to the transformation of the variables needed to estimate the "spline" function. Thus, these tests were of little use.
Since load varies systematically over the afternoon hours, we also tested for auto-correlation in the error terms. If autocorrelation in present, then the error in the current hour is related to those in one or more previous hours, and again the OLS estimators remain unbiased, but are inconsistent. The test for autocorrelation is to regress the estimated squared error from the OLS regression in time t on the estimated errors in times t-1, ..., (t-k). To conduct these tests, it was necessary to assume that the same auto-regressive error structure exists from the evening of one day to the afternoon of the next as it does from hour to hour. There is no good way to test the validity of this assumption, but a similar assumption is often implicitly necessary in other electricity demand and supply studies when weekends are treated differently from weekdays. If the tests suggest autocorrelation is present, the model is essentially re-estimated using maximum likelihood (ML) methods. This procedure generates the appropriately estimated variance-covariance matrix from which to calculate the standard errors of the coefficients and the t-ratios. The tests for autocorrelation and the corrected estimates of the models were performed using PROC AUTOREG in SAS.

[3] There are a couple of variables, such as the number of minutes during which constraints are binding in a given hour, in which there are legitimately many zero observations. These variables could not be transformed into logarithms, and are entered into the model as level terms. This presents no problem in interpretation, since they only enter as intercept or slope shifters. Further, the logarithmic specification required that we ignore those few observations in which LBMPs are negative. These usually occur in the morning hours, and we were not concerned with the morning hours in our models. The few instances of afternoon negative prices were in the first segment of the "spline"—the part of the supply function that is of little interest in our evaluation of EDRP and DADRP programs. We had to exclude them in our logarithmic formulation. The other advantages of the logarithmic specification (goodness of fit, flexibility as a

were of no help, primarily because capacity in 2003 was larger than in 2001, but loads were not. In spite of the flexibility in the "spline" model specification, there was no way to accommodate within-year and between-year regime changes within a single model.

As was the case in the previous two years, the performance of the supply models in the DAM is quite remarkable. For the summer models, between 51% and 72% of the variation in the dependent variable is explained (Tables 2-1D through 2-4D). Just over 45% of the variation in DAM-LBMP is also explained in the Capital/Hudson Region in the winter/spring model for the Capital/Hudson Region. One could hardly hope for any better results, given the variation in LBMP at high load levels and the availability of only a small number of other variables for use as shifters in the models to capture the effects of factors other than load that affect LBMP.

The overall explanatory power of the supply models for the RTM, as measured by the R^2 (Tables 2-6D through 2-9D) is somewhat lower for New York City, Long Island and the Capital/Hudson Region (0.48, 0.35 and 0.43, respectively). This is consistent with previous years' results. The only really disappointing results are in Western New York, where less than 10 percent of the overall variations in LBMP's in the RTM are explained. For the winter/spring model in the Capital/Hudson Region, about 30% of the variation in RTM-LBMP is explained (Table 2-10D).

The generally good level of overall performance of these models is due in large measure to the availability of data to include as slope shifters. This was accommodated by constructing interaction variables between the logarithm of load and the "shifter" variables. For this year's analysis, we included shifters related to:

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functional form, and the ease in calculating supply price flexibilities) clearly outweighed this slight disadvantage.

- The load weighted minutes that important regional constraints are binding (both for the current and previous hours)
- A weather index
- An index of natural gas prices
- Load as a proportion of generation offered
- A measure of load in adjacent zones or regions

Despite the performance of these estimated functions, they do not pick up all the variation in LBMPs, There are a number of reasons why one could hardly expect them to do so. For example, although the scheduling algorithm in the real-time market, SCD, minimizes the cost of meeting load, real-time dispatch must also respond to immediate changes in system conditions. Since many of these actions are taken to ensure system security in the face of unforeseen circumstances, they would increase variability in LBMPs. Further, system security considerations often take precedence over economic considerations in selecting which units to dispatch in real time, and minimum run time bids influence real-time LBMPs as well through the hybrid pricing algorithm. It is not likely that all effects of these actions on the LBMPs in real time can be captured by load or these “shifter” variables that by necessity only reflect general changes in system conditions at the zonal level.

Supply Price Flexibilities

For our purposes, we are less interested in being able to forecast the change in actual LBMPs from hour-to-hour or day-to-day then we are in estimating the change in LBMPs due to marginal changes in load—load reductions in ICAP/SCR and EDRP. The supply flexibility is defined as the percentage change in LBMP due to a one percent change in load served. For this purpose, it is most important to have precise estimates of the model coefficients that are used to calculate the supply flexibilities. The high t-ratios on all the estimated coefficients, even after correcting for autocorrelation, are important indications that these marginal effects have been measured effectively.

Supply Price Flexibilities in the DAM, Summer 2003

Above in the text, we have already discussed the supply flexibilities for the DAM for that part of the supply curves corresponding to the high load levels. They are compared with the values for the previous two years and were found to be generally lower and less variable.

The fact that the flexibilities are not constant has to do with the interaction terms in the model and the flexibilities thus depend on the coefficient for the logarithm of the level of load (fixed bid load in the case of the DAM) as well as coefficients for the interaction terms multiplied by the value of the “shifter” variables.[4]

The fact that the variability in the flexibilities is reduced in 2003 implies that their net effects on LBMP response to load changes is less than in previous years, but the individual effects are still critical and must be modeled, particularly in the final regimes of each model. The fact that these effects “net out” in many cases may explain why only two regimes are needed to model supply in the DAM.[5]

Regardless of their net effects, these effects of each shifter variable on the price response (as indicated by sign on the estimated coefficient) is always statistically significant and is as expected. Each of the “shifter” variables is included in at least one of four supply models. They are discussed in turn. We focus on the effect only in the last portion of the “spline” function. To

[4] See equations (18-20) of Appendix 2C for the general formulas.

[5]The small “net” effects may be due to there being less variation in the values of these variables than in previous years.

begin, one would expect that the time during which major transmission constraints are binding would lead to increase in LBMP, all else equal. This was found to be true in two of the four models. In New York City, the constraints in the previous hour increased LBMP in the DAM in the current hour (Table 2-3D, segment 2) and the current constraints increase LBMP in the DAM on Long Island (Table 2-4D, segment 2). The effect in New York is slightly larger than on Long Island.

In contrast, as the proportion of offered generation relative to ICAP system wide increases, there is, as one would expect, a *ceteris paribus* decrease in LBMP in the DAM. This occurs in all four pricing regions modeled for the 2003 evaluation (Tables 2-1D – 2-4D, segment 2). The effects, as measured by the coefficients are largest (in absolute value) in the Capital-Hudson Region (-0.2723) and lowest in New York City (-0.1359).

The other two important "shifter" variables in this year's supply models for the DAM are the weather index and an index of natural gas prices, this latter variable to reflect changes in fuel prices. These two variables are included for the first time in this year's supply models, and they perform as expected. They are both positively related to LBMP's in the DAM. The interaction between load and the gas price index is included only in the New York City model (Table 2-3D), but the weather index has a positive effect on LBMP in Western New York and the Capital-Hudson Region (Tables 2-1D and 2-3D). The effect in both regions are small but of similar size (0.0006 and 0.0007), respectively.[6]

To summarize, these supply models for the DAM suggest that LBMP does change with fixed bid load, and in all four regions, there LBMP increases by more than one percent for a one percent change in load. On average, for the last regime in each model, this price flexibility ranges

[6] While the coefficients are small, it is important to remember that the variables effect on LBMP is this coefficient multiplied the index.

from a high of 3.53 in New York City to a low of 1.24 on Long Island Tables 2-3D and 2-4D). It averages 1.38 in Western New York and 1.86 in the Capital/Hudson Region (Tables 2-1D and 2-2D). Within each region, there is almost no variation about these means. Because there was generally less price variability in the DAM during 2003, the net effect of these shifter variables was small indeed.

Because many of the scheduled DADRP bids in 2003 occur when load in the DAM is within the range of the first segment of the "spline", it is important to comment on these price flexibilities. The flexibilities in Western NY and the Capital/Hudson region are most important in this regard; it is only in these regions that any DADRP bids are scheduled. In both of these cases, there are no shifter variables in the fist segment of the "spline". Thus, the supply flexibilities are constant, and they are nearly identical across the two regions. They are 0.60 and 0.58 for the Western NY Region and the Capital/Hudson Region, respectively.

Supply Price Flexibilities in the DAM, Winter/Spring 2003

This is the first year in which the DADRP bids during the winter/spring months have been examined. Thus, it was necessary to estimate supply models in the DAM for this period of the year. And, just as it was not possible to pool the data across years in the estimation of the summer supply models, the differences in the structure of the market during the winter/spring and the summer also led to separate supply model estimation for 2003. As is evident in the data, there are some relatively high prices in hours where fixed bid load in the DAM is high, as well as when fixed bid load in the DAM is quite low. This observation is in contrast to what we see during the summer (e.g. some relatively high and relatively low prices at high fixed bid loads). For this reason, there was no need to estimate a "spine" function for the winter/spring months in the Capital/Hudson Region, the only region in which DADRP bids were scheduled. In the supply model in Table 2-5D, it is clear that two "shifter" variables have statistically significant effects on the supply flexibilities, the weather index, and fixed bid load in adjacent zones. In both cases, the sign on the coefficient is positive, indicating that as these variables increase, so does the price flexibility. Also, it should be noted that the sign on the coefficient of the logarithm of fixed bid load is negative. Ordinarily, this would be counter-intuitive. However, since the supply flexibilities are calculated according to equation (C-19) from Appendix 2C, this negative coefficient is offset sufficiently by the sum of the products of the "shifter" variables multiplied by their respective coefficients that all estimated price flexibilities are positive, and range from a low 1.32 to and high of 3.79.[7] They average 2.70 (Table 2-5D).

Supply Price Flexibilities in the DAM, Summer 2003

As is the case with the DAM, we have already discussed in the text of the report the supply flexibilities for the RTM for that part of the supply curves corresponding to the high load levels. They are compared with the values for the previous two years and were found to be generally lower and less variable.

Here again, the flexibilities are not constant because they depend of coefficients for the interaction terms in the model multiplied by the values of the "shifter" variables, as well as on the coefficient on the logarithm of the level of load served.[8]

The fact that the variability in the flexibilities is reduced in 2003 implies that their net effects on LBMP response to load changes is less than in previous years, but the individual

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[7] We only estimated one supply model for the winter/spring for the same hours as the summer models (12:00 noon through 7:00 pm). However, in the simulations to evaluate DADRP, some of the bids are scheduled in hours outside this time period. There was no significant justification for estimating a separate model, but it is possible that the supply "shifter" variables will be outside their range in the hours over with the model was estimated. Thus, the price flexibilities for some of the hours were outside this range as well. They, however, are positive for every hour in which DADRP bids are scheduled.

[8] See equations (C-18 through C-20) of Appendix 2C for the general formulas.

effects are still critical and must be modeled, particularly in the final regimes of each model.[9] The fact that these effects "net out" in many cases may explain why only two regimes are needed to model supply in the RTM in Western NY, the Capital/Hudson Region and in New York City. It is only in Long Island that three regimes are needed, and it is here where there is still quite a bit of variation in the supply flexibility (Tables 2-6D through 2-9D).

In all four of the supply models, the coefficients on the logarithm of real time load are positive and statistically significant. However, there are different "shifter" variables appearing in each model, and the signs on the coefficients are as expected and are statistically significant. As the weather index rises, for example, the supply price flexibilities rise in both Western NY and in the Capital/Hudson Region (Tables 2-6D and 2-7D). The supply flexibility in the Capital/Hudson Region also rises with the gas price index. On average, the supply price flexibility in Western NY is 3.40, and it varies around this mean only from 3.39 to 3.41 (Table 2-6D). The average supply flexibility in the Capital/Hudson Region is 2.54, and it again has little variation, only from 2.53 to 2.55 (Table 2-7D).

In New York City, the average supply price flexibility in the last part of the "spline" is 5.86; it increases with the number of minutes that the system is constrained, and falls as the proportion of generation available rises. However, there is little variation in its value—ranging only from 5.85 to 5.90 (Table 2-8D). The average supply price flexibility on Long Island is similar to that of New York—5.96 (Table 2-9D). However, its range is much wider—from 4.26 to 16.98. This is due to the significant effect the number of minutes that the system is constrained has on the value of the flexibility.

[9]The small "net" effects may also be due to there being less variation in the values of these "shifter" variables than in previous years.

In this year's evaluation, we argue that the net welfare benefits of scheduled bids in DADRP include the size of the deadweight social losses avoided in the RTM for that load reduction that shows up in real time. Therefore, this welfare evaluation depends on the supply flexibilities in the RTM. Further, because many of the scheduled bids in DADRP occur at relatively low loads, it is also important to note here that the supply flexibilities in the first segments of the "spline" in both Western NY and the Capital/Hudson Region are quite small—0.47 and 0.22, respectively (Table 2-6D and 2-7D). These small flexibilities generally reduce the size of these deadweight losses avoided.

Supply Price Flexibilities in the RTM, Winter/Spring 2003

Because of the need to evaluate the net social value of DADRP scheduled bids, it is necessary have a supply flexibility for the Capital/Hudson Region for the winter and spring months of 2003. This model is reported in Table 2-10D. As is evident in the data for the DAM, there are also some relatively high prices in hours where real time load is high, as well as when real time load is quite low. For this reason, there was no need to estimate a "spline" function for RTM supply model of the winter/spring months in the Capital/Hudson Region.

Purely from a statistical point of view, it is the most problematic. It has an R^2 just below 0.30, and the coefficient on the logarithm of load is negative and not statistically significant (Table 2-10D). Despite these difficulties, the effects of the two "shifter" variables compensate for this negative coefficient, and lead to positive, and reasonable flexibilities at all of the observations. The average value is 3.74 (Table 2-10D). As the gas price index rises, the supply flexibility does as well. Further as the proportion of generation available rises, the price flexibility falls. The variation in these variables allows the price flexibility to range from 1.45 to 5.90 (Table 2-10D).

Table 2-1D. Estimated Day Ahead Electricity Supply Function, Western NY Super Zone, Summer 2003

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-8.2167	-1.1171		
Load	0.5977	18.7443	1.2773	1.5631		
Wgt Constraints						
Weather Index			0.0006	11.3749		
Gas Price Index***						
Proportion of Gen Offered			-0.2414	-27.8787		
Lagged Wgt. Constraints						
Adjacent Zonal Load						
Arch (0)	0.0015	7.43				
Arch (1)	0.7141	4.77				
Arch (2)	0.0940	2.81				
R^2 =	0.7190					

	Knots (% of Maximum Load)		
Price Flexibilities**	90.0%	100.0%	
Minimum	0.60	1.38	
Maximum	0.60	1.39	
Mean	0.60	1.38	

* Variables are defined in Appendix Table 2-11D; All are in logarithms, except where noted.
The model estimated is from equation (C-17) of Appendix 2C, and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (C-18-C-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.
***The Gas price index was supplied by Gas Daily.

Table 2-2D. Estimated Day Ahead Electricity Supply Function, Capital/Hudson Super Zone, Summer 2003

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-11.1713	-3.8679		
Load	0.5820	26.0754	1.7456	5.0340		
Wgt Constraints						
Weather Index			0.0007	15.5478		
Gas Price Index***						
Proportion of Gen Offered			-0.2723	-30.7760		
Lagged Wgt. Constraints						
Adjacent Zonal Load						
Arch (0)	0.0013	8.98				
Arch (1)	1.0440	6.63				
Arch (2)						
R^2 =	0.6701					

	Knots (% of Maximum Load)		
Price Flexibilities**	85.0%	100.0%	
Minimum	0.58	1.86	
Maximum	0.58	1.86	
Mean	0.58	1.86	

* Variables are defined in Appendix Table 2-11D; All are in logarithms, except where noted.
The model estimated is from equation (C-17) of Appendix 2C, and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (C-18-C-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.
***The Gas price index was supplied by Gas Daily.

Table 2-3D. Estimated Day Ahead Electricity Supply Function, New York City Zone, Summer 2003

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-26.3819	-12.2841		
Load	0.1154	2.4480	3.4011	13.8401		
Wgt Constraints						
Weather Index						
Gas Price Index***			0.0010	1.8440		
Proportion of Gen Offered			-0.1359	-11.8442		
Lagged Wgt. Constraints			0.0014	7.4072		
Adjacent Zonal Load			0.0000	27.0351		
Arch (0)	0.0017	8.16				
Arch (1)	1.0739	6.97				
Arch (2)						
R^2 =	0.5341					
	Knots (% of Maximum Load)					
Price Flexibilities**		85.0%		100.0%		
Minimum	0.12		3.51			
Maximum	0.12		3.56			
Mean	0.12		3.53			

* Variables are defined in Appendix Table 2-11D; All are in logarithms, except where noted.
The model estimated is from equation (C-17) of Appendix 2C, and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (C-18-C-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.
***The Gas price index was supplied by Gas Daily.

Table 2-4D. Estimated Day Ahead Electricity Supply Function, Long Island Zone, Summer 2003

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-5.9317	-0.9991		
Load	0.4966	28.1716	1.2007	1.6988		
Wgt Constraints			0.0010	7.3218		
Weather Index						
Gas Price Index***						
Proportion of Gen Offered			-0.2378	-27.4640		
Lagged Wgt. Constraints						
Adjacent Zonal Load						
Arch (0)	0.0026	11.50				
Arch (1)	0.8440	6.83				
Arch (2)						
R^2 =	0.5132					
	Knots (% of Maximum Load)					
Price Flexibilities**		90.0%		100.0%		
Minimum	0.50		1.24			
Maximum	0.50		1.25			
Mean	0.50		1.25			

* Variables are defined in Appendix Table 2-11D; All are in logarithms, except where noted.
The model estimated is from equation (C-17) of Appendix 2C, and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (C-18-C-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.
***The Gas price index was supplied by Gas Daily.

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Table 2-5D. Estimated Day Ahead Electricity Supply Function, Capital/Hudson Super Zone, Winter 2003

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	3.2002	23.1932				
Load	-3.5135	-10.9955				
Wgt Constraints						
Weather Index	0.0016	2.6630				
Gas Price Index***						
Proportion of Gen Offered						
Lagged Wgt. Constraints						
Adjacent Zonal Load	0.0005	20.9615				
Arch (0)	0.0033	9.50				
Arch (1)	0.9853	8.42				
Arch (2)						
R^2 =	0.4550					
	Knots (% of Maximum Load)					
Price Flexibilities**		100.0%		100.0%		
Minimum	1.32					
Maximum	3.79					
Mean	2.70					

* Variables are defined in Appendix Table 2-11D; All are in logarithms, except where noted.
The model estimated is from equation (C-17) of Appendix 2C, and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (C-18-C-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.
***The Gas price index was supplied by Gas Daily.

Table 2-6D. Estimated Real Time Electricity Supply Function, Western NY Super Zone, Summer 2003

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-26.5824	-5.1861		
Load	0.4696	1.9004	3.3092	5.5770		
Wgt Constraints						
Weather Index			0.0011	2.6471		
Gas Price Index***						
Proportion of Gen Offered						
Lagged Wgt. Constraints						
Adjacent Zonal Load						
Arch (0)	0.0716	20.76				
Arch (1)	1.0759	7.76				
Arch (2)						
R^2 =	0.0825					
	Knots (% of Maximum Load)					
Price Flexibilities**	68.0%		100.0%			
Minimum	0.47		3.39			
Maximum	0.47		3.41			
Mean	0.47		3.40			

* Variables are defined in Appendix Table 2-11D; All are in logarithms, except where noted.
The model estimated is from equation (C-17) of Appendix 2C, and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (C-18-C-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.
***The Gas price index was supplied by Gas Daily.

Table 2-7D. Estimated Real Time Electricity Supply Function, Capital/Hudson Super Zone, Summer 2003

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-18.8851	-5.9384		
Load	0.2154	0.8196	2.4339	6.1780		
Wgt Constraints						
Weather Index			0.0003	1.1153		
Gas Price Index***			0.0131	4.7586		
Proportion of Gen Offered						
Lagged Wgt. Constraints						
Adjacent Zonal Load						
Arch (0)	0.0236	10.34				
Arch (1)	0.3377	4.33				
Arch (2)	0.2791	4.67				
R^2 =	0.4287					
	Knots (% of Maximum Load)					
Price Flexibilities**	65.0%		100.0%			
Minimum	0.22		2.53			
Maximum	0.22		2.55			
Mean	0.22		2.54			

* Variables are defined in Appendix Table 2-11D; All are in logarithms, except where noted.
The model estimated is from equation (C-17) of Appendix 2C, and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (C-18-C-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.
***The Gas price index was supplied by Gas Daily.

Table 2-8D. Estimated Real Time Electricity Supply Function, New York City Zone, Summer 2003

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-49.7111	-10.5199		
Load	-1.3049	-2.5129	5.8292	11.1620		
Wgt Constraints			0.0008	12.9813		
Weather Index	0.0146	2.6373				
Gas Price Index***						
Proportion of Gen Offered	-8.6440	-3.6378	-0.1471	-4.0902		
Lagged Wgt. Constraints						
Adjacent Zonal Load						
Arch (0)	0.0137	5.81				
Arch (1)	0.5960	4.52				
Arch (2)	0.5379	6.71				
R^2 =	0.4798					

	Knots (% of Maximum Load)		
Price Flexibilities**	85.0%	100.0%	
Minimum	0.68	5.85	
Maximum	3.09	5.90	
Mean	1.22	5.86	

* Variables are defined in Appendix Table 2-11D; All are in logarithms, except where noted.
The model estimated is from equation (C-17) of Appendix 2C, and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (C-18-C-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.
***The Gas price index was supplied by Gas Daily.

Table 2-9D. Estimated Real Time Electricity Supply Function, Long Island Zone, Summer 2003

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-18.8996	-4.2210		
Load	2.0168	2.7066	2.7180	4.8488	4.2623	1.6593
Wgt Constraints					0.6275	1.3162
Weather Index						
Gas Price Index***	-0.2644	-2.2804				
Proportion of Gen Offered						
Lagged Wgt. Constraints						
Adjacent Zonal Load						
Arch (0)	0.0409	17.59				
Arch (1)	0.2983	4.52				
Arch (2)	0.0682	2.04				
R^2 =	0.3496					
	Knots (% of Maximum Load)					
Price Flexibilities**			67.5%		90.0%	
Minimum	0.22		2.72		4.26	
Maximum	0.69		2.72		16.98	
Mean	0.51		2.72		5.96	

* Variables are defined in Appendix Table 2-11D; All are in logarithms, except where noted.
The model estimated is from equation (C-17) of Appendix 2C, and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (C-18-C-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.
***The Gas price index was supplied by Gas Daily.

Table 2-10D. Estimated Real Time Electricity Supply Function, Capital/Hudson Super Zone, Winter 2003

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	2.8828	18.6444				
Load	-0.6798	-1.0415				
Wgt Constraints						
Weather Index						
Gas Price Index***	0.0750	1.6223				
Proportion of Gen Offered	-17.1530	-8.7942				
Lagged Wgt. Constraints						
Adjacent Zonal Load						
Arch (0)	0.0846	22.99				
Arch (1)	0.5240	6.77				
Arch (2)						
R^2 =	0.2976					
	Knots (% of Maximum Load)					
Price Flexibilities**		100.0%		100.0%		
Minimum	1.45					
Maximum	5.90					
Mean	3.74					

* Variables are defined in Appendix Table 2-11D; All are in logarithms, except where noted.
The model estimated is from equation (C-17) of Appendix 2C, and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (C-18-C-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.
***The Gas price index was supplied by Gas Daily.

Table 2-11D. Deifinitions of the Variables Used in the Electricity Supply Models

Variable Names	Variable Definitions
LBMP*	Price in the Day-Ahead Market ($/MW) or Price in the Real-Time Market ($/MW)
Load*	Fixed Bid Load in the DAM, including Bilaterials (MW) or Actual Load Served in the RTM (MW)
Wgt Constraints	Number of Minutes in the Hour in which there is Congestion on Major Transmission Constraints affecting the Region being Modeled (weighted by line capacity relative to the total capacity of all relevant lines)
Weather Index	
Gas Price Index	Daily Natural Gas Price Index
Proportion of Gen Offered	Proportion of ICAP bid in the DAM (system wide) or Proportion of ICAP bid in the RTM (system wide)
Lagged Wgt. Constraints	Number of Minutes in the Hour (lagged one hour) in which there is Congestion on Major Transmission Constraints affecting the Region being Modeled (weighted by line capacity relative to the total capacity of all relevant lines)
Adjacent Zonal Load	Load Served (RTM) or Fixed Bid Load (DAM) in Zones Adjacent to the One being Modeled

* These varibles are specified in the model in logarithms, and LBMP is the dependent variable, while Load is a regressor. Load multiplied by the other explanatory variables to create the interaction terms that are the supply shifters in estimated equation (C-17) from Appendix 2C.

Chapter 3 – Methodology For Evaluating the Effects of PRL Programs

Estimates of the supply flexibilities are a critical element in calculating the effects of PRL load reduction on electricity prices, and in the overall program evaluation. The Day-Ahead Demand Response Program (DADRP) allows end-use customers to offer demand reduction bids into New York's day-ahead electricity market to help reduce system demand, and to receive market prices for any load reduction. Participants in the Emergency Demand Response Program (EDRP) are notified at least two hours in advance of when emergency system conditions are imminent, and they are guaranteed a minimum price for any load curtailment. Participants in ICAP/SCR must curtail after receiving two hours prior notice, provided that they were warned the day before that curtailments might be called for.

The overall strategy for evaluating both the DADRP and the EDRP and ICAP/SCR curtailments, and a list of the major market effects is given in Exhibit 3.1.

The Market Effects

The theory underlying the effect of load reduction or on-site generation from the two PRL programs is developed in detail in an earlier report to the NYISO by Neenan Associates (2001). The major components of this theory are illustrated simply in Exhibits 3.2a and 3.2b. The theory underlying EDRP effects is discussed first, and it is followed by a discussion of DADRP effects.

<u>Market Effects of EDRP</u>

In developing the theory underlying market effects of EDRP, it is assumed that demand is initially at a level indicated by point Q2 in Exhibit 3.2a. When the event is called, as the exhibit illustrates, demand is reduced to Q1 due to the load reduction, and the LBMP in the RTM consequently falls from P2 to P1. The situation when an event is called could, in fact, be worse than the one in the Exhibit 3.2a. Demand could initially be well beyond Q2, not intersecting the supply curve at all.

In either case, the load relief forthcoming during an EDRP event would depress market prices as long as the load curtailment results in a shift of the load level to the left of where it otherwise would have intersected the supply curve. Further, either an actual system outage would be avoided, or at a minimum, the reliability of the system (measured in terms of reducing the likelihood of a system outage) would be improved.

To assess the effects of actual EDRP events, one must essentially view things in reverse order. That is, once an EDRP event is called, the market equilibrium is at point 1 in Exhibit 3.2a. The observed price and quantity are P1 and Q1, respectively. Now, using the estimated supply price flexibilities from above (combined with data on actual EDRP load response), one must simulate what LBMP would have been had the load response not occurred—in this case simulate point 2 in Exhibit 3.2a. As indicated in Exhibit 3.2a, the most significant market effects are:

1. Reduction in RT-LBMP;
2. EDRP Payments (the shaded area 3 in Exhibit 3.2a);
3. Collateral Benefits, or Savings to Customers (area 4 in Exhibit 3.2a);
4. Any Reduction in Average Price or Price Variability; and
5. Effects on System Reliability.

Markets Effects of DADRP

The theory underlying the effect of load reduction bids in the DAM through DADRP is also developed in detail in an earlier report to the NYISO by Neenan Associates (2001). The major components of this theory are illustrated simply in Exhibit 3.2b. The detailed discussion of similar diagrams for EDRP provided above also applies to the circumstances involving DADRP. The primary differences in the theory underlying the two programs relate to the mechanisms by which the DADRP load reduction is scheduled. The DADRP load reduction is scheduled according to customers' bid prices, while EDRP's load reduction is called by the system operator. Once load is scheduled, the effects on the markets can be traced in similar fashions, except the effect of EDRP is obviously in the RTM, while the primary effect of DADRP is in the DAM.[1] As indicated in Exhibits 3.1, 3.2a, and 3.2b, the most significant market effects of DADRP are:

1. Reduction in DAM-LBMP;

[1] Having said this, however, the discussion regarding the EDRP highlights the fact that the effects of the programs are not entirely limited to the markets in which the loads are initially scheduled.

2. DADRP Payments to Customers (the area [Q1-Q2]*P2 in Exhibit 3.2b);

3. Collateral Benefits, or Savings to Customers (area 5 Exhibit 3.2b); and

4. Any Reduction in Average Market Price or Price Variability.

While the market effects of both DADRP and EDRP can be evaluated in a similar fashion, there are two other important effects that must be examined. The primary purpose for EDRP is to increase the level of system security in situations where there is a shortage of system-wide generation reserves. Accordingly, to complete the evaluation, one must examine the potential value of EDRP load reduction on the expected value of unserved energy. In contrast, DADRP is designed to improve market efficiency, and from this perspective, it is important to quantify the extent to which payments for DADRP load reductions are offset by the corresponding reductions in deadweight market losses to society. These additional parts of the evaluation are now discussed in turn.

EDRP Effects on System Reliability

As stated above, the primary function of EDRP and the ICAP/SCR program is to provide system dispatchers with a way to improve system reliability. Customers willing to curtail under the direction of dispatchers provide a unique stock of resources that can be dispatched during periods of forecasted or actual reserve shortfalls. According to the NYISO Operations Manual, the NYISO can, under these conditions, count dispatched EDRP load and ICAP/SCR as operating reserves.

By agreeing to curtail on terms that are acceptable to them, which include being paid, these customers improve system reliability. This delivered value is, in turn, enjoyed by all other customers system-wide (Boisvert and Neenan, 2003). In order to design and operate these programs optimally, it is essential to explicitly assign a value to such curtailments to assure that the benefits delivered exceed their cost.

The benefits from EDRP-supplied reserves depend upon the relationship between reserves and the Loss of Load Probability (LOLP), as illustrated in Exhibit 3.3. As reserves continue to fall, at some point LOLP begins to rise steeply. This in turn increases the likelihood of a need to shed load in order to maintain system reliability. Such load shedding imposes outage costs on customers. Dispatching EDRP resources forestalls the increase in LOLP. The avoidance of increased LOLP reduces the potential for forced service outages, and generates value in terms of avoided outage costs.

Quantifying the reliability benefits of EDRP requires first determining by how much EDRP curtailments improved LOLP. Then, the improvement in LOLP must be converted into a dollar value of benefit to customers. To convert this expectation into a corresponding dollar value to customers, the method of analysis developed for previous years' evaluations is to first multiply the change in expectations of an outage by the amount of load that is subject to an outage. This yields the change in the expected amount of load subject to an outage (expected unserved energy). In turn, this number is multiplied by the value of lost load (VOLL). The latter value is a measure of the cost to consumers when service is curtailed under such circumstances.

This methodology utilizes time-honored methods for valuing reliability, and the benefits from EDRP curtailments are thus measured as the change in the expected value of unserved energy (EVUE). In past EDRP evaluations, the application of this method has been both feasible and compelling, since EDRP curtailment events corresponded to times when reserves were short, and therefore additional reserves were of considerable value at the margin. However, a full empirical analysis of the reliability benefits of EDRP would require reconstructing system operations at the time of each hour of each event to determine the change in LOLP. This level of detail has always been beyond the scope of EDRP evaluations. Therefore, it has been common to report the benefits over a range of changes in LOLPs and a range of VOLL values, in order to reflect reasonable upper and lower bounds on the estimates of the cost to customers of forced outages.

Although the logic of the methodology just described is compelling during normal EDRP events, there are some new challenges for evaluating EDRP's contribution to system reliability in 2003. These stem from the fact that EDRP was called this year only immediately after the Northeast Blackout of August 14, 2003. It should not be surprising that the method described above is not directly appropriate for assessing the value of EDRP and ICAP/SCR curtailments called on August 15 and 16. On August 15th, system operators declared an EDRP and ICAP/SCR emergency event as part of their effort to restore the bulk power grid in the wake of a 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 reserves available in the face of still uncertain and less than normal operating circumstances, again called the EDRP and ICAP/SCR programs. While the valuation method used in previous years seems applicable to the second day's circumstances, it is not applicable to valuing curtailment resources when millions of customers are still without power.

Under conditions when load is being restored step-by-step, curtailment resources supplied by EDRP and ICAP/SCR customers allow other customers to come back online sooner. These other customers are moved 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 an LOLP=1 state, in which the customer's expected unserved energy is equal to the load they would use if they could be brought back on line. Put differently, there is a one-to-one correspondence between EDRP and ICAP/SCR curtailment resources and the corresponding expected unserved energy. With this unique relationship established, valuing these curtailments can be accomplished by using the conventional methods of multiplying this quantity by the value of lost load.

In past evaluations, a range of VOLL values has also been used to reflect the potential wide range in the estimates of the cost to customers of forced outages. The literature suggests that, for relatively short duration outages (for example those due to rolling blackouts that move across the system), on average customers can adapt in ways that at least partially mitigate their outage costs. Under these circumstances, it is probably appropriate to use the lower range of values that have been proposed for VOLL. In contrast, where the outage is both widespread and of extended duration, customers have little recourse except to endure the hardships. For such cases, the use of higher VOLL in estimating the value of PRL program load curtailment resources seems appropriate. (See Billington (2002) for a review of outage costs.)

Measuring the Reduction in Deadweight Social Losses from DADRP

Although assessing the market impacts from DADRP is critical to an overall evaluation of the PRL programs, it is also important to understand the extent to which DADRP may contribute to overall market efficiency. This task can be accomplished by measuring the extent to which DADRP bids, when scheduled, contribute to a reduction in what economists call social deadweight losses. These losses are a result of customers overuse or underuse of electricity when subject to fixed tariffs, compared with what their use would have been if they could, or were forced to, under very specific conditions, respond to market prices. This type of behavior is exactly what is made possible through DADRP.

The full development of this welfare analysis is reported in Boisvert and Neenan (2003), and much of it is repeated for convenience in Appendix 3A. The essence of the analysis is found in Exhibit 3.4, where both peak and off-peak demand situations are depicted. The supply curve S, has the "hockey stick" shape, whereas peak and off-peak demands are given by D_p and D_o, respectively.

From the standpoint of DADRP, it is most important to focus on the demand and supply situation during the peak period. If customers face a fixed tariff T, then they will wish to consume X_4* during peak periods. Although customers pay only T/MW at retail, the wholesale price suppliers would require to deliver X_4* is P_4*. While the nature of electricity markets requires LSEs to purchase sufficient energy to meet demand X_4*, in economic terms, the market cannot clear at this quantity and price T, because the supply curve does not pass through that point. In contrast, if customers faced full wholesale prices in the competitive market, the market would clear at price P_4^c and quantity X_4^c. The inefficiency of the fixed tariff results from the fact that, for all units of consumption between X_4^C and X_4*, the marginal cost (given by the supply curve) of meeting this load is higher than its value to the customer (given by the demand curve).

The total difference between the value to customers and the cost to producers over the load range X_4* - X_4^C can be shown to be equal to the area d + d' in Exhibit 3.4. However, some of this social deadweight loss can be avoided through DADRP if:

- Customers bid load reduction equal to X_4* - X_4^C at any offer price at or below P_4^c., and
- The DADRP payment (equal to the area s" + e + d') is less than the deadweight loss (the area d + d'). For this to be true, the area s" + e must be less than the area d.

As is demonstrated in Appendix 3A, we can view this situation in two different ways. The first relates to the characteristics of supply and demand if firms have an incentive to respond to price and achieve the equilibrium defined by point Z'' in Exhibit 3.4. Viewed from this perspective, it is clear that as the supply curve becomes steeper (e.g. pivoting counter clockwise around point Z’’), the net welfare from a DR program increases because the area d becomes larger. Similarly, if the initial demand curve were less price responsive (made steeper by pivoting clockwise about the competitive equilibrium z’’) the net welfare calculation would also move in favor of the DR load, as the areas e and s’’ would both become smaller. In summary, the potential welfare gains from DR load programs are highest in situations where both the supply and demand curves are initially extremely price inelastic (“steeper”). These are the very circumstances that have lead to price spikes that disrupt newly formed wholesale markets.

The size of these two areas is clearly an empirical question, and an important part of this year’s PRL evaluation is an attempt to measure the reduction in this social deadweight loss from the past three years’ of DADRP bids. In so doing, however, it is important to recognize that because of the NYISO’s two settlement system, bids accepted under DADRP produce efficiency gains (reductions in deadweight losses) in both the DAM (when the load is initially scheduled) and in the RTM (when the load does not show up in real time). Payment is made only once.

In discussing these potential gains in the RTM, one must also recognize that if the price in the RTM is less than in the DAM on which they were scheduled to curtail, it can be seen that market efficiency is increased by letting customers who had DADRP bids accepted in the DAM buy through in real time and consume the extra electricity.[2] This result speaks directly to the long- term efficacy of DADRP and militates for a change in the current provisions that charge participants the greater of the DAM or RTM price for curtailment shortfalls.

[2] Although not illustrated here, this result can be established in a similar way to the analysis in Appendix 3A that demonstrates that deadweight losses are reduced if consumption during off-peak periods is greater than it would be under a fixed tariff.

Exhibit 3.1: Simulation of Effects of PRL Reduction

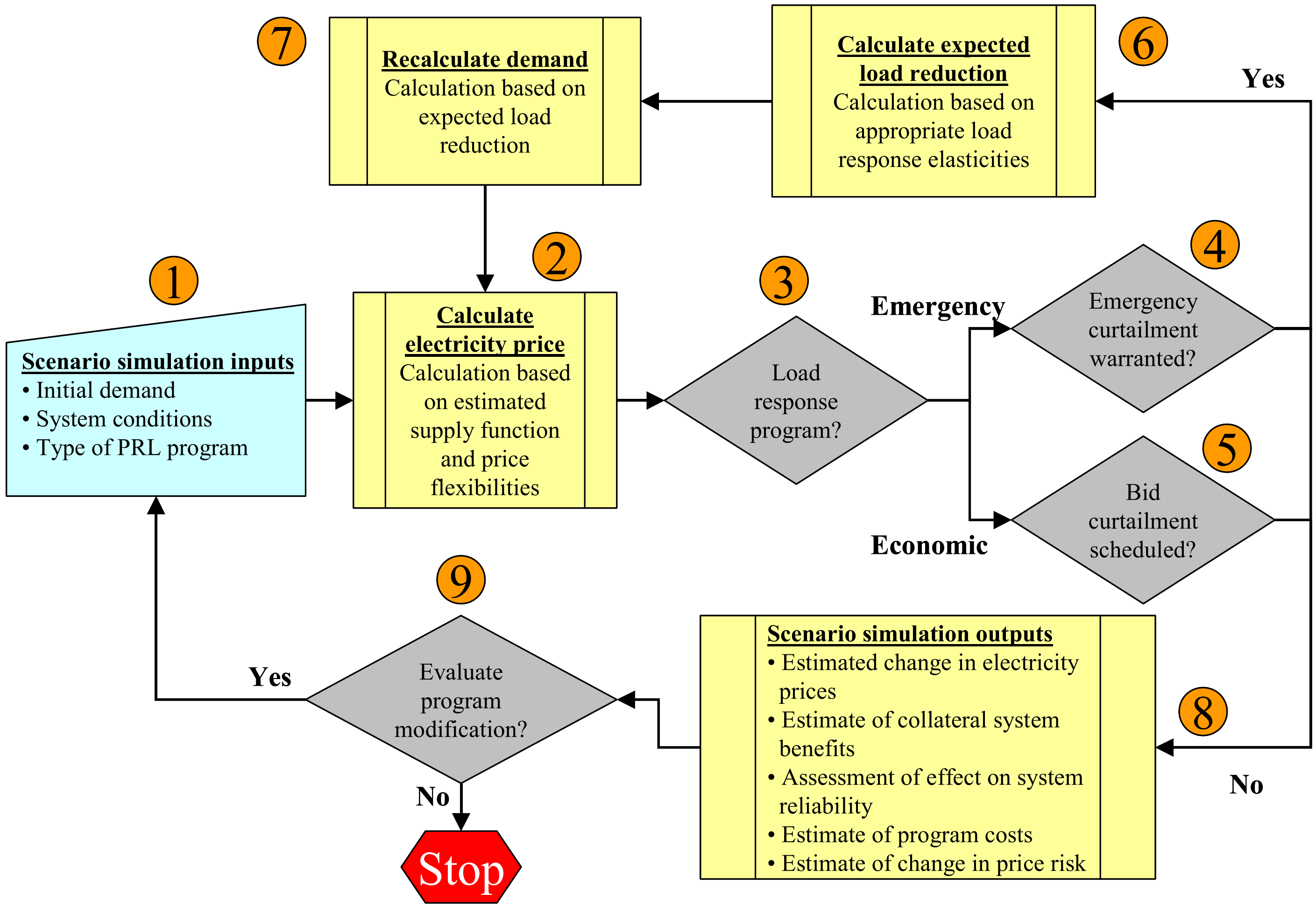
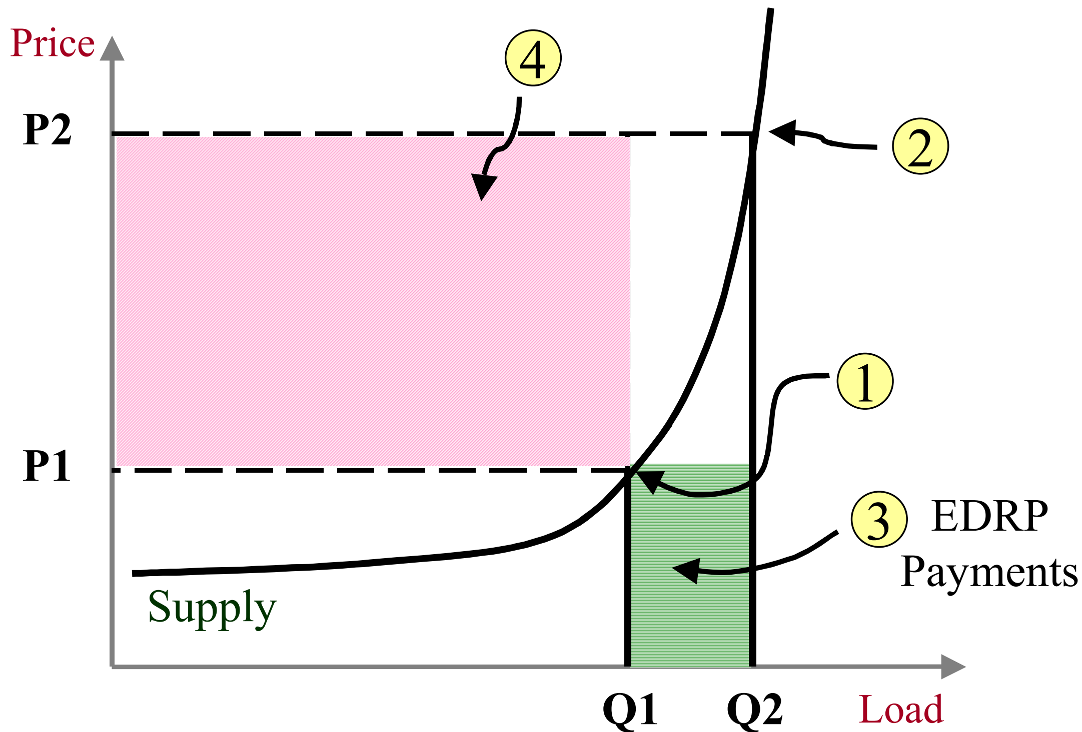
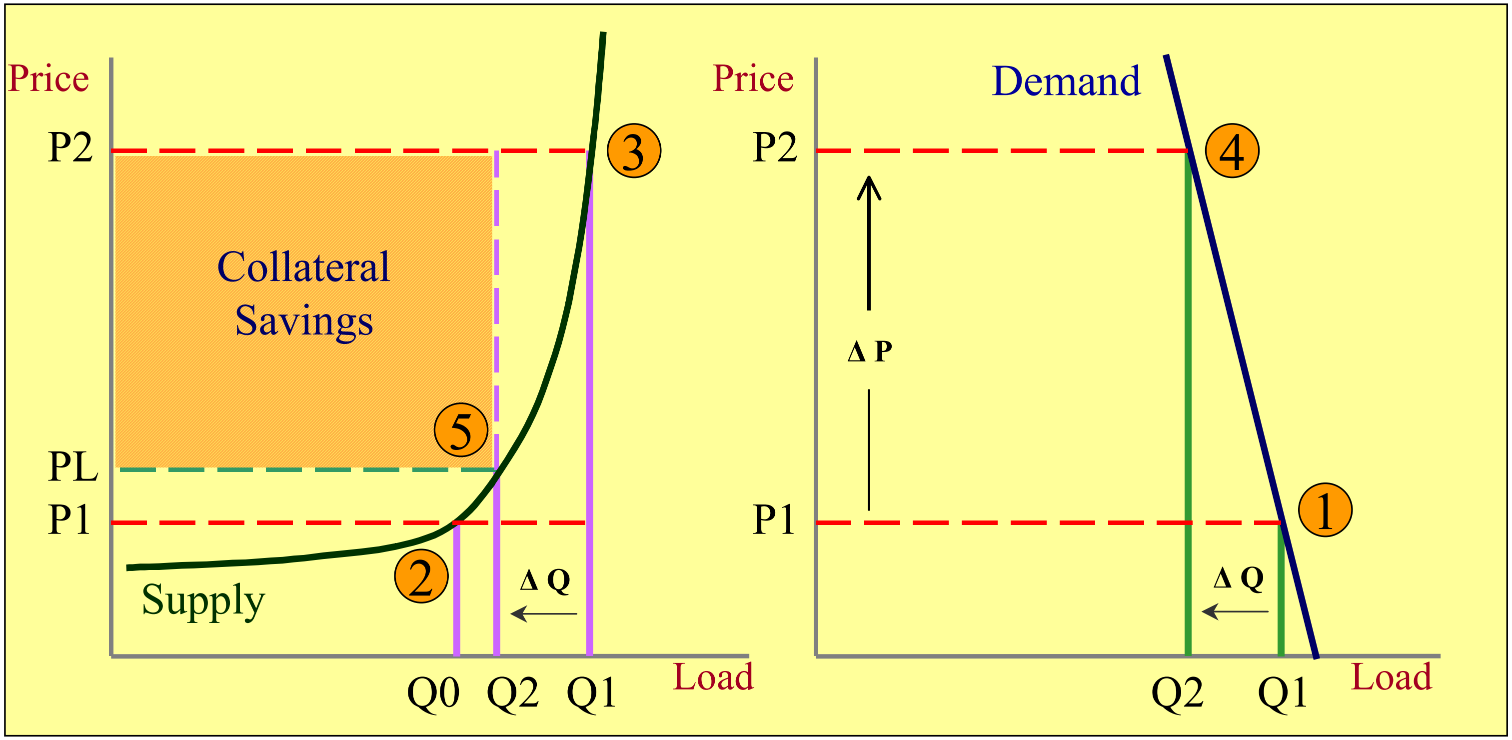


Exhibit 3.2a: Market Adjustments for EDRP



1. Demand and Equilibrium Price, Q1 and P1, after EDRP Event called yielding load reduction of Q2 – Q1, equilibrium observed in the data.
2. Demand and Equilibrium Price without EDRP Load Reduction, Q2 and P2.
3. Program Payments: (Q2 – Q1) x P1 or $500, whichever is higher
4. Collateral Savings: Q1 x (P2 – P1)

Exhibit 3.2b: The Dynamics of DADRP Price-Responsive Load



1. Retail rate and corresponding demand.
2. Supply offered at retail rate.
3. Retail demand supplied only at higher price.
4. Reduction in retail demand due to higher price.
5. LBMP after scheduled load reduction.

Exhibit 3.3: EDRP Value of Expected Unserved Energy

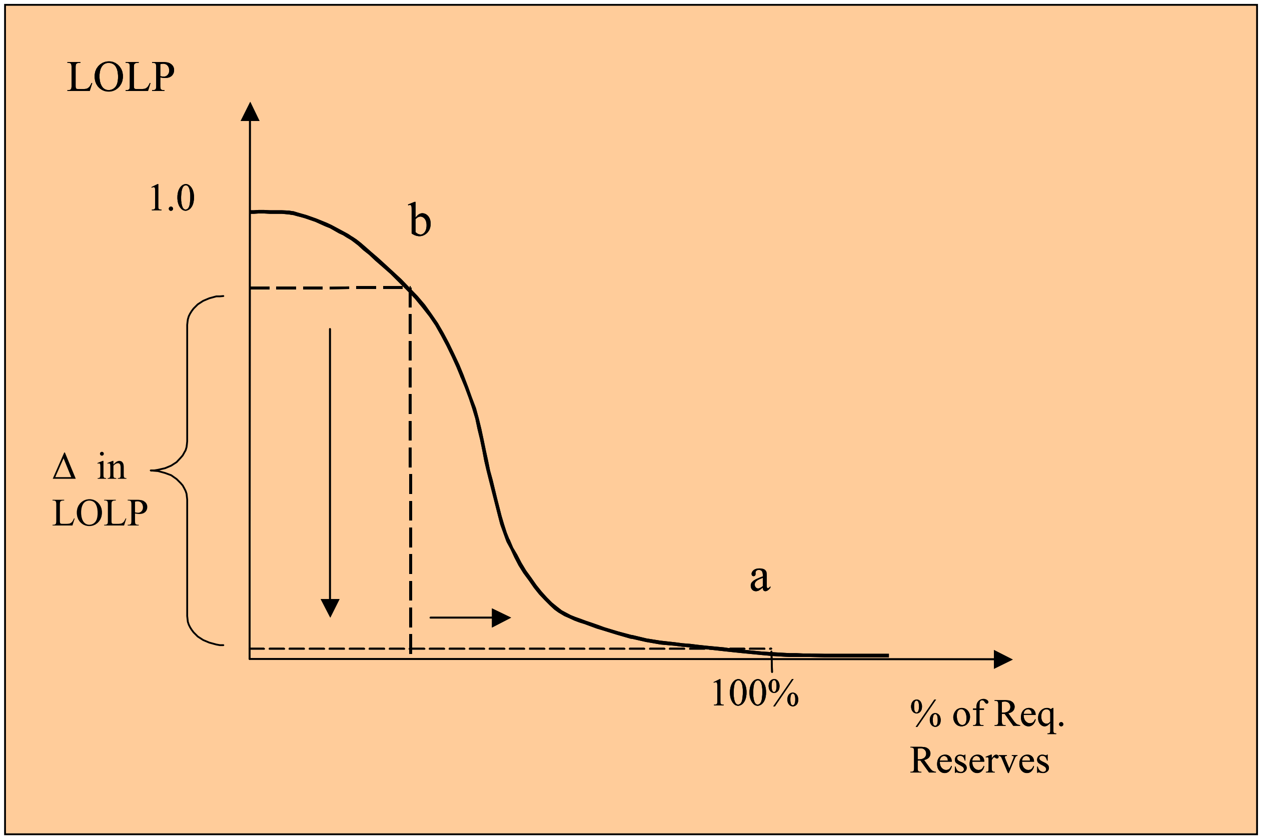
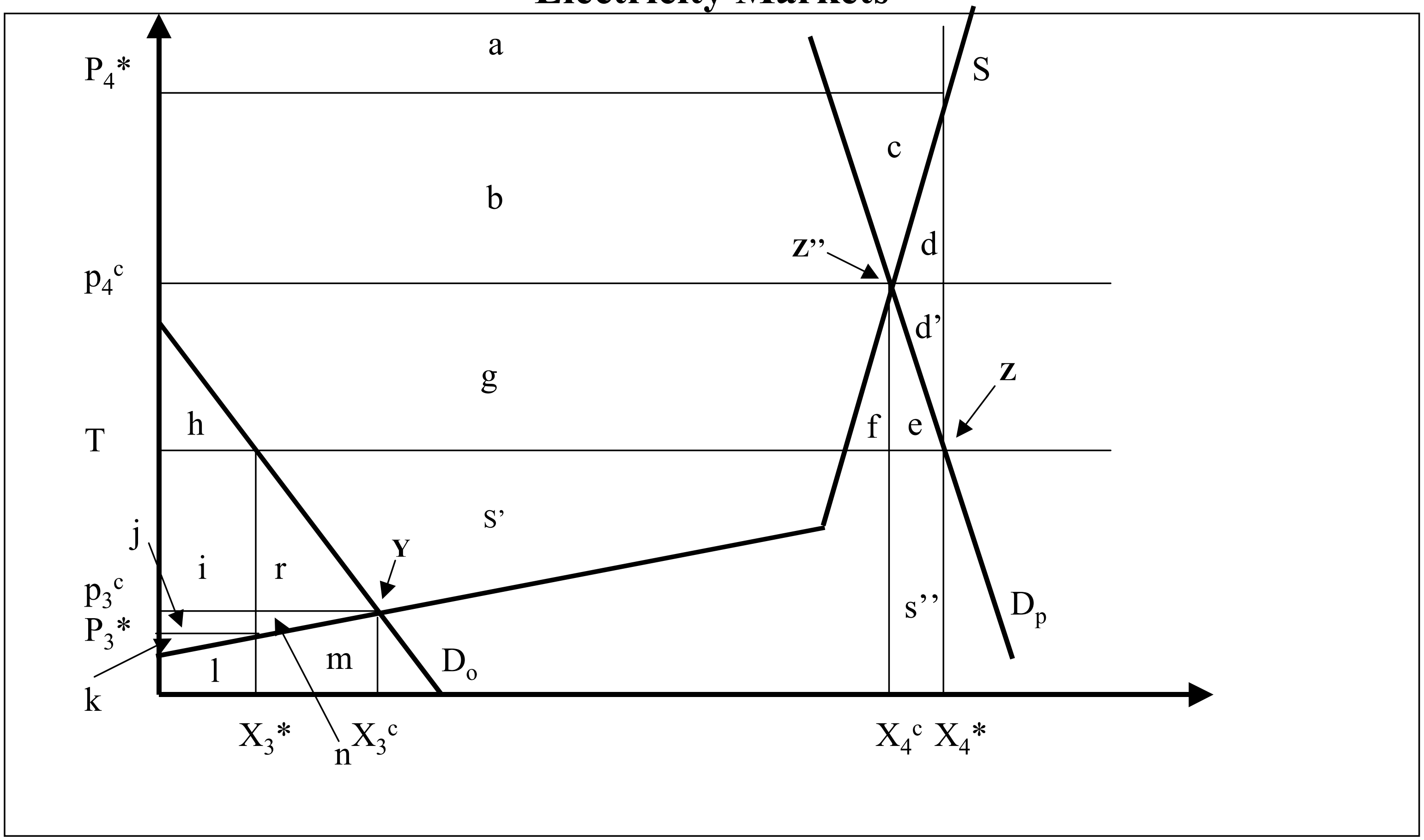


Exhibit 3.4: Net Welfare Gain from PRL Programs in Competitive Electricity Markets



Appendix 3A – A Diagrammatic Welfare Analysis of Competitive Electricity Markets

While assessing these market effects is a critical element of evaluating DADRP, one can also assess the effect on market efficiency through an analysis of DADRP effects on social welfare. Put differently, we wish to measure the change in combined producer and consumer surplus in allowing customers to respond to wholesale prices at certain times rather than face a flat rate. This welfare analysis is taken from Boisvert and Neenan (2003).

Competitive Electricity Market with Full Capacity to Adjust to Price Signals

To begin the analysis, we assume that the market for electricity is divided into two distinct periods, a peak period and an off-peak period. Further, it is a market that when generators' offers to sell un-contracted capacity and energy are submitted to a last price auction. However, demand is uncertain; price is known just prior to when the quantities each generator is to serve are determined. These conditions characterize day-ahead wholesale electricity markets such as that run by the New York ISO and are consistent with the standard market design as currently proposed by FERC.

We initially assume that customers can make *full* and *costless* adjustments to demand in response to price changes according to established derived demand schedules for electricity that represent the value of the marginal product of electricity to the firm. The situation is depicted in Exhibit 3-1A.

Off-Peak Demand

According to Exhibit 3-1A, the competitive equilibrium in the off-peak period is at point Y. Here, retail customers during off-peak periods follow demand curve depicted as D_o in the exhibit and buy X_3^c at price P_3^c at a total cost of $X_3^c\ P_3^c$. The demand curve is net of a constant wholesale margin, M. The generators supply X_3^c according to supply curve S and are paid P_3^c yielding revenue equal to $P_3^c X_3^c$. Under these conditions, welfare is measured by the sum of consumer and producer surplus:

- Consumer surplus is the area under the demand curve Do and above the price line P_3^c, as indicated by the box labeled i and the triangles h and r.
- Producer surplus is the area above the supply curve S and below the price line P_3^c, as indicated by (j + k + n).
- Welfare is the sum of the producer and consumer surpluses, area {h + i + r} + {j + k + n}.

Peak Demand

The competitive equilibrium for the peak period if customers respond to price changes is at Z'', the intersection of the peak demand curve D_p and price P_4^c (see Exhibit 3-1A). During periods of peak demand, retail customers buy X_4^c at a price of P_4^c and a cost of $X_4^c P_4^c$, where the demand curve is net of a constant wholesale margin, M, similar to the case for the off-peak period. The generators supply X_4^c and are paid P_4^c, and they receive revenues of $P_4^c X_4^c$. The measure of welfare is again given by the sum of consumer and producer surplus.

- Consumer Surplus is the area to left of D_p and above P_4^c , the area (a + b).
- Producer Surplus is the area above S, to the left of D_p and below P_4^c , the area (h + i + r + j + k + n + s' + g).
- Welfare is the area {a + b} + {h + i + r + j + k + n + s' + g}.

Unfortunately, electricity is not storable, so the analysis of Just et al. (1982) does not apply directly to these circumstances. Further, under current retail market conditions most customers can still buy electricity at fixed rates, but their suppliers face fluctuating market prices.[1] To see the value of inducing price responsiveness by DADRP participants, we must

[1] For many customers, it is not practical to adjust demand in response to price changes; the transactions costs (outage costs plus costs of administration, meters, etc.) of doing so are very high. This means that the

compare the case just illustrated, where demand can fully respond to price, with the previous situation whereby retail customers can use any amount of electricity at fixed prices.

Competitive Wholesale Electricity Market with Retail Demand Served at Fixed Prices

Off-Peak

We begin by examining the outcome for the off-peak period under the flat tariff T, again assuming that demand curves are net of any wholesale margin.

In off-peak periods, the fixed tariff (T in Exhibit 3-1A) is set above the off-peak market price, because peak power is purchased at a price higher than T. For the wholesaler to cover the cost of both peak and off-peak power purchases, T must be a weighted average of the peak and off-peak prices.[2] The equilibrium for the customer, in this case, is at point X, consuming quantity X_3^*. At point X:

- Consumer Surplus = (h)
- Producer Surplus = (i + j + k) (i + j go to the customer's load-serving entity (LSE); k goes to the generator)
- Social Welfare = {h} + {i + j + k}
- Social loss compared with the competitive market situation where customers can respond to price is: { r (foregone consumer surplus) + n (foregone producer surplus)}.

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two aggregate demand curves in Figure 1 are the horizontal sum of many individual demand curves, most of them completely inelastic (e.g. completely vertical), or nearly so.

[2] As above, T is a weighted average price, where the weights are the proportion of electricity consumed in each period.

Compared with the situation where customers can respond to price, social welfare is reduced under the flat tariff by the areas r + n, which is called deadweight loss, while consumer surplus, area i, is transferred from customers to the LSE. Transfers do not affect the level of net social welfare, only how it is shared among consumers, generators, and retail suppliers.

To summarize, social welfare can be increased by offering to sell additional load at the lower price P_3^c. Demand and supply will continue to adjust, until the equilibrium point Y is reached. At Y:

- Producer surplus increases by an amount equal to the area n
- Consumer surplus increases by an amount equal to the area r, which either the supplier retains unless it lowers the price of all X_3^c to the customer, in which case the customer would realize the full benefit, and area i is transferred back to consumers.

Regardless of who retains the increase in producer and consumer surplus, Y is preferred socially to X since it represents the optimal use of resources.

Peak Period

We next examine the situation in the peak period in a similar fashion, using Exhibit 3-2A for ease of exposition. When customers are faced with a fixed tariff, the equilibrium point will be at point Z in Exhibit 3-2A, where the retail price is fixed at T and quantity consumed is X_4*. The flat tariff also leads to inefficiencies in the peak period because for demand greater than X_4^c, the usage price, which represents value to the firm given by points on the demand curve, is below marginal cost (e.g. the supply curve). The use of electricity whose value in production is below the cost of electricity results in deadweight loss in welfare to society represented by the combined area d + d′.

The distribution of producer and consumer surplus in the peak period case requires care to disentangle. We know that on average the price T covers the cost of the LSE's purchases of energy to serve the customers both during peak and off-peak periods. Therefore, in looking at Exhibit 3-2A, we can assume that expenditures by LSE to buy power at peak prices above T is effectively collected from the customer through off-peak sales at T which is above the supply cost, and which is then passed along to the generator. If the supply curve were indeed flat, as it effectively is from the customer's perspective when facing a fixed price of T, consumer surplus at price T (Exhibit 3-2A) would be: a + b + g′ + f + e, and there would be no producer surplus. The wholesale suppliers and in turn generators would be paid T for each unit, and that payment would equal marginal cost.

However, implicit in the fixed tariff T (determined simultaneously with X_4*and X_3*) is a payment of X_4*[P_4*- T] (and quantity weighted) to cover the wholesaler's cost of X_4* over and above T. This amount is transferred to the generator and is equal to the combined area b + c + d + d′ + g′ + f + e. The areas b + c + f + e are consumer surplus transfers from the customer to the generator during the peak period and thus augment producer surplus above the level s′. The final result is that consumer surplus = a, and producer surplus = s′ + b +g' + c + d + d'. The generator also receives payments (economic rents) equal to the combined area d′ + d, which represents additional costs to the customer resulting from the inefficiency in pricing all usage at T rather than at the true differential prices that reflect the marginal cost of supplying electricity. From society's perspective, the additional resources needed to produce $X_4^* – X_4^c$ (e.g., consumption over and above the optimal level) would have been better allocated to other uses; thus the combined area d′ + d is lost to detriment of society, and is referred to as the deadweight loss.

The challenge facing electricity market designers and policy makers is how to design retail programs that can reduce or eliminate altogether the size of these deadweight losses. There is perhaps no single solution to the problem, but we can highlight the important issues by illustrating the impact of a Demand Response (DR) program, which encourages customers to bid P_4^c to provide load reduction in the amount $[X_4^* – X_4^c]$, thereby eliminating the deadweight loss. Payments to those that accomplish this load reduction would be the combined area s″ + e + d′ (see Exhibit 3-2A). As long as this area is less than the deadweight loss of d′ + d, then social welfare is unequivocally improved. In other words, for there to be an increase in net social welfare for a DR program, (s" + e) < d; these areas are illustrated in Exhibit 3-2A.[3]

The size of these two areas is clearly an empirical question.[4] From a policy perspective, we can view this situation in two different ways. The first relates to the characteristics of supply and demand if firms had an incentive to respond to price and achieve the equilibrium defined by point Z'' in Exhibit 3-2A. Viewed from this perspective, it is clear that as the supply curve becomes steeper (e.g. pivoting counter clockwise around point Z''), the net welfare from a DR program increases because the area d becomes larger. Similarly, if the initial demand curve were less price responsive (made steeper by pivoting clockwise about the competitive equilibrium Z'')

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[3] Borenstein and Holland (2002) provide an analysis of the second-best optimum if customers are to remain on flat tariffs. Their arguments are summarized here because through further analysis, one may be able to discover an algebraic relationship between these areas, although such an analysis is not done in this paper. As stated above, Borenstein and Holland (2002) shows that the quantity weighted average price, T, is the flat tariff that will cover the costs of retail electricity suppliers. However, this is not the flat tariff that provides the second-best welfare solution if retail customers stay on flat tariffs. Instead, they show that the flat rate tariff that minimizes the dead weight loss is one in which the price weights are the relative slopes of the peak and off-peak demand curves. This rate may be higher or lower than the value of T. This is an important result, but it depends on the supply curve being perfectly elastic up to system capacity, and vertical at that point. If supply elasticities are in between these extremes, the second-best fixed tariff would also likely involve the slopes of the supply curves as well, although this is not derived explicitly here. At some time it would be useful to derive this more general result, although it is not critical to the validity of their argument.

As Borenstein and Holland (2002) also point out, one difficulty with this second-best fixed tariff does not necessarily allow retail suppliers to cover their costs. However, these costs can be covered along with achieving the second-best solution under competition through a tax or subsidy that is the quantity weighted average of the new second-best flat tariff.

[4] For convenience, Figure 3 was drawn assuming linear supply and demand curves, but this representation may in fact distort the size of the areas being compared.

the net welfare calculation would also move in favor of the DR load, as the areas e and s’’ would both become smaller. In summary, the potential welfare gains from DR load programs are highest in situations where both the supply and demand curves are initially extremely price inelastic (“steeper”). These are the very circumstances that have lead to price spikes that disrupt newly formed wholesale markets.

Therefore, from a societal perspective, it makes sense to focus on exposing customers to market prices during the peak period when they are high. This view provides a basis for understanding the size of the deadweight losses and the potential gains from implementing DR programs. Prior to program implementation, firms would be facing a fixed tariff and consuming at point Z in Exhibit 3-2A. Thus, if we take this as a starting point, the welfare gains from a DR program can be increased if firms: a) can be encouraged to reduce overall peak demand (e.g. resulting in a shift in D_p to the left) and/or, b) if the supply curve is sufficiently steep, firms can be encouraged to be more price responsive just during peak periods (e.g., resulting in D_p pivoting counterclockwise around point Z’’). The former situation calls for permanent changes in consumption patterns by introducing time-of-use pricing. The latter is more effectively accomplished by exposing customers to prices, or incentives derived there from, when such market conditions obtain.

Exhibit 3-1A: Net Welfare Gain from PRL Programs in Competitive Electricity Markets

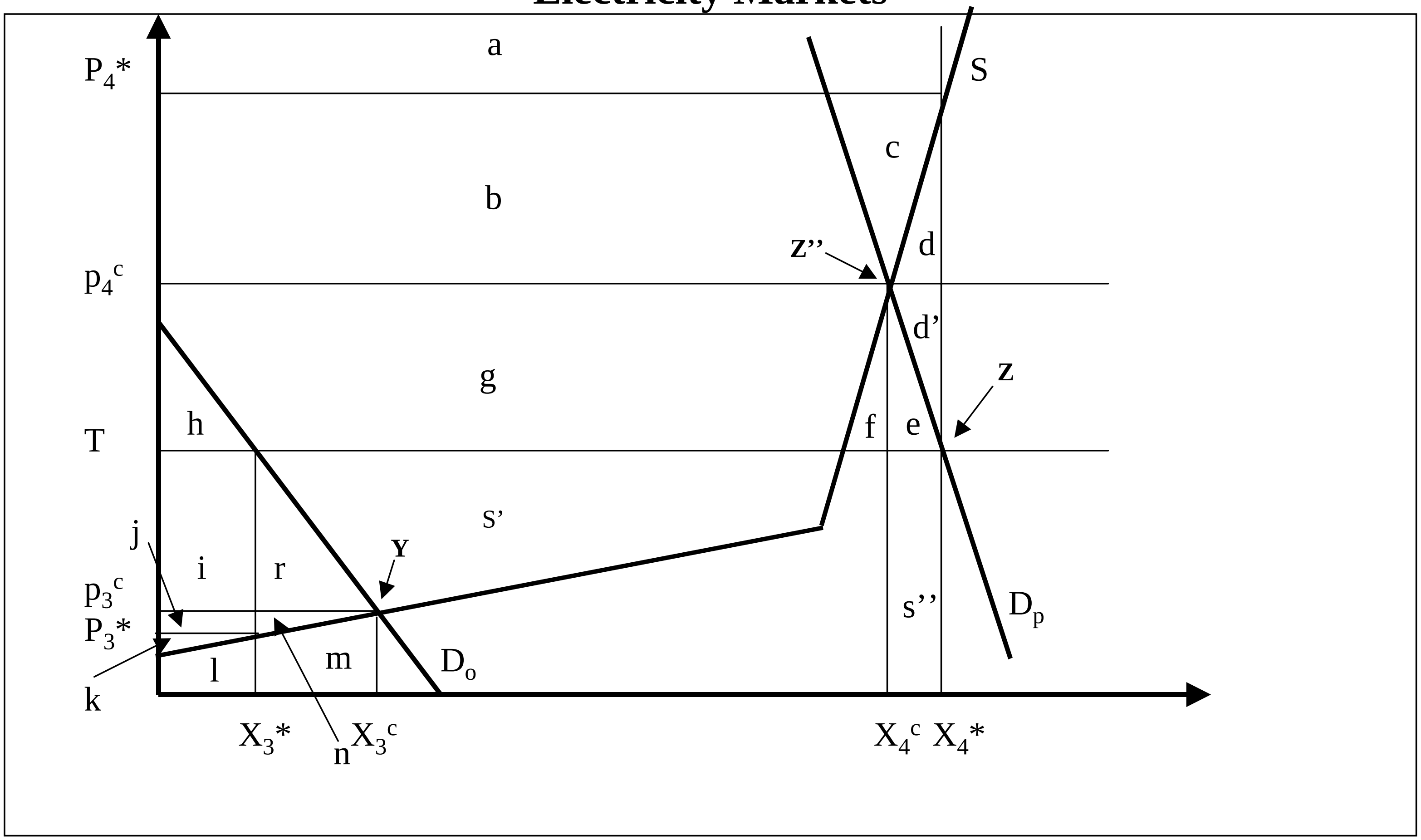
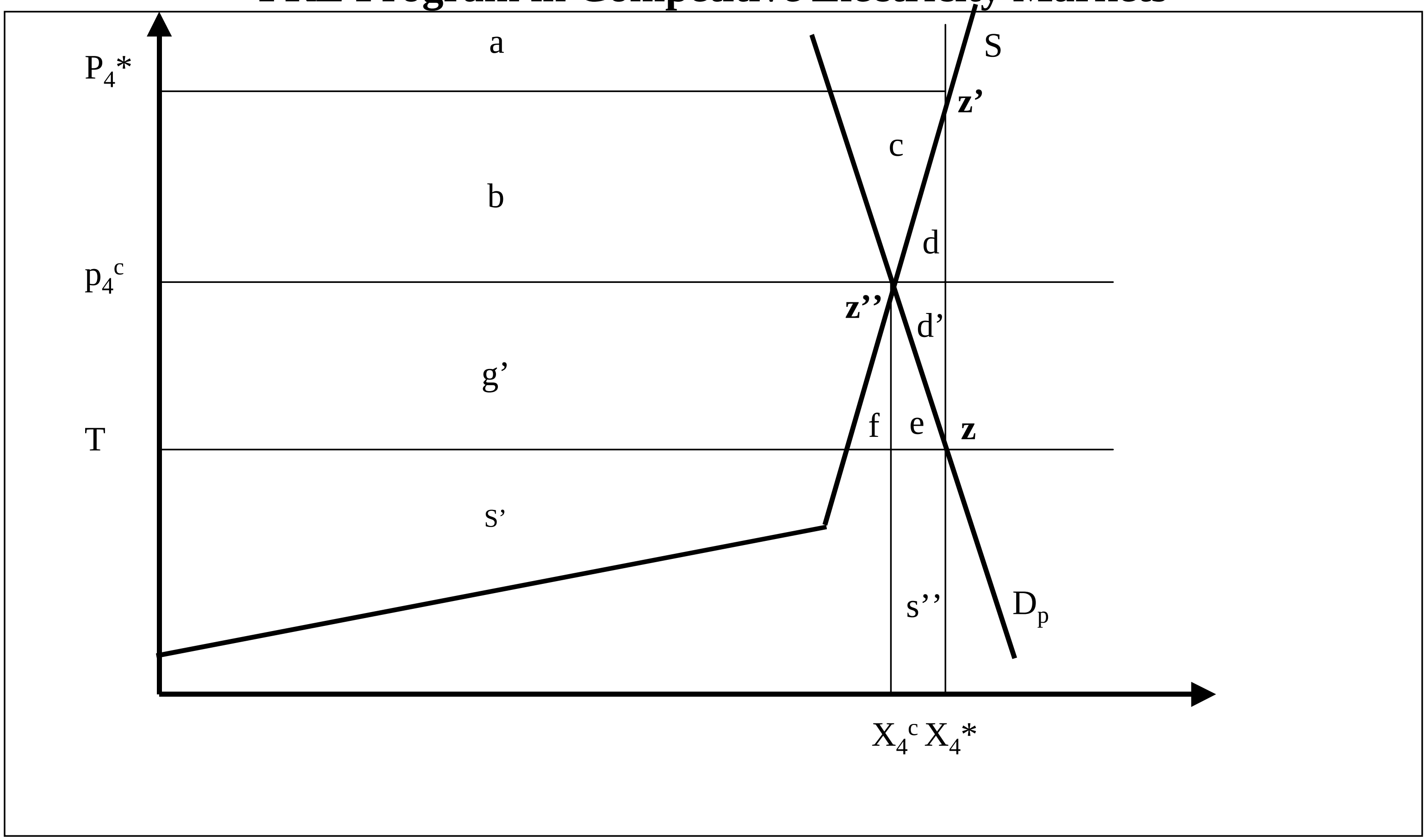


Exhibit 3-2A: Net Welfare Gain from an Interruptible Load Bidding PRL Program in Competitive Electricity Markets



Chapter 4 – Results from the PRL Program Evaluation

Now that some background data on the day-ahead and real time electricity markets have been discussed, and the evaluation methodology has been outlined, the remainder of the report focuses on the results of the evaluation. Efforts to characterize the effects on participation due to the 2003 program changes are presented in the section below. That section is followed by the evaluation of EDRP, and finally, the results from the DADRP evaluation are discussed.

Summary of PRL Program Changes

The year 2003 marks the third year in which customers could participate in the NYISO's EDRP and DADRP programs, and the fourth year for the ICAP/SCR program. During 2001 and 2002 customers (with the exception of those operating DG units) were able to participate in any single program or in any combination of the three programs.[1] Prior to the 2003 enrollment period, the NYISO implemented several important changes in the programs that could potentially change participation rates. They include:

- The imposition of $50/MWH price floor for DADRP bids;
- The elimination of a 10% penalty applied to curtailment imbalances in DADRP;
- The uncoupling of EDRP and ICAP/SCR, allowing customers to be enrolled in only one of the two programs at any point in time;
- The ability for dispatchers to deploy only a portion of ICAP/SCR curtailment capability, during an emergency event, where only some participants might be called to curtail load during an emergency event;
- To implement a partial dispatch, ICAP/SCR customers are required to nominate a strike price (capped at $500/MWH) at which they would be dispatched during events where not all-available curtailment capability was needed; and
- During ICAP/SCR curtailments, those called to curtail are eligible for an energy payment-- the higher of their nominated strike price or the prevailing LBMP.

[1] Sequencing protocols determined under which program a joint participant was paid when a day-ahead DADRP scheduled curtailment became coincident with a same-day EDRP or ICAP/SCR event.

In addition, some changes in market operating protocols have implications for demand response program participation and performance. These changes include:

- When dispatched, ICAP/SCR and EDRP resources can now set LBMP during SCD intervals in which their reductions are needed to maintain required reserve levels.
- The ICAP reconfiguration auction created a more robust monthly spot market that was expected to raise the clearing prices for ICAP/SCR resources when sold into that auction.

This latter change in operating protocols might well be expected to make ICAP/SCR participation more attractive than EDRP. Further, by allowing these resources to set LBMP, the ICAP/SCR dispatch strike price (which could be as high as $500/MWH) or the EDRP price floor ($500/MWH) could effectively place a floor on the real-time LBMP during emergency events. This protocol could therefore lead to higher prices during those periods when EDRP and ICAP/SCR are dispatched than has been the case in previous years.

Efforts to Assess the Effects of Program Changes

Several working hypotheses help guide the assessment of how these 2003 program changes might affect program participation. They are outlined below.

The changes in DADRP are likely to have distinct and opposite affects:

- The elimination of the 10% penalty on DADRP imbalances would have a negligible impact on participation; and
- The imposition of a $50/MWH bid floor would act as a deterrent to DADRP participation.

The uncoupling and realignment of ICAP/SCR and EDRP are likely to have at least three distinct effects:

- The uncoupling of the programs may lead to the migration of EDRP participants to ICAP/SCR;
- The requirement that ICAP/SCR participants nominate a curtailment strike price may complicate recruitment and possibly act as deterrent to participation; and

- ICAP/SCR participant strike price nominations may well cluster around very low prices (near zero) and very high prices (close to the $500/MWH bid cap).

The uncoupling of the two programs is accommodated in conjunction with new dispatch rules (ICAP/SCR first and as needed) and the addition of energy payments for ICAP/SCR. For this reason, EDRP participants may migrate to ICAP/SCR because these additional provisions increase the benefit/risk ratio to ICAP/SCR participants. At the same time, the need for ICAP/SCR participants to nominate a strike price may reduce the attractiveness of the program, but for those remaining participants, one might expect low strike prices from customers confident in their ability to comply when asked to curtail. These customers might be somewhat eager to be asked to curtail so they can receive the energy payment. Alternatively, the cluster of high strike prices may be from some customers, content with the ICAP/SCR payment, attempting to limit their curtailment exposure.

To effect this evaluation, two separate initiatives were undertaken to generate information to test the above hypotheses. First, to characterize how the program changes affected recruiting efforts and program administration, a survey was administered to a small number of the entities that recruit customers to participation in the NYISO's demand response programs. These entities include regulated and competitive load serving entities (LSEs) and curtailment service providers. The survey was administered during the fall of 2003, so that this past summer's program history could be reflected in respondents' assessment of the programs' new provisions. The NYISO distributed the survey to everyone on the mailing list from its Price Responsive Load Working Group. The list includes entities that currently enroll participants in the NYISO's demand response programs, and direct serve and limited customers that represent themselves in the programs.

Second, to establish any patterns of retention or migration of customers between programs that might be attributable to the program changes, there was a detailed examination of the NYISO's program registration database to track the changes in program participation from previous years.

While no specific effort was made to sort out the separate effects of the general changes in dispatch protocol, some effects are implicit in the observed behavior of participants. In addition, because the only events called during 2003 are the ones immediately after the blackout, there is little that can be done to document the effect of these program changes on participations' behavior during the "typical" emergency events that had been experienced during 2001 and 2002.

The Survey Results

There are four major components to the survey. The results from each are described below.

The Survey Respondents

Of the 13 survey respondents, five are LSEs (two regulated and three competitive), six are demand response provider (DRPs), one is a retail customer, and one is an institutional respondent (Table 4.1). All but the institutional respondent and one competitive LSE 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. Some are also active in similar programs offered by the adjacent electricity markets, PJM Interconnection and ISO-NE.

As Chart 4.1 illustrates, most (10 of 13) enrolled customers in ICAP/SCR, and nearly half (6 of 13) sponsored customer participation in EDRP. Three respondents (one regulated LSE and two DRPs) actively promoted DADRP, but only two (one regulated LSE and one DRP) enrolled a customer in DADRP. Another two promoted DADRP only when the customer asked about participation. Seven of the respondents did not actively promote participation in DADRP (Chart 4.2).

These results generally square with previous evaluations of the DADRP program (Neenan Associates (2002) and Neenan Associates and CERTS (2003)), where awareness of DADRP was found to be low in general, and even low among those customers participating in ICAP/SCR or EDRP. Thus, it appears that LSEs and DRPs have concluded either that customers are not interested in DADRP, or that building such interest is not to their (the LSE's or DRP's) interest.

DADRP Experience

The five respondents that recruited customers to DADRP were also asked a number of questions regarding DADRP based on their experience. They were asked which customer groups were most receptive to learning about DADRP. Chart 4.3 illustrates the results, sorted by the response of the three DRPs and the two LSEs. All respondents agreed that some sectors (hospitals, colleges and secondary schools, light manufacturing, and restaurants) were unreceptive to DADRP participation. The two types of respondents disagreed, however, about the interest of other sectors. The DRPs reported that big box stores, wastewater treatment plants, and office buildings were relatively receptive, while the LSE's response indicates a perception of lower interest on the part of these customers.

Three of these five respondents reported that the removal of the 10% penalty for curtailment noncompliance created interest in DADRP, but did not lead to actual participation. The other two respondents thought that its removal had no influence. One possible interpretation of these results is that the penalty is perceived by some customers as being unduly severe, and its removal only highlights other features of the program that are seen as barriers to participation.[2]

In this regard, two of the respondents that actively marketing DADRP said the requirement that bids be submitted in one MW increments is the major barrier to customer participation in DADRP. The one MW bid increment requirement has been cited before as a deterrent to participation, because it forces the LSEs or DRPs to manage the risks if customers' bids do not meet that standard, or it forces customers to undertake the consequential market risk.

Two others said the major barrier to participation is the recently instituted $50/MWH bid floor. Objections to the bid floor have been voiced many times in NYISO Working Group meetings. The same objection has been raised about programs sponsored by PJM (which impose a slightly different but functionally similar price floor on bids).

Despite these responses, it is difficult to understand the reasons for this objection to the bid floor. Most customers already pay a commodity rate of at least $50/MWH; it is difficult to construct a situation where a customer would curtail at a DADRP price lower than what it pays for electricity use, except in cases where the customer can dispatch on-site generation with a

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[2] As part of previous evaluations, customers were asked about barriers to participation in DADRP. Few view the penalty as a barrier. More common responses were: that customers cannot curtail usage under the program circumstances, or even if they could curtail, the perceived benefits were not sufficient for them to do so.

lower fuel cost. Such actions, however, are not allowed under DADRP protocols. The one explanation favoring a lower (or no) bid floor is that some customers may want to bid curtailments coincident with planned partial or total facility shutdowns. This type of behavior is contrary to the DADRP objectives, one of which is to promote market efficiency by inducing curtailments that otherwise do not occur at times when such curtailments could lead to lower prices in the DAM price. A primary motivation for establishing the floor price is to forestall DADRP bidding during planned facility outages.

The active DADRP marketers were also asked to comment on four separate program changes in DADRP that might possibly boost program participation. None was enthusiastic about a provision whereby participants with scheduled bids would be paid for additional curtailments, beyond what was scheduled. Two thought that lowering the bid increment to 100 kW would increase participation, while two others thought that lowering the bid floor would do so as well. One respondent thought that settling scheduled curtailment shortfalls at the RTM LBMP, rather than the higher of RTM LBMP or the DAM LBMP at which the load reduction was scheduled, would be most helpful.[3]

The DADRP promoters were also asked if they preferred the current ‘incentivized’ DADRP to an ‘unincentivized’ alternative, and if DRPs not serving customers’ commodity needs should be authorized to promote participation in DADRP. Three of five prefer keeping the existing program, and all believe that DRPs should be part of the market structure, regardless of the specific features of DADRP. Finally, these five respondents were asked what they would do if there were no NYISO-sponsored DADRP program of any kind. The regulated LSEs said they would implement a Niagara Mohawk-type real-time pricing tariff indexed to DAM LBMPs. Two of the DRPs said they would offer some bidding opportunity; the third indicated that it would not offer any equivalent opportunity to participate in the NYISO spot market.[4]

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[3] On average, DAM prices are 3-5% higher than RTM LBMPs, which might appear to offer an arbitrage opportunity if participants could settle at the RTM LBMP. However, when prices are most volatile, RTM prices tend to be higher, thus foreclosing any opportunities for arbitrage. 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. More is said about this later in Chapter 4 in the section, The Market Effects of DADRP.

[4] The largest customers served by Niagara Mohawk are offered a POLR rate where the hourly energy prices

EDRP Experience

Seven of the provider survey respondents active in promoting some aspect of the NYISO's demand response program recruited customers to participate in EDRP in 2003 (Chart 4.4). Half (4 of 8) expected that the benefits of participation would be lower in 2003 than in 2002 (Chart 4.5). One important change in EDRP is a consequence of decoupling ICAP/SCR; the dispatch rules were changed so that ICAP/SCR resources could be called first, and EDRP curtailments would be called only if needed.[5] Moreover, the NYISO undertook initiatives to increase available capacity. As more customers gravitate to ICAP/SCR because they now also receive an energy payment for curtailments, the odds of needing EDRP curtailments, in addition to what ICAP/SCR provides, are reduced. One respondent believes that higher system reserves would reduce the number of events of any kind that would be called.

Those respondents expecting the EDRP benefits to be the same or greater than in 2002 offered two separate explanations for their views. Two respondents expected that EDRP will still always be called when ICAP/SCR curtailments are invoked, while two others believe that the new provisions of ICAP/SCR will cause customers to switch from that program to EDRP, thereby reducing the amount of ICAP/SCR available for curtailment. If these respondents are correct, the odds of calling the two programs simultaneously would increase, despite the new uncoupling provisions. Perhaps inadvertently, this expectation came to fruition in 2003, but not for the reasons cited. The only curtailment events invoked by the NYISO under either program in 2003 were on August 15 and 16, coincident with the blackout that necessitated calling both programs.[6]

Five of these respondents thought that the policy to uncouple EDRP and ICAP/SCR had no effect on their EDRP marketing efforts. One respondent said that marketing efforts became easier, and two reported greater difficulties in EDRP marketing efforts (Chart 4.6). Most

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indexed to the NYISO DAM prices are posted a day ahead.

[5] ICAP/SCR participants must have first been given a day-ahead notice that a curtailment was possible the next day. If the day-ahead notice does not occur, then compliance to an ICAP/SCR curtailment call is voluntary. This was the case on August 15th, the day of the Northeast blackout and a substantial number of curtailments were provided, probably in large part because of the energy payments that accompanied them.

[6] EDRP was called on August 15 but ICAP/SCR was not called until the next day because day-ahead notice is required. However, on August 15 ICAP/SCR customers were asked to curtail on a voluntary basis with the prospect of receiving an energy payment.

respondents marketing EDRP said that prior years' EDRP participants remained satisfied (4 of 7) or highly satisfied (1 of 7) with the 2003 offering. One reported that its customers were very dissatisfied (Chart 4.7). Finally, in response to an inquiry about participation in 2003 relative to 2002, three of seven respondents reported greater participation, and four reported it to be down. As shown in Table 4.2, the number of enrolled participants in EDRP declined in 2003. (There are 507 dropouts from 2002 and 269 new subscribers). There was also a decrease in total MWs pledged (from 949 to 854, Table 4.3).

ICAP/SCR Experience

Ten of the survey respondents also recruited customers to ICAP/SCR in 2003; of these ten, six are DRPs (Chart 4.8). Of these ten, eight reported that customers found nominating a strike price to be not difficult at all, or to be only somewhat difficult. Two others said that customers found it difficult to nominate a strike price (Chart 4.9). Most (8 of 10) believe that if the new energy payment provisions of ICAP/SCR were eliminated, participation would decrease (Chart 4.10). Estimates of that reduction range from 50% to 68% of the number of MWs enrolled in 2003 (Chart 4.11). One DRP thought that the inclusion of the energy payment would increase participation and enrolled load by 25%.

Respondents were also asked to indicate how they arrange for ICAP/SCR curtailments in situations where not all of the available curtailment capacity is needed. Two respondents rely on a round-robin dispatch, and two others prorate the curtailment proportionally to all participants. Four others have established no specific protocol since they have not faced that situation. Eight of the 10 respondents prefer the existing practice, which is to have each individual LSE and DRP assign its own curtailment resources. The remaining two prefer having the NYISO dispatch the curtailment obligations to specific participants based on the nominated strike prices.

Program Retention and Migration

The second strategy to help determine the effects of the PRL program changes on participation is to track changes in participation for each customer. This analysis is based on the NYISO's program registration database.

Program Enrollment

Table 4.2 provides a detailed accounting of how participation in the PRL programs has changed from 2002 to 2003. The first column lists 2002 participation by program option.[7] The next five columns of Table 4.2 account for the differences from 2002 to 2003 participation by tracking: a) re-subscriptions in the same program option, b) migration to another program option, c) dropouts from the program option altogether, and d) new subscribers to the program option.

The number of PRL program participants totaled 1,785 in 2002. There were 1,535 EDRP participants, 226 ICAP/SCR participants and 24 DADRP participants. By the fall of 2003, the number of participants in all demand response programs declined by about 10%.[8] However, a more careful examination of the data indicates that the changes in participation differed by program and by NYISO pricing zone.

For example, consider the EDRP participant accounting in the first row of Table 4.2. Tracking the changes between 2002 and 2003 shows that 1,021 of the 2002 EDRP participants re-enrolled in 2003, 507 dropped out, none migrated to DADRP, and seven migrated to ICAP/SCR. There were 269 new customers enrolled in EDRP in 2003. The amount of EDRP curtailable load decreased by 10% (95 MW) between the two years (Table 4.3). The curtailable load from the new participants (148 MW) just barely offset that of the customers that left the program (142 MW). The (53 MW) net reduction in EDRP's curtailable load from 2002 to 2003 is due to the migration of customers to ICAP/SCR, and to changes in the amount of curtailable load subscribed by those that re-enrolled. Thus, while the overall changes in EDRP participation from 2002 are modest, it is important to examine the dropouts and new entrants more closely below to see if there are any discernable patterns of behavior.

The data in Tables 4.2 and 4.3 reveal that ICAP/SCR participation also decreased by 6% (13 participants) but the amount of curtailable load increased by 29% (190 MW). Thus, the average curtailable load per participant increased substantially. As the data in Table 4.2 show, the

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[7] Participation data for 2002 represent enrollments 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.

[8] A participant is defined by a single customer or an aggregation of customers.

drop in participation occurred despite the 89 new enrollees. There are 76 that left the program, and another 33 that switched to EDRP. Clearly, the new participants pledged more curtailable load than was lost through attrition (Table 4.3). The average curtailment of new participants is 3.8 MW, while that of customers leaving the program is only 2.0. It appears that ICAP/SCR participation in 2003 was attractive to customers with larger curtailment capability, but the data may be slightly misleading because some of the participants represent aggregations comprised of several, or in some cases many, customers.

Load subscribed to DADRP increased slightly (4%), proportionally less than the increase in enrollment (13%). The added participants are new to this program.

Zonal Distribution of Program Participants

In addition to there being changes in participation among the PRL programs, the location of participants has changed.

Table 4.4 contains data on program participation by NYISO pricing zone and Table 4.5 records the changes in program composition by zone. Zones J (New York City) and K (Long Island), for example, account for 69% of EDRP participants but only 33% of curtailable load that is enrolled in EDRP. The difference is due, in large measure, to the large number of residential customers and small businesses in these zones that are aggregated for program purposes. Similarly, these same two zones account for 37% of ICAP/SCR participants, but only 16% of total load enrolled. It appears that building up the stock of curtailable load downstate will require recruiting a lot of new customers.

Of the total of 507 EDRP dropouts in 2003, 55% (281) came from zones J and K. The statewide total of new participants was only 269. With three exceptions (zones F, G, and H) the EDRP dropouts exceeded new enrollees in the other zones. In terms of MW, the story is similar. Zones J and K had a total of 61 EDRP-enrolled MW drop out in 2003, and only 39 MW of new enrollment (Table 4.6).

The data in Tables 4.5 and 4.6 distinguish changes in participants and curtailable load for EDRP and ICAP/SCR in one additional important way: as being Sold or Unsold. This distinction highlights a subtle, but important PRL program provision new in 2003. In contrast to earlier years, customers could not enroll the same load in both ICAP/SCR and EDRP. However, customers that enrolled in ICAP/SCR were not necessarily able to sell their ICAP to an LSE. Consequently, they may have had to offer their curtailable load into the NYISO ICAP six-month strip auction or into the monthly reconfiguration auction. If their bids were not accepted in one of these two auctions, they were not eligible for payment under the ICAP program, and are, therefore, not active participants the ICAP/SCR program. Under these circumstances, the NYISO temporarily enrolls the customer in EDRP—thus making the customer eligible for payments for voluntary curtailments, until such time as the customer successfully sells its ICAP. As seen by the data in Table 4.6, this provision was used only in a small number of cases, because most ICAP/SCR enrollees sold their capacity to an LSE or had their load purchased in one of the two auctions.

To recap the discussion so far, participation in EDRP measured in the number of customers enrolled fell from 2002 to 2003, as did the load available for curtailment. Is this an emerging trend? The data in Table 4.7 address this question, by showing changes in participants from 2001 to 2002, and also from 2002 to 2003. As data in the first two columns illustrates, 2002, the second year of the program marked by aggressive marketing by CSPs, was a big growth year for EDRP participation; there were 1,497 new participants and only 117 dropouts from 2001. In 2003, there was a net reduction in participation (269 new, 507 dropouts).

This is not necessarily an indication that the program has reached its apex and is now in decline. Rather, another interpretation of the data would suggest that the EDRP program is maturing. A closer examination of the 507 EDRP dropouts from 2002 to 2003 reveals that 41% (208) of them provided no load curtailment during the 11 hours of EDRP events in 2002 (Table 4.8, Panel D). Thus the loss of these "participants" had no effect on the performance of EDRP load as a resource. The simple, no-penalty provisions of EDRP are designed to attract customers that can then gain experience with load management, at little risk. Through EDRP, one would hope that many would find that they have more control over their usage than they had first anticipated. For those for which this is the case, they may in the future either increase their level of EDRP participation, or switch to one of the other PRL programs. However, it should also be expected that other customers, still finding little capacity or willingness to manage load, or having their circumstances otherwise change, could still drop out after a year or two. Thus, for EDRP to experience these kinds of changes poses no long-term problem, as long as there are new entrants to take the place of those leaving the program. Put differently, if it is customers having difficulties managing load that leave the program, the program's efficiency and effectiveness is actually improved, as dispatchers can better estimate the effect of a call for curtailments.

Another question is: from where did the new ICAP/SCR participants in 2003 come? The 89 ICAP/SCR participants were classified as new entrants in 2003 because they were not registered in ICAP/SCR during 2002. However, they could have participated previously in 2001, but could have just taken a year off in 2002. An examination of the 2001 records reveals that only three of the new 2003 participants had participated in ICAP/SCR in 2001. The rest of them are new to the program, an indication that LSEs and DRPs are actively working on establishing new accounts to increase program participation. This is a clear sign of a robust program.

Strike Price Nominations for ICAP/SCR

Before moving on to other components of this year's PRL program evaluation, it is important to examine one remaining feature of the ICAP/SCR program that is new for 2003. This provision requires ICAP/SCR participants' to nominate a strike price in order to establish priorities for the partial dispatch of ICAP/SCR load curtailments. It was argued above that the need for ICAP/SCR participants to nominate a strike price might reduce the attractiveness of the program. For those remaining participants, one might expect low strike prices from customers confident in their abilities to comply when asked to curtail. Other customers, content with the ICAP/SCR payment, and attempting to limit their curtailment exposure, might routinely bid high strike prices. To shed some light on the validity of these propositions, Chart 4.12 contains the bid curves for ICAP/SCR participants, grouped according to their years of experience in the program.

There is, in fact, substantial clustering of bids around the two extremes. For example, the bid curve for the first-year participants has two distinct clusters, and one very steep but narrow segment (representing less than 5% of the bids). The shape of the curve clearly supports the maintained hypothesis that some customers want to be curtailed, (e.g., strike prices at or near zero), while others may be trying to avoid curtailments by bidding strike prices at or near the $500 ceiling. For customers in the program for two years, over 60% of the strike prices are at or near the $500/MW ceiling, while there is almost no clustering at the low end. For customers in the program for three years, there is some clustering of the bids at both extremes, but over 70% of customer bids are between $250/MW and $300/MW.

While the clustering of these bids can certainly be explained by customer behavior of the kind described above, it could also be the consequence of polar views of the market postulated by the LSEs and DRPs that promote participation. Some might universally recommend that customers bid low to be guaranteed an energy payment at every opportunity. Since, under NYISO scarcity pricing rules, the prevailing ICAP/SCR payment rate can set LBMP, other LSEs or DRPs may recommend that customers bid high to guarantee a high market price, and, therefore, a correspondingly high energy payment. For this strategy to work effectively, most participants would have to bid high enough to ensure a high price even under partial dispatch of the curtailable load by the NYISO.

The above hypotheses are plausible explanations for these clustered strike price nominations, and clearly other explanations are possible. Regardless of the reasons, bid clustering will clearly complicate the use of these strike prices, by an LSE or DRP, to effect a partial dispatch of curtailable load during events requiring less than the total amount of enrolled resources. In contrast, a partial dispatch based simply on prorating every customer's load is far less complicated for the NYISO, which is responsible only for determining the quantity to be curtailed, not for which participants are asked to meet the requirement.

A Brief Summary

There are several important conclusions regarding the effects of this year's changes in EDRP and ICAP/SCR to be drawn from this examination of the survey results and the registration data.

1. There is little evidence to suggest that the changes in the programs were the cause for any substantial migration of customers from EDRP to ICAP/SCR. Participation in ICAP/SCR did increase dramatically, but it was not due to migration from EDRP; rather, it was from new subscribers, and large ones at that.
2. There is also little evidence that ICAP/SCR participants would find it challenging to nominate a strike price for curtailments, thereby being a deterrent to participation. LSEs and DRPs report that most customers were able to meet this requirement with

little difficulty, a belief that is consistent with the large increase in ICAP/SCR participation in 2003. This year, there were 76 customers that left ICAP/SCR; and there is no way to know if this new requirement to nominate a strike price contributed to their departure decisions. However, the fact that these "dropouts" (by definition) did not even participate in EDRP, which requires no strike price and imposes no penalty for failure to comply, suggests that these departing customers more likely based their decisions on the difficulty of curtailing loads (for business or other reasons) rather than on changes in the ICAP/SCR program.

3. Finally, curtailment bids by ICAP/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.

The Results of the Evaluation of EDRP Resources

As indicated above, EDRP events were only called on August 15th and 16th, the two days following the Northeast blackout of August 14, 2003. On those two days, the real-time LBMPs in all zones were set administratively at the day-ahead LBMPs; thus, there is no basis from which to estimate the market effects of EDRP load reduction on those event days. Even though it is impossible to estimate any market effects of EDRP load reduction for 2003, it is clear from the previous evaluations for 2001 and 2002 that under more "normal" EDRP events, the value of EDRP load reduction, in terms of reductions in price, collateral benefits, and reduction in price variability was substantial in those two years (Neenan Associates, 2002, and Neenan Associates and CERTS, 2003). However, under 2003 protocols, the load reduction resources can now set LBMP, and the ICAP/SCR dispatch strike price (which could be as high as $500/MWH) or the EDRP price floor ($500/MWH) could effectively place a floor on the real-time LBMP during emergency events. Therefore, it is possible that this protocol could lead to higher prices during those periods when EDRP and ICAP/SCR are dispatched than would have been the case in previous years. While it is difficult to say if this change would increase or decrease price variability, it would almost surely reduce the size of any collateral benefits to customers.

Given this uncertainty with respect to market effects, the evaluation of the EDRP events in 2003 clearly must focus almost exclusively on the effect of the load reduction on system reliability. As indicated above, the methodology for evaluating the effects of EDRP load reduction in the days immediately following the blackout had to be modified from that of previous years. In addition to modifying the methodology, the availability of more detailed data on reserve margins during the two event days assisted in the evaluation.[9]

As argued above, the standard methodology is used to quantify the reliability benefits of EDRP, by first determining by how much the curtailments improved LOLP. Then, the improvement in LOLP must be converted into a dollar value of benefit to customers. This expectation is converted into a corresponding dollar value to customers, by multiplying the change in expectations of an outage by the amount of load that is subject to an outage to estimate the change in the expected amount of load subject to an outage. In turn, this number is multiplied by the value of lost load (VOLL)—yielding a measure of the cost to consumers when service is curtailed under such circumstances. However, in the case where the system is restored step-by-step, each curtailed MWH corresponds to the moving of another MWH from the state where its LOLP is one and the expected unserved energy for these customers is equal to the load they would use, if they could be brought back on line. There is thus a one-to-one correspondence between EDRP and ICAP/SCR curtailment resources and the corresponding expected unserved energy. With this unique relationship established, valuing these curtailments can be accomplished by using the conventional methods multiplying this quantity by the value of lost load.

Based on these methods, the estimates of the system reliability benefits of the EDRP events following the 2003 blackout are given in Table 4.9 for a range of outage cost values and

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[9] In contrast to this year's evaluation, the evaluation of EDRP in 2001 in terms of system reliability by Neenan Associates (2002) relied on data on reserves for only one of the event hours. In that report, the EDRP reliability benefits were estimated, during the hour examined, for four different levels of LOLP reductions, ranging from 0.05 to 0.50, and for four levels of outage cost. The average hourly system benefits outstrip the hourly program payments of about $182,000 by a very wide margin under every combination of LOLP and outage cost assumptions displayed in the table. The lowest benefit/cost ratio was over seven under the assumption that the entire system load was at risk of being interrupted. Further, even under a more stringent view, when only 5% of load was at risk for interruption and outage costs in the range of $2,500-5,000/MWH, the benefit/cost ratio for that hour was between 4.8 to one to 9.5 to one. Similar conclusions were reached in the 2002 EDRP evaluation (Neenan Associates and CERTS, 2003).

load at risk. In this table, load at risk is defined either in terms of the percentage of actual EDRP/SCR MWs of performance, or in terms of the percentage of EDRP/SCR performance needed to meet the 30-minute reserve margin. Both estimates of load at risk are conservative, but it is the latter definition that provides the *most* conservative estimate of the load at risk, and it is this definition that is consistent with the modified methodology applied to the events of August 16, 2003.

As one might expect because of the differences in methodology, the results also differ somewhat across the two days. On August 15, 2003, there was an hourly average of 803 MWh of load reduction, with 56% coming from EDRP participants, and 44% coming from ICAP/SCR participants. Program costs were just over $5.8 million,[10] and depending on the assumptions about load at risk and outage costs, system benefit/cost ratios range from 1.9 to 19.2 (Table 4.9).

On August 16, 2003, a Saturday, the hourly average load reduction was 473 MWh, with 37% coming from EDRP participants, and 63% coming from ICAP/SCR participants. The program payments to those that curtailed were just under $1.7 million,[11] but in contrast to the results of August 15th, the system benefit/cost ratio was less than one, if outage costs are assumed to be only $1,000/MW. It was argued above, however, that where the outage is widespread and is of an extended duration, customers have little recourse except to endure the hardships of an outage. Under these circumstances, the use of higher VOLL in estimating the value of PRL program load curtailment resources would seem appropriate. Under this assumption (where outage costs are assumed to be at least $2,500/MW) the system benefit/cost ratio of EDRP/SCR load reduction on the 16th would range from 1.0 to 3.8, depending on the assumptions regarding load at risk (Table 4.9).

The Results of the DADRP Evaluation

In all three years that DADRP has been in operation, bids have been scheduled during the winter and spring months, as well as during the summer months. For the past two years, however,

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[10] These payments are for energy only.

[11] These payments are for energy only.

only the bids for the summer months have been examined. This was, in part, to maintain consistency with the EDRP evaluations.

Because of the current interest in the efficacy of DADRP, however, this year's evaluation does include data for the winter and spring months, as well as for the summer months of 2003. Both the market effects and the social welfare evaluation were conducted for the complete set of data.[12] Further, since the data are available from previous years, the social welfare evaluation is also conducted for the summer months of 2001 and 2002.

This additional analysis contributes to the program evaluations in those years and to the evaluation of the efficacy of DADRP.

The Market Effects of DADRP

The market effects of DADRP for the winter and spring months combined and for the summer months are summarized in Tables 4.10 and 4.11, respectively. For 2003 as a whole, DADRP bids were scheduled only in the Capital Zone and in Western New York. During the winter and spring, bids were scheduled only in the Capital Zone. During the summer, bids were scheduled both in the Capital Zone and in Western New York.

During the winter and spring of 2003, there were 909 DADRP bids accepted (Table 4.10, Column 5). There was a total of 1893 MW scheduled, corresponding to an hourly average of 2MW (Table 4.10, Column 5). Program payments totaled $142,167, for an average of $156 per bid, see Table 4.14.

During the hours in which bids were scheduled, the load was reduced by about 0.1% relative to what it would have been otherwise (Table 4.10, Column 8). Without the scheduled bids, the LBMP in the DAM would have averaged $71.43/MW, up slightly from $71.29—an

[12] The supply flexibilities for the aggregate Capital-Hudson super zone are used throughout in evaluating the market and social welfare effects of DADRP in the Capital Zone. It should also be noted that because most of the scheduled DADRP bids are during hours of relatively small fixed bid load in the DAM, the supply flexibilities in the first regime of the day-ahead "spline" supply model are used extensively in the evaluation of the market and social welfare effects of DADRP. Since the supply flexibilities in the real-time market are also needed to estimate the social welfare implications of DADRP, the supply flexibilities in the first regime of the real-time "spline" supply model are used extensively as well. For the year 2003, these supply flexibilities are reported in Appendix 3A. For the two previous years, the appropriate supply flexibilities are reported in Neenan, 2002 and Neenan and CERTS, 2003.

estimated 0.2% price reduction due to DADRP (Table 4.10, Columns 7, 4, and 9, respectively). The bill savings spread across all customers in the zone are estimated at $223,426 (Table 4.10, Column 11).

During the summer of 2003, there were 628 bids scheduled in DADRP, all but 18 of which were in the Capital Zone (Table 4.11, column 5). Program payments totaled $121,144, with 92% of them going to customers in the Capital Zone, see Table 4.15.

The total load reduction from scheduled DADRP bids during the summer months was 1,752MW, with 90% occurring in the Capital Zone (Table 4.11, column 5). The average load reduction per scheduled bid was 3MW in the Capital Zone and was 10MW in Western New York.

With these small average load reductions (less than 0.1% of load), it is not surprising that the effects on LBMP in both the Capital Zone and in Western New York were small as well. In the Capital Zone, LBMP without the scheduled load reduction would have been on average less than 0.1% higher in the hours where bids were scheduled. In Western New York, the LBMPs in those hours would have been on average 0.1% higher without the scheduled bids. Having this scheduled load reduction would in turn lead to system wide bill savings of $45,772—with 92% of the savings going to the Capital Zone.

The Social Welfare Effects of DADRP

The market effects of DADRP in 2003 are quite small, as was found to be the case as well during 2001 and 2002 (Neenan Associates, 2002, and Neenan Associates and CERTS, 2003). This is primarily the result of the small number of participants in the program (see above), the relatively low level of active bidding, and the relatively small number of scheduled bids. It is also the case that the bid strike prices are relatively low, and the bids are scheduled during times when load is not terribly large.

These factors clearly raise questions about the extent to which DADRP is or can be made an effective way for customers to participate in the day-ahead market by adjusting load in response to price, and being paid to do so. To shed some light on this issue, this year's PRL program evaluation included an examination of the improvements in market efficiency due to DADRP. As discussed above, this involves measuring the reduction in the deadweight social losses avoided at times when bids are scheduled and customers effectively are able to reduce load in response to price. These efficiency gains from responding to market prices essentially are the savings in the cost of electricity over and above its value to customers facing fixed prices compared to those customers adjusting load in response to price. This difference between the value to customers and the cost of the load purchased at the fixed tariff can be shown to be equal to the area d + d' in Exhibit 3.4. However, if customers bid load reduction through DADRP, there is the potential to avoid some of this deadweight social loss, as long as the DADRP payment (equal to the area s" + e + d') is less than the deadweight loss (the area d + d'). For this to be true, the area s" + e must be less than the area d.

The size of these two areas is clearly an empirical question. An important part of this year's PRL evaluation is an attempt to measure the reduction in this social deadweight loss from the past three years' of DADRP bids. In so doing, however, it is important to recognize that because of the NYISO's two settlement system, bids accepted under DADRP produce efficiency gains (reductions in deadweight losses) in both the DAM (when the load is initially scheduled) and in the RTM (when the load does not show up in real time). Payment, however, is made only once.[13]

Because of the importance of this issue, this welfare analysis is conducted for the summers of 2001, 2002, and 2003, as well as for the combined winter and spring (referred to in the tables as "Winter") months of 2003, and the results are reported in Tables 4.12 through 4.15. Each table reports the program payments (column 2), the deadweight losses avoided due to DADRP load in the day-ahead market (column 3) and the real-time market (column 4), and the change in net social welfare (column 5). The change in net social welfare is defined as the sum of the deadweight losses avoided less the program payments.

Perhaps the most striking feature of these results is the difference between the net social welfare benefits in summer 2001, compared with those in subsequent years. In DADRP's first

[13] It is important to reiterate from above that in discussing these potential gains in the RTM, one must also recognize that if the price in the RTM is less than in the DAM, it can be seen that market efficiency is increased by letting customers who had DADRP bids accepted in the DAM buy through in real time and consume the extra electricity. Although the effects of this potential buy through are not simulated here, the entire social welfare analysis speaks directly to the long- term efficacy of DADRP.

year of operation, the change in net social welfare was positive. For subsequent years, it is negative.

In 2001, the change in net social welfare from DADRP is positive, and in relative terms, substantially so. The reduction in deadweight losses in the DAM and RTM markets combined totaled $256,932 (Table 4.12, the sum of columns 3 and 4), exceeding program payments of $213,944 by $42,737. The positive change in net social welfare is due entirely to scheduled bids in the Capital Zone. In Western New York, the net change is slightly negative, $-752 (Table 4.12, column 5). On a per hour or bid basis, the net change in social welfare averaged $118 in the Capital Zone, and $-3 in Western New York.

In contrast to these results, there was a net reduction in social welfare due to DADRP during the summer of 2002. Program payments of $110,294 exceed the combined reduction in deadweight losses, and net social welfare declined by $23,919 (Table 4.13, column 5). Hourly average changes in net social welfare are $-69 and $-35 in the Capital Zone and Western New York, respectively.

For the Capital Zone, the story is similar for the combined winter and spring months of 2003. Program payments of $142,167 exceeded the reduction in deadweight losses by $25,869 (Table 4.14, columns 2 and 5). On an hourly basis, however, the average reduction in net social welfare is only $28 (Table 4.14), substantially below the average reduction of $69 for the summer of a year earlier (Table 4.13).

During the summer of 2003, the change in net social welfare from scheduled DADRP bids is also negative. Program payments of $121,144 exceeded reductions in deadweight losses by $72,271 (Table 4.15, Columns 2 and 5). For the Capital Zone, the reduction in net social welfare on an hourly average basis was $104. For the 18 scheduled bids in the Western New York region, net social welfare was reduced by an average of $479 (Table 4.15).

The significance of these yearly results for policy and program design lies in the substantial variation in the net change in social welfare on an hourly basis. In some cases, the change was a large positive number, while in others, the net change was negative. The important task is to identify any systematic relationship between market conditions and the size of the net change in social welfare. The theory outlined above and in Appendix 3A provides an initial guide to this analysis. In particular, the potential welfare gains from DR load programs are highest in situations where both the supply and demand curves are initially extremely price inelastic (“steeper”). These are the very circumstances that have led to price spikes that disrupt newly formed wholesale markets.

To identify the importance of these and other factors, the hourly changes in net social welfare are regressed on several market variables. Results of the estimated regression equation are reported in Table 4.16. The six variables used in the regression reflect market conditions in both the DAM and RTM, and they explain 75% of the variation in net social welfare changes due to scheduled DADRP bids. All but one of the variables is statistically significant.

The results of the regression analysis can be summarized in the following way. Net social welfare increases as the supply price flexibilities in both markets, increase. The strength of this effect is nearly the same for both markets (estimated coefficients on the DAM flexibility and RTM flexibility terms are 44 and 41, respectively). Net social welfare also increases as the load in the real time market increases. Merely because of a scale effect, the net social welfare also increases with the size of the DADRP load scheduled. On the other hand, net social welfare decreases as the ratio of the LBMP in the DAM to the LBMP in the RTM rises.

If one were to translate these findings into recommendations for making long-term changes in DADRP, the following changes could be recommended:

1. To ensure positive changes in net social welfare the program should contain some type of minimum bid threshold.
2. This threshold should be dynamically determined, based on the forecasted price differences between the DAM and RTM, as well as the “steepness” of the supply curves in both markets, as measured by the supply price flexibilities.
3. Since deadweight losses are reduced when more energy is purchased at prices below some fixed tariff, (Appendix 3A), it follows that there ought to be provisions for participants to “buy through” when RT LBMP is less than the DAM LBMP at which the DADRP load reduction bid was scheduled.

Table 4.1 Survey Respondents

• Regulated LSE	2
• Competitive LSE	3
• Demand Response Provider	6
• Retail Customer	1
• Other-Non-Profit Agency	1
• TOTAL	13

Table 4.2 Program Participation Summary

	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 4.3 Program Participation Summary – MW

	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 4.4 Program Participation By Zone

Zone	EDRP		DADRP		ICAP	
	#	**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 4.5 Migration By Zone

	EDRP				ICAP					DADRP	
Zone	*Dropped*	*EDRP to ICAP Sold*	*EDRP to ICAP Un-Sold*	*New*	*Dropped*	*ICAP Sold to EDRP*	*ICAP Un-Sold to EDRP*	*New Sold*	*New Un-Sold*	*Dropped*	*New*
A	55	1		12	28	1	1	12	4		
B	58			9	12			5			
C	61	2		35	1	1		11			
D	4			1	2			4			
E	34	1		13	4			7	1		
F	8	1	1	28	2	1		2			2
G	1			14		2					
H				2				1			
I	5			13	2	1		3	1		
J	60			59	20	3		33	4		1
K	221	1		83	5	23		1			
Total	**507**	**6**	**1**	**269**	**76**	**32**	**1**	**79**	**10**	**0**	**3**

Table 4.6 Participation Changes (2002 to 2003) By Zone – MW

	EDRP (MW)				ICAP (MW)					DADRP (MW)	
Zone	***Dropped***	***EDRP to ICAP Sold***	***EDRP to ICAP Un-Sold***	***New***	***Dropped***	***ICAP Sold to EDRP***	***ICAP Un-Sold to EDRP***	***New Sold***	***New Un-Sold***	***Dropped***	***New***
A	20.42	43.00		5.78	75.00	0.60	0.10	78.70	3.30		
B	24.38			30.79	7.20			11.00			
C	9.42	1.00		11.70	0.60	0.20		10.90			
D	0.90			0.30	2.30			108.00			
E	19.43	0.30		13.70	5.20			11.70	2.10		
F	4.18	1.20	7.00	24.84	7.90	17.20		16.40			20.00
G	0.10			12.37				0.70			
H				1.50		4.60					
I	2.80			7.74	0.60			4.20	0.40		
J	26.55			20.77	53.30	4.20		83.10	1.70		2.50
K	34.24	0.30		18.47	2.50	1.60		0.50			
Total	**142.41**	**45.80**	**7.00**	**147.96**	**154.60**	**28.40**	**0.10**	**325.20**	**7.50**	**0.00**	**22.50**

Table 4.7 Participation Changes 2001 – 2003

	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 4.8 Migration and Dropout Details

Panel A

2002 ICAP to 2003 EDRP with ICAP performance in 2002		
ZONE	#	MW
A	2	0.7
C	1	0.2
F	1	17.2
I	1	0
J	2	1.6
K	18	0.5
Total	**25**	**20.2**

Panel B

New Participants with 2001 Program Experience			
EDRP		**ICAP**	
ZONE	#	ZONE	#
F	1	A	2
		J	1

Panel C

2002 ICAP dropped in 2003 with ICAP performance in 2002		
ZONE	#	MW
A	21	68.9
B	10	6.2
D	1	0.8
E	2	4.9
F	1	7.9
I	1	0.6
J	11	51.3
K	2	1.2
Total	**49**	**141.8**

Panel D

2002 EDRP Dropouts with no performance in 2002 Events	
Zone	**Count**
A	25
B	50
C	50
D	2
E	18
F	5
G	1
H	0
I	1
J	24
K	32
Total	**208**
Western NY	145
Capital	5
Hudson River	2
NYC/LI	56
Total	**208**

All MW reported are subscribed – not performance

Table 4.9 Value of Expected Unserved Energy, Summer 2003

% of Load at Risk	% Load at Risk as % of RT Load	Outage Cost $1,000/MW	Outage Cost $2,500/MW	Outage Cost $5,000/MW	Program Payments
8/15/2003*					
100%	3.8%	$ 11,244,655	$ 28,111,636	$ 56,223,273	$ 5,850,398
B/C ratio		1.9	4.8	9.6	
150%	5.8%	$ 16,866,982	$ 42,167,455	$ 84,334,909	$ 5,850,398
B/C ratio		2.9	7.2	14.4	
200%	7.7%	$ 22,489,309	$ 56,223,273	$ 112,446,546	$ 5,850,398
B/C ratio		3.8	9.6	19.2	
8/16/2003**					
100%	1.7%	$ 645,585	$ 1,613,963	$ 3,227,925	$ 1,680,213
B/C ratio		0.4	1.0	1.9	
150%	2.6%	$ 968,378	$ 2,420,944	$ 4,841,888	$ 1,680,213
B/C ratio		0.6	1.4	2.9	
200%	3.5%	$ 1,291,170	$ 3,227,925	$ 6,455,850	$ 1,680,213
B/C ratio		0.8	1.9	3.8	

* Assumes Change in LOLP=1.0, Load at Risk=EDRP & SCR Perf MWHs

** Assumes Change in LOLP=0.2, Load at Risk = % EDRP & SCR MWHs needed to meet 30-Min Reserve Margins

Table 4.10 Average Zonal and Total Effects of DADRP Scheduled Bids on New York Electricity Markets, Winter 2003

Zone	Fixed Bid Load in the DAM	With DADRP Day-Ahead Load (MW)	With DADRP Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Simulated Day-Ahead Load (MW)	Simulated Day-Ahead LBMP ($/MW)	% Change in Due to DADRP Load	% Change in Due to DADRP LBMP	Arc Price Flexibility*	Bill Savings ($)***
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Capital										
Hourly Avg.	3,684	2,872	71.291	2 (909)*	2,874	71.431	0.1%	0.2%	2.6	246
Total	3,348,669	2,610,513		1,893	2,612,406					223,426
% of G. Total	100%	100%		100%	100%					100%

*The number of bids scheduled.

Table 4.11 Average Zonal and Total Effects of DADRP Scheduled Bids on New York Electricity Markets, Summer, 2003

Zone	Fixed Bid Load in the DAM	With DADRP Day-Ahead Load (MW)	With DADRP Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Simulated Day-Ahead Load (MW)	Simulated Day-Ahead LBMP ($/MW)	% Change in Due to DADRP Load	% Change in Due to DADRP LBMP	Arc Price Flexibility*	Bill Savings ($)***
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Capital										
Hourly Avg.	4,413	3,467	66.1	3 (610)*	3,470	66.1	0.1%	0.0%	0.6	69
Total	2,692,185	2,114,979		1,576	2,116,555					42,244
% of G. Total	96%	95%		90%	95%					92%
Western New York										
Hourly Avg.	7,016	6,581	55.7	10 (18)*	6,591	55.8	0.1%	0.1%	0.6	196
Total	126,280	118,457		176	118,633					3,529
% of G. Total	4%	5%		10%	5%					8%
Grand Total	2,818,465	2,233,436		1,752	2,235,188					45,772

*The number of bids scheduled.

Table 4.12 Net Social Welfare from DADRP Scheduled Bids in the NY Electricity Markets, Summer 2001

Zone	Program Payments	Reduction in Deadweight Loss#		Change In Net Social Welfare#
		Day Ahead	Real-time	
(1)	(2)	(3)	(4)	(5)
Capital				
Hourly Avg.	376 (370)*	239	255	118
Total	139,170	88,400	94,258	43,489
% of G. Total	65%	68%	74%	102%
Western New York				
Hourly Avg.	268 (279)*	148	119	-3
Total	74,775	41,166	33,107	-752
% of G. Total	35%	32%	26%	-2%
Grand Total	213,944	129,567	127,365	42,737

#The change in deadweight loss and net social welfare are calculated using the methodology in Appendix E.
*The number of bids scheduled.

Table 4.13 Net Social Welfare from DADRP Scheduled Bids in the NY Electricity Markets, Summer 2002

Zone	Program Payments	Reduction in Deadweight Loss#		Change In Net Social Welfare#
		Day Ahead	Real-time	
(1)	(2)	(3)	(4)	(5)
Capital				
Hourly Avg.	291 (301)*	154	68	-69
Total	87,494	46,389	20,472	-20,632
% of G. Total	79%	78%	75%	86%
Western New York				
Hourly Avg.	243 (94)*	135	72	-35
Total	22,801	12,720	6,794	-3,287
% of G. Total	21%	22%	25%	14%
Grand Total	110,294	59,109	27,266	-23,919

#The change in deadweight loss and net social welfare are calculated using the methodology in Appendix E.
*The number of bids scheduled.

Table 4.14 Net Social Welfare from DADRP Scheduled Bids in the NY Electricity Markets, Winter 2003

Zone	Program Payments	Reduction in Deadweight Loss#		Change In Net Social Welfare#
		Day Ahead	Real-time	
(1)	(2)	(3)	(4)	(5)
Capital				
Hourly Avg.	156	64	64	-28
	(909)*			
Total	142,167	58,196	58,103	-25,869
% of G. Total	100%	100%	100%	100%

#The change in deadweight loss and net social welfare are calculated using the methodology in Appendix E.
*The number of bids scheduled.

Table 4.15 Net Social Welfare from DADRP Scheduled Bids in the NY Electricity Markets, Summer 2003

Zone	Program Payments	Reduction in Deadweight Loss#		Change In Net Social Welfare#
		Day Ahead	Real-time	
(1)	(2)	(3)	(4)	(5)
Capital				
Hourly Avg.	182 (610)*	48	30	-104
Total	111,300	29,323	18,335	-63,643
% of G. Total	92%	97%	99%	88%
Western New York				
Hourly Avg.	547 (18)*	58	9	-479
Total	9,844	1,049	168	-8,628
% of G. Total	8%	3%	1%	12%
Grand Total	121,144	30,371	18,502	-72,271

#The change in deadweight loss and net social welfare are calculated using the methodology in Appendix E.
*The number of bids scheduled.

Table 4.16 Factors Affecting Net Social Welfare from DADRP

Variables	Parameter Estimate	T-value
Intercept	31.12	1.25
dam_price_flex	44.02	2.82
rt_price_flex	41.37	9.46
rt_load	0.02	4.26
dam_load	0.00	-0.27
dadrp_mw	-39.14	-34.32
dam_to_rt_lbmp	-134.39	-15.79
R^2	0.75	

The variables defined below correspond to the hourly zonal variables in the zones in which the DADRP load was scheduled:
dam_price_flex = supply price flexibilitiy in the DAM.
rt_price_flex = supply price flexibility in the real-time market.
rt_load = load in the real time market.
dam_load = load in the DAM
dadrp_mw = the MW's of dadrp load scheduled.
dam_to_rt_lbmp = the ratio of the price in the DAM to that in real tim

Chart 4.1 Which Programs Were Promoted

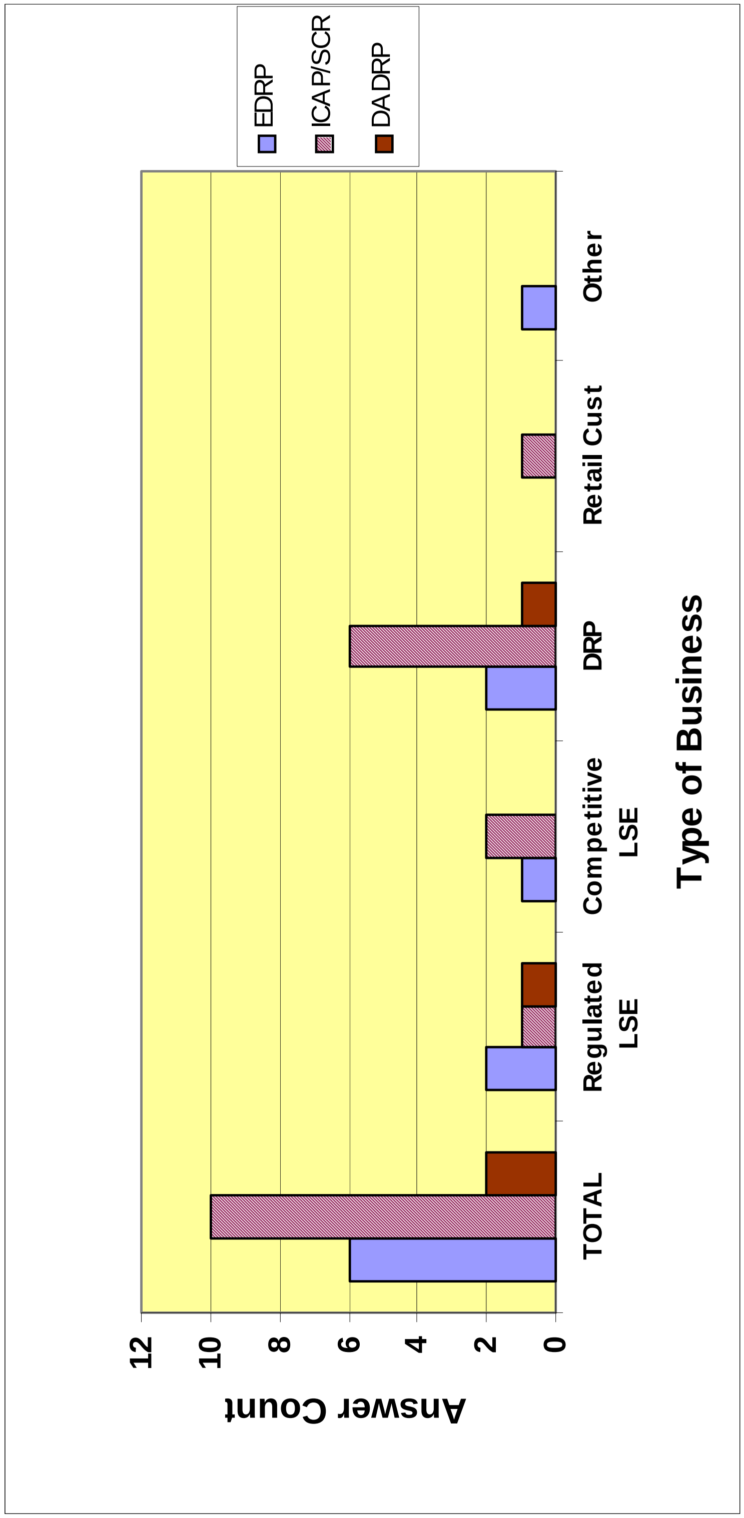


Chart 4.2 Efforts to Promote DADRP Participation

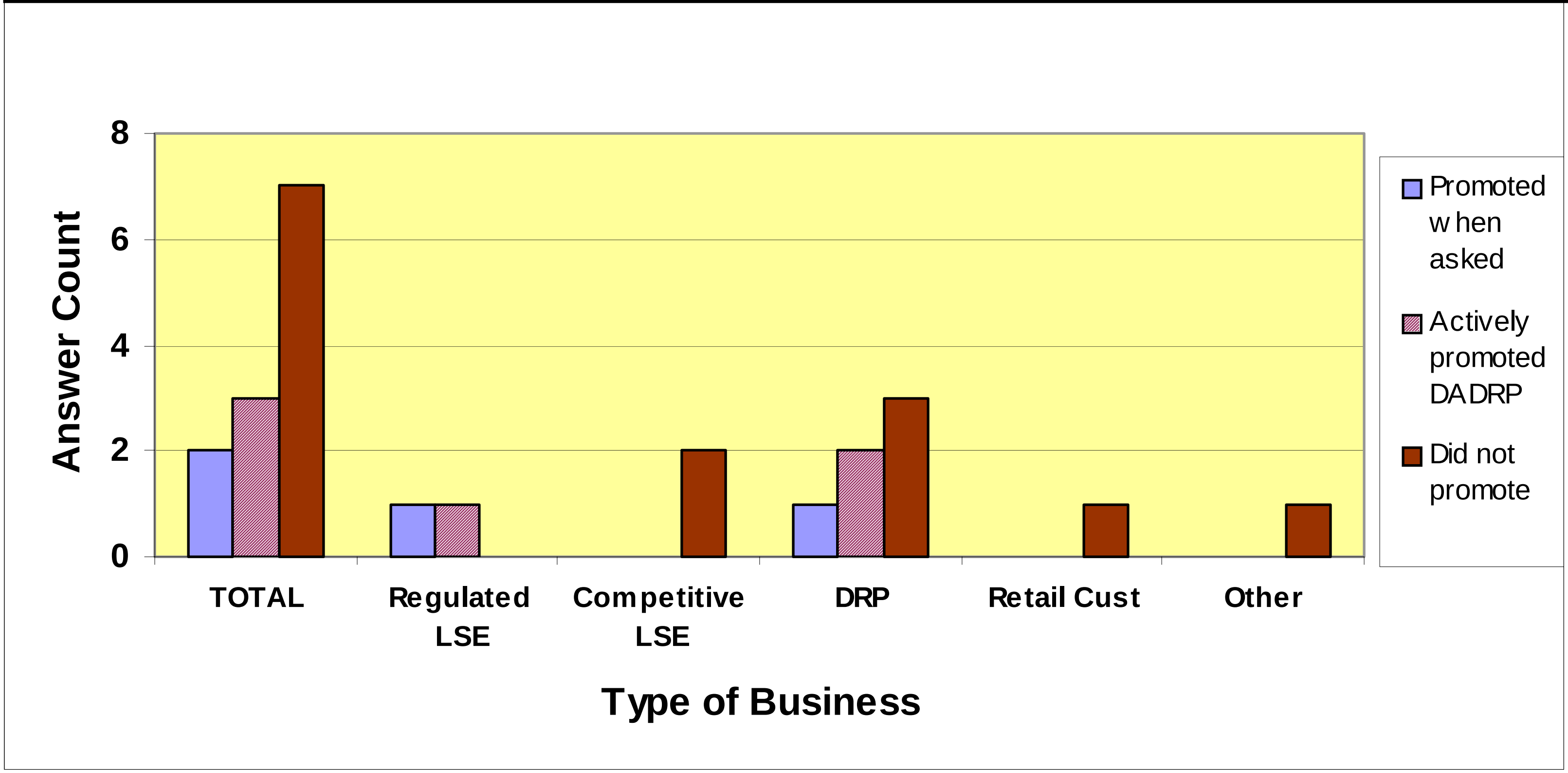


Chart 4.3 Customer Receptiveness to DADRP

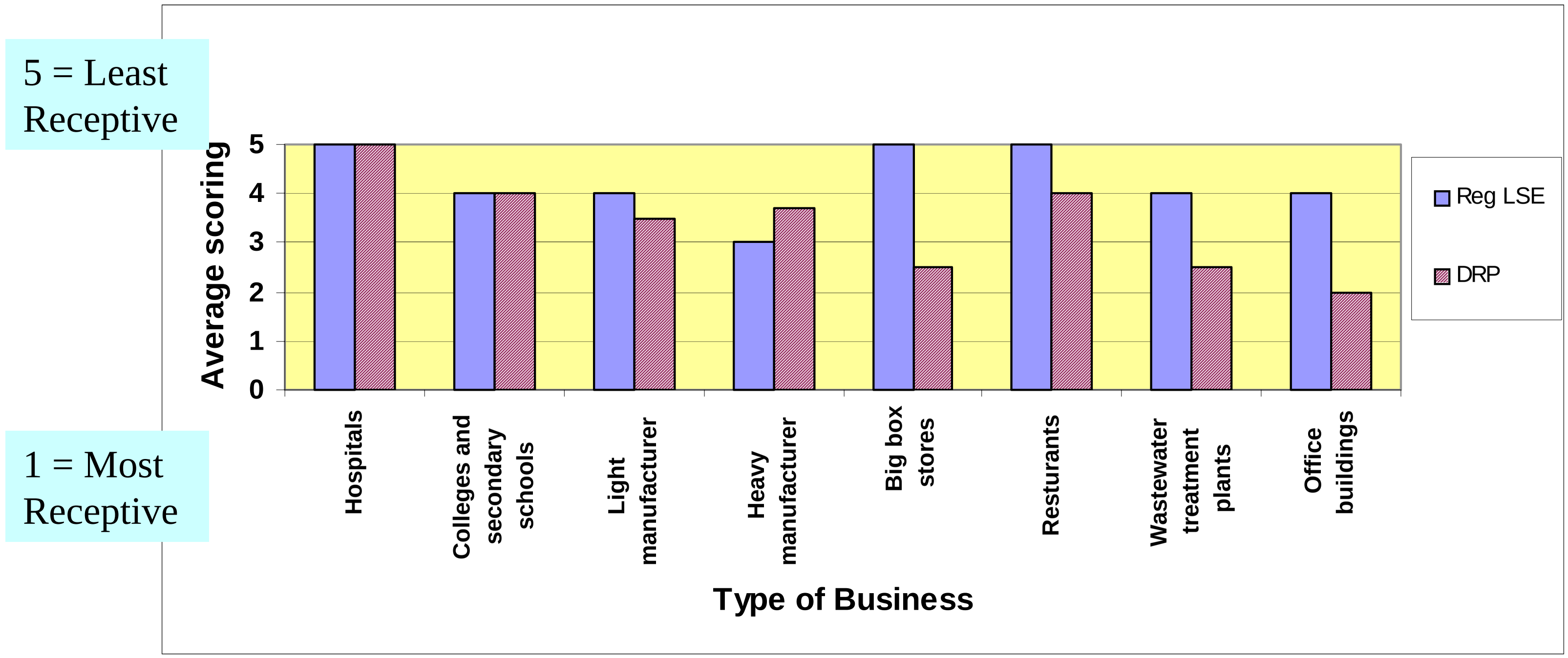


Chart 4.4 Promotion of EDRP Participation

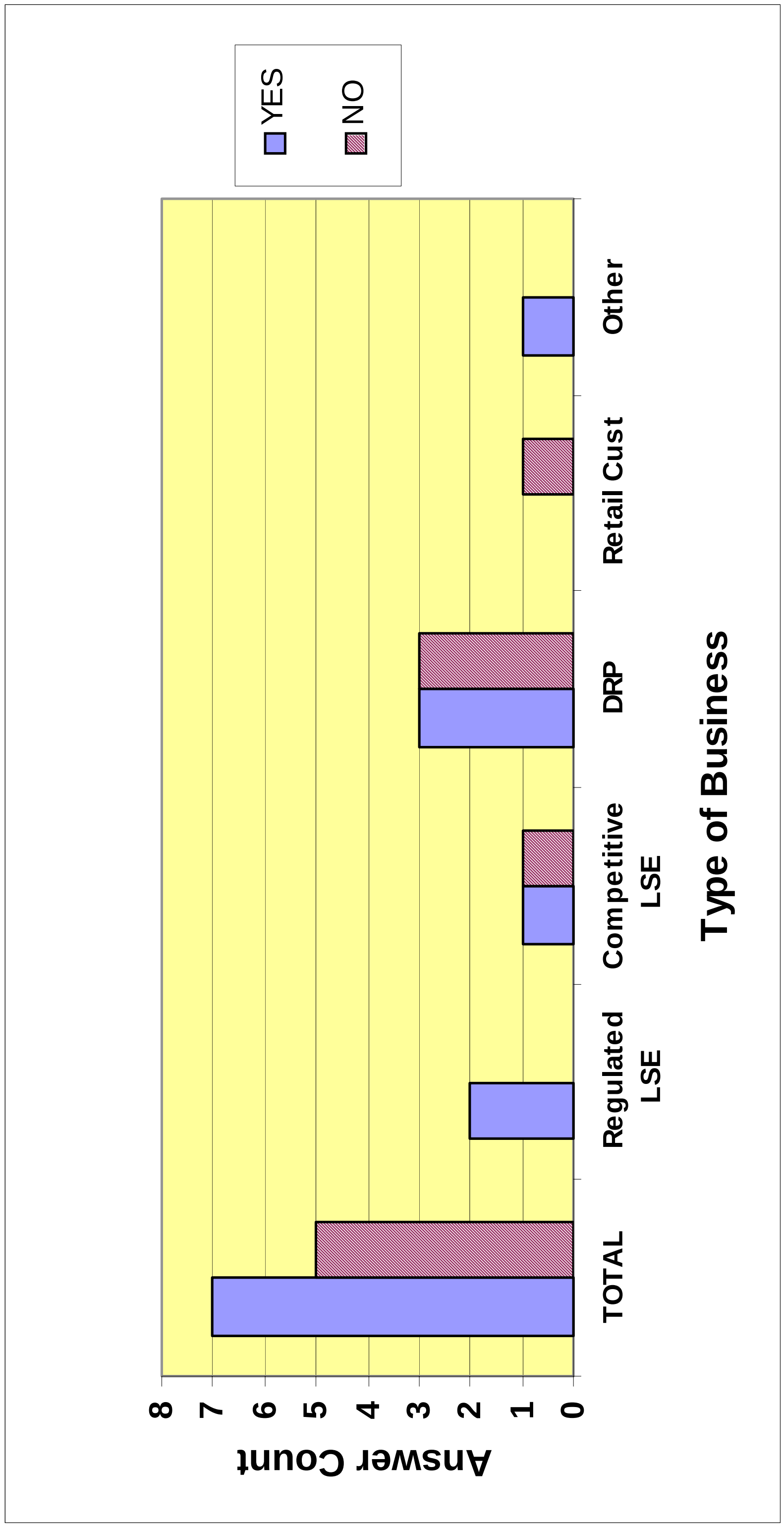


Chart 4.5 Expectations of 2003 Benefits from EDRP Participation

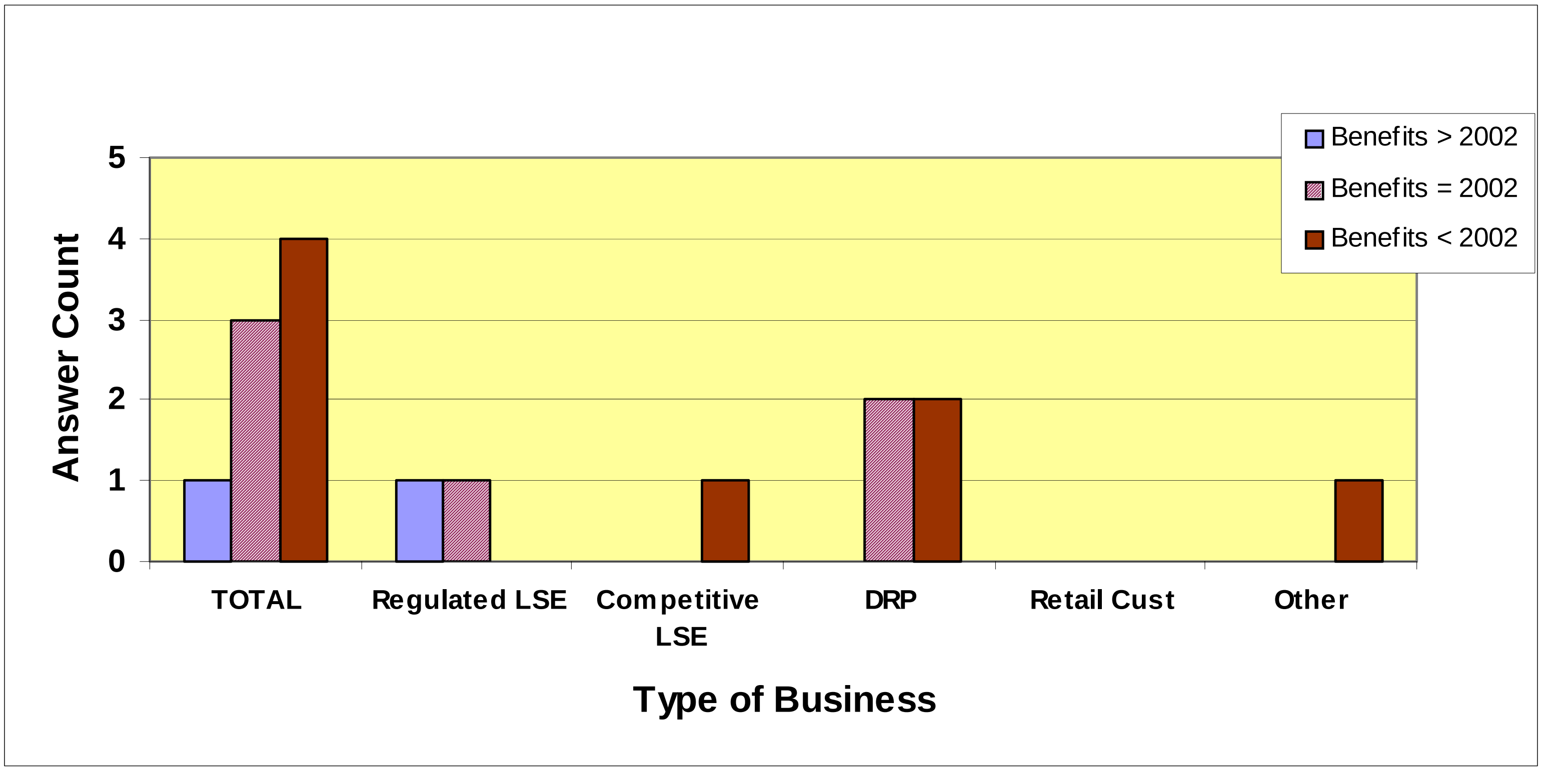


Chart 4.6 Experience in Marketing Revised EDRP

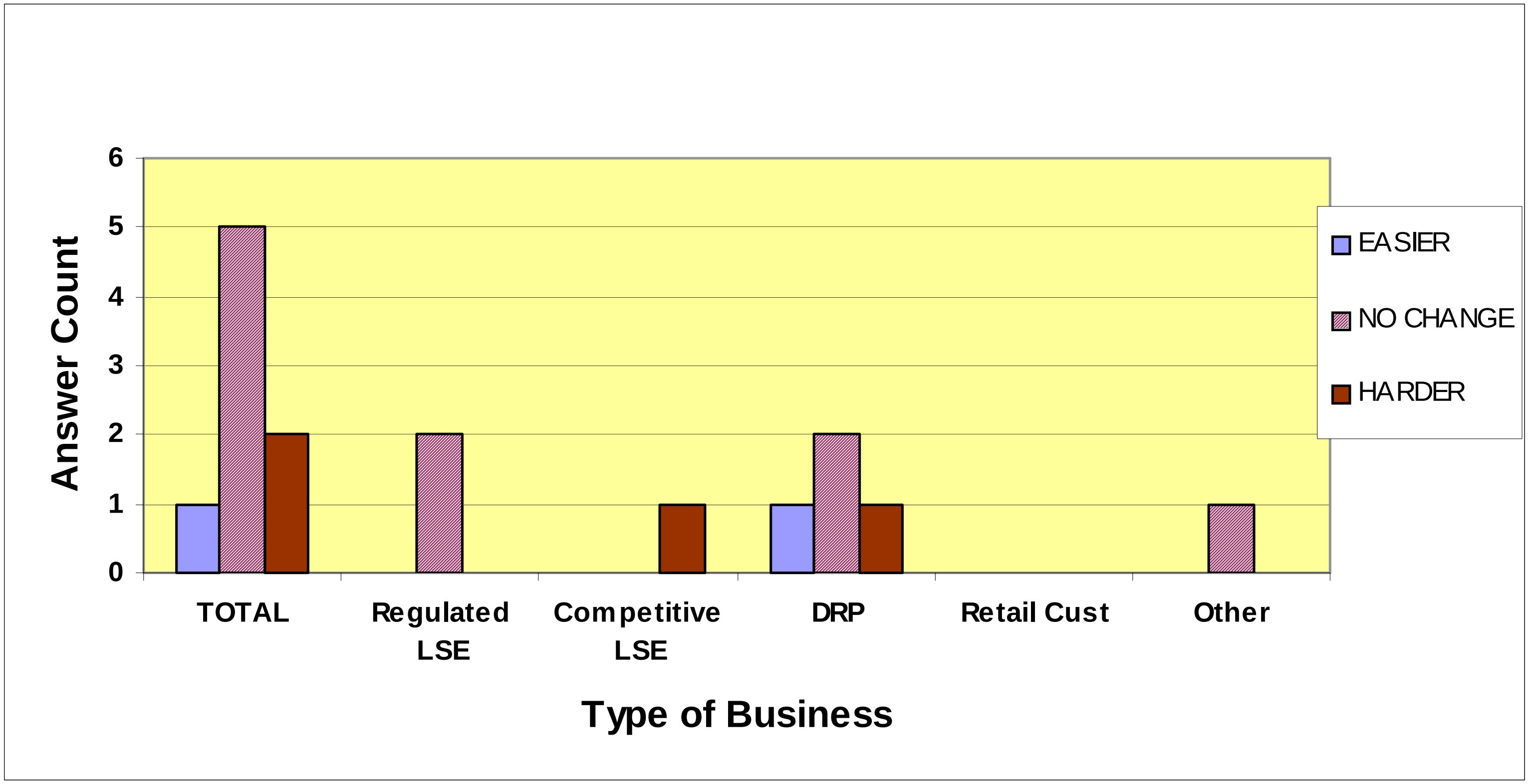


Chart 4.7 Satisfaction with ICAP/EDRP Unbundling

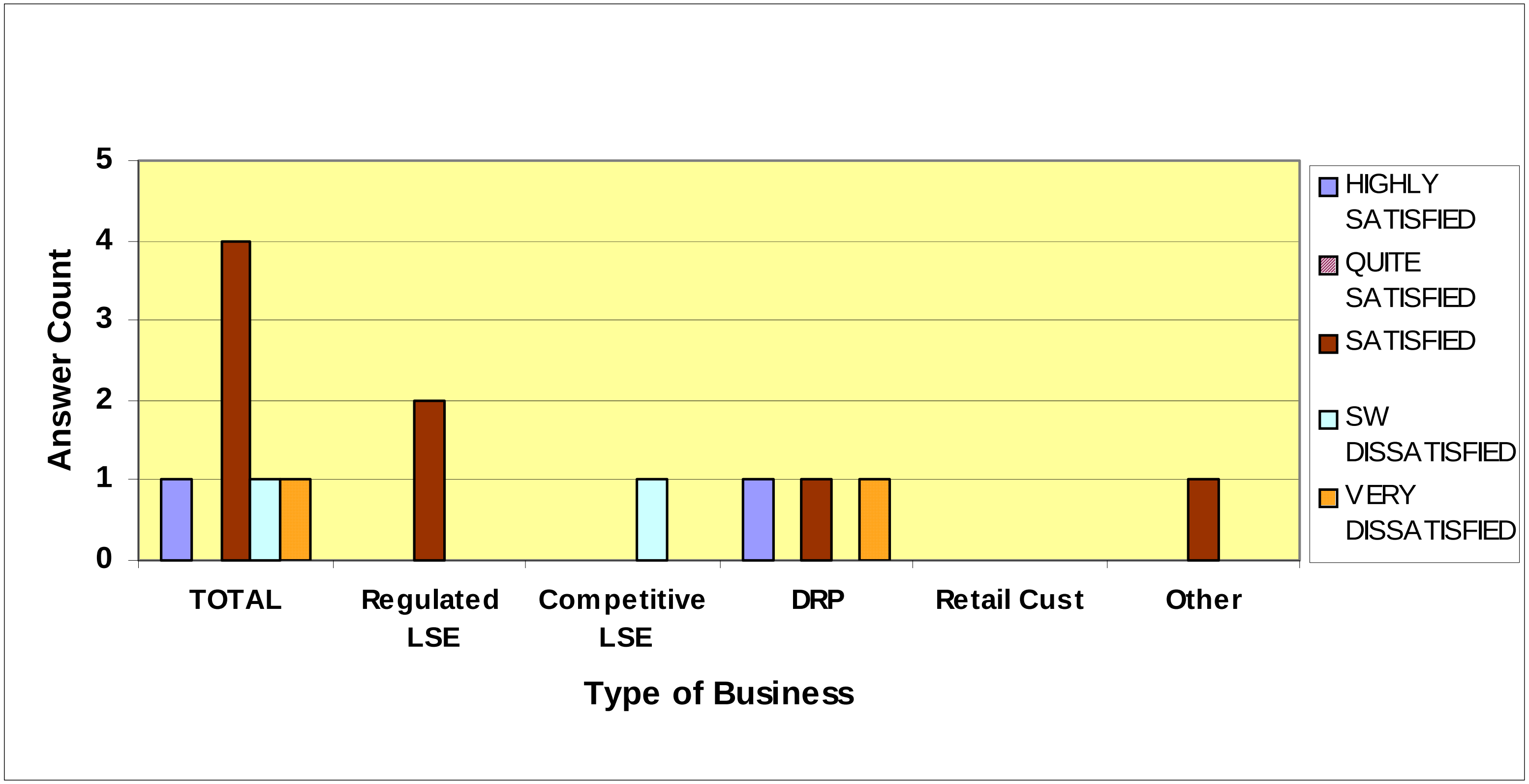


Chart 4.8 Promote ICAP/SCR

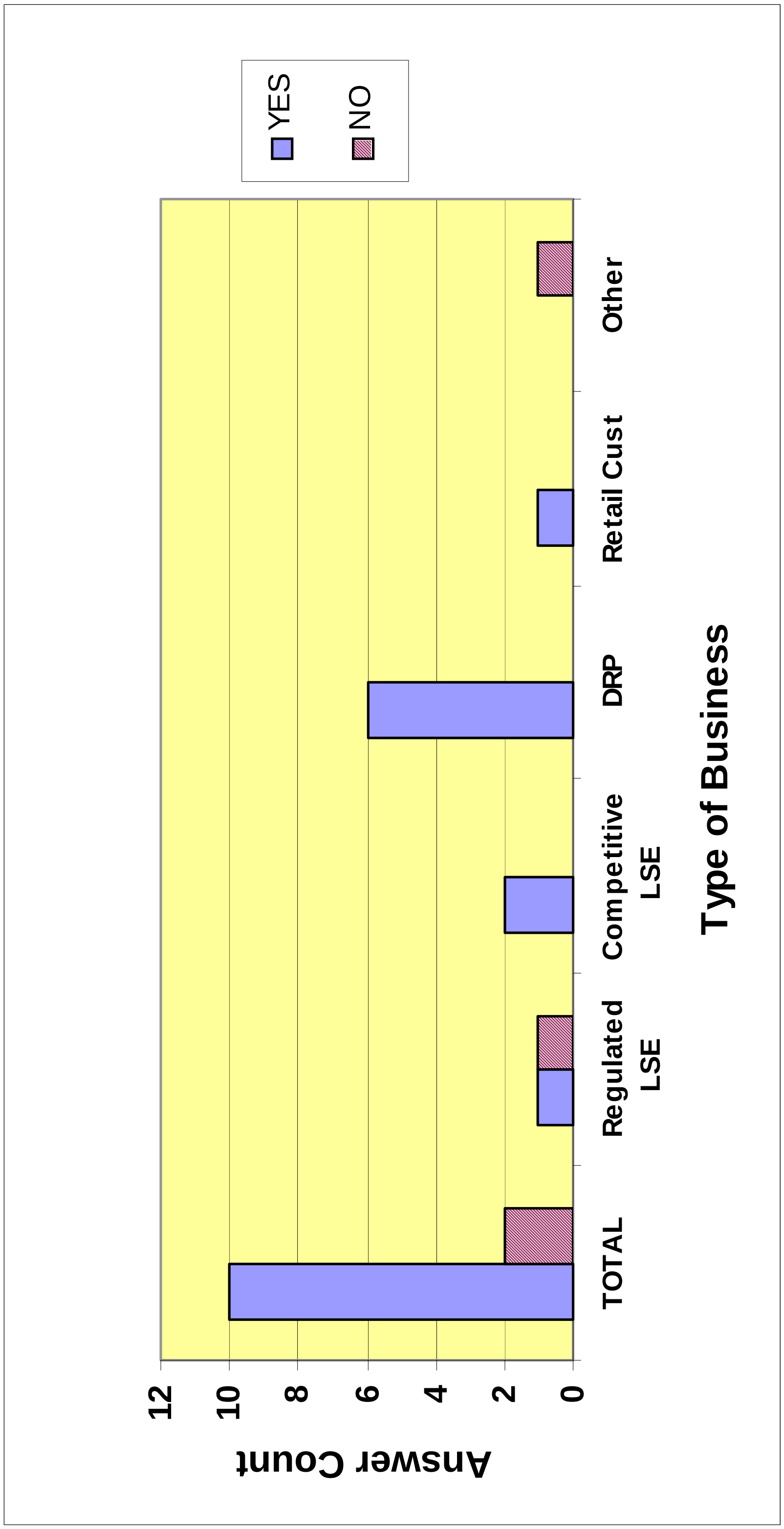


Chart 4.9 Satisfaction with ICAP/SCR Strike Price Nomination Protocols

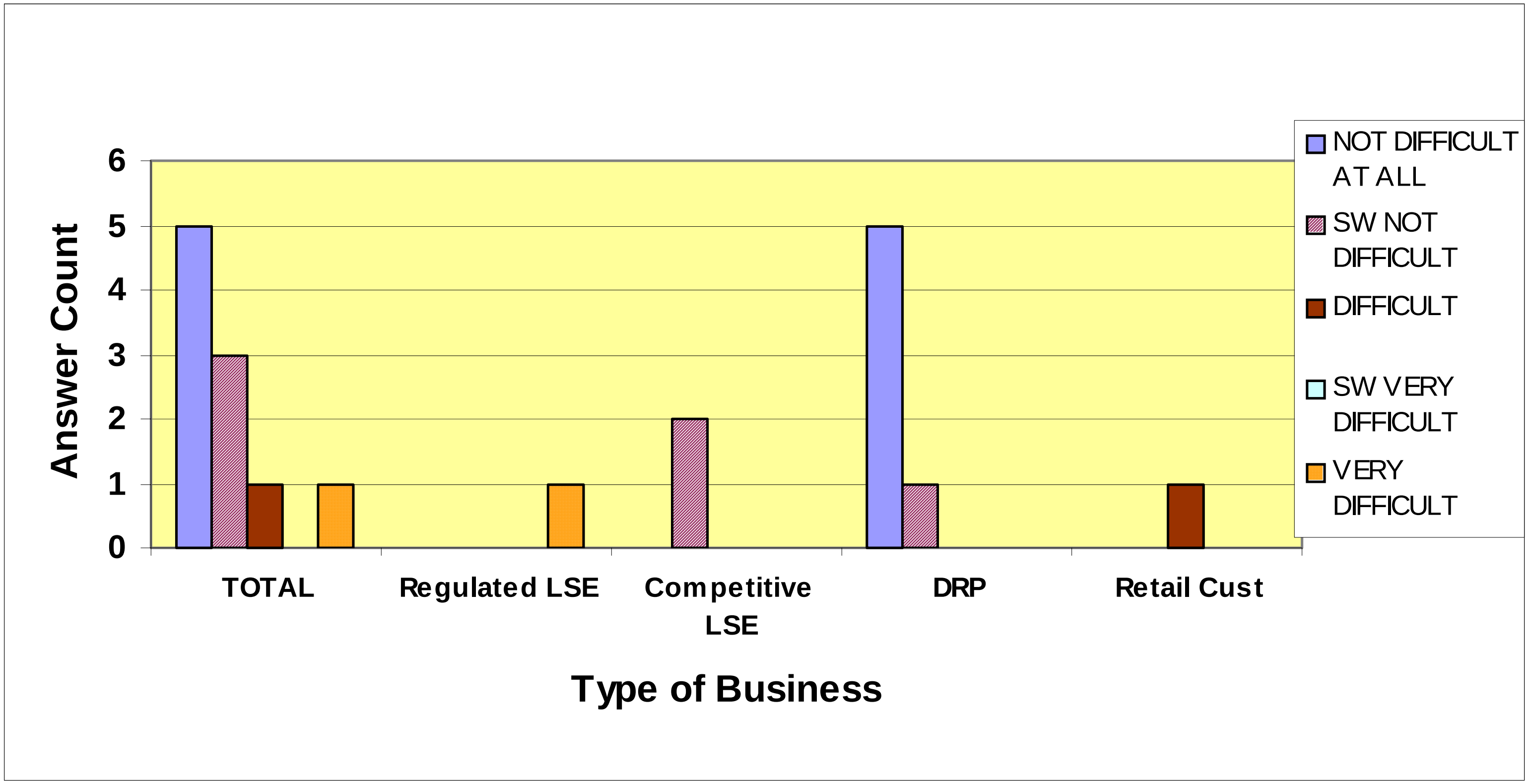


Chart 4.10 Impact of Elimination Energy Payment under ICAP/SCR

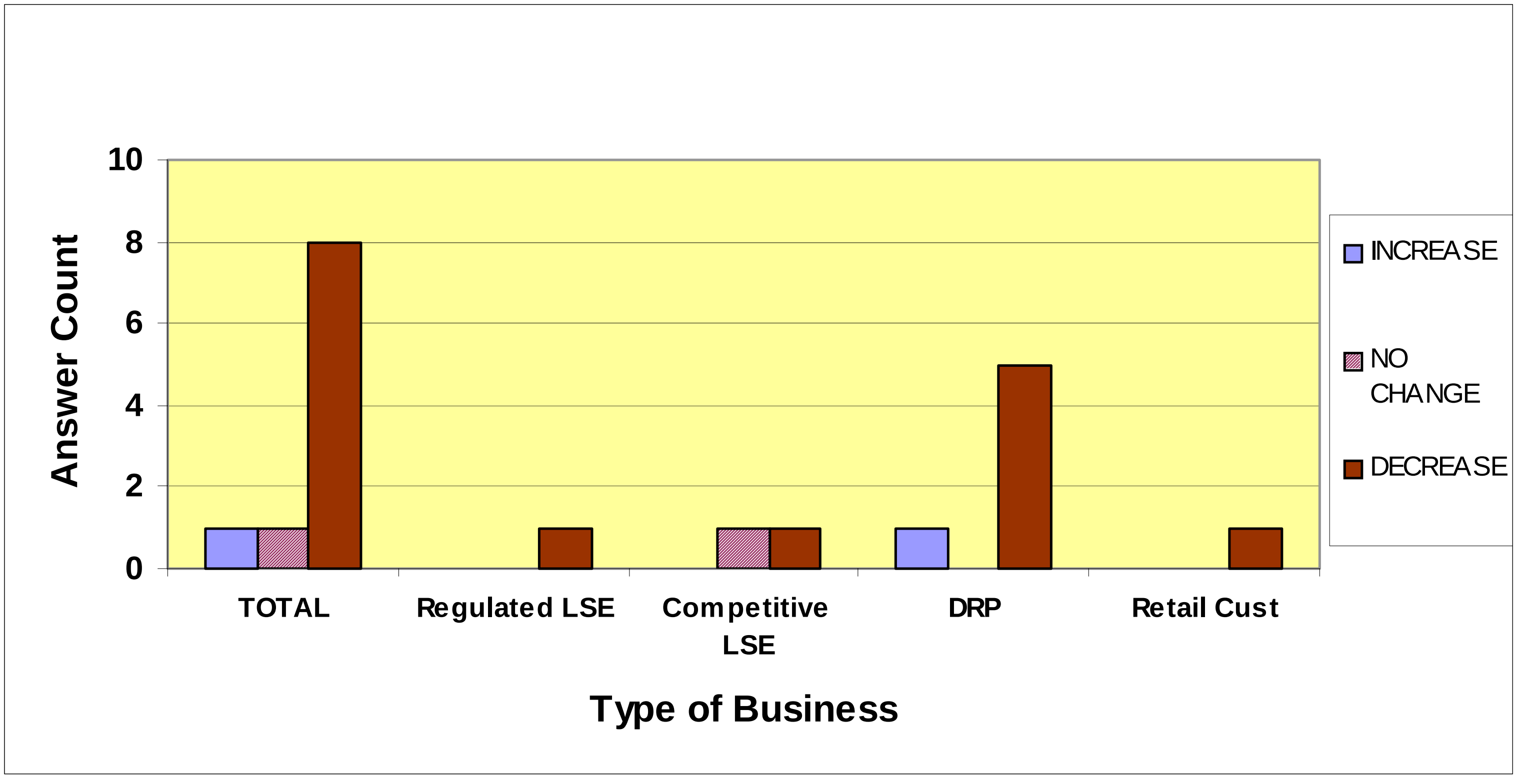


Chart 4.11 Estimated Change in Enrolled ICAP/SCR MW if Energy Payment Eliminated

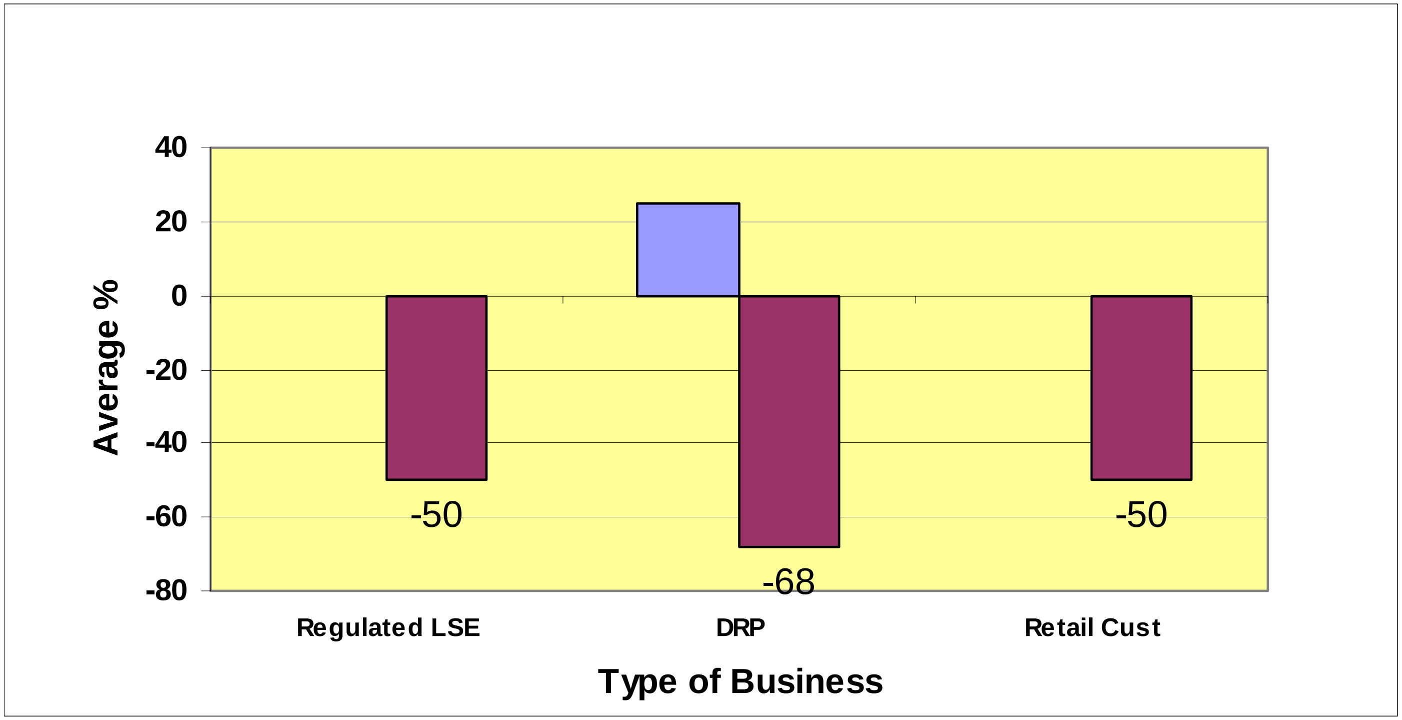
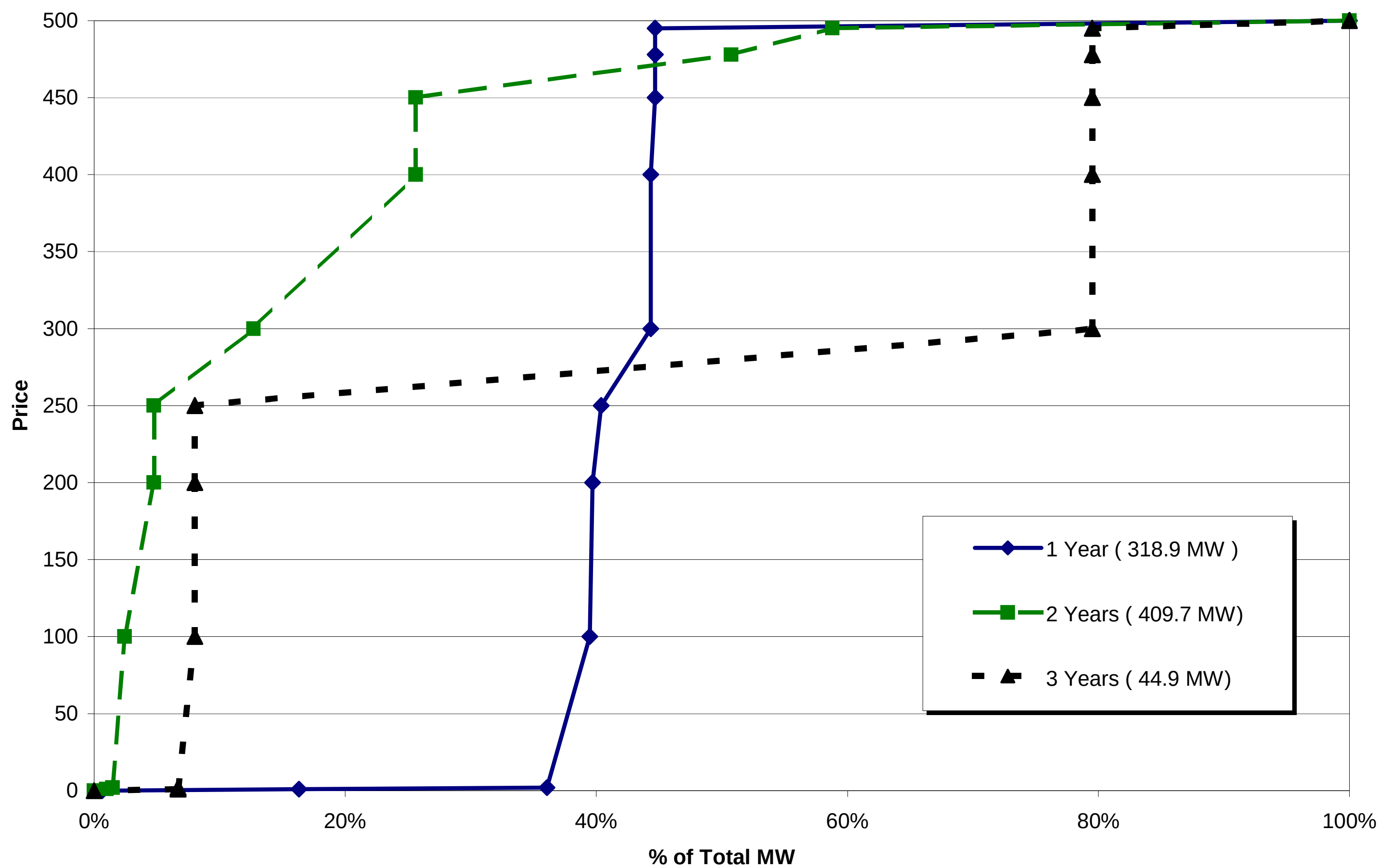


Chart 4.12 ICAP/SCR Curtailment Bid Curves by Years of Experience



Chapter 5 – Demand Resource Participation in Ancillary Services Markets

Background

The NYISO desires to accommodate the participation of end-use customers in some of its ancillary services markets by allowing them to submit offers to curtail usage as equivalent to generation. When fully integrated into market operations, such curtailments supplement the resources available to maintain system reliability, and serve to ensure that resources are dispatched to match the marginal value of electricity in consumption. In this manner, curtailment bids compete with those of generation resources, so when they are selected, they are subject to essentially the same settlement rules that determine compliance payments and nonperformance penalties. The degree to which customers will avail themselves of these opportunities depends on the benefits they can expect to realize compared to the costs and risks they involve.

The NYISO has developed protocols (referred to as the Real-Time Demand Response Program (RTDRP)) for customer participation in its revised operating reserves markets. To evaluate customer interest in RTDRP, Neenan Associates conducted briefings to introduce potential participants to the concept and to measure their interest.

Protocols were developed to characterize the opportunities and barriers to demand resource participation in this market, including representations of how bids to provide service would be submitted by customer participants, how they would be evaluated by NYISO, and how performance would be measured and payment made for services rendered. These protocols were then used to simulate the outcome of alternative RTDRP bidding strategies representative of an industrial customer and a commercial building. These simulations provided numerical examples of RTDRP participation that supplemented extensive descriptive materials developed by Neenan.

To develop a preliminary indication of interest in participation in RTDRP, the NYISO organized concept briefings held in Manhattan and Albany in September of 2003 and extended invitations to a wide audience of stakeholders, including end-use customers, potential program providers (LSEs and CSPs) and other stakeholders. Attendees were given a presentation that described the details of the proposed RTDRP, including the numerical examples. To provide a means of measuring interest in participation, the estimated benefits from three other demand response programs were presented, as follows:

1. **Day-Ahead Ancillary Services program**, which would allow end-use customers to bid to provide ancillary services in the Day-Ahead Market to meet the reliability needs of the NYISO;
2. **LSE-sponsored day-ahead bidding program**, whereby the LSEs extend their day-ahead bidding activities to allow customers an opportunity to reduce load when the LSE requires and receive a share of the resulting benefit, which is defined as the price differential between Day-Ahead and Real-Time market prices; or
3. **Real-Time Demand Response Program with an energy payment,** whereby the existing RTDRP program is modified so that customers that are scheduled to provide ancillary service and are dispatched, to provide energy or for a reserve pickup, are provided an additional payment for their curtailment based on the Real-Time LBMP.

Following each presentation, attendees were asked to complete a brief survey to assess level of interest in the current RTDRP and the proposed alternatives. The survey is included in Appendix 5A. The presentation materials are included as Appendix 5B.

Survey Results

Figure 5.1 shows the distribution of briefing attendees. The majority of attendees were representatives of customer interests: LSEs and CSPs (15% each) and other interested parties (55%). Customers comprised only 15% of those that attended one of the briefings. It is important in interpreting the results to recognize that only 30% of briefing participants are or represent entities to which the program is directed.

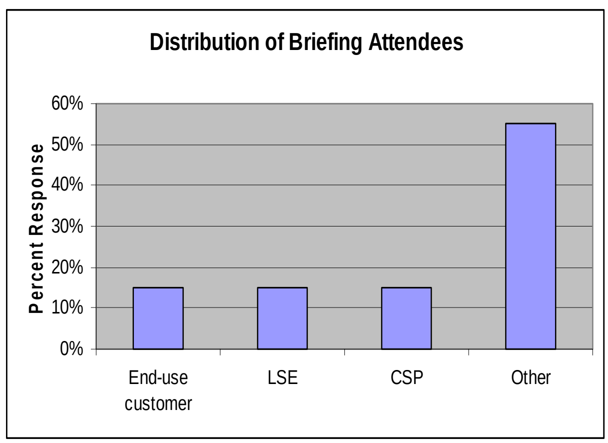


Figure 5.1. Distribution of Briefing Attendees

Briefing attendees were asked to indicate whether they would consider participating in the proposed RTDRP program (customers) or offer the program to their customers (LSEs and CSPs). While more than half of the LSE/CSP/Other Stakeholder attendees indicated that they were interested (YES in Figure 5.2), most of the end-use customers (2 out of 3) said they were not interested (No in Figure 5.2).

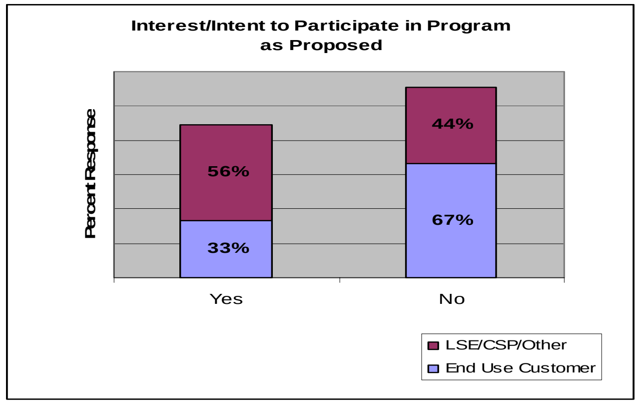


Figure 5.2. Interest/Intent to Participate in RTDRP Program as Proposed

Attendees were asked to indicate the importance of alternative types of assistance that might help them to participate. Figure 5.3 shows the types of assistance each group identified as important to facilitating participation by each group.

The results suggest that customers and their representatives have different views on what would be required to induce participation. Customers (two out of three) selected higher benefits and funding to cover the high cost of the telemetry required to participate, while the other participants indicated standardization of protocols with other ISOs (presumably those in the northeast), or another concern. The only overlap of interest was for the cost of telemetry.

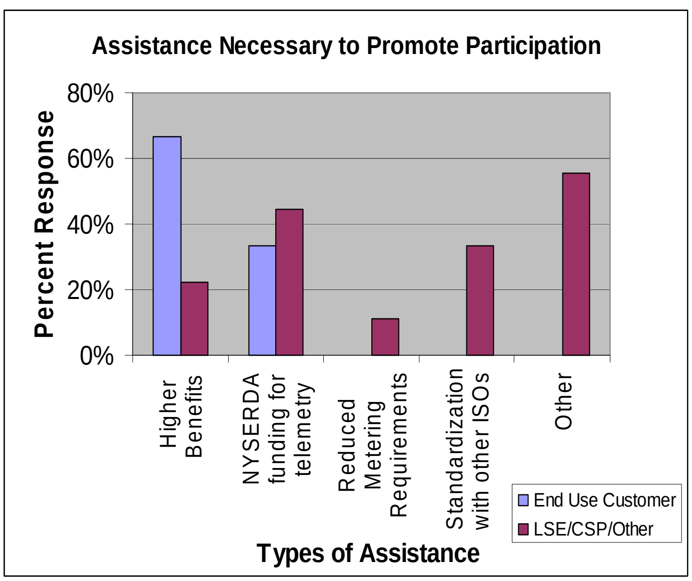


Figure 5.3. Types of Assistance Necessary to Promote Participation in RTDRP

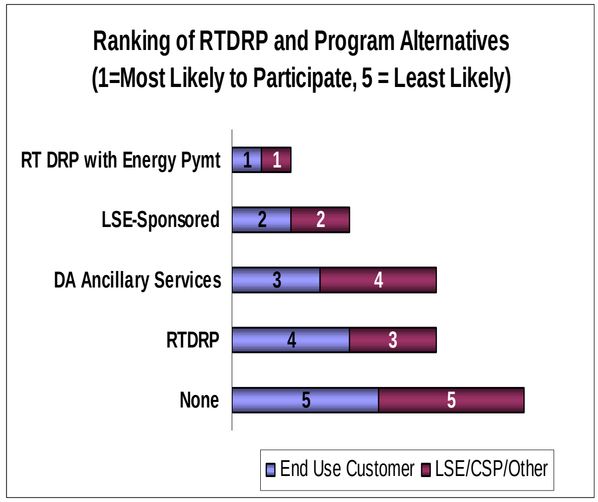


Figure 5.4. Ranking of RTDRP and Alternative Programs

Descriptions of each of the three proposed programs were presented to the attendees along with numerical examples of potential benefits. The examples suggest that RTDRP would produce very low benefits relative to the other program options, and that RTDRP bidding might be over ten times more lucrative if participants also received an energy payment, in addition to their availability payment, when they were dispatched (required to curtail). Attendees were asked to rank, on a scale of 1 to 5, with 1 being Most Likely to Participate, the likelihood of participating in each of the proposed programs. Figure 5.4 illustrates the results separately for customers and for others. In general, their responses were about the same.

Both groups indicated the strongest preference for the Real Time Demand Reduction Program with an energy payment. Under the current design customers would receive an availability payment if selected to provide ancillary services but they would not receive any additional compensation when they are actually curtailed, which may explain why the proposed

Table 5.1. Most Appealing Features of RTDRP and Alternative Programs

	End-Use Customer	LSE/CSP/Other
RTDRP	*none*	*Economically efficient*
Day-Ahead Ancillary Svcs	*Should be standardized to other ISO programs*	*Economically efficient*
LSE-Sponsored Program	*Should be standardized to other ISO programs Might work with other ISO DR programs*	*Economically efficient*
RTDRP with Energy Pymt	*Should be standardized to other ISO programs Might work with other ISO DR programs*	*Economically efficient*

RTDRP program ranked fourth, ahead only of No Ancillary Services Program, which was the least favorable alternative for both customers and other stakeholders. Finally, attendees were asked to specify the most appealing feature of each proposed program and identify any barriers to each program. Table 5.1 provides the most appealing features by group and Table 5.2 shows barriers identified by each group of attendees.

Customers' stated perspective is clearly different than that of the other stakeholders. Customers could find nothing favorable about the proposed RTDRP program, while the others indicated that it has merit because it is economically efficient. For the other programs, customers indicated that standardization was important, while the others are focused on ensuring an efficient market structure.

As Table 5.2 shows, customers indicated that none of the four programs provided sufficient benefits based on the analyses they were presented. The other stakeholders joined them in this belief. An additional consideration to both groups is the high-cost metering requirements for RTDRP given the expected benefits.

Table 5.2. Barriers to Participation in RTDRP and Alternative Programs

	End-Use Customer	LSE/CSP/Other
RTDRP	*Benefits, prices too low* *Metering requirements*	*Benefits, prices too low* *Metering requirements*
Day-Ahead Ancillary Svcs	*Benefits, prices too low*	*Benefits, prices too low* *Metering requirements* *Too complex*
LSE-Sponsored Program	*Benefits, prices too low*	*Benefits, prices too low*
RTDRP with Energy Pymt	*Benefits, prices too low* *Need forecasted benefits*	*Benefits, prices too low*

Conclusions

Gauging interest in a new and complex electricity-purchasing program is difficult. In order to indicate their degree of interest, customers have to wade through the highly technical nature of NYISO bidding and settlement rules. In addition, without the benefit of experience to provide a framework for comparing benefits with risks and costs, customers can be expected to be tentative about obligating themselves to shut down part of their operations and services.

The proposed RTDRP is complex, as befits the nature of how ancillary services are used to maintain system reliability. It's not surprising that some customers are wary of undertaking such an obligation, especially since the estimated benefits are very low. However, one customer indicated that it would be likely to participate, which indicates that there is at least some prospects for customer participation. The other stakeholders indicated through the survey results a stronger interest in participation, presumably reflecting their constituency. Perhaps they see no downside in having such a program available to their customers, and their relative optimism does not reflect the expectation of participation by a substantial number of customers.

As one might expect, making RTDRP more lucrative improves customers' (and others') view of participation, ranking it even above an LSE-based split the savings. But, given the apparent low customer interest in similar LSE offerings in the day-ahead market, whereby obligations are established with much greater notice, and limited interest in the more beneficial DADRP program, it seems unlikely that even with this concession there would be a substantially greater number of participants. However, it might ensure participation by those customers that have the technical ability and managerial acumen to participate in the RTDRP.

Would the results be different if the workshops involved more customers? Is there a constituency that was not represented that might be willing and able to participate in RTDRP? Regarding the first question, it seems unlikely that holding additional workshops would do more than reinforce the results of already recorded. The NYISO extended invitations to the entire demand response community, located the workshops to accommodate participation by a wide range of interests, and provided an opportunity to participate through a conference bridge. It seems reasonable to assume that those that did participate, by virtue of their taking time to understand such a highly technical matter, represent those that would be most capable of participation.

Some have proposed that residential electricity devices under close control represent a rich ancillary services resource (Hirst 2003). This research effort did not explicitly investigate that potential, although one of the workshop participants represents residential buildings interests. Given the relatively low stream of benefits from RTDRP participation, even with an additional energy payment, provides an added perspective on the feasibility of financing an investment in load control technology based on ancillary services participation.

Glossary of Acronyms

CBL – Customer Baseline Load

CSP – Curtailment Service Provider

CERTS - Consortium for Electric Reliability Technology Solutions

DADRP – Day-Ahead Demand Response Program

DAM – Day-Ahead (Electricity) Market

DG – Distributed Generation

DOE – Department of Energy

DR – Demand Response

DRP – Demand Response Provider

DVD – Digital Video Disk

EDRP – Emergency Demand Response Program

EIS – Energy Information System

EMCS – Energy Management and Control System

ESCO – Energy Service Company

EVUE – Expected Value of Unsaved Energy

FERC – Federal Energy Regulatory Commission

FTE – Full-Time Employee

HR – Heat Rate

HVAC – Heating, Ventilation, and Air Conditioning

ICAP – Installed Capacity

ICAP/SCR – Installed Capacity Special Case Resource program

INP – Informed Non-Participant

IOU – Investor-owned Utility

ISO – Independent System Operator

kW - Kilowatt

kWh – Kilowatt-Hour

LBMP – Location-Based Marginal Price

LBNL - Lawrence Berkeley National Laboratory

LIPA – Long Island Power Authority

LOLP – Loss of Load Probability

LSE – Load Serving Entity

MC – Marginal Cost

MR – Marginal Revenue

MW – Megawatt

MWh – Megawatt-Hour

NPV – Net Present Value

NYCA – New York Control Area

NYISO – New York Independent System Operator

NYPA – New York Power Authority

NYSDPS – New York State Department of Public Service

NYSPSC – New York State Public Service Commission

NYSERDA – New York State Energy Research and Development Authority

PJM – Pennsylvania, New Jersey, Maryland Interconnection

PNNL - Pacific Northwest National Laboratory

POLR – Provider of Last Resort

PON – Program Opportunity Notice

PPI – Peak Performance Index

PRL – Price Responsive Load

RIP – Responsible Interface Party

ROI – Return on Investment

RT – Real Time

RT-LBMP – Real Time - Location-Based Marginal Price

RTDRP – Real Time Demand Response Program

RTM – Real-Time (Electricity) Market

RTP – Real-Time Pricing

SCD – Security Constrained Dispatch

SCUC – Security Constrained Unit Commitment

SD – Standard Deviation

SIC – Standard Industrial Classification

SPI – Subscribed Performance Index

TO – Transmission Owner

TOU – Time of Use

VEUE – Value of Expected Un-served Energy

VIPP – Voluntary Interruptible Power Program

VMP – Value of the Marginal Product

VOLL – Value of Lost Load

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