Chapter 6 - Assessing the Market Impacts of the NYISO's 2002 PRL Programs in New York's Day-Ahead and Real-Time Markets for Electricity

Introduction

This chapter documents and evaluates the performance of New York Independent System Operator's (NYISO) two price responsive load (PRL) programs in 2002. Ordinarily, one would expect EDRP events to be called during the hottest summer months. However, in addition to there being events called during July and August, there were also some unexpected EDRP events in April 2002. Rather than being needed to restore reserve margins during the periods of peak summer demand coincident with extreme weather conditions, EDRP load reductions were called in several zones in April due to some local conditions. Since it is expected that market conditions during the spring differ than during the summer months, it is appropriate to examine the April events independently from the summer events. More is said about this below, but at a minimum, it is important to base our estimates of the market effects on short-run supply curves for April, rather than supply curves representing the three summer months of June, July, and August.

In evaluating the EDRP events, the main focus is on the programs' benefits to system reliability, although they are also likely to have some effect on locational based marginal prices (LBMPs) in the real-time market, particularly in terms of mitigating extreme price spikes. In contrast, it is through the potential effectiveness in mitigating extreme price spikes that many believe bidding programs such as DADRP will bring additional "discipline" to the New York Electricity markets.

As part of this continuing evaluation of the performance of NYISO's price-responsive load (PRL) programs, it is, therefore, essential to understand how load bids accepted in DADRP or load offered in EDRP and SCR will affect locational based marginal prices (LBMPs) in both the day-ahead market (DAM) and the real-time market (RTM). Estimates of these price effects also help determine the over-arching, long-term value of PRL programs to customers, LSEs, and generators that comprise the NYISO membership. These effects have implications for market participation and for recruiting customers into the programs.

Because 2002 has already seen a substantial growth in EDRP enrollment and load subscription, it is also important to identify price reductions perhaps due to dispatching load reduction during EDRP events over and above that needed to reestablish system reserve margins. This situation could lead to excessive downward pressure on market prices and could have important implications for how much SCR and EDRP load is dispatched, of course within the context of what is feasible for system operators responsible for dispatch in real time.

We begin with some descriptive data that characterize the nature of load and LBMPs in the DAM and RTM in several of the major zones for which separate hourly prices are determined. Next, we provide a brief summary of the supply models described in greater detail by Neenan Associates (2002). As is seen in that report, a "spline" formulation, incorporating some variables that act to shifters, is needed to capture the "hockey stick" shape of the market supply curve. The price response to changes in load served is characterized in percentage terms by the price flexibility of supply: the percentage change in price due to a one percent change in load served. We re-estimate the supply models for the summer months of 2002. Further, we estimate separate models using April 2002 data, because the supply relationships during the spring probably differ from those in the summer months. Next, the data on the performance of customers in EDRP are presented and are used to estimate the effects of the program on electricity markets. This analysis is followed by a similar evaluation of DADRP. Finally, some conclusions and recommendation are presented.

Summary Data on Demand and LBMPs in the DAM and the RTM

To place the analysis into proper perspective, it is helpful to examine some summary statistics on hourly LBMPs and demand for the month of April, as well as for the three summer months of June, July, and August. We focus on the afternoon hours (1:00 pm through 7:00 pm) for two reasons. 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.[1] These circumstances would suggest that EDRP would be most likely be called during this time of the day. Second,

[1] 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.

through careful examination of the data, the structure of the short-run supply relationship during this period is distinct from that during other times of the day.

In the discussion of the price data, and in the supply analysis below, the Capital zone is treated separately, as are the NYISO pricing zones for New York City and Long Island. [2] For both modeling and discussion purposes, the remaining eight zones are aggregated into two "super" zones. The three zones in the Hudson Valley between the Capital zone and New York City are combined into a single region (Hudson River "super" zone). The same is true for the five zones west of the total east transmission corridor (Western New York "super" zone).[3] By combining zones in which prices seem to be similar, we facilitate the analysis and improve the ability to estimate the short-run supply relationships. Fig. 6-1 contains the boundaries of these aggregate zones in relation to the boundaries of the 11 individual pricing zones.[4]

The Data for April 2002

Table 6-1 contains summary statistics on LBMPs in the DAM and RTM for April of 2002, as well as for fixed bid load in the DAM and actual load served in the RTM. [5] Because it is the NYISO's policy not to report load separately for New York City and Long Island, we aggregate those two zones for purposes of presenting summary data. However, separate supply models are estimated for New York and Long Island.

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[2] For this discussion, however, the NYISO has a policy not to report loads in the real-time or day-ahead markets separately for New York City or Long Island. 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] To introduce some variety in presentation, the Hudson River "super" zone is sometimes referred to as the Hudson Region or Hudson River Zone, while the aggregate zone west of the total east transmission corridor is sometimes referred to as the Western "super" zone or just Western New York. Unless otherwise indicated, it is these aggregate zones that are being discussed. Further, in some cases, the term region is used interchangeably with zone.

[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 want 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.

For the afternoon hours in April 2002, fixed bid load in the DAM averaged 14,724 MW statewide. In real-time, load served averaged 18,324 MW, nearly 20% higher than in the DAM. The difference between average load in the DAM and real time (52%) was most pronounced in the Hudson River super zone. In Western New York, the difference was only 17%, while in the downstate zones and in the Capital zone, average load in real time exceeded that scheduled in the DAM by about 25%.

In both real time and in the DAM, about 35% of the load was in Western New York, while about 46% was downstate, 7% was in the Capital zone and the remaining 10% to 11% was in the Hudson River super zone. Not surprisingly, the variability of load served in real-time was substantially higher than in the DAM in each zone. This difference in variability was most pronounced in the Hudson River super zone; the difference in variability in the downstate zones was also quite marked, while less so elsewhere in the state.

During the afternoon hours in April 2002, the prices both in the DAM and in real time were rather modest, on average. In the DAM, they averaged $49/MW downstate, and between $43/MW and $44/MW in the Hudson and Capital regions. They were substantially lower in Western New York, averaging about $32/MW. At no time did prices in any region exceed $200/MW, and they reached a low in Western New York of $19/MW.

The pattern was similar in the DAM, although downstate and in Hudson River regions prices in real time averaged between 5% and 7% higher than in the DAM, respectively. In the other two regions in Table 6-1, real time prices were averaged about 12% below those in the DAM. The variability of prices in real time was substantially higher than in the DAM. The downstate zones saw a small number of prices in excess of $300/MW, while the highest price in the Hudson super zone was just over $280/MW. In the Capital zone, the highest real time price in April 2002 was $121/MW. In the western super zone, real time prices never exceeded $88/MW, and they fell to as low as $5/MW.

The Data for the Summer of 2002

Table 6-2 contains summary statistics on LBMPs in the DAM and RTM for the three summer months of 2002, as well as for fixed bid load in the DAM and actual load served in the

RTM. [6] 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 data. However, as in the case of the April evaluation, separate supply models are estimated for New York and Long Island.

For the afternoon hours of summer 2002, fixed bid load in the DAM averaged 19,006 MW statewide. In real-time, load served averaged 23,438 MW, nearly 23% higher than in the DAM (Table 6-2). The difference between average load in the DAM and real time (55%) was most pronounced in the Hudson River super zone. In Western New York, the difference was only 12%, while in the downstate zones and in the Capital zone average load in real time exceeded that scheduled in the DAM by about 13%.

Not surprisingly, the variability in load served in real time statewide (a standard deviation of 3,707) was substantially larger than the variability in fixed bid load in the DAM (a standard deviation of 2,619). This difference was even more pronounced for New York City and Long Island combined and in the Hudson region. However, in both the Capital zone and in Western New York, the variability in load in the two markets was nearly identical (Table 6-2).

Statewide, average summer prices for these afternoon hours were rather modest, but in the DAM and in real time (Table 6-2). The load weighted average prices statewide were $65/MW and $61/MW in the DAM and in the RTM, respectively. Downstate average prices were somewhat higher. In the DAM, prices averaged $87/MW on Long Island and $76/MW in the City. In real time, prices were somewhat lower, averaging $81/MW on Long Island and $71/MW in the City. For the Hudson River Region, average prices were $59/MW and $55/MW in the DAM and RTM, respectively, while in Western New York average prices were $47/MW in the DAM and only $44 in the RTM. Interestingly, average prices in the RTM were about 7% lower than in the DAM in all zones expect those in the Capital Zone. In that zone, average prices in the RTM were about 14% below those in the DAM ($49/MW in real time vs. $58/MW in the DAM).

The ranges and variability in prices in all regions were also higher in the RTM than in the DAM (Table 6-2). Prices in real time fell as low as $12/MW in Western New York and reached a high of $1,123/MW in New York City; maximum prices were very near or exceeded $1,000/MW

[6] Fixed bid load is the load bid into the DAM that the LSEs or other market participants what 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.

in all other zones as well ($996/MW, $1,008/MW, $1,106/MW, and $1,109/MW in Western New York, the Capital Zone, the Hudson River Region, and on Long Island, respectively). In the DAM, prices in the afternoon hours exceeded $200/MW only in the Capital Zone ($214/MW) and on Long Island ($600/MW). The variability of prices, as measured by the standard deviation, was over twice as large in real time ($69/MW) as it was in the DAM ($33/MW). The differences in price variability were similar in all other zones, except for Long Island, where the standard deviation in real time prices was only $7/MW higher in real time than in the DAM.

The Econometric Model of Supply

To assess the effects of EDRP and load reduction or on-site generation on the real-time electricity market in New York, we must quantify the change in price due to changes in the amount of PRL load bought or sold. 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 here.

In most research of this kind, the common strategy 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 3 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.[7] 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

[7] Price data are publicly available on the NYISO web-site. Load data by zone are similarly available, but with a six-month lag. For this analysis, the NYISO made some still confidential load data available.

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 RTM we had to pay particular attention to:

- the way in which equilibrium prices and quantities are determined; and
- 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.

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 in the DAM at what ever prices clear the 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.[8]

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.

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., Fig. 6-2). It is as though the curves had separate regimes (Fig. 6-3 and 6-4). These regimes were captured as piece-wise "spline" functions with different intercepts between the regimes (Neenan Associates, 2002). The points in Fig. 6-5 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 Fig. 6-6. The supply flexibilities, defined as the percentage

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[8] 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.

change in price due to a percentage change in load, are used to estimate the change in prices due to a change in load.

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), there are cases in which two regimes are sufficient. Assuming a log-linear specification, we begin 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) measured in logarithmic terms (lnL):

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

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

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

where, L = fixed bid load or real time load and the subscripts indicate specific MW loads.

The Linear "Spline" Function

Now, for a linear "spline" specification, the inverse supply relation is given by:[9]

(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 (4) in the following way (Ando, 1997 and Neenan Associates, 2002):

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

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

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

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

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

In the data, the three zero-one variables add to a vector of ones. Thus, the first term in equation (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 (5) and (6).

Once equation (7) is estimated and the remaining parameters are identified, we can use equation (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 (7) with respect to the logarithm of L are:

$$(8)\ \partial \ln LBMP / \partial \ln L = \beta_1, \text{ if } \ln L \leq \ln L_1^*;$$

$$(9)\ \partial \ln LBMP / \partial \ln L = \beta_2, \text{ if } \ln L_1^* < \ln L \leq \ln L_2^*;$$

$$(10)\ \partial \ln LBMP / \partial \ln L = \beta_3, \text{ if } \ln L > \ln L_2^*.$$

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. 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

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[9] 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.

differ. From equation (5) we see that $\beta_1 < \beta_2$, as long as $\alpha_1 > \alpha_2$. Likewise, $\beta_2 < \beta_3$ as long as $\alpha_2 > \alpha_3$.

<u>A More Complex "Spline" Formulation</u>

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".[10] The "spline" equation becomes:[11]

$$(11)\quad \ln LBMP = a_1D_1 + b_1D_1X + c_1D_1 \ln L + d_1D_1 X \ln L$$
$$+ a_2D_2 + b_2D_2X + c_2D_2 \ln L + d_2D_2 X \ln L$$
$$+ a_3D_3 + b_3D_3X + c_3D_3 \ln L + d_3D_3 X \ln L$$

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

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

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

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

[10] 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.

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

$> d_2 > d_1$; 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:

(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

(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 (11), we have;

$$\begin{aligned}(16)\ \ \ln LBMP = {} & D_1 \{a_2 + b_2X + c_2 \ln L_1^* + d_2X \ln L_1^* - [b_1X + c_1 \ln L_1^* + d_1X \ln L_1^*]\}+ \\ & b_1D_1X + c_1D_1 \ln L + d_1XD_1 \ln L + a_2D_2 + b_2D_2X + c_2D_2 \ln L + d_2D_2X \ln L \\ & + D_3 \{ a_2 + b_2X + c_2 \ln L_2^* + d_2X \ln L_2^* - [b_3X + c_3 \ln L_2^* + d_3X \ln L_2^*]\}+ b_3D_3X + \\ & c_3D_3 \ln L + d_3D_3X \ln L .\end{aligned}$$

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

$$\begin{aligned}(17)\ \ \ln LBMP = {} & a_2 [D_1+ D_2+ D_3]+b_1 [D_1 X–D_1X]+b_2 [D_1X+ D_2X+D_3X]+b_3 [D_3X-D_3X] \\ & + c_1 [D_1 \ln L - D_1 \ln L_1^*] + c_2 [D_1 \ln L_1^* + D_2 \ln L + D_3 \ln L_2^*] \\ & + c_3 [D_3 \ln L - D_3 \ln L_2^*] + d_1 [D_1X \ln L – D_1X \ln L_1^*] \\ & + d_2 [D_1X \ln L_1^* + D_2X \ln L + D_3X \ln L_2^*] + d_3 [D_3 \ln L – D_3 \ln L_2^*]\end{aligned}$$

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 (14) and (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 (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:

(18) $\partial \ln LBMP / \partial \ln L = c_1 + [d_1 X]$, if $\ln L \leq \ln L_1^*$;

(19) $\partial \ln LBMP / \partial \ln L = c_2 + [d_2 X]$, if $\ln L_1^* < \ln L \leq \ln L_2^*$;

(20) $\partial \ln LBMP / \partial \ln L = c_3 + [d_3 X]$, if $\ln L > \ln L_2^*$.

These marginal effects differ by segment and are now functions of X. 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:

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

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

(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.

Estimates of the Short-Run Electricity Supply Curves

This section contains a discussion of the estimated short-run electricity supply curves for the three NYISO pricing zones and the two "super" zones developed above. We begin with estimates of the real-time supply curves for the Hudson "super" zone and for New York City and Long Island for April 2002. These are the results needed to simulate the effects in the real-time market of the April 2002 EDRP emergency events. These supply relationships are in Tables 6-3 through 6-5. The supply models needed to simulate the market effects of the summer 2002 EDRP events are reported in Tables 6-6 through 6-10. Finally, the summer 2002 supply models for the DAM are needed to assess the performance of DADRP, and they are reported in Tables 6-11 through 6-15.

In each table, the estimated coefficients for the explanatory variables are reported, along with the t-ratios.[12] For the most part, the supply models are specified entirely in logarithmic form

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

so that the supply flexibilities are calculated according to equations (18-20). 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 will be constant, as they are in conditions (8-10).[13]

Before discussing the specific results in detail, some general comments are in order. Overall, the performance of the supply models is quite remarkable. In all cases over half the variation in the dependent variable is explained. One could hardly hope for any better results, given the substantial 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 figures in Appendix A contain graphs of the estimated supply functions over-laid on a scatter of the actual load and LBMP data for each zone, market, and time period. The supply functions were estimated and plotted for the minimum, maximum, and average levels of the appropriate "shifter" variables. In so doing, we demonstrate the importance

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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.

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

of these variables in reflecting the situation depicted in Fig. 6-6. These variables do indeed improve the ability to model these supply relations.

Despite the excellent 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 variables that by necessity only reflect general changes in system conditions at the zonal level.

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. 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 Real-Time Market for April 2002

Because of the need to include interaction variables in the models to isolate the effects of system conditions on LBMP, the supply flexibilities need not be constant in any regime, and they cannot be read directly from the models' coefficients. The ranges in supply price flexibilities for April 2002, as well as the average values, are reported in the bottom sections of Tables 6-3 through 6-5. Before discussing the supply flexibilities in the individual markets, there are also several general conclusions evident in the empirical results. First, the supply price flexibilities increase as load increases—as we move from regime 1 to regime 3 (see Fig. 6-2 and 6-6). Thus, the empirical results support the notion of a "hockey" stick shape for supply. At initially high levels of load served, small changes in load can have dramatic effects on LBMP.

In Neenan Associates (2002) previous evaluation of the PRL programs for 2001, it was suggested that the supply price flexibilities would be highest in markets where price variability was high relative to load variability, and average prices were high. Supply price flexibilities are indeed larger the real-time market in New York City and Long Island then they are for the Hudson "super" zone. This is consistent with the fact that price variability is higher in these two former zones, as are average prices. On average, the April supply flexibility (e.g. the percentage change in LBMP due to a percentage change in load) in the real time market in New York City is 13.06, which is 10 % higher than for Long Island (11.88), and over twice as large as for the Hudson "super" zone (5.69).

In the last part of the "spine" functions for all three zones, the supply flexibilities are affected by variables that shift the supply function. In some of the models, real-time load squared is used as a explanatory variable, as are variables that reflect the number of minutes in the previous or current hours that constraints transmission constraints were binding and the proportion of the current generation offered to maximum generation offered during the month system wide. This latter variable is designed to reflect the proportion of generation available in April (not on scheduled outage) that was bid into the system during a particular hour. One would expect prices to rise with the number of constraint minutes and fall as the proportion of maximum generation offered rises. As is seen in Tables 6-3 through 6-6 and the graphs in Appendix A, this is indeed what happens.

<u>Supply Price Flexibilities in the Real-Time Market for the Summer 2002</u>

Although we only needed supply curves for three of our supply regions to study the effects of the April EDRP events, we need supply relations for all five regions for the analysis of the summer 2002 EDRP events.

The two regions that were not needed in April are the Capital zone and the Western New York "super" zone (Tables 6-7 and 6-8). In the third part of the "spline" function price flexibilities averaged 6-67 and 5.97 for western New York and the Capital zone, respectively. A priori, one might have expected to see the higher average price flexibilities in the Capital zone, as was the case in the 2001 evaluation (Neenan Associates, 2002). However, this past summer there were some high prices in western New York, and it is clear that much to the extreme price responsiveness was also due to the effect of high loads in adjacent zones. It is this latter effect that is more pronounced in western New York than in the Capital zone.

As we expected, the supply equations for the real-time market during the summer of 2002 differ from those in April (compare Tables 6-3 through 6-6 and Tables 6-8 through 6-10 for the differences in the Hudson Region, New York City and Long Island, respectively). The average price flexibilities in the third part of the "spline" functions for these zones are 4.69, 12.82, and 5.16 in the Hudson Region, New York City, and Long Island, respectively. These averages are slightly lower than those for April, a surprising result at first glance given that there were no extreme prices in April. However, a careful examination of the data reveals that although prices in April never exceeded $350/MW in these regions, the supply curves still rise very steeply. Therefore, in percentage terms, prices rise considerably for small changes in load because of the low initial price against which the percentage changes are measured.

Further, the price data for high loads followed a more definite pattern during April; there greater complexity and interaction among zones during the summer led to a more diverse pattern of price and quantity combinations during the summer. As a result of this complexity, the range in elasticity values during the summer in these three zones is wider than in April.[14] This complexity also explains the negative flexibilities, which appear contour intuitive at first glance. However, it is in these negative flexibilities that explain the extremely low prices in some hours of high loads (e.g., the situations reflected in Fig. 6-5 and 6-6). Because of the influence of adjacent load, it is possible for a *ceteris paribus* change in load in one of these regions to lead to a drop in the LBMP, perhaps due to being now able to serve total load with a higher proportion of base load.

Supply Price Flexibilities in the Day-Ahead Market for the Summer 2002

We also need estimated supply flexibilities for the summer of 2002 in the day-ahead market in order to assess the performance of load bid in DADRP. These are reported in Tables 6-11 through 6-15. On balance, we were able to explain more of the variation in prices in these markets than in the real-time markets, and we were able to rely on the same types of "shifters" to accommodate some of the complexity inherent in price formation. As seen in Appendix A, the estimated supply equations, accommodating the extreme values these "shifters" track the data well. The average price flexibilities are 4.21, 4.96, 3.91, 3.55, and 6.52 in western New York, the

[14] It is for this reason that the supply functions plotted in Appendix A do not track the data for these regions in the summer to the same extent that they do in April. Still, there performance is rather remarkable given the small number of supply "shifters" for which data are available.

Capital zone, the Hudson Region, New York City, and Long Island, respectively. Within each zone, they do vary considerably around these mean values.

In general these averages are smaller than for real time, as one might expect, and they are smaller than for the summer of 2001 (see Neenan Associates, 2002). These lower values are undoubtedly explained in large measure by the fact that average summer prices in 2002 in the DAM were lower than last year, and were less variable as well.

Evaluation of the 2002 PRL Program Events

Somewhat unexpectedly, EDRP events were called as early as April 2002; the remaining events were called during late July and mid August, times during which one would most likely expect any system reliability problems due to peak loads on hot summer afternoons. After first describing these 2002 EDRP events, we summarize the strategy for evaluation and provide empirical estimates of these various effects. In most cases, these effects are broken out by pricing zone or "super" zone. Since the pricing zones were established for reasons other than overall system security, the discussion of this latter issue is most effectively done at the system level.

2002 EDRP Events

Because the supply models that must be used to estimate the effects of the April events differ from those for the summer events, we discuss the events separately. Moreover, the summer events were called statewide, and there were many more program participants during the summer events.

The April Events

These April events were called on April 17, from 12:00 noon to 6:00 pm, and on April 8, from 12:00 noon to 6:00 pm. These events were called primarily for the pricing zones in the lower Hudson Valley (G, H, and I) and New York City (J) and Long Island (K). On April 18, the events were also called in the Genesee zone (B).[15]

The April events were called prior to the May 31, 2002 deadline for program enrollment. Based on data supplied by the NYISO, the total program participants at that time numbered 333

[15] Because of the low prices in Western New York and difficulty in modeling supply for a single zone in Western New York, it was impossible to estimate any market effects in that one zone.

(including the 116 combined EDRP/SCR participants), essentially those firms enrolled in the 2001 programs (Table 6-16). There were an additional 94 customers enrolled only in the ICAP/SCR program.[16] The average hourly load reductions from EDRP participants during the April events are given by zone in Table 6-17. During the April event hours, there were on average 36.1 MW of PRL load reduction (Table 6-17, column d); 61% of the EDRP load reduction came from New York City (Table 6-17, column d). Another 22% was from the Hudson Region, while the remaining 17% was from Long Island (Table 6-17, column d).

The Summer Events

In contrast to the April events, the 2002 EDRP events of July 30, from 1:00 pm to 6:00 pm, and August 14, again from 1:00 pm to 6:00 pm, were called statewide. Further, these events occurred after the deadline for 2002 enrollment, and the load reduction realized reflects the substantial increases in the numbers of customers and subscription in both SCR and EDRP over and above the 2001 levels.

At the time the summer 2002 events were called, there were a total of 1,785 customers enrolled in the EDRP and SCR programs, up from 395 in 2001 (Table 6-18, column d). Of this total, 1,534 end-use customers enrolled only in EDRP; another 177 customers were enrolled in both SCR and EDRP, while 74 customers were enrolled only in SCR (Table 6-18). Western New York had 519 PRL program participants (Table 6-18, column d). Long Island has over 900 PRL participants, but the vast majority of them are small residential customers belonging to a direct load control program (Table 6-18, column d).

Due to the increased enrollment, at the time of the summer events there over 1,478 MW subscribed to EDRP (sum of columns e and h, Table 6-18), and 681 MW subscribed to SCR (sum of columns f and g, Table 6-18). To the extent that between 500 MW and 600 MW of SCR and EDRP loads are subscribed to joint program participants, it is unlikely that these are independent amounts of load reduction resources. To assume so would most likely be double counting the potential load reduction available during an EDRP event. Because of the number of customers and their size, it is not surprising that the largest proportion of subscribed MW is found in

[16] The distribution of EDRP customers in the 2001 programs by zone and type of program provider is in Table 1.12 of the 2001 evaluation report (Neenan Associates, 2001).

Western New York. This has not changed from last year, although subscription levels in the City and Long Island have increased disproportionately to those of the other zones.

As one would expect, the hourly load reductions from EDRP participants during the July and August events were much higher, averaging 663.2 MW (Table 6-19, columns d and j, respectively). Western New York accounted for 61% of the SCR and EDRP load reduction, while the Capital zone accounted for 10% of the EDRP load reduction (Table 19, columns d and j). New York City accounted for 13% of the EDRP load reduction and 10% of the SCR load reduction. Long Island accounted for 11% of the EDRP load reduction, while the Hudson region accounted for the remaining 5%.

Overall Strategy for Evaluating the Effects of the PRL Programs

The overall strategy for evaluating the effects of the PRL programs, and a list of the major market effects are given in Fig. 6-6. These effects include:

- Estimated changes in electricity prices;
- Estimated collateral benefits—redistribution of payments from generators to customers, or vice versa;
- Effect of program on system reliability;
- Program costs; and
- Estimated reduction in risk.

We begin with an evaluation of the EDRP events and then proceed to the evaluation of DADRP.

The EDRP Evaluation

The theory underlying the effect of load reduction or on-site generation during an EDRP event is developed in detail in earlier reports to the NYISO by Neenan Associates (2001 and 2002). It need not be repeated here.

To estimate the effects of the EDRP events on LBMP in real time, we must perform two sets of simulations for each pricing zone or "super" pricing zone. The simulations are:

1. The first set of simulations is designed to calculate a set of base prices in the real-time market for the hours in the April, July, and August 2002 emergency events. These prices

for the event hours are calculated by adding back into load the load reduction from EDRP. These reflect the prices at which the market would have cleared had the load reduction measures been taken. These base prices are thus the appropriate ones against which to compare the prices resulting from the partial dispatch of the 2002 EDRP load reduction.

2. The second set of simulations is designed to estimate the additional effect on LBMP in real time if EDRP resources are dispatched in addition to resources in ICAP/SCR.

In these simulations we assume that EDRP resources cannot set LBMP, although there has been some discussion that this will change for next year's program.

Effects of the April 2002 EDRP Events

Effects on LBMP's

The effects of the April 2002 EDRP events on the real-time electricity market in New York State are also provided in Table 6-17.[17] As stated above, there was, on average, about 36.1 MW of hourly load reduction during these events. During those hours, LBMP in real time averaged \$215/MW, \$209/MW and \$187/MW in New York, Long Island, and the Hudson River region, respectively (Table 6-17, column e). Had this load reduction not been delivered by EDRP participants, our simulations estimated that the average LBMPs in real time would have been somewhat higher, \$223/MW, \$215/MW and \$191/MW in New York, Long Island and the Hudson River region, respectively (Table 6-17, column c). [18]

These implicit price reductions due to EDRP load curtailments are modest since load reductions as a percent of real time load averaged less than 0.3% in all of the regions (Table 6-17, column f). Thus, although the supply flexibility in New York was on average over 13 during the month of April (Table 6-17, column h), the average hourly reduction in LBMP due to EDRP curtailments was only 3.42% (Table 6-17, columns g). The average reductions in LBMP in the other zones were smaller still, 2.18% and 1.63% in Long Island and the Hudson region,

[17] The hourly results are detailed in Appendix B.

[18] As described in Neenan 2001, supply flexibility models are used to simulate what the price otherwise would have been. The supply flexibility is defined as the percentage change in price due to a one percent change in load.

respectively (Table 6-17, columns g), despite average supply flexibilities of about 6 and over 11, respectively (Tables 6-5 and 6-6).

One consequence of the decline in NYISO real-time prices due to the EDRP curtailments is that there would have been some transfers from generators to LSE's (perhaps ultimately to customers) relative to what would have happened without the load reductions. From a customer perspective, these can be called collateral benefits. From last year's evaluation (Neenan Associates, 2002), the collateral savings are defined as the real-time LBMP price change due to the EDRP participant load reductions multiplied by the difference between the loads served in real time and those served in the DAM. This is the energy that is settled in the real time market.

The transfers from generators to others are estimated to equal $358,874 (columns i in Table 6-17); 82% ($293,433) are associated with load curtailments in New York City. On an hourly basis, these collateral benefits averaged $24,453, $948, and $4,506, in New York City, on Long Island and in the Hudson River Region, respectively (Table 6-17, column i).

Program Payments

The distribution of EDRP program payments to participants, which totaled $216,583, is summarized in Table 6-20. Of the total, 58% were to participants in New York City, while another 17% went to participants in Long Island. About 21.5% went to customers in the Hudson River Region, and the remaining 3.4% was paid to participants in Western New York.

Effects on Average LBMP and its Variability

As discussed in the 2001 evaluation (Neenan Associates, 2002), the collateral benefits arising from load curtailments mentioned above are transfers to buyers from sellers. However, by affecting the number of extreme prices, EDRP load curtailments reduce both average LBMPs and the variability in LBMPs, thus adding importantly to the liquidity of the market. [19]

[19] There is no need in this report to discuss in detail the role of mean price and price variability in affecting the value of an investment or portfolio. The results are well known and the details can be found in standard texts such as Sharpe, Alexander and Bailey (1995, Chapters 6-8), and the associated references. In theory, one would ultimately expect the price of hedging contracts to reflect both average price reductions and reductions in price variability. It is easy to calculate the cost reduction due to lower average prices simply by accounting for the differences in average prices Note that these benefits reflect the available PRL load. If more loads participate, or participant price elasticity increases, then so do the benefits.

In considering these potential cost savings, it is important to emphasize that these estimates are probably lower bounds on the actual saving because they don't reflect any cost reduction due to the fact that prices are less variable as well. To estimate the effect of lower variability on the price of hedges, it would be

From the data in Table 6-21, one can see this is the case, although the effects are very small.[20] But, given the relatively small amount of load reduction in these April events, one could hardly expect otherwise. The average LBMP for the hours from 6:00 a.m. to 10:00 p.m. during weekdays in April were lower than they would have been without the EDRP load reduction by about $0.27/MW in the City, and by about $0.18MW and $0.11/MW on Long Island and in the Hudson Region, respectively (Table 6-21, column g). The standard deviations in prices in all three zones fell slightly as well (compare column b with column e in Table 6-21). If these slightly lower prices were reflected in the long-term cost of hedging load, the savings would be estimated at $260,780 (Table 6-21, column h).

<u>Effects of the Summer 2002 EDRP Events</u>

Effects on LBMP's

The effects of the summer 2002 EDRP events on the real-time electricity market in New York State are also provided in Table 6-19.[21] As stated above, there was, on average, about 663.2 MW of hourly load reduction during these events. During those hours, LBMP in real time averaged $93/MW, $99/MW, $161/MW, $54/MW, and $87/MW in the Capital Zone, New York City, Long Island, the Western Region, and the Hudson River region, respectively (Table 6-19, column e). Had this load reduction not been delivered by EDRP participants, our simulations estimated that the average LBMPs in real time would have been somewhat higher, $114/MW, $107/MW, $177/MW, $74/MW, and $92/MW in the Capital Zone, New York City, Long Island, the Western Region, and the Hudson River region, respectively (Table 6-19, column c). [22]

These implicit price reductions due to EDRP load curtailments are significant in some pricing zones due to a combination of the relative load reduction, and the relatively high price

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necessary to have information about how risk- averse purchasers of electricity are as a group (e.g. the extent to which they discount price risk in their hedging decisions). Alternatively, a financial model that reliably produced hedge prices using price means and variances would indicate the value of PRL loads. These results are beyond the scope of this study.

[20] These effects would be even more modest, or could actually be reversed in the event that SCR and EDRP load reductions are allowed to set LBMPs according to the current hybrid pricing rules in those pricing intervals when the load reduction is needed to maintain system reserves.

[21] The hourly results are detailed in Appendix D.

[22] As described in Neenan 2001, supply flexibility models are used to simulate what the price otherwise would have been. The supply flexibility is defined as the percentage change in price due to a one percent change in load.

flexibilities of supply. As a result of EDRP, load in these event hours was reduced in these hours by an average of 4.41%, 3.15%, and 1.53% in the Western Region, the Capital Zone, and Long Island, respectively. Load was reduced by less than 1% in both the Hudson Region and New York City (Table 6-19, column f). Thus, although the supply price flexibilities in the Capital Zone and the Western Region were lower on average during these hours than in New York (Table 6-19, column g), the average hourly reduction in LBMP due to EDRP curtailments were estimated to be 20.05% and 25.09% in the Capital Zone and the Western Region, respectively—between two and three times the 7.36% reduction in New York City (Table 6-19, columns g).

One consequence of the decline in NYISO real-time prices due to the EDRP curtailments is there would have been some transfers from generators to LSE's (perhaps ultimately to customers) relative to what would have happened without the load reductions, From a customer's perspective, these can be called collateral benefits. From last year's evaluation (Neenan Associates, 2002), the collateral savings are defined as the real-time LBMP price change due to the EDRP participant load reductions multiplied by difference between the loads served in real time and that served in the DAM. This is the energy that is settled in the real time market.

The transfers from generators to others are estimated to equal $577,979 (column i in Table 6-19); 53% ($305,761) are associated with load curtailments in New York City. Another 21% of the collateral benefits were in the Western Region, while shared in the Hudson Region and the Capital Long Island were 10% and 12 %, respectively. The Capital Zone received the remaining 5% (Table 6-19, column i).

Program Payments

The EDRP program payments for EDRP for the July 30 and August 14, 2002 summer events are given in Table 6-22. In total, payments equaled $3,318,381. The lion's share (61%) of the payments went to participants in the Western New York Region, while 13% went to participants in New York City, 11% went to Long Island participants, 10% went to the Capital zone, and the remaining 5% went to customers in the Hudson River Region. In contrast to last year, real-time LBMPs during the event hours never exceeded $500/MW in any pricing zone, so payments are distributed in exactly the same proportion as a zone's contribution to overall EDRP performance.

Effects on Average LBMP and its Variability

As stated above, these collateral benefits arising from load curtailments during the summer of 2002 are transfers to buyers from sellers. However, by affecting the number of extreme prices, one might also expect EDRP load to reduce both average LBMPs and the variability in LBMPs, thus adding importantly to the liquidity of the market.

Although these effects are relatively modest, they are similar on an hourly basis to those from last year's EDRP events (Neenan Associates, 2002), and if these programs persist in the long run and market participants come to expect that real-time LBMPs are likely to be lower and less variable, eventually this influence will be reflected in the prices at which customers can hedge load, either through physical bilateral supply contracts or financial hedges.

The average real-time LBMPs for the hours from 6:00 a.m. to 10:00 p.m. during weekdays in July and August were lower than they would have been without EDRP event load reduction by $0.20/MW in the Capital Zone and by $0.19/MW in Western New York (compare columns a and d in Table 6-23). The average price reductions are even smaller for the other zones, ranging from a reduction of $0.15/MW on Long Island and $0.08/MW in New York City to only $0.04/MW in the Hudson River Region (compare columns a and d in Table 6-23).

The standard deviations in LBMPs fall as well, by a high of $0.23/MW and $0.22/MW on Long Island and in the Capital Zone, respectively, to lows of $0.10/MW in both New York City and Western New York and $0.05/MW in the Hudson River Region (compare columns b and e in Table 6-23).

Based on these estimated price changes, the estimated long-term reduction in the cost of hedging load would total $330,307 (column h of Table 6-23). Of this total, about 56% would accrue to customers in Western New York and about 19% would accrue in New York City (calculated using column h of Table 6-23). Long Island would see 22% of these cost reductions, while the Capital Zone would see 12% and the Hudson River Region would receive just over 3%.

Effects of both the April and Summer EDRP Events on System Reliability

Load reduction during EDRP events will also affect the reliability of New York's entire electricity system. Indeed, some might argue that this purpose, and this purpose alone, justifies an emergency program and dictates how it should be deployed and participants should be paid. After all, the name *emergency program* implies that it would be utilized when market operations fail to provide the desired level of system security. Regardless of whether one holds this view, clearly the positive effects of EDRP on system reliability are an essential component of the program's benefits, and should be included in assessing the program's market effects.

Conceptually, the effects of EDRP load reduction on system security are more difficult to define than are the collateral benefits of or the potential effects on the cost of hedging load, and they are certainly more challenging to estimate empirically. To begin to understand this measure of benefits, it should be noted that a forecasted deficiency in operating reserves allows the NYISO to count EDRP load and Special Case Resources as operating reserve in order to assist in eliminating the shortfall (NYISO Emergency Operations Manual, 2001). Therefore during both the April and summer events of 2002, EDRP and Special Case Resources were deployed by the NYISO, perhaps along with more conventional actions, such as voltage reduction and external emergency energy purchases, in effect confirming that at least one role of these programs is to provide the system with emergency operating reserves.

We can assess the benefits of EDRP load in terms of its effect on system security by looking at how an increase in reserves would reduce the Loss of Load Probability (LOLP) and thereby reduce the costs associated with brownouts and blackouts that result in un-served energy.[23] Fig. 6-8 depicts graphically the relationship between reserves and LOLP. As seen in the graph, the LOLP associated with 100% of the required reserves (point a) is very small. However, as reserves fall below this required level (moving to the left of point a), the LOLP begins to rise, gradually at first, but as reserves continue to fall, LOLP rises much more rapidly, approaching 1 as reserves approach zero. Thus, as system operators forecast a reserve shortfall, the system state is represented by a point such as b. By calling EDRP, the load reduction works to restore reserve margins—thus moving the system from point b to the right toward point a. The extent to which reserve margins are completely restored is a function of the amount of load reduction or on site generation that is provided by EDRP participants. As is apparent in the data provided by the NYISO, this load reduction was sufficient to restore reserves during some hours or portions of hours during both the April and summer EDRP events. In other hours, they only partially restored reserve margins to 100% level (Fig. 6-9).

From this perspective, a measure of the benefits of EDRP can be defined by the change in the Value of Expected Un-served Energy (VEUE), as follows:

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[23] This interpretation is consistent with how Analysis Group (1991) valued load reduction in its early 1990s voluntary interruptible load program (VIPP).

(24) ΔVEUE = (Change in LOLP) * (Outage Cost/MW) * (Un-Served Load in MW)

The change in the VEUE, labeled ΔVEUE quantifies the impact on end-use customers of service interruptions. If the deployment of EDRP resources results in a positive change in VEUE, then that benefit qualifies as a contribution to system security.

To estimate ΔVEUE, one must know the relationship between the system reserve margin and the probability of an outage (Change in LOLP), as well as the cost incurred by customers from an outage (Outage Cost/MW) and the amount of un-served energy associated with the situation under evaluation (Un-Served Load MW). While these factors all have a sound basis in engineering and economic principles, none of these pieces of information is readily quantifiable from conventional market transactions data.[24] Put differently, in order to make a direct application of equation (24) for estimating the change in the expected value of un-served energy due to an EDRP load reduction, one would clearly need to estimate the relationship between reserve levels and the loss of load probability (e.g., the relationship in Fig. 6-8) for the entire New York State electricity market to effect the most appropriate comparison of EDRP payments relative to the value of EDRP load reduction in restoring system security. This could only be accomplished by the NYISO through a production system simulation analysis conducted from a total system-wide planning perspective. This type of analysis was clearly beyond the scope of this research.

Furthermore, only a handful of comprehensive studies to estimate outage costs have been completed in the past 15 to 20 years. Fortunately, one of the most comprehensive studies was conducted by Niagara Mohawk Power Corporation in the early 1990's. In that study, the average outage costs for industrial and commercial customers were estimated at $7,400/MWh (Analysis Group, 1990). However, in a subsequent study evaluating Niagara Mohawk's Voluntary Interruptible Pricing Program (Analysis Group, 1991), Analysis Group used a range of outage costs from $500/MWh to $15,000/MWh to calibrate their demand models.[25] This broad range in values was used because of the subjectivity associated with the initial outage cost estimates. The

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[24] A discussion of how outage cost and LOLP are conceptualized and measured, see Chao, H.P., R. Wilson (1987).

[25] RTP programs operated by many vertically integrated utilities derived the LOLP/Reserves curve using production simulation models and then established an hourly outage costs by tracing the hour's reserve against the curve and multiplying the corresponding LOLP by an established value for outage cost, usually a value of one to two dollars per kWh.

British PoolCo model, which required a value for lost load, adopted a value of approximately \$2,500/MWh.[26]

To circumvent these problems, we begin the analysis of the system-wide security benefits of EDRP load reduction by solving equation (24) for the un-served load (e.g. the load that would need to be at risk in order ΔVEUE to exactly to EDRP program payments to customers). This essentially is the load at risk that would be needed for the program to "break even" if the only benefits considered are those from changes in system security. Solving equation (24) for the change in LOLP, we have:

(25) (Un-Served Load in MW) = [ΔVEUE] / [(ΔLOLP) * (Outage Cost/MW)]

We can now evaluate this equation for alternative estimates of outage costs and a range in values for the ΔLOLP.[27] Recalling that the EDRP payments to customers are \$216,583 and \$3,318,381 for the April and summer events, respectively, these calculations (for four alternative outage costs and six reductions in LOLP) are presented in Tables 6-24 and 6.25.

Perhaps the most striking feature of the results of this analysis for the April events is that under the most conservative assumptions about both outage costs (e.g. \$1,000/MW) and the reduction in LOLP (e.g. 0.05) only 3.6% of the load would have had to be at risk in order for the benefits in terms of VEUE to exceed the program costs (column a of Table 6-24). If one assumes that either the reduction in LOLP due to EDRP load is larger or if outage costs exceed \$1,000/MW the load at risk needed for the benefits to outweigh the costs falls rapidly. At the other extreme (where outage costs are assumed to be \$5,000/MW and the change in LOLP is assumed to be 0.50), only 0.1% of load would have to be at risk for the program benefits to equal program costs.

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[26] Patrick and Wolak (2000) estimate that in the England and Wales power markets, the outage costs, or willingness to pay to avoid supply interruptions during 1990/91 was £2,000/MWh (approximately \$2.50/kWh), and that increased steadily in subsequent years with the growth of the Index of Retail Prices. In 2001, Britain converted from central pool pricing to bilateral markets and as a result the value of lost load is no longer used directly to set market prices.

[27] To account for the fact that EDRP load could be equal to, fall short of, or exceed the reserve shortfall during any five-minute interval of an event hour, we multiplied the outage cost by the proportion EDRP contributed to total reserve shortfall during all intervals of the event hours. In this way, we are effectively assuming that outage costs are zero in those portions of the hour in which EDRP load was not needed to restore system reserves. These adjustments are based on interpolations from the graphic display of EDRP load and system-wide provided by NYISO.

As seen from a slightly different perspective, in Appendix Tables 6-1D and 6-2D, the system security benefits due to the April EDRP load reduction could be small if only a small fraction of load had been at risk or could exceed program costs by several orders of magnitude if all or nearly all load had been as risk of an outage. For the April events, system security benefits would fall short of program costs only under the most conservative assumptions: no greater than 5% of the load was at risk; outage costs were no greater than $1000/MW; and the load reduction led to a decrease in LOLP of no more than 0.05.

The situation is not so clear-cut for the summer events. In contrast to the April results, under the most conservative assumptions about both outage costs (e.g. $1,000/MW) and the reduction in LOLP (e.g. 0.05) 48.9% of the load would have had to be at risk in order for the benefits in terms of VEUE to exceed the program costs (column a of Table 6-25). It remains true that the load at risk needed for the benefits to outweigh the costs falls rapidly if one assumes that either the reduction in LOLP due to EDRP load is larger or if outage costs exceed $1,000/MW. However, at outage costs of $1,000/MW, the load at risk needed to equate VEUE benefits to program costs would remain above 20% until the reduction in LOLP due to EDRP load relief exceeds 0.10 (column a of Table 6-25). Alternatively, of a reduction in LOLP of only 0.05, the percentage of the load at risk needed to equate VEUE benefits to program costs would fall to 9.8% if outage costs were assumed to be $5,000/MW.

Again, as seen from a slightly different perspective in Appendix Tables 6-3D and 6-4D, the system security benefits due to the April EDRP load reduction could be small if only if a small fraction of load had been at risk or could exceed program costs by several orders of magnitude if all or nearly all load had been as risk of an outage. For the summer events, system security benefits would fall short of program costs if only 5% of the load had been at risk except under the assumption that outage costs are at least $5,000/MW or the load reduction led to a reduction in the LOLP of at least 0.20. If a somewhat larger share of the load were at risk, it is likely that the benefits in terms of VEUE would exceed program costs. Clearly, in this case, as well as in April, if nearly all load had been at risk, benefits would always exceed program costs, and often many times over.

Effects of the Summer 2002 DADRP Bidding Activity

Our analysis of the effects of bidding in the day-ahead market is limited to the activity during the summer months of 2002. It is in these months that the effects of load reduction on prices in the DAM are of most interest, and because the primary focus of the EDRP evaluation was on the summer events, the NYISO was able to make price and fixed bid load data for the DAM in the summer months available without much additional effort. It is these data that were needed to estimate the supply curves for the DAM.

According to records supplied by the NYISO, there are currently 24 customers participating in the DADRP. Most, but not all are located in the Capital district and in Western New York, and it is only in these regions that any DADRP were accepted during the months of June, July, and August. There were 158 hours during which bids were accepted in the Capital Zone, and 59 hours for which bids were accepted in western New York. The effects on the DAM from these bids accepted in DADRP are summarized in Tables 6-26, 6-27, and 6-28.

The Effects on LBMP in the DAM

The aggregate and hourly effects of DADRP bidding on prices in the DAM are given in Table 6-26.[28] For the three summer months, there were a total of 1,468 MW of bids accepted in the DAM; 29% of this total was from customers in western New York, while the remaining 71% was in the Capital region (Table 6-26, column d). The average hourly load reduction in both zones was 7 MW (Table 6-26, column d). In these hours, this load reduction represented 0.4% of the fixed bid load in the DAM for the Capital region, and 0.1% of the fixed bid load in western New York (Table 6-26, column g). The changes in hourly LBMPs in the DAM due to this load reduction averaged 1.1% in the Capital region and 0.4% in western New York (Table 6-26, column h).

These modest price reductions in the DAM led to an estimated revenue transfer of $394,574 in collateral benefits from generators to wholesalers, assuming that all fixed bid load was settled in the DAM (Table 6-26, column k). However, it is estimated that only about 60% of the fixed bid load is settled in the DAM (40% through bilateral contracts); thus, actual collateral transfers would be only $236,745 (Table 6-26, column l).

Program Payments

Program payments for DADRP are summarized in Table 6-27. Of the $110,216 in total payments, 75% went to customers in the Capital zone, while the remaining 25% was paid to

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[28] The hourly details are given in Tables in Appendix E.

customers in western New York (Table 6-27). Average hourly payments were somewhat higher in the Capital zone as well ($521 vs. $473).

Effects on Average LBMP and its Variability

Because of the very modest decreases in LBMPs in the DAM due to the activity in DADRP, it is not surprising that the effects of this program on average summer prices in the DAM and price variability were extremely modest as well (Table 6-28). Average prices in the Capital zone would have fallen between $0.06/MW and $0.21/MW in these months, while the reduction would have been no more than $0.04 during any of the months in western New York (Table 6-28, column g). The estimated reduction in the long-term cost of hedging would have been $202,349—73% accruing in the Capital zone (Table 6-28, column h).

Table 6-1 Summary Data for Hourly LBMP and Load by Zonal Aggregates for Which Separate Supply Functions are Estimated (April 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	6,374	$56	7,377	$88
Mean	5,507	$32	6,459	$28
Minimum	4,548	$19	5,373	$5
Standard Deviation	421	$7	520	$10
	Capital (Zone F)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	1,265	$88	1,572	$121
Mean	1,030	$43	1,275	$38
Minimum	794	$29	1,029	$19
Standard Deviation	98	$11	124	$13
	Hudson River (Zones G, H & I)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	1,608	$78	3,030	$281
Mean	1,342	$44	2,044	$47
Minimum	1,153	$31	1,139	$20
Standard Deviation	90	$9	321	$39
	New York City & Long island (Zones J & K)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	8,867	$197	12,064	$321
Mean	6,846	$49	8,547	$52
Minimum	5,585	$34	6,809	$21
Standard Deviation	727	$23	1,205	$45

* Afternoon hours correspond to 1:00 p.m. through 7:00 p.m. Prices in zonal aggregates are load weighted averages.

Table 6-2 Summary Data for Hourly LBMP and Load by Zonal Aggregates for Which Separate Supply Functions are Estimated (Summer, Afternoon Hours, 2002)*

	Capital (Zone F)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	901	$25	1,114	$12
Maximum	1,928	$214	2,108	$1,008
Mean	1,413	$58	1,594	$49
Standard Deviation	246	$31	242	$66
	New York City (Zone J)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum		$29		$21
Maximum		$199		$1,123
Mean		$76		$71
Standard Deviation		$32		$74
	Long Island (Zone K)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum		$37		$21
Maximum		$601		$1,109
Mean		$87		$81
Standard Deviation		$72		$77
	West of Total East (Zones A, B, C, D, & E)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	4,701	$17	5,345	$12
Maximum	8,882	$158	9,506	$996
Mean	6,643	$47	7,460	$44
Standard Deviation	925	$25	927	$64
	Hudson River (Zones G, H, & I)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	1,193	$24	1,884	$13
Maximum	2,700	$197	4,031	$1,106
Mean	1,843	$59	2,858	$55
Standard Deviation	387	$30	555	$73
	New York City & Long Island (Zones J & K)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	6,331	$32	7,373	$24
Maximum	11,384	$375	15,443	$1,118
Mean	9,107	$81	11,525	$74
Standard Deviation	1,170	$45	2,091	$74
	New York State (Zones A - K)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	13,229	$28	16,212	$22
Maximum	24,359	$228	30,664	$1,072
Mean	19,006	$65	23,438	$61
Standard Deviation	2,619	$33	3,707	$69

*For June, July and August, 1:00 pm through 7:00 pm. Prices in zonal aggregates are load weighted averages.

** It is NYISO policy not to report load separately for New York and Long Island.

Table 6-3 Estimated Real Time Electricity Supply Function, Hudson Super Zone, April 2002

	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			-1.2552	-1.84		
Real-Time Load			0.6238	7.03	5.1082	7.11
Trans. Const. Wt. by Load					0.2128	3.55
Proportion of Gen. Offered	-2.8526	-5.64	-2.8526	-5.64	-2.8526	-5.64
Arch (0)	0.0107	6.65				
Arch (1)	1.0989	4.55				
Arch (2)						
R^2 =	0.6976					
	Knots (% of Maximum Load)					
Price Flexibilities**			10.0		68.5	
Minimum	0.00		0.62		5.10	
Maximum	0.00		0.62		8.57	
Mean	0.00		0.62		5.69	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20) 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.

Table 6-4 Estimated Real Time Electricity Supply Function, New York City, April 2002

	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			-29.9625	-3.08		
Real-Time Load	2.6237	12.06	3.8310	3.50		
Real-Time Load Squared					0.4845	6.11
Proportion of Gen. Offered					-69.1351	-7.94
Lag.Trans. Const. Wt. by Load	0.0001	0.13	0.0001	0.13	0.0001	0.13
Arch (0)	0.0054	3.55				
Arch (1)	0.8616	3.56				
Arch (2)	0.3443	2.24				
R^2 =	0.8701					
	Knots (% of Maximum Load)					
Price Flexibilities**		45.0		60.0		
Minimum	2.62		3.83		10.04	
Maximum	2.62		3.83		15.95	
Mean	2.62		3.83		13.06	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated
with intercept shifterif 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 (18-20)
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.

Table 6-5 Estimated Real Time Electricity Supply Function, Long Island, April 2002

	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			-59.0869	-13.90		
Real-Time Load	1.3431	7.45	7.9871	14.85		
Real-Time Load Squared					0.7358	13.16
Trans. Const. Wt. by Load			0.0001	3.01		
Arch (0)	0.0035	2.10				
Arch (1)	0.8035	4.04				
Arch (2)	0.5458	3.99				
R^2 =	0.5508					

	Knots (% of Maximum Load)		
Price Flexibilities**		35.0	59.0
Minimum	1.34	7.99	11.76
Maximum	1.34	7.99	11.96
Mean	1.34	7.99	11.88

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20)
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.

Table 6-6 Estimated Real Time Electricity Supply Function, Western NY Super Zone, Summer 2002

	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			-22.2721	12.37		
Real-Time Load	1.0473	1.53	2.8851	14.37	-953.2731	-12.23
Adjacent Zonal Load					114.4911	12.37
Arch (0)	0.0451	19.85				
Arch (1)	0.6698	8.24				
Arch (2)						
R^2 =	0.6084					
	Knots (% of Maximum Load)					
Price Flexibilities**		30.0		75.0		
Minimum	1.05		2.89		-11.10	
Maximum	1.05		2.89		15.39	
Mean	1.05		2.89		6.67	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20) 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.

Table 6-7 Estimated Real Time Electricity Supply Function, Capital Zone Super Zone, Summer 2002

	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			-11.3357	-3.03		
Real-Time Load	1.8765	11.79	2.0197	4.05	-637.8404	-2.56
Adjacent Zonal Load					82.0124	2.59
Wgt. Transmission Const.	0.0051	4.10	0.0051	4.10	0.0051	4.10
Arch (0)	0.0544	16.07				
Arch (1)	0.6686	6.74				
Arch (2)						
R^2 =	0.5543					
	Knots (% of Maximum Load)					
Price Flexibilities**		60.0		80.0		
Minimum	1.88		2.10		-4.30	
Maximum	1.88		2.10		10.94	
Mean	1.88		2.10		5.97	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20) 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.

Table 6-8 Estimated Real Time Electricity Supply Function, Hudson Super Zone, Summer 2002

	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			-13.0014	-3.75		
Real-Time Load	1.9250	14.52	2.0974	4.92	-1122.0000	-6.58
Adjacent Zonal Load					115.1531	6.62
Arch (0)	0.0387	11.12				
Arch (1)	0.7482	7.81				
Arch (2)						
R^2 =	0.6555					
	Knots (% of Maximum Load)					
Price Flexibilities**		57.5		75.0		
Minimum	1.93		2.10		-8.47	
Maximum	1.93		2.10		10.66	
Mean	1.93		2.10		4.69	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20)
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.

Table 6-9 Estimated Real Time Electricity Supply Function, New York City, Summer 2002

	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			-62.5755	-11.20		
Real-Time Load	1.9621	19.10	7.3021	11.99		
Real-Time Load Squared					0.6930	3.98
Proportion of Off. Gen. Bids	-1.4157	-4.19	-1.4157	-4.19	-1.4157	-4.19
Arch (0)	0.0325	10.23				
Arch (1)	0.6491	7.17				
Arch (2)						
R^2 =	0.6656					

Price Flexibilities**	Knots (% of Maximum Load) 77.5	90.0	
Minimum	1.96	7.30	12.76
Maximum	1.96	7.30	12.79
Mean	1.96	7.30	12.82

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20) 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.

Table 6-10 Estimated Real Time Electricity Supply Function, Long Island, Summer 2002

	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			-44.3926	-20.96		
Real-Time Load	0.4610	2.05	4.283	13.76		
2-Lag Wgt. Trans. Const.					-0.6104	-5.40
Real-Time Load Squared					0.8798	5.70
Adjacent Zonal Load	1.4393	5.37	1.4393	5.37	1.4393	5.37
Arch (0)	0.0285	6.87				
Arch (1)	0.7571	4.65				
Arch (2)						
$R^2 =$	0.7406					
	Knots (% of Maximum Load)					
Price Flexibilities**		60.0		87.5		
Minimum	0.46		4.28		-7.39	
Maximum	0.46		4.28		8.12	
Mean	0.46		4.28		5.16	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20) 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.

Table 6-11 Estimated Day Ahead Electricity Supply Function, Western NY Super Zone, Summer 2002

	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			-18.1659	-7.29		
Fixed Bid Load	2.3107	29.17	2.4806	8.82	-78.9708	-2.20
Proportion of Gen. Offered					-46.5309	-10.88
Adjacent Zonal Load					9.9067	2.26
Arch (0)	0.0052	0.00				
Arch (1)	0.8078	5.13				
Arch (2)						
R^2 =	0.8384					
	Knots (% of Maximum Load)					
Price Flexibilities**		45.0		60.0		
Minimum	2.31		2.48		1.46	
Maximum	2.31		2.48		7.10	
Mean	2.31		2.48		4.21	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20) 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.

Table 6-12 Estimated Day Ahead Electricity Supply Function, Capital Zone, Summer 2002

	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			-18.6887	-13.77		
Fixed Bid Load	1.2455	18.78	3.0852	16.77	1.6304	2.43
Proportion of Gen. Offered					-60.6415	-7.92
Arch (0)	0.0084	7.04				
Arch (1)	0.8786	5.07				
Arch (2)						
R^2 =	0.7007					
	Knots (% of Maximum Load)					
Price Flexibilities**		55.0		75.0		
Minimum	1.25		3.09		1.95	
Maximum	1.25		3.09		7.79	
Mean	1.25		3.09		4.96	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20) 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.

Table 6-13 Estimated Day Ahead Electricity Supply Function, Hudson Super Zone, Summer 2002

	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			7.1917	-24.13		
Fixed Bid Load	1.0240	13.83	1.4715	37.88	-205.7204	-3.47
Proportion of Gen. Offered					-118.8051	-9.78
Adjacent Zonal Load					21.3135	3.43
Arch (0)	0.0045	6.23				
Arch (1)	1.2500	8.19				
Arch (2)						
R^2 =	0.6612					
	Knots (% of Maximum Load)					
Price Flexibilities**		30.0		80.0		
Minimum	1.02		1.47		-3.66	
Maximum	1.02		1.47		9.11	
Mean	1.02		1.47		3.91	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20) 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.

Table 6-14 Estimated Day Ahead Electricity Supply Function, New York City, Summer 2002

	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			-15.9041	-5.99		
Fixed Bid Load	1.6828	1.33	2.3107	7.49	-61.4152	-15.50
Proportion of Gen. Offered					-14.2942	-4.94
Adjacent Zonal Load						
Arch (0)	0.0059	16.44				
Arch (1)	0.9305	6.41				
Arch (2)						
R^2 =	0.6163					
		Knots (% of Maximum Load)				
Price Flexibilities**		15.0		40.0		
Minimum	1.68		2.31		-0.01	
Maximum	1.68		2.31		6.49	
Mean	1.68		2.31		3.55	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20) 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.

Table 6-15 Estimated Day Ahead Electricity Supply Function, Long Island, Summer 2002

	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			-18.5048	-17.82		
Fixed Bid Load	0.9444	7.94	2.7750	22.09	1.3877	2.56
Proportion of Gen. Offered					-100.0372	-15.17
Arch (0)	0.0164	7.86				
Arch (1)	0.8355	6.56				
Arch (2)						
R^2 =	0.7473					
	Knots (% of Maximum Load)					
Price Flexibilities**		30.0		80.0		
Minimum	0.94		2.77		1.46	
Maximum	0.94		2.77		11.68	
Mean	0.94		2.77		6.52	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), 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 (18-20) 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.

Table 6-16. NYISO 2002 Emergency Program Participants

Year	EDRP Only	EDRP & SCR	SCR Only	Total
2001	217	116	94	427
2002	1534	177	74	1785

Table 6-17. Average Zonal and Total Effects of EDRP Events on NYISO Electricity Markets, April 2002

		Simulated Without EDRP		With EDRP Load Reduction					
Zone	DAM FBL	Real-Time Load (MW)	Real-Time LBMP ($/MW)	EDRP (MW)	LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
New York City									
Hourly Avg.	5,451		223	22.2	215	-0.26%	-3.42%	13.2	24,453
Total	65,416			266.4					293,433
% of G. Total	54%			61%					82%
Long Island									
Hourly Avg.	3,169		215	6.1	209	-0.19%	-2.18%	11.8	948
Total	38,026			73.7					11,370
% of G. Total	31%			17%					3%
Hudson Region									
Hourly Avg.	1,551	2,922	191	7.8	187	-0.26%	-1.63%	6.2	4,506
Total	18,611	35,067		93.3					54,071
% of G. Total	15%	20%		22%					15%
Average				**36.1**					
Grand Total	**122,053**	**177,092**		**433.4**					**358,874**

Table 6-18. NYISO 2002 Emergency Program Participant Statistics by Superzone

	Participant Count				Subscribed MWs				
	EDRP	SCR	Joint		EDRP	SCR	Joint EDRP & SCR		
Superzone	Only	Only	EDRP & SCR	Total	Only	Only	SCR	EDRP	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Western NY	411	23	85	519	541	54	422	385	1,402
Capital	47	3	9	59	53	2	68	51	174
Hudson River	47	2	19	68	49	0	13	19	81
NYC	107	35	32	174	116	27	82	61	286
Long Island	922	11	32	965	191	7	5	13	216
Total	1534	74	177	1785	950	91	591	529	2,160

Note: These superzones are aggregations of the NYISO pricing zones, as follows:
Western NY = pricing zones A, B, C, D, and E.
Capital = pricing zone F.
Hudson River = pricing zones G, H, and I.
NYC = pricing zone J.
Long Island = pricing zone I.
Note: na = not applicable; N/A = not available.

Table 6-19. Average Zonal and Total Effects of EDRP Events on NYISO Electricity Markets, Summer 2002

		Simulated w/o EDRP		Simulated w/ EDRP					
	DAM	Real-Time Load	Real-Time	EDRP Perf	LBMP	% Change in		Arc Price	Transfer from
Zone	FBL	(MW)	LBMP ($/MW)	(MW)	($/MW)	Load	LBMP	Flexibility	Gens to LSEs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Capital									
Hourly Avg.	1,840	2,052	114	64.6	93	-3.15%	-20.05%	6.2	2,926
Total	18,401	20,518		645.6					29,264
% of G. Total	8%	7%		10%					5%
New York City									
Hourly Avg.	6,321		107	86.2	99	-0.84%	-7.36%	8.8	30,576
Total	63,205			861.7					305,761
% of G. Total	27%			13%					53%
Long Island									
Hourly Avg.	4,488		177	75.4	161	-1.53%	-8.92%	5.9	6,760
Total	44,881			754.4					67,604
% of G. Total	19%			11%					12%
Western Region									
Hourly Avg.	8,306	9,237	74	406.6	54	-4.41%	-25.09%	5.8	11,973
Total	83,057	92,368		4,065.9					119,728
% of G. Total	35%	30%		61%					21%
Hudson Region									
Hourly Avg.	2,445	3,806	92	30.5	87	-0.80%	-4.39%	5.4	5,562
Total	24,452	38,060		304.6					55,622
% of G. Total	10%	13%		5%					10%
Grand Total	**233,996**	**303,125**		**6,632**					**577,979**

Table 6-20 EDRP Program Payments on New York Electricity Markets, April 2002

	EDRP Program Payments		
Zone or Region	Hourly Avg.	Total	% of G. Total
Western NY	$1,243	$7,461	3.4%
Hudson River	$6,658	$46,605	21.5%
New York City	$17,949	$125,646	58.0%
Long Island	$5,267	$36,871	17.0%
Total		$216,583	

Table 6-21 Effect of EDRP on the Average Level and Variability of Real-Time LBMPs (April, 2002)*

Zone or Region	RT-LBMP ($/MW) (w/o EDRP)			RT-LBMP ($/MW) (w/ SCR & EDRP)			Reduction in Mean LBMPs ($/MW)	Estimated Long-Term *Reduction* in Cost of Hedging Load#
	Mean	Std. Dev.	Coef. of Var.**	Mean	Std. Dev.	Coef. of Var.**		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
New York City	$52.80	52.00	0.98	$52.53	50.92	0.97	$0.27	$181,066
Long Island	$57.43	47.68	0.83	$57.25	46.87	0.82	$0.18	$58,046
Hudson River Region	$49.01	42.18	0.86	$48.90	41.72	0.85	$0.11	$21,667
Total								**$260,780**

* Hourly averages are for April week days, hours 6:00 a.m. through 10:00 p.m.

** The coefficient of variation is a measure of relative variability. It is the standard deviation divided by the mean.

This value is the difference in mean RT-LBMP times the average amount of load scheduled in the DAM that is purchased under bilateral contracts. There are no data for the portion of fixed bid load settled under bilaterals by zone, but it is thought to be about 40% system wide.

Table 6-22. EDRP Program Payments on New York Electricity Markets, Summer 2002

Zone	Program Payments ($)	Zone	Program Payments ($)
Capital		**Western New York**	
Hourly Avg.	32,279	Hourly Avg.	203,450
Total	322,787	Total	2,034,502
% of G. Total	10%	% of G. Total	61%
New York		**Hudson Region**	
Hourly Avg.	43,161	Hourly Avg.	15,228
Total	431,606	Total	152,281
% of G. Total	13%	% of G. Total	5%
Long Island			
Hourly Avg.	37,720		
Total	377,205	**Grand Total**	**3,318,381**
% of G. Total	11%		

Table 6-23 Effect of EDRP on the Average Level and Variability of Real-Time LBMPs (Summer, 2002)*

Zone or Region	RT-LBMP ($/MW) (w/o EDRP)			RT-LBMP ($/MW) (w/ EDRP)			Overall Reduction in Mean LBMPs ($/MW)	Estimated Long-Term *Reduction* in Cost of Hedging Load#
	Mean	Standard Deviation	Coefficient of Variation**	Mean	Standard Deviation	Coefficient of Variation**		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Capital	$45.48	54.68	1.20	$45.28	54.47	1.20	$0.20	$39,925
New York City	$66.71	60.36	0.90	$66.64	60.31	0.91	$0.08	$62,272
Long Island	$75.42	65.75	0.87	$75.26	65.52	0.87	$0.15	$72,138
Western NY	$41.32	52.65	1.27	$41.13	52.55	1.28	$0.19	$184,426
Hudson River Region	$49.54	59.58	1.20	$49.50	59.53	1.20	$0.04	$11,471
Total								**$330,307**

* Hourly averages are for week days, hours 6:00 a.m. through 10:00 p.m.

** The coefficient of variation is a measure of relative variability. It is the standard deviation divided by the mean.

This value is the difference in mean RT-LBMP times the average amount of load scheduled in the DAM that is purchased under bilaterial contracts. There are no data for the portion of fixed bid load settled under bilaterial by zone, but it is thought to be about 40% system wide. There are 352 hours in April week days from 6:00 a.m. through 10:00 p.m.

Table 6-24. April 2002 % Load At Risk to Equate VEUE and Program Payments

Reduction in LOLP	Outage Cost			
	$1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	(a)	(b)	(c)	(d)
0.05	3.6%	2.4%	1.4%	0.7%
0.10	1.8%	1.2%	0.7%	0.4%
0.15	1.2%	0.8%	0.5%	0.2%
0.20	0.9%	0.6%	0.4%	0.2%
0.25	0.7%	0.5%	0.3%	0.1%
0.50	0.4%	0.2%	0.1%	0.1%

Note: Calculated using equation (25). For any combination of reduction in LOLP and outage cost, program benefits outweigh costs for % loads at risk higher than those reported in each cell of the table.

Table 6-25. Summer 2002 % Load At Risk to Equate VEUE and Program Payments

Reduction in LOLP	Outage Cost			
	$1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	(a)	(b)	(c)	(d)
0.05	48.9%	32.6%	19.6%	9.8%
0.10	24.4%	16.3%	9.8%	4.9%
0.15	16.3%	10.9%	6.5%	3.3%
0.20	12.2%	8.1%	4.9%	2.4%
0.25	9.8%	6.5%	3.9%	2.0%
0.50	4.9%	3.3%	2.0%	1.0%

Note: Calculated using equation (25). For any combination of reduction in LOLP and outage cost, program benefits outweigh costs for % loads at risk higher than those reported in each cell of the table.

Table 6-26. Average Zonal and Total Effects of DADRP Scheduled Bids on New York Electricity Markets, Summer, 2002

Zone	Load in in RTM	With DADRP Day-Ahead Load (MW)	With DADRP Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Without DADRP Day-Ahead Load (MW)	Without DADRP Day-Ahead LBMP ($/MW)	% Change in Due to DADRP Load	% Change in Due to DADRP LBMP	Arc Price Flexibility*	Program Payments ($)#	Collateral Benefits ($)** Total	Collateral Benefits ($)** Net
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Capital												
Hourly Avg.	1,733	1,553	70.2	7	1,559	71.2	0.4%	1.1%	3.0	521	1,696	1,018
Total	273,842	245,322		1,046	246,368					82,317	267,963	160,778
% of G. Total	35%	35%		71%	35%					75%	68%	68%
Western New York												
Hourly Avg.	8,464	7,591	74	7	7,598	74	0.1%	0.4%	4.7	473	2,146	1,288
Total	499,382	447,847		422	448,269					27,899	126,611	75,967
% of G. Total	65%	65%		29%	65%					25%	32%	32%
Grand Total	773,224	693,169		1,468	694,637					110,216	394,574	236,745

*As with most mathematical relations of this kind, the supply price flexibilities in the tables above are only vaild for small changes in load. Here the supply models are calibrated to the observed prices, and in mathematical terms, the load response was large. The average "arc" flexibilities only approximate the averages from the tables.

The effects in this table are based on bids accepted in the DAM. At this writing, we had no data on actual performance. Also, the program payments are based on LBMPs in the DAM. There was no way we could account for the start-up or outage cost portion of customers' bids.

**The collateral benefits are equal to the difference in actual and simulated LBMP multiplied by load served. The net collateral benefits are estimated to be 0.6 of the total collateral benefits. This assumes that an average of 40% of load is purchased through bilaterals. Thus, this net amount is the savings to customers buying load in the DAM.

Table 6-27. DADRP Program Payments from New York Electricity Markets, Summer, 2002

Zone	Program Payments ($)#	Zone	Program Payments ($)#
Capital		**Western New York**	
Hourly Avg.	521	Hourly Avg.	473
Total	82,317	Total	27,899
% of G. Total	75%	% of G. Total	25%

Grand Total	**110,216**

The effects in this table are based on bids accepted in the DAM. At this writing, we had no data on actual performance. Also, the program payments are based on LBMPs in the DAM. There was no way we could account for the start-up or outage cost portion of customers' bids, although the preliminary analysis of the data by the NYISO suggests that our cost estimates would increase by about 30%

Fig. 6-1: Estimated Price Flexibility Zones

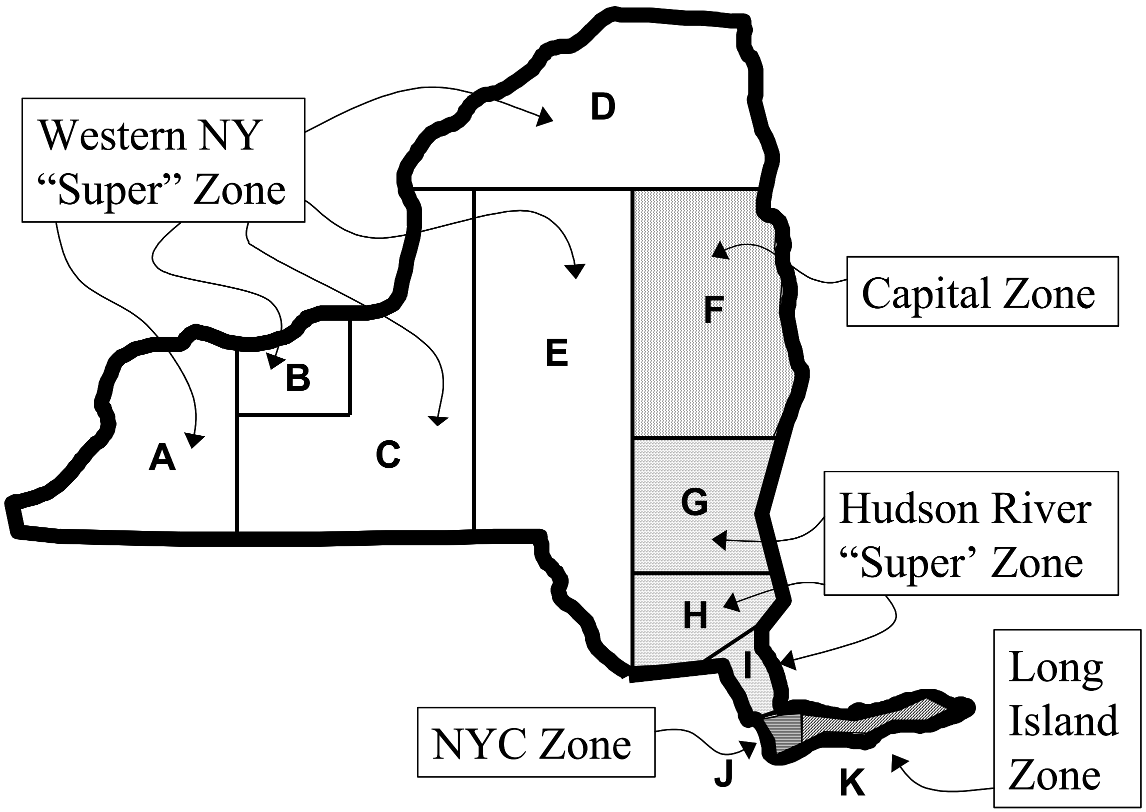


Fig. 6-2. Scatter Diagram of LBMP vs. Load

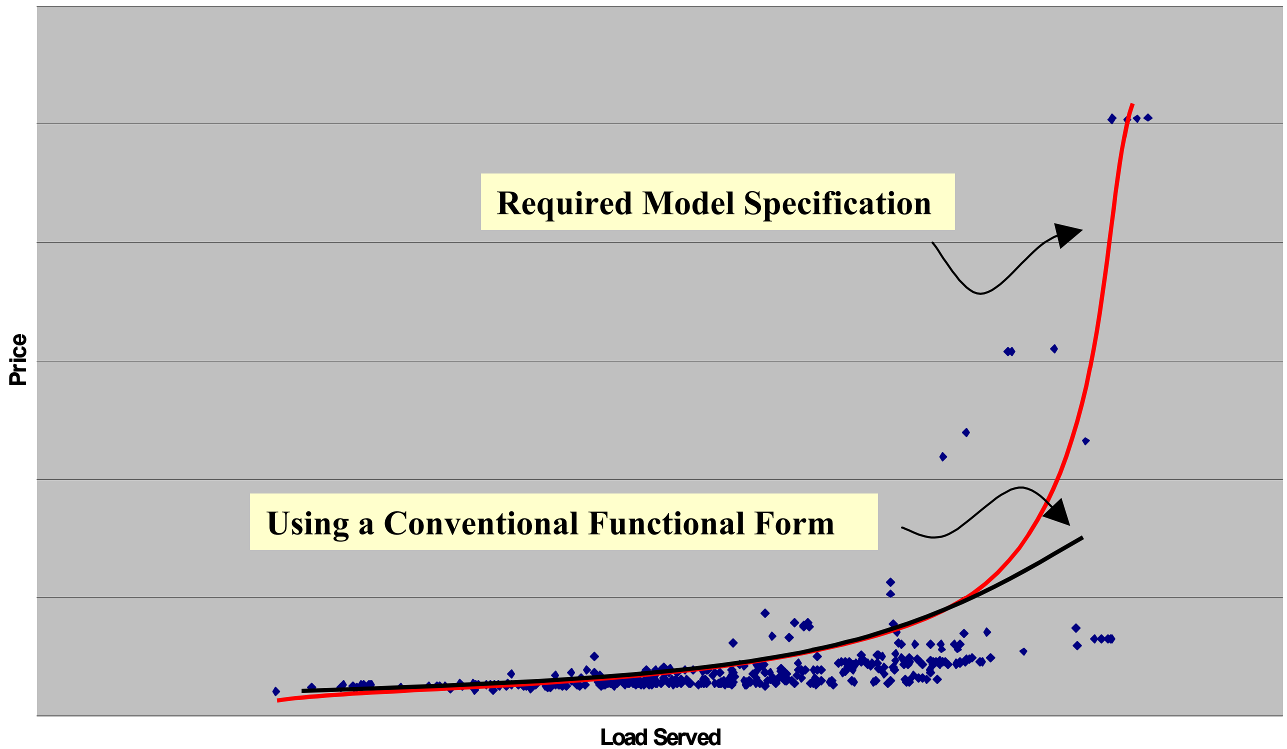


Fig. 6-3. Different Supply Regimes

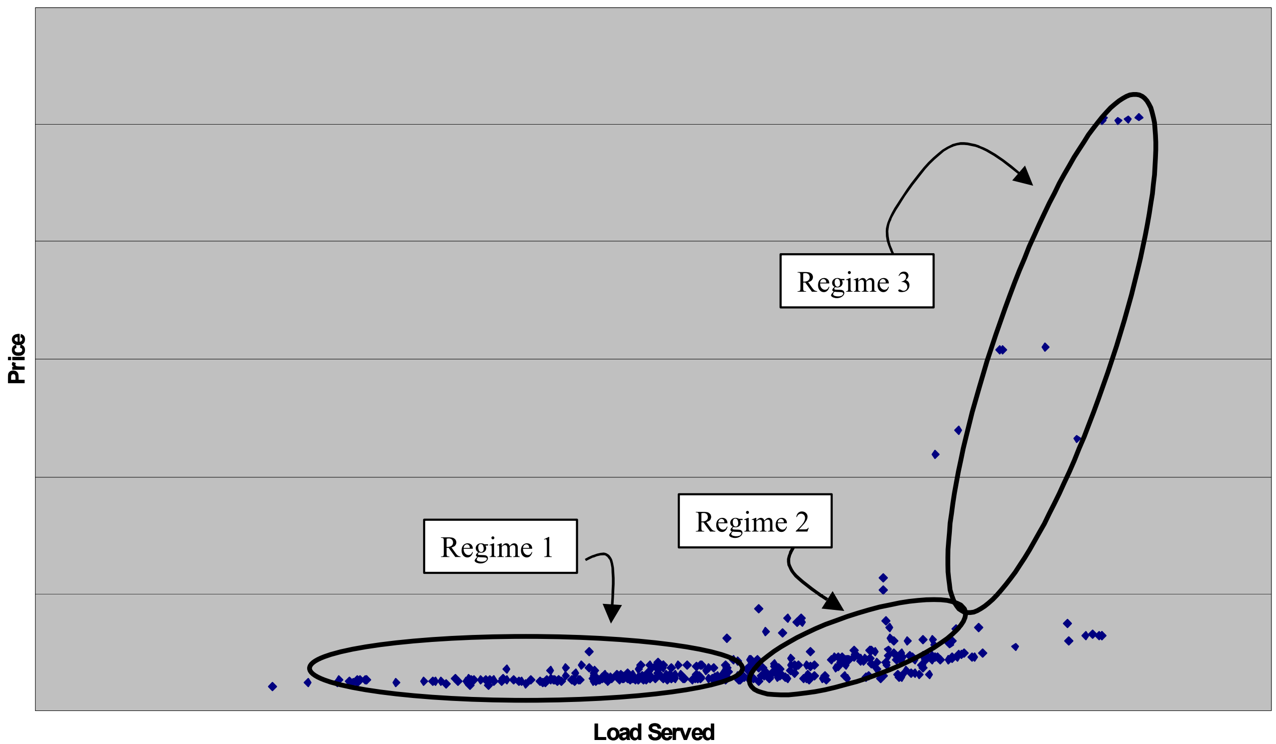


Fig. 6-4. "Spline" Model Specification

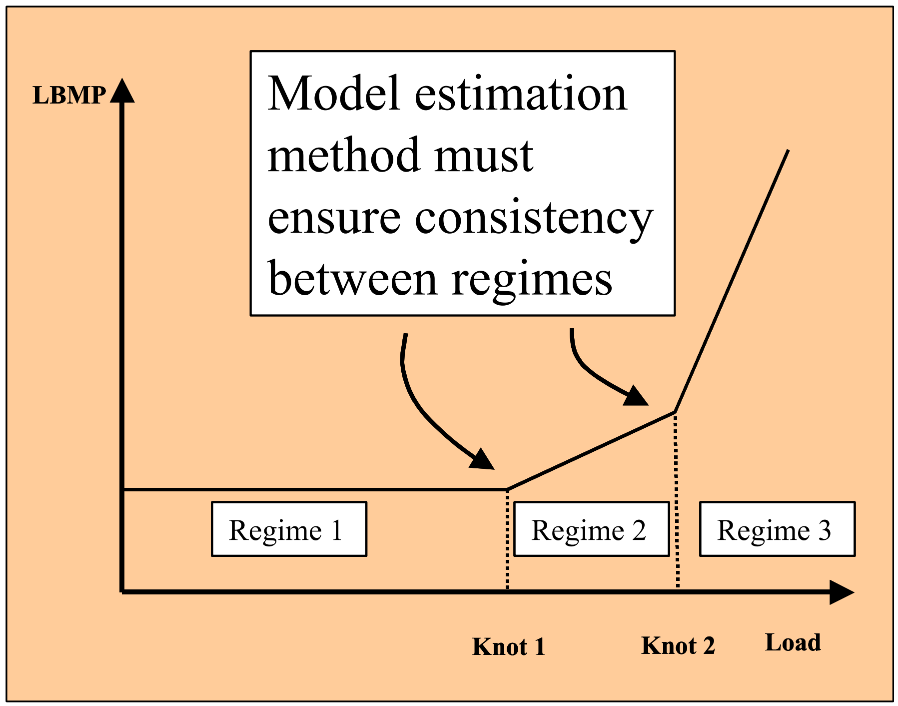


Fig. 6-5. Modeling Apparent Outliers

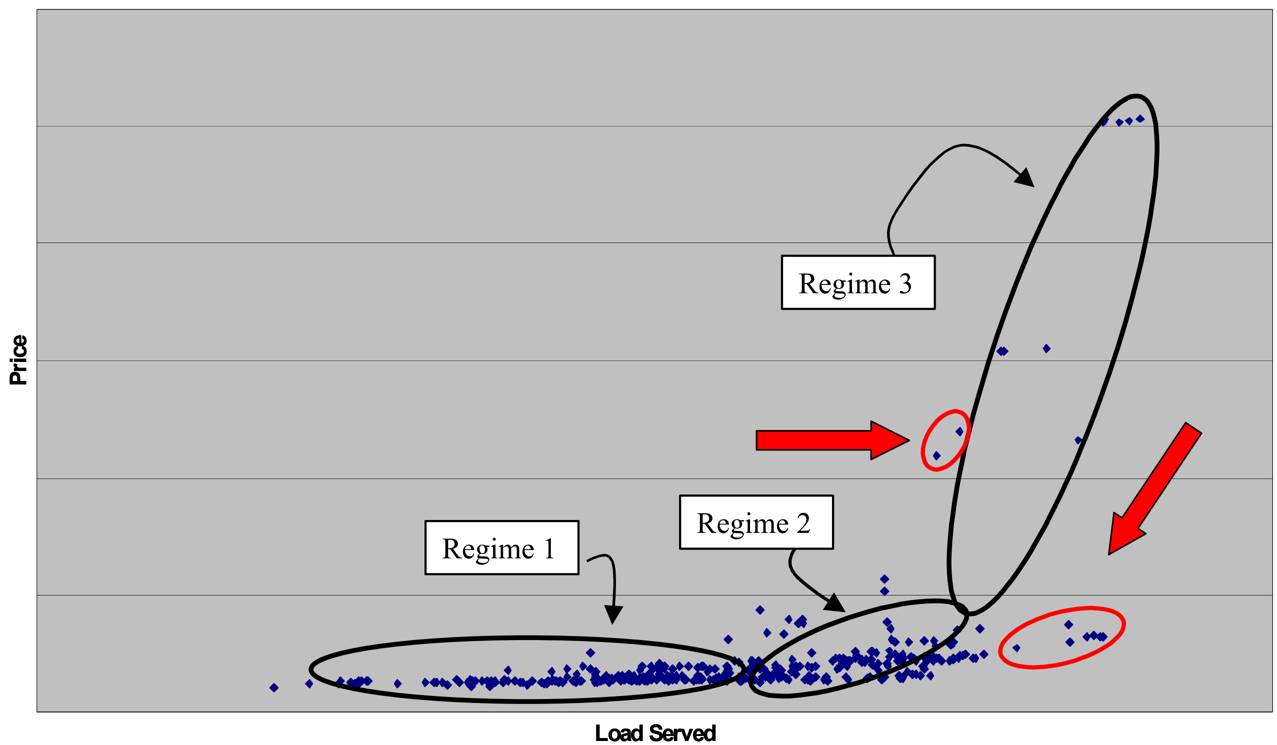
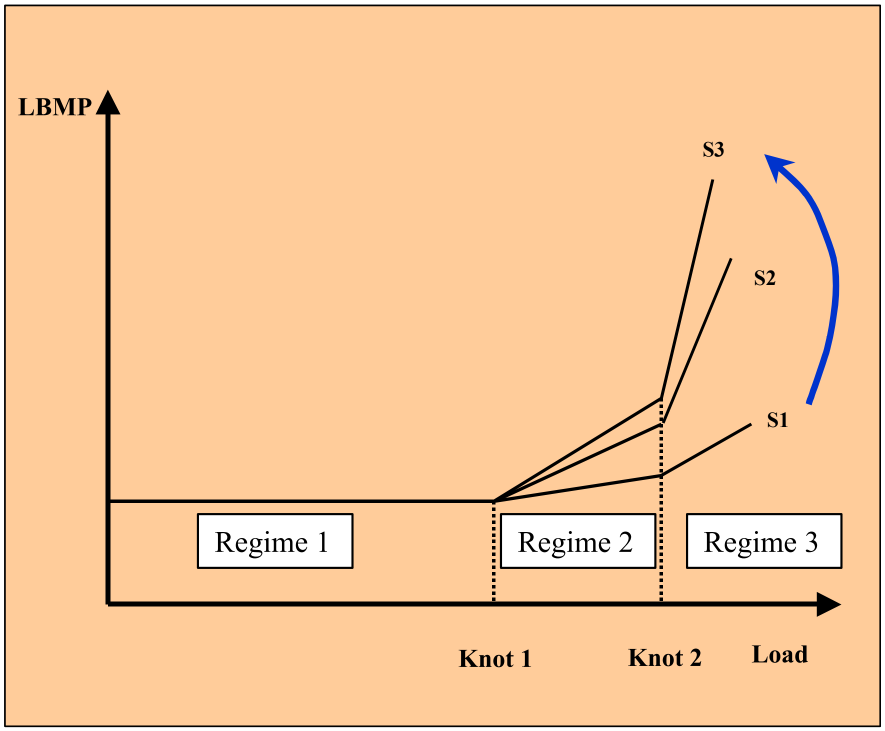


Fig. 6-6. Final Model Specification



Supply Shift due to:

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

Fig. 6-7. Simulation of Effects of PRL Reduction

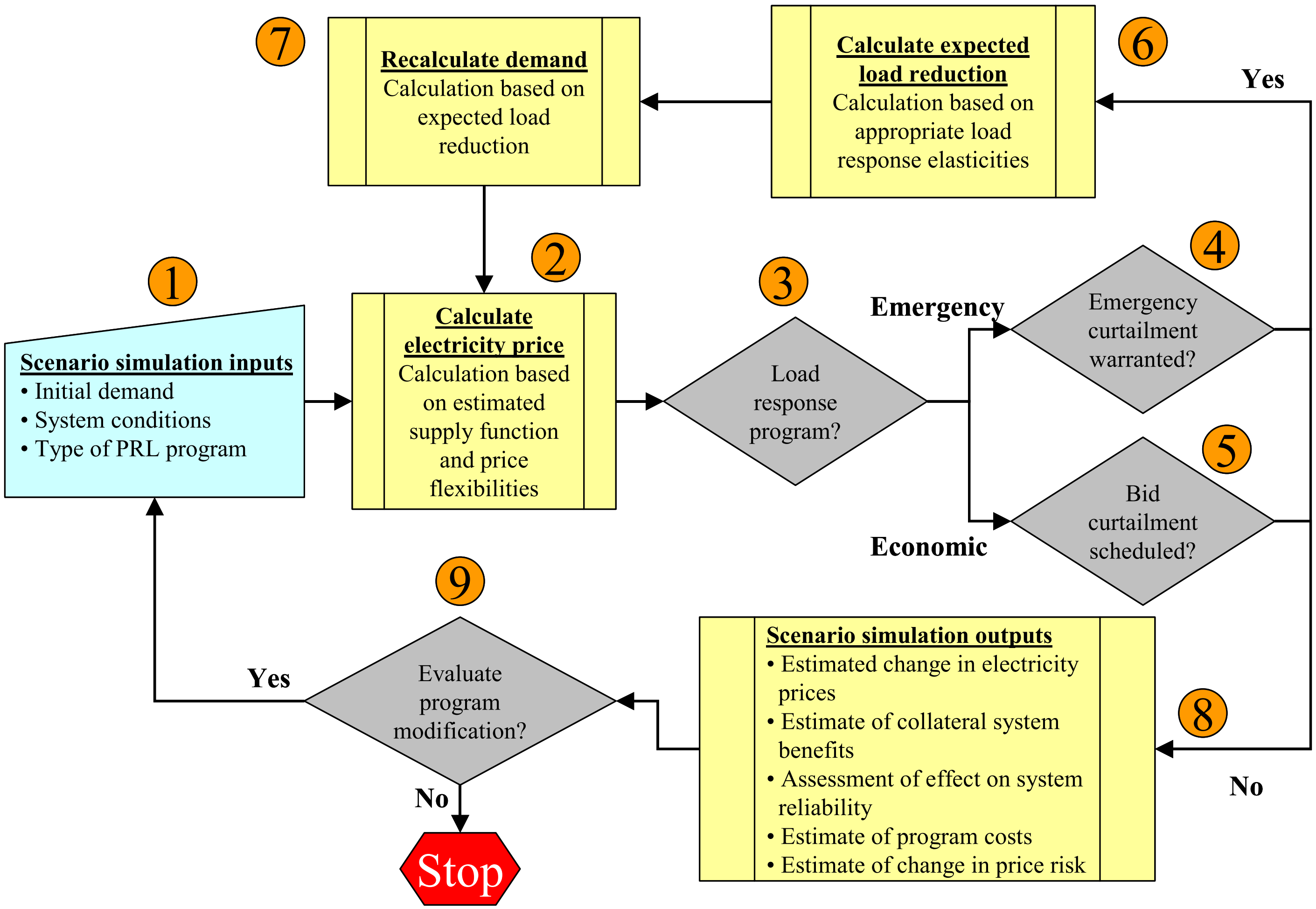


Fig. 6-8. EDRP Value of Expected Un-served Energy

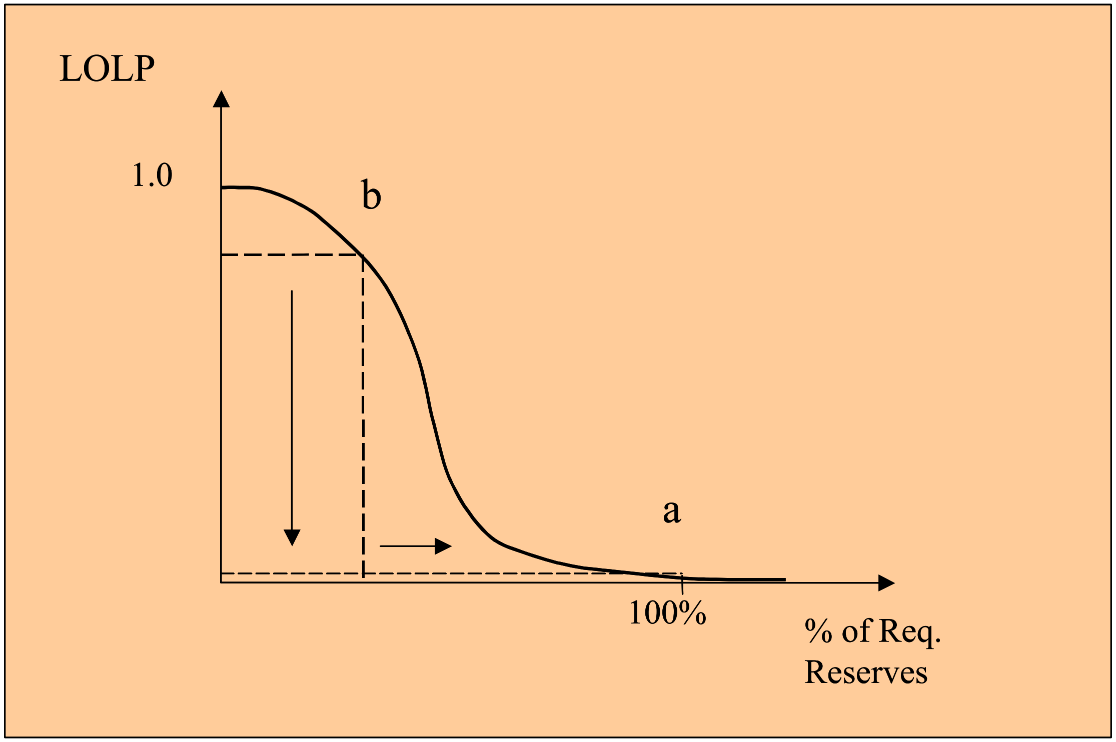


Fig. 6-9. EDRP Event Needed Reserves vs. EDRP Load Response

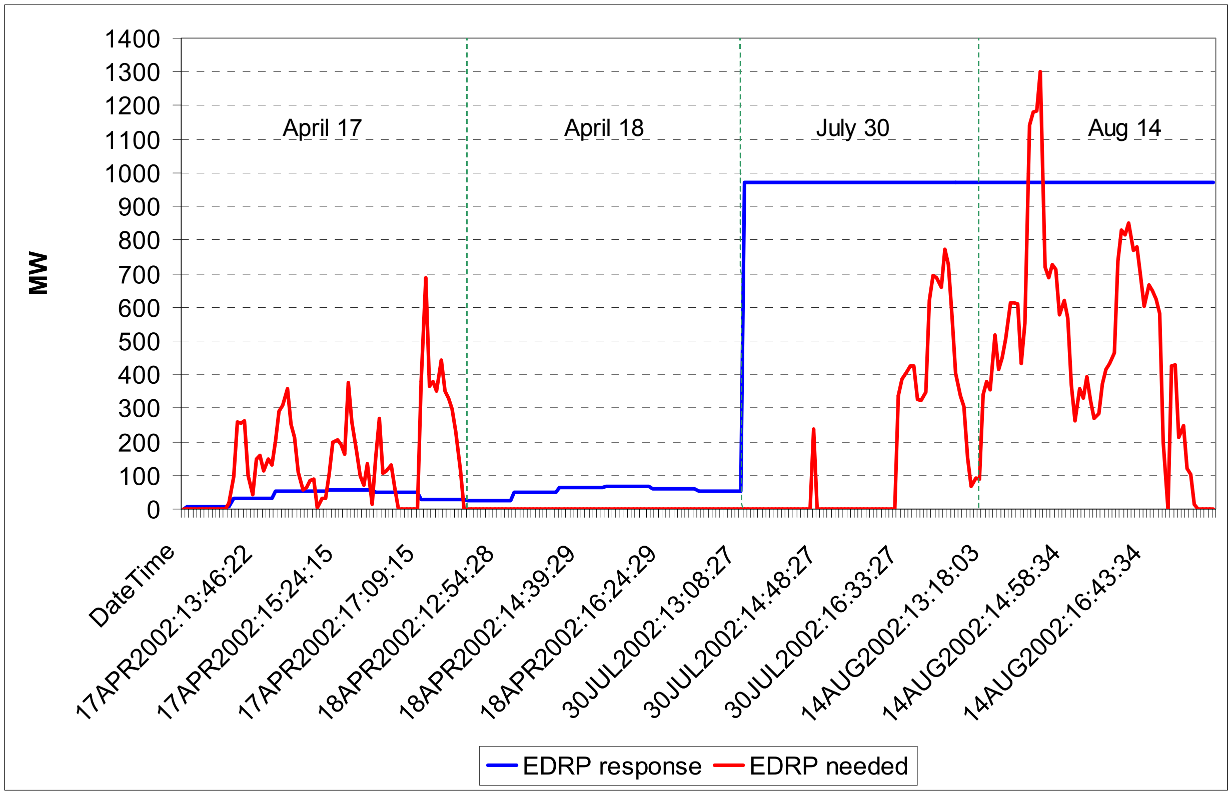


Fig. 6-1A. Hudson River Real-Time Market Estimated Supply Curve for April 2002

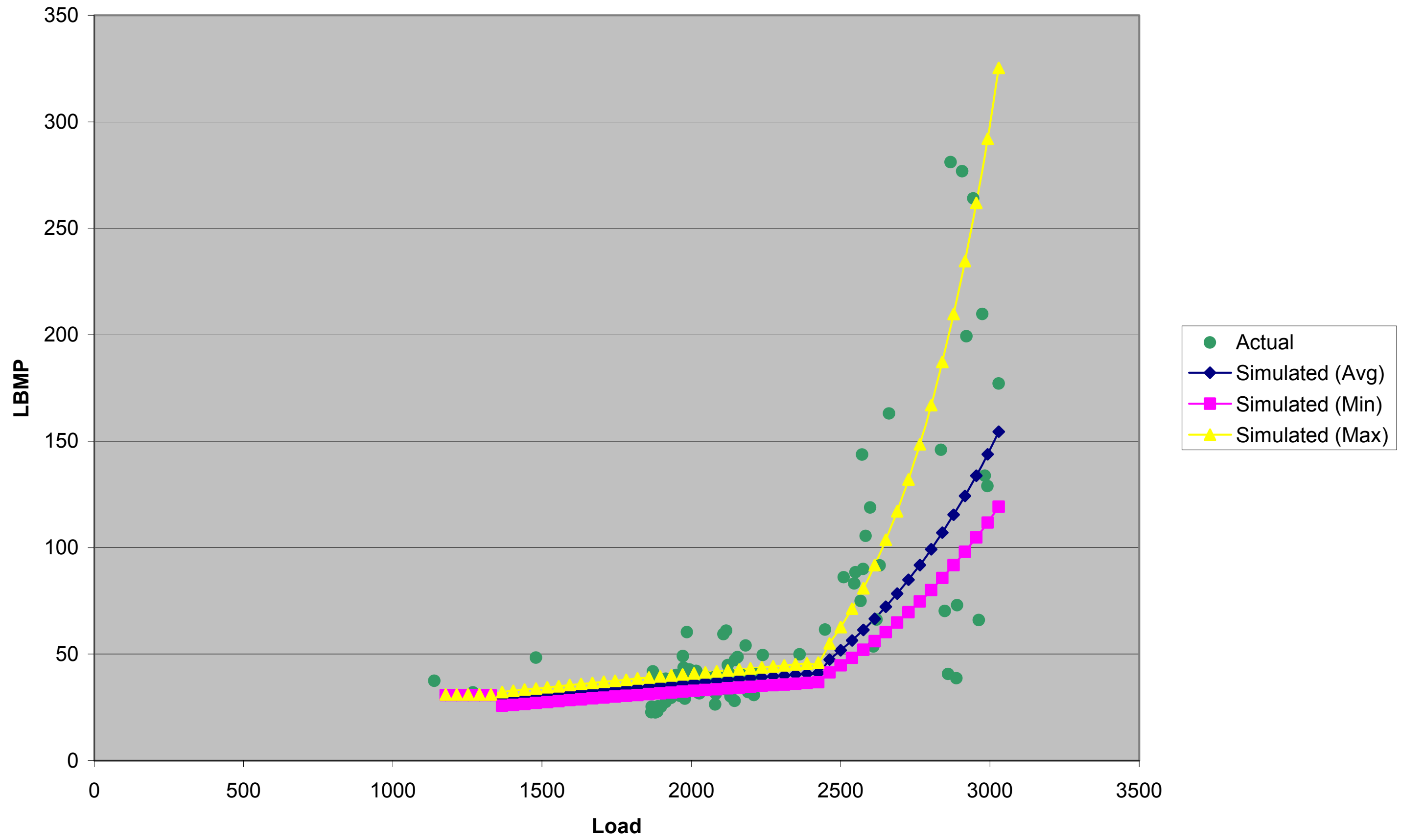


Fig. 6-2A. New York City Real-Time Market Estimated Supply Curve for April 2002

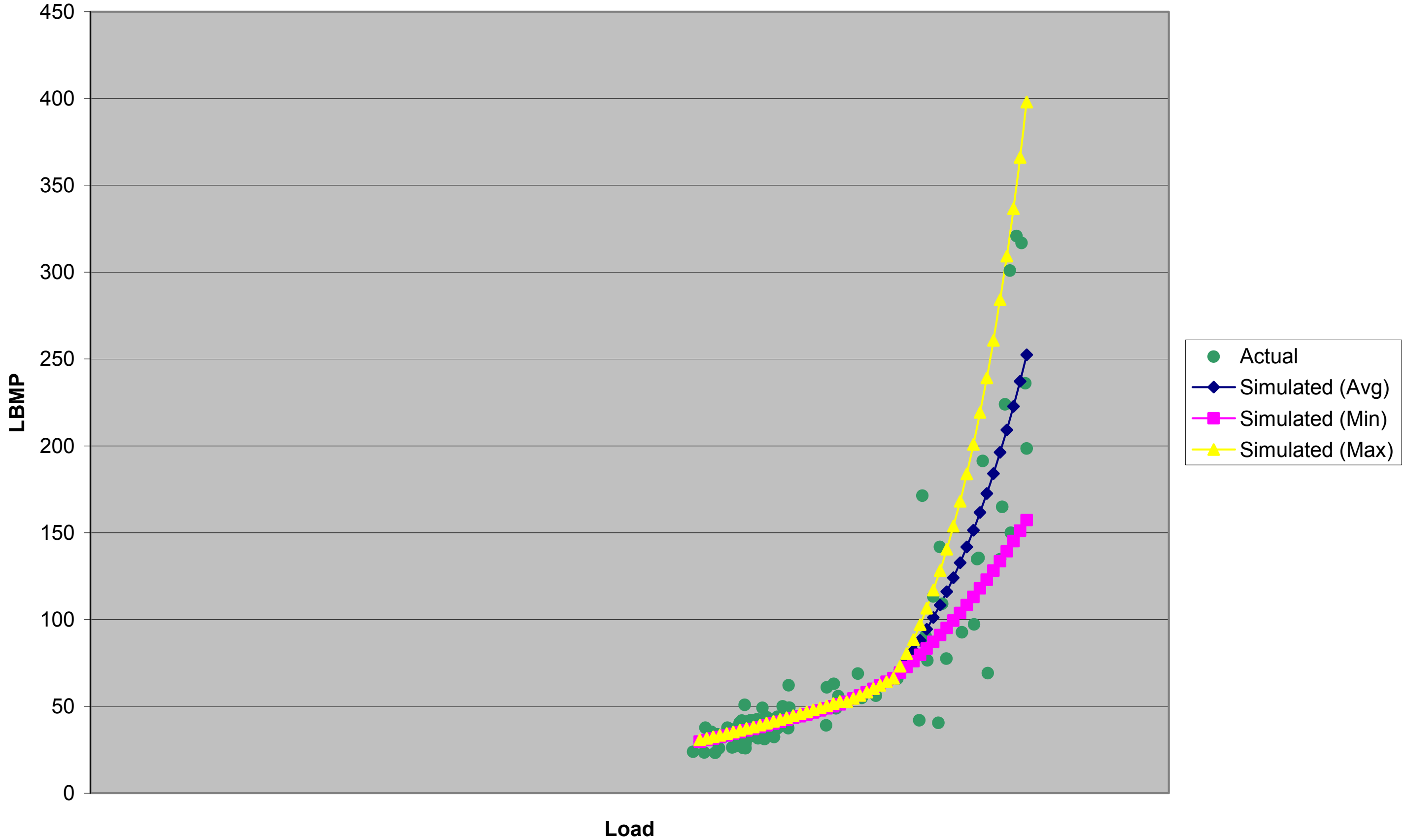


Fig. 6-3A. Long Island Real-Time Market Estimated Supply Curve for April 2002

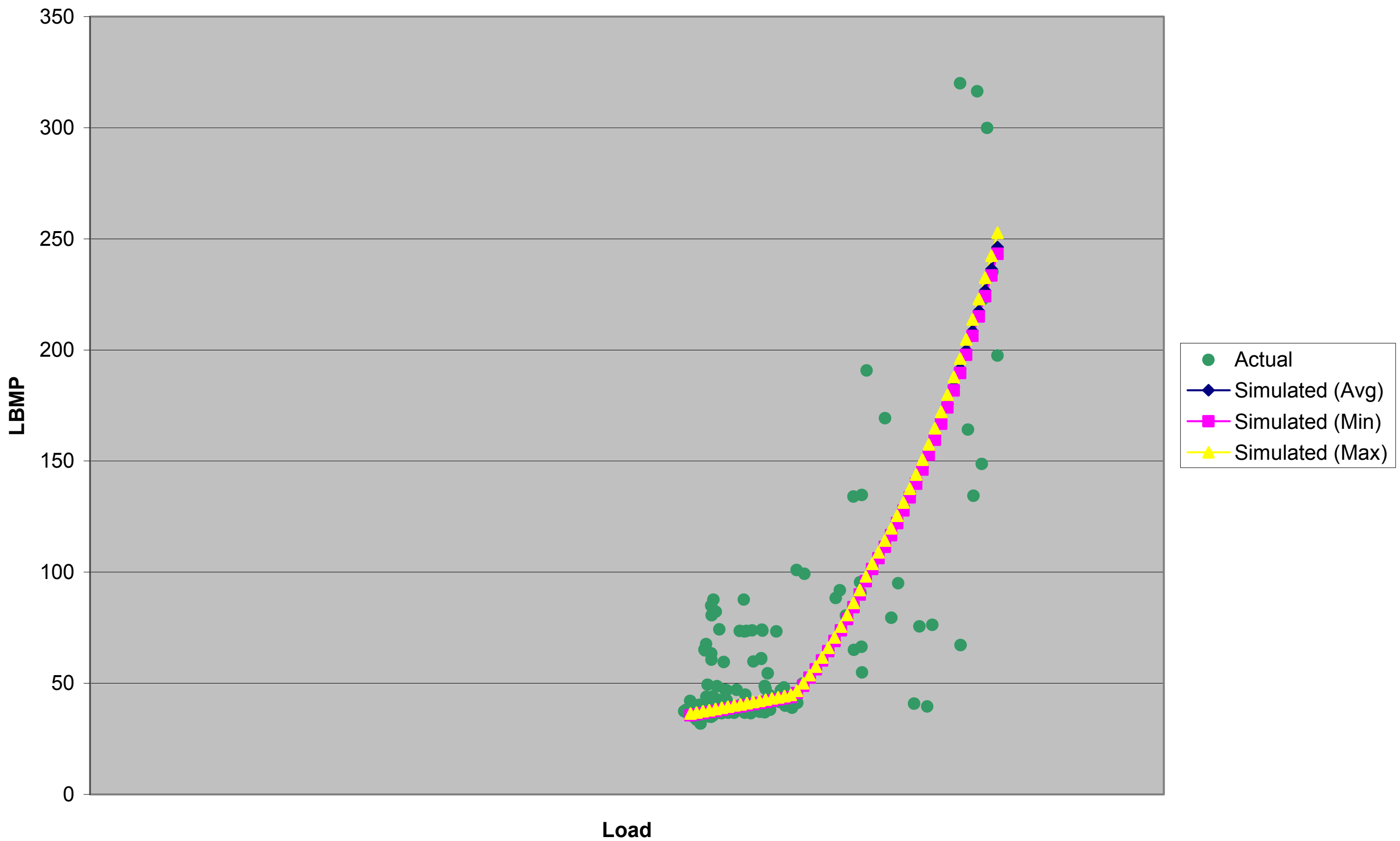


Fig. 6-4A. Western NY Real-Time Market Estimated Supply Curves for Summer 2002

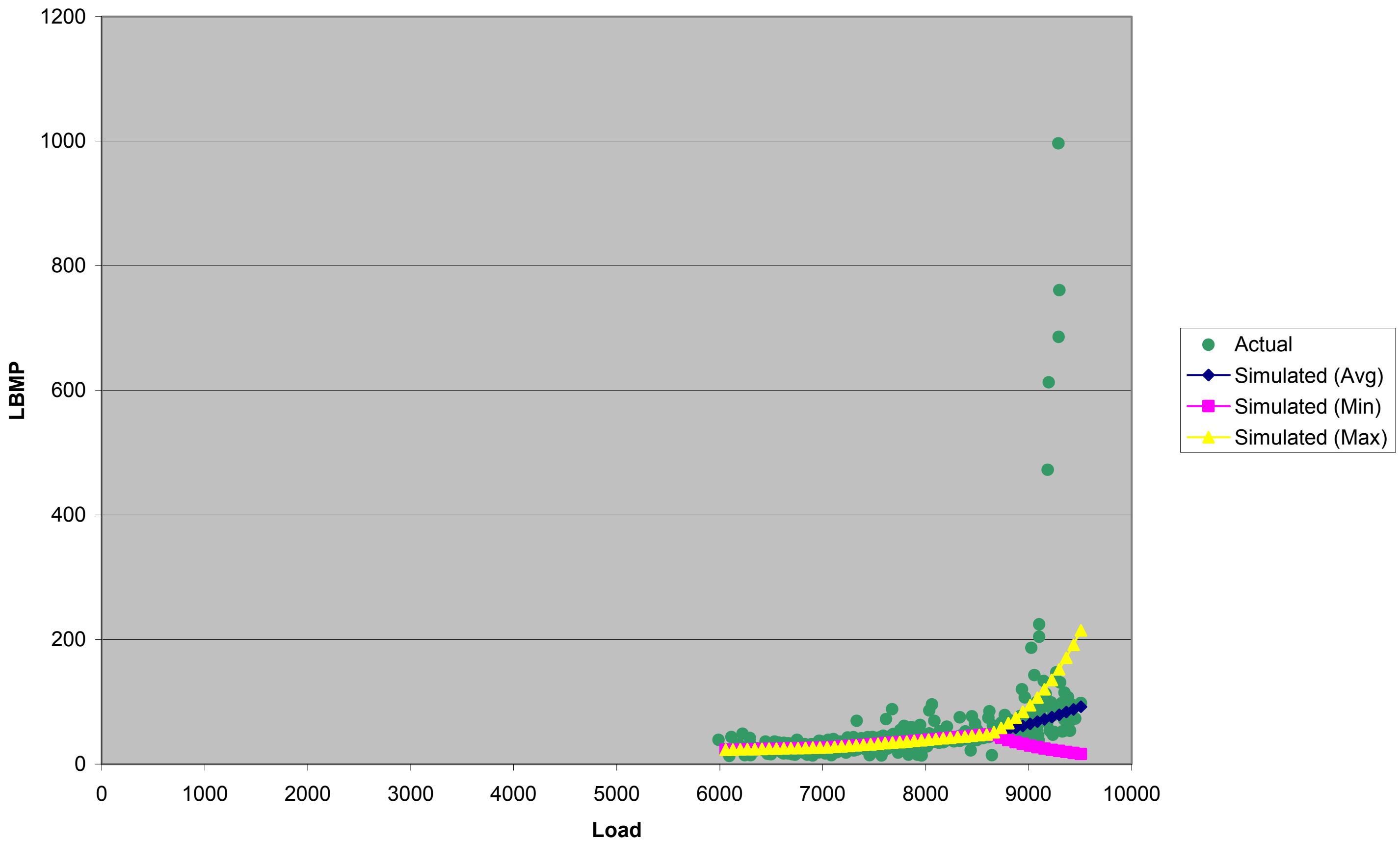


Fig. 6-5A. Capital Real-Time Market Estimated Supply Curve for Summer 2002

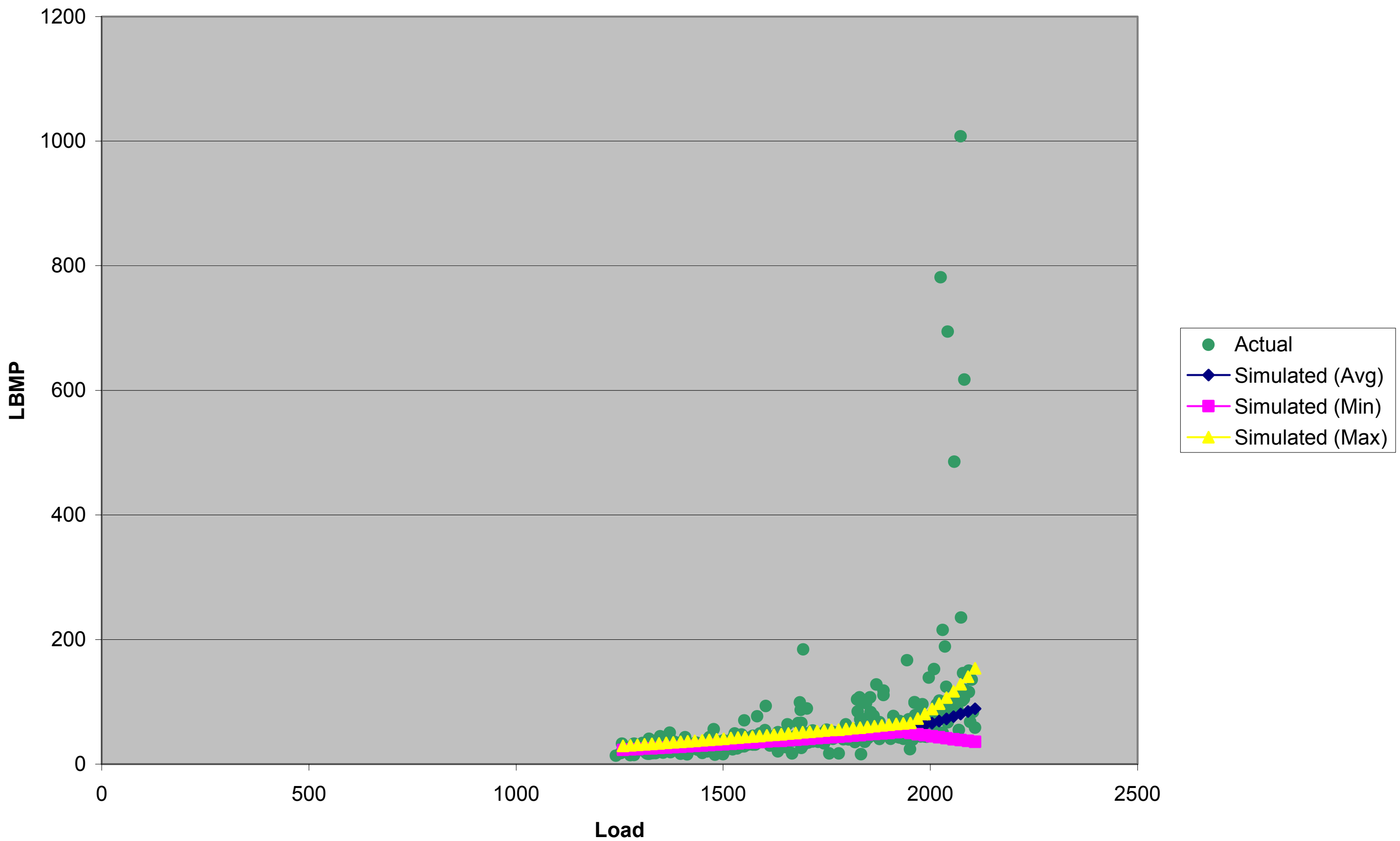


Fig. 6-6A. Hudson River Real-Time Market Estimated Supply Curve for Summer 2002

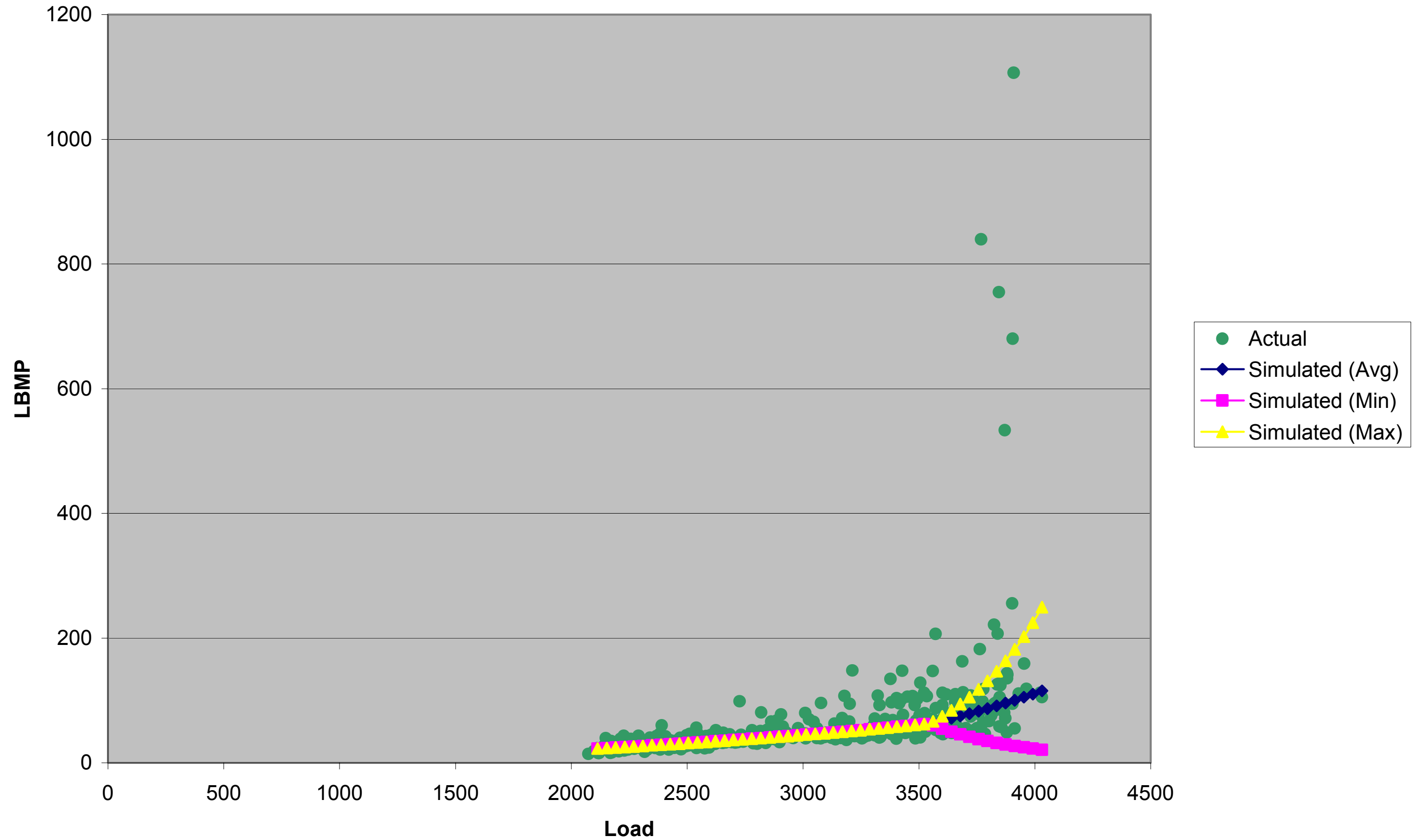


Fig. 6-7A. New York City Real-Time Market Estimated Supply Curve for Summer 2002

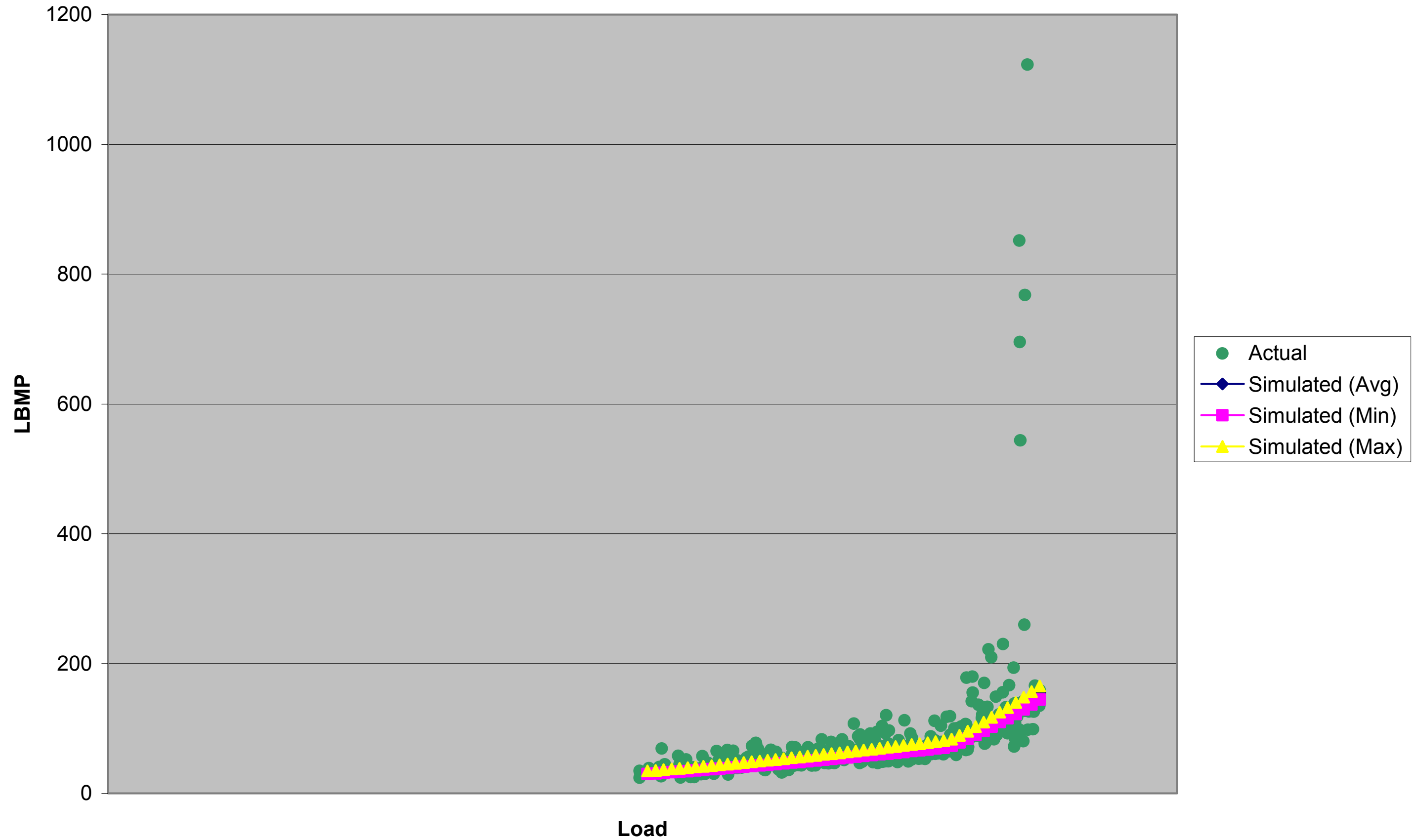


Fig. 6-8A. Long Island Real-Time Market Estimated Supply Curve for Summer 2002

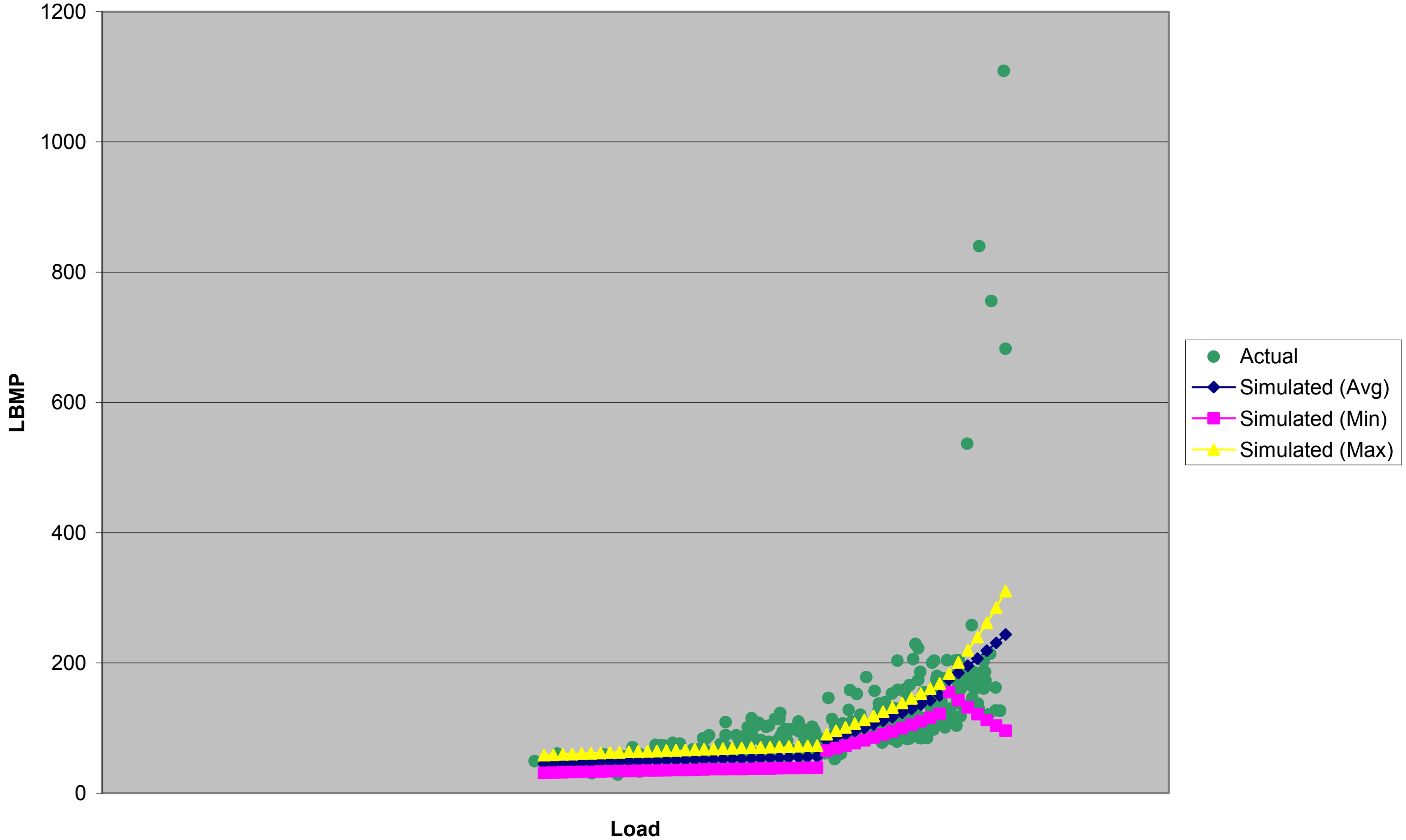


Fig. 6-9A. Western NY Day-Ahead Market Estimated Supply Curves for Summer 2002

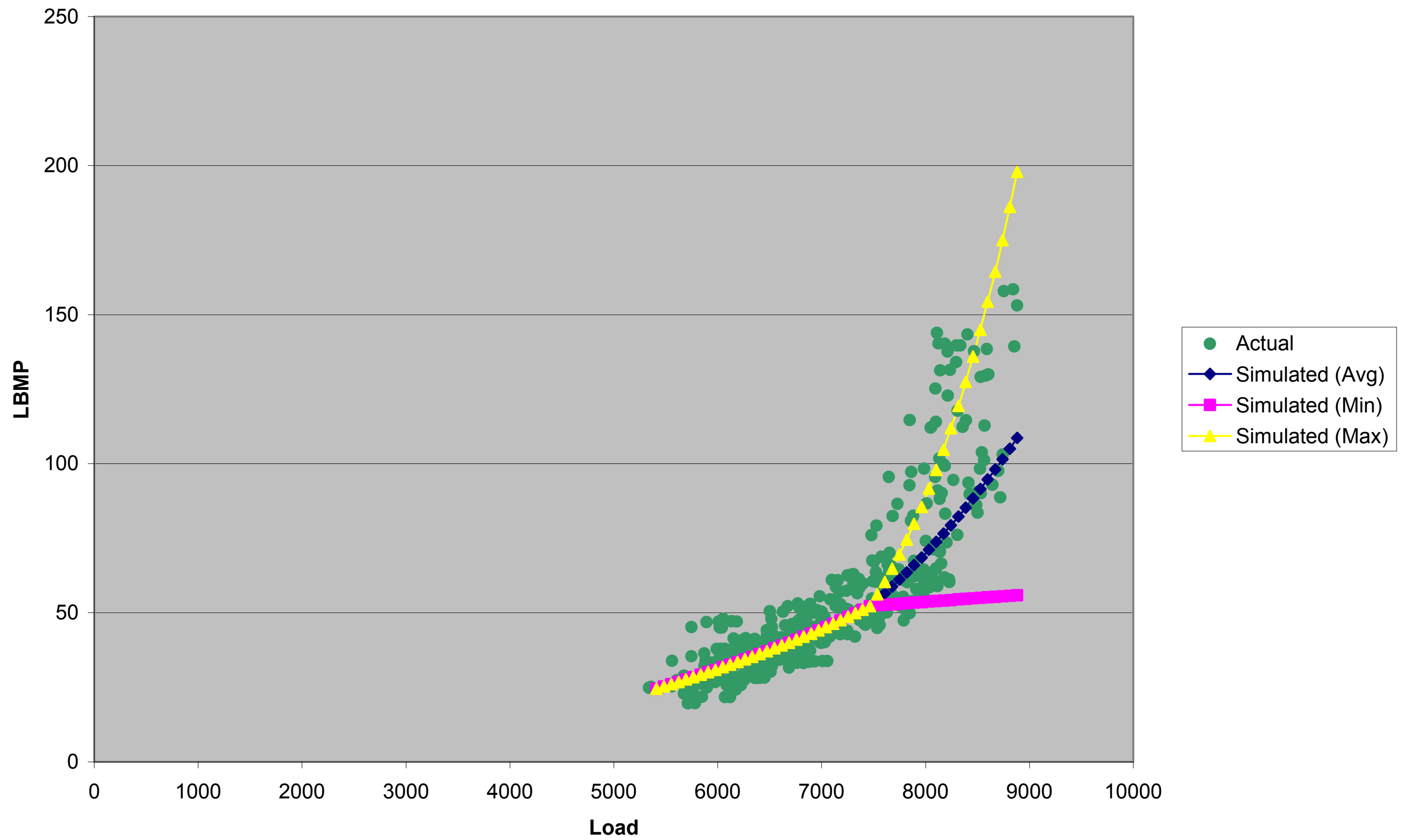


Fig. 6-10A. Capital Day-Ahead Market Estimated Supply Curve for Summer 2002

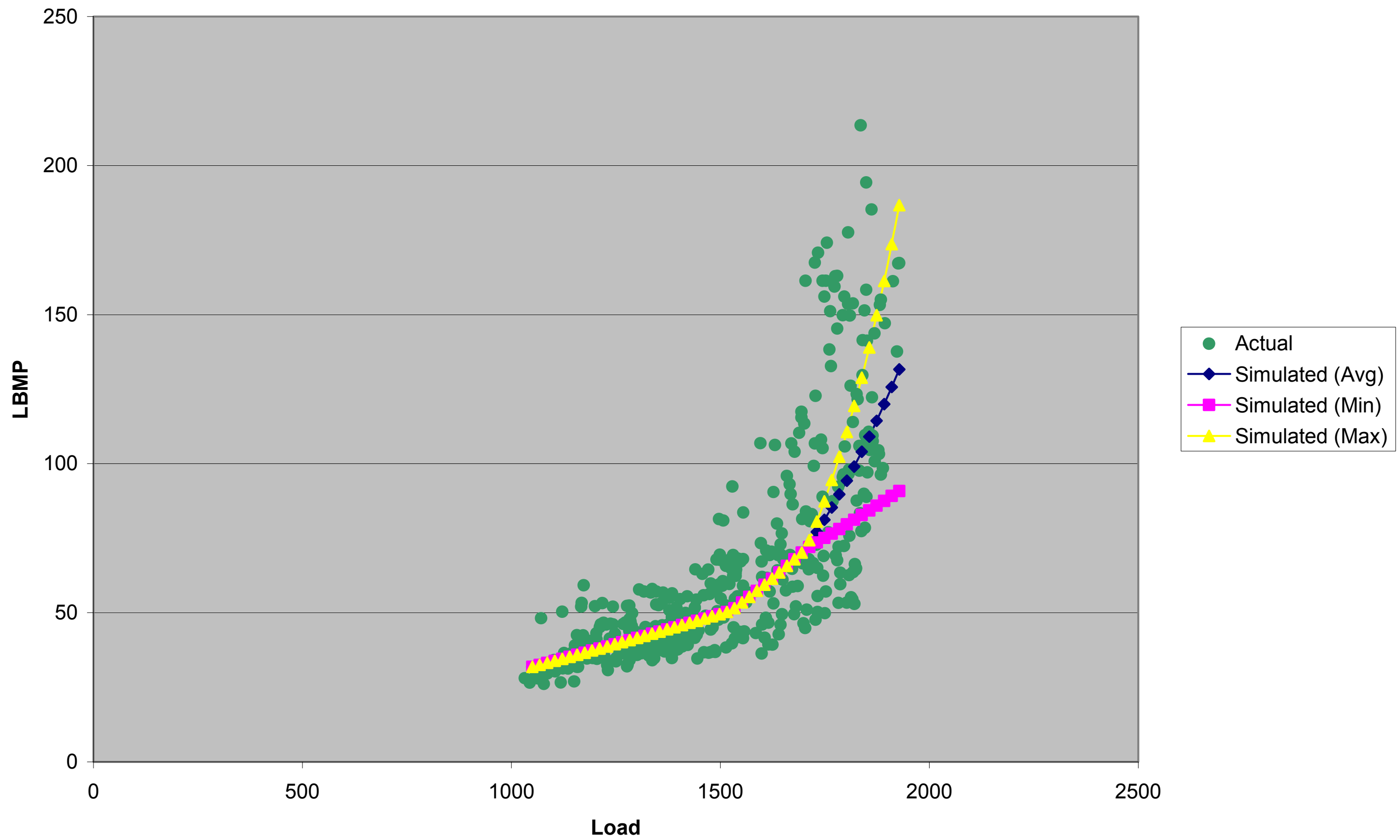


Fig. 6-11A. Hudson River Day-Ahead Market Estimated Supply Curve for Summer 2002

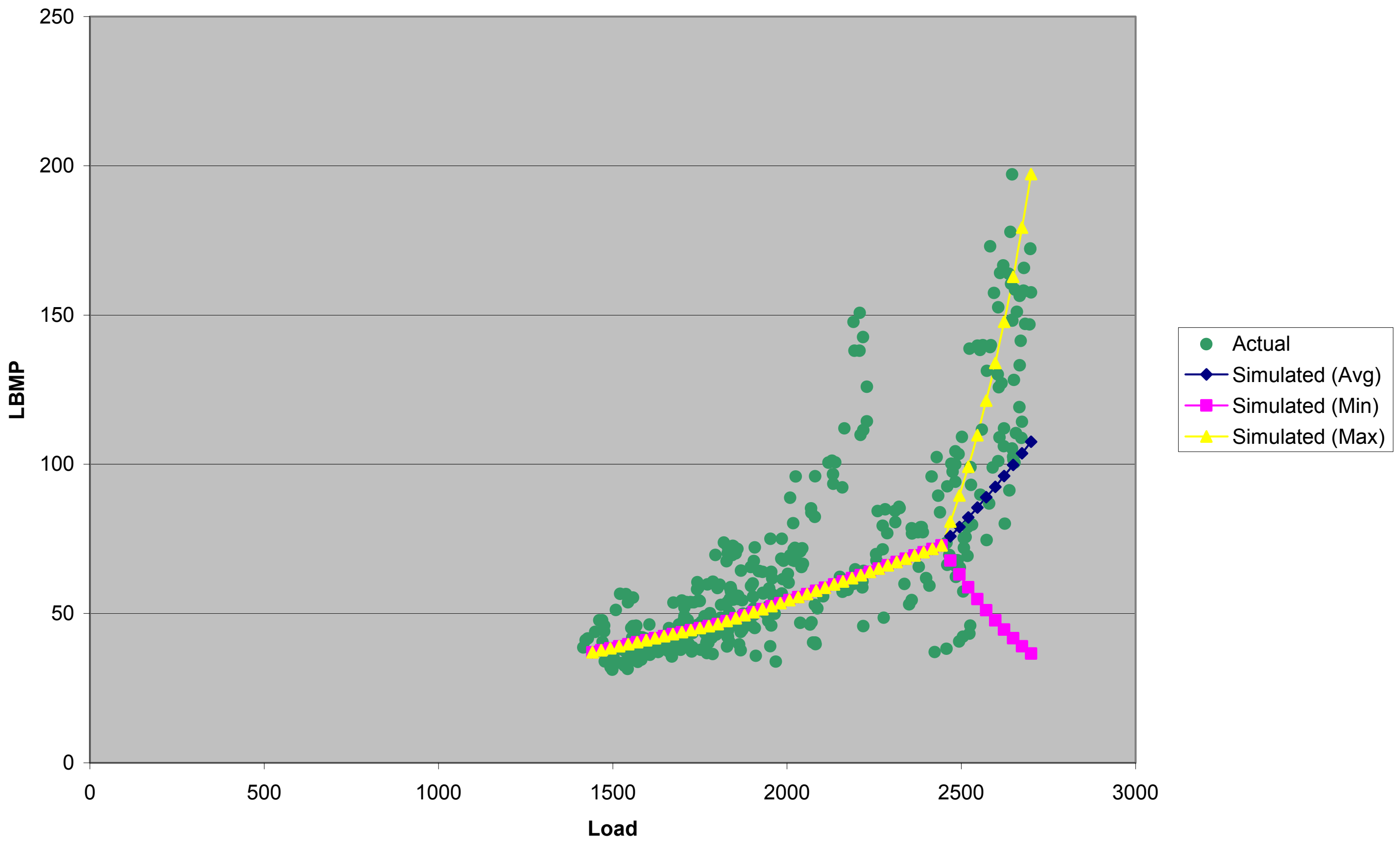


Fig. 6-12A. New York City Day-Ahead Market Estimated Supply Curve for Summer 2002

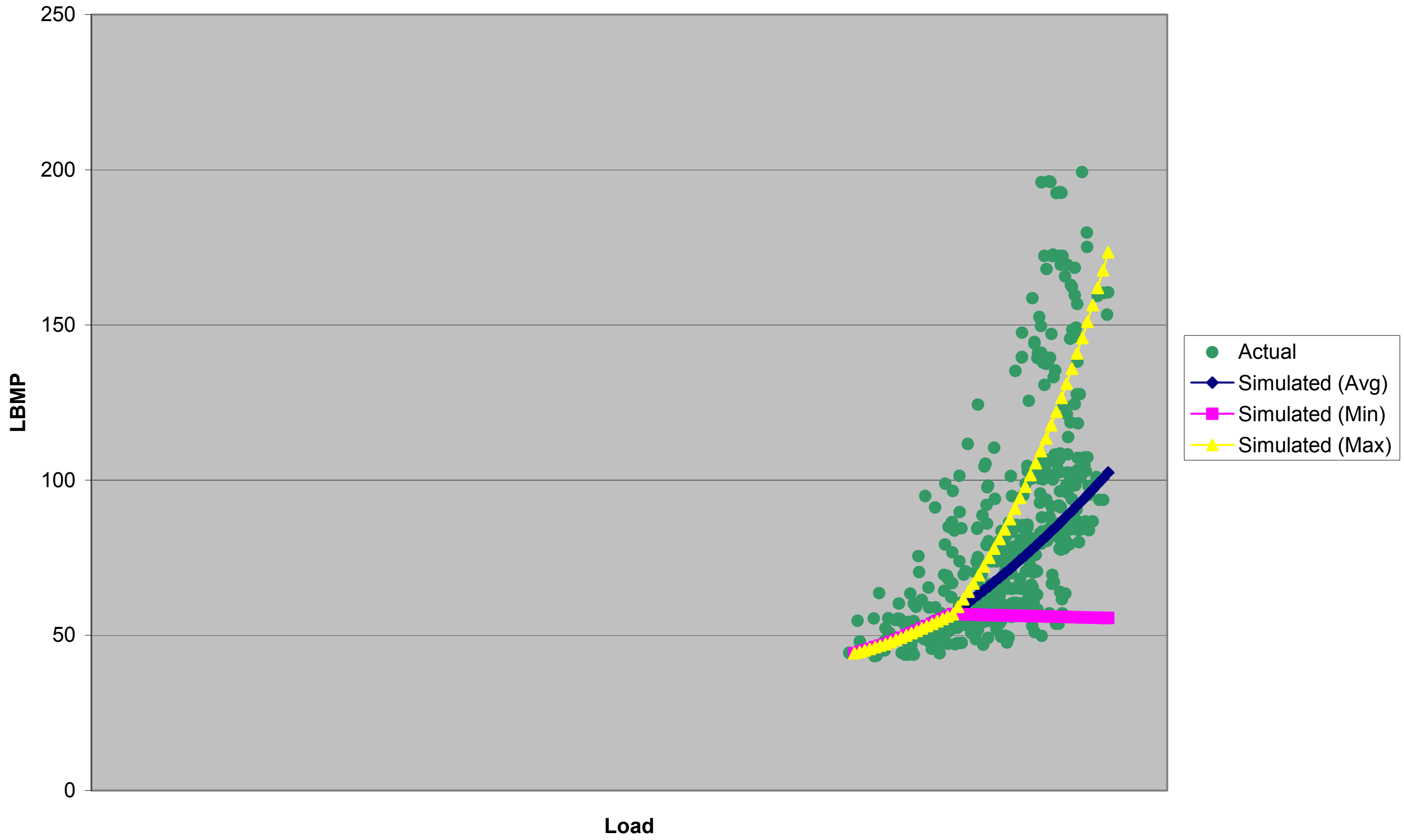


Fig. 6-13A. Long Island Day-Ahead Market Estimated Supply Curve for Summer 2002

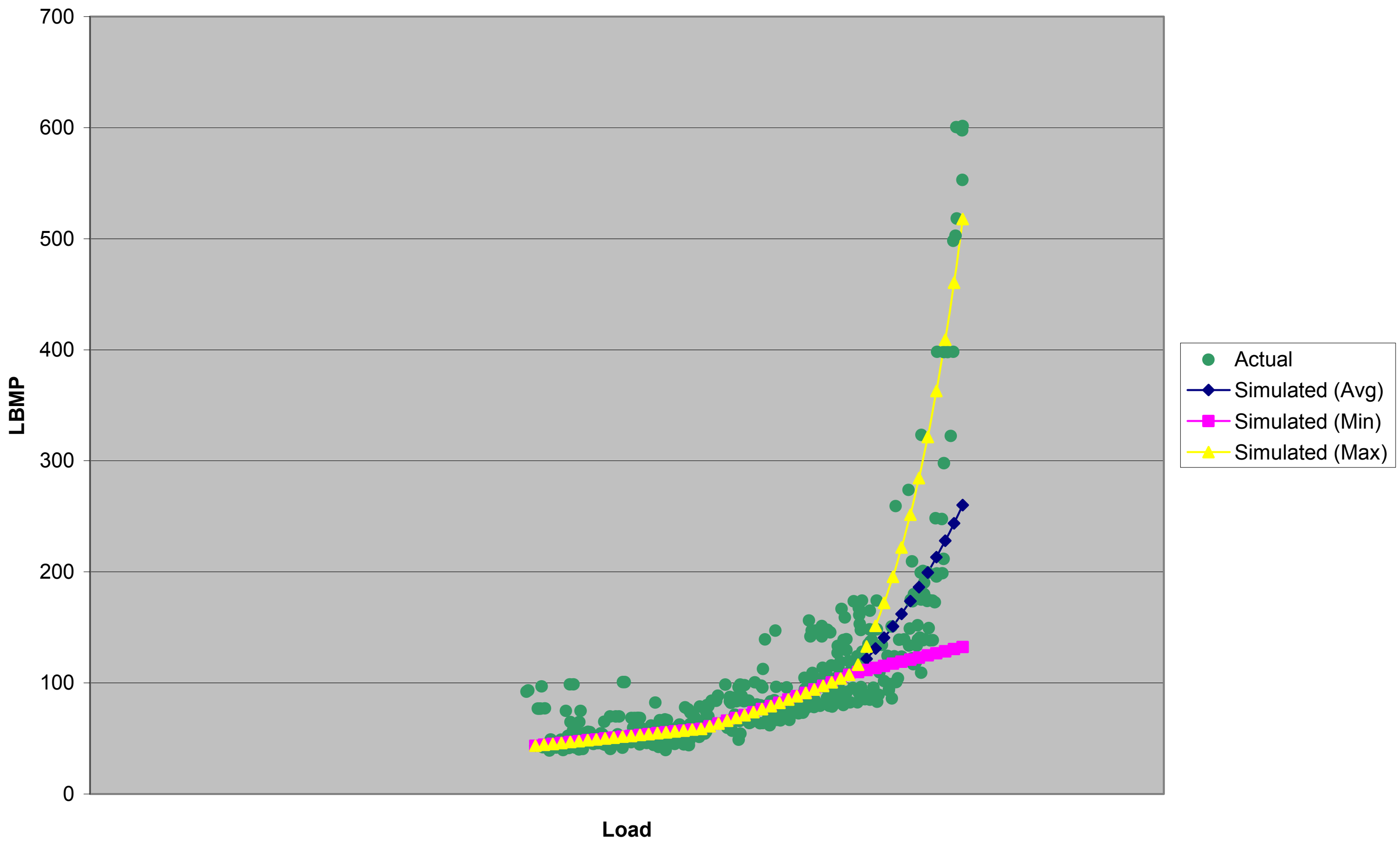


Table 6-1B. Daily Effect of EDRP Events in the New York City Zone, April 2002

			Simulated w/o EDRP			Simulated w/ EDRP						
		DAM FBL	Real-Time	Real-Time		EDRP Perf.	Real-Time	Real-Time	% Change in		Arc Price	Transfer from
Date	Hour	(MW)	Load (MW)	LBMP ($/MW)		(MW)	Load	LBMP	Load	LBMP	Flexibility	Gens to LSEs ($)
4/17/02	12	5,449		90		6		89	-0.1%	-1.0%	14	2,655
4/17/02	13	5,471		171		22		165	-0.3%	-3.5%	13	17,643
4/17/02	14	5,457		233		25		224	-0.3%	-4.0%	13	27,849
4/17/02	15	5,485		313		26		301	-0.3%	-4.0%	13	38,333
4/17/02	16	5,451		155		25		150	-0.3%	-3.6%	12	17,196
4/17/02	17	5,359		71		19		69	-0.2%	-2.7%	12	5,688
4/18/02	12	5,491		386		9		380	-0.1%	-1.4%	14	16,800
4/18/02	13	5,510		333		23		321	-0.3%	-3.6%	14	36,684
4/18/02	14	5,491		332		29		317	-0.3%	-4.7%	14	48,714
4/18/02	15	5,467		247		29		236	-0.3%	-4.6%	14	36,842
4/18/02	16	5,436		207		29		199	-0.3%	-4.3%	13	28,676
4/18/02	17	5,349		140		25		135	-0.3%	-3.8%	13	16,351
Hourly Average		**5,451**		**223**	**#**	**22**		**215**	**-0.3%**	**-3.4%**	**13**	**24,453**
Total		**65,416**			**0**	**266**						**293,433**

Table 6-2B. Daily Effect of EDRP Events in the Long Island Zone, April 2002

			Simulated w/o EDRP			Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load	Real-Time LBMP	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
4/17/02	12	3,210		89		0		88	0.0%	-0.1%	12	-2
4/17/02	13	3,281		165		2		164	0.0%	-0.6%	12	-11
4/17/02	14	3,333		230		9		223	-0.3%	-3.1%	12	-50
4/17/02	15	3,373		310		10		300	-0.3%	-3.4%	12	-324
4/17/02	16	3,416		151		5		149	-0.1%	-1.6%	12	-233
4/17/02	17	3,339		68		2		67	-0.1%	-0.9%	12	-56
4/18/02	12	2,903		325		6		317	-0.2%	-2.3%	12	2159
4/18/02	13	2,968		329		8		320	-0.2%	-2.8%	12	2496
4/18/02	14	3,027		326		8		316	-0.2%	-2.8%	12	2541
4/18/02	15	3,076		242		8		235	-0.2%	-2.9%	12	1983
4/18/02	16	3,082		204		9		197	-0.3%	-3.0%	12	1816
4/18/02	17	3,018		138		8		134	-0.2%	-2.8%	12	1050
Hourly Average		**3,169**		**215**	**#**	**6**		**209**	**-0.2%**	**-2.2%**	**12**	**948**
Total		**38,026**				**74**						**11,370**

Table 6-3B. Daily Effect of EDRP Events in the Hudson River Superzone, April 2002

			Simulated w/o EDRP		Simulated w/ EDRP						
		DAM FBL	Real-Time	Real-Time	EDRP Perf.	Real-Time	Real-Time	% Change in		Arc Price	Transfer from
Date	Hour	(MW)	Load (MW)	LBMP ($/MW)	(MW)	Load	LBMP	Load	LBMP	Flexibility	Gens to LSEs ($)
4/17/02	12	1,564	2,771	80	2	2,769	80	-0.1%	-0.5%	6	486
4/17/02	13	1,603	2,843	148	7	2,836	146	-0.2%	-1.6%	7	2,954
4/17/02	14	1,608	2,931	204	9	2,922	199	-0.3%	-2.2%	7	5,822
4/17/02	15	1,598	2,954	272	10	2,944	264	-0.3%	-2.8%	8	10,280
4/17/02	16	1,590	2,992	137	9	2,983	134	-0.3%	-2.1%	7	3,996
4/17/02	17	1,578	2,968	67	5	2,963	66	-0.2%	-0.8%	5	766
4/18/02	12	1,516	2,788	289	3	2,785	286	-0.1%	-0.9%	8	3,465
4/18/02	13	1,524	2,876	285	8	2,868	281	-0.3%	-1.4%	5	5,548
4/18/02	14	1,520	2,916	281	9	2,907	277	-0.3%	-1.6%	5	6,085
4/18/02	15	1,505	2,986	214	11	2,975	210	-0.4%	-1.8%	5	5,781
4/18/02	16	1,508	3,041	180	11	3,030	177	-0.4%	-1.8%	5	5,074
4/18/02	17	1,497	3,001	131	9	2,992	129	-0.3%	-1.9%	7	3,813
Hourly Average		**1,551**	**2,922**	**191**	**#** **8**	**2,915**	**187**	**-0.3%**	**-1.6%**	**6**	**4,506**
Total		**18,611**	**35,067**		**93**	**34,974**					**54,071**

Table 6-1C. Daily Effect of EDRP Events in the Capital Zone, Summer 2002

			Simulated w/o EDRP			Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
7/30/02	13	1,851	2,019	64		65	1,954	47	-3.2%	-25.9%	8	1,698
7/30/02	14	1,865	2,025	67		69	1,956	48	-3.4%	-29.0%	9	1,779
7/30/02	15	1,855	2,042	73		72	1,970	51	-3.5%	-29.5%	8	2,479
7/30/02	16	1,829	2,042	114		71	1,971	80	-3.5%	-29.5%	8	4,784
7/30/02	17	1,798	2,026	104		63	1,963	78	-3.1%	-24.9%	8	4,270
8/14/02	13	1,826	2,110	107		57	2,053	95	-2.7%	-11.6%	4	2,825
8/14/02	14	1,841	2,142	118		61	2,081	105	-2.8%	-11.7%	4	3,328
8/14/02	15	1,845	2,154	170		61	2,093	150	-2.9%	-11.8%	4	4,980
8/14/02	16	1,851	2,006	191		62	1,944	167	-3.1%	-12.9%	4	2,297
8/14/02	17	1,840	1,952	128		65	1,887	111	-3.3%	-13.7%	4	825
Hourly Average		**1,840**	**2,052**	**114**	#	**65**	**1,987**	**93**	**-3.2%**	**-20.1%**	**6**	**2,926**
Total		**18,401**	**20,518**			**646**	**19,872**					**29,264**

Table 6-2C. Daily Effect of EDRP Events in the New York City Zone, Summer 2002

			Simulated w/o EDRP		Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	EDRP Perf. (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
7/30/02	13	6,326		78	86		72	-0.8%	-7.9%	9	23,721
7/30/02	14	6,319		91	92		84	-0.9%	-7.8%	9	27,253
7/30/02	15	6,301		92	93		85	-0.9%	-7.1%	8	25,613
7/30/02	16	6,256		105	94		98	-0.9%	-6.5%	7	26,848
7/30/02	17	6,123		99	87		93	-0.9%	-6.4%	7	25,038
8/14/02	13	6,431		102	77		95	-0.7%	-7.1%	10	27,779
8/14/02	14	6,427		106	82		98	-0.8%	-7.1%	9	29,335
8/14/02	15	6,415		136	82		126	-0.8%	-7.0%	9	36,982
8/14/02	16	6,369		153	85		142	-0.8%	-7.6%	9	45,634
8/14/02	17	6,238		108	85		98	-0.8%	-9.2%	11	37,557
Hourly Average		**6,321**		**107**	# **86**		**99**	**-0.8%**	**-7.4%**	**9**	**30,576**
Total		**63,205**			**862**						**305,761**

Table 6-3C. Daily Effect of EDRP Events in the Long Island Zone, Summer 2002

			Simulated w/o EDRP			Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
7/30/02	13	4,094		206		71		186	-1.5%	-9.4%	6	14002
7/30/02	14	4,143		207		76		186	-1.5%	-9.8%	6	14421
7/30/02	15	4,193		205		73		186	-1.5%	-9.2%	6	13348
7/30/02	16	4,227		204		71		186	-1.4%	-8.7%	6	13089
7/30/02	17	4,182		205		64		187	-1.3%	-8.7%	7	13828
8/14/02	13	4,725		110		46		104	-0.9%	-5.9%	6	533
8/14/02	14	4,760		132		95		118	-1.9%	-10.9%	6	1009
8/14/02	15	4,809		151		90		136	-1.8%	-10.3%	6	421
8/14/02	16	4,875		159		86		143	-1.8%	-10.4%	6	-1091
8/14/02	17	4,873		185		82		175	-1.7%	-5.9%	3	-1954
Hourly Average		**4,488**		**177**	#	**75**		**161**	**-1.5%**	**-8.9%**	**6**	**6,760**
Total		**44,881**				**754**						**67,604**

Table 6-4C. Daily Effect of EDRP Events in the Western NY Superzone, Summer 2002

			Simulated w/o EDRP		Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	EDRP Perf. (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
7/30/02	13	8,176	8,942	52	385	8,557	46	-4.3%	-11.9%	3	2382
7/30/02	14	8,185	8,927	53	427	8,500	46	-4.8%	-13.2%	3	2214
7/30/02	15	8,131	8,833	57	419	8,414	50	-4.7%	-13.1%	3	2107
7/30/02	16	8,050	8,867	88	417	8,450	77	-4.7%	-13.0%	3	4579
7/30/02	17	7,863	8,736	86	404	8,332	75	-4.6%	-12.8%	3	5138
8/14/02	13	8,568	9,718	77	319	9,399	53	-3.3%	-30.5%	9	19467
8/14/02	14	8,606	9,732	90	378	9,354	54	-3.9%	-40.0%	10	26909
8/14/02	15	8,590	9,677	102	585	9,092	46	-6.0%	-55.2%	9	28396
8/14/02	16	8,530	9,577	82	373	9,204	54	-3.9%	-33.7%	9	18536
8/14/02	17	8,358	9,359	57	359	9,000	41	-3.8%	-27.5%	7	10001
Hourly Average		**8,306**	**9,237**	**74**	# **407**	**8,830**	**54**	**-4.4%**	**-25.1%**	**6**	**11,973**
Total		**83,057**	**92,368**		**4,066**	**88,302**					**119,728**

Table 6-5C. Daily Effect of EDRP Events in the Hudson River Superzone, Summer 2002

			Simulated w/o EDRP		Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	EDRP Perf. (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
7/30/02	13	2,165	3,720	53	30	3,690	52	-0.8%	-2.9%	3	2324
7/30/02	14	2,219	3,792	53	31	3,761	52	-0.8%	-2.3%	3	1892
7/30/02	15	2,229	3,782	57	31	3,751	55	-0.8%	-2.3%	3	2005
7/30/02	16	2,229	3,761	88	28	3,733	86	-0.8%	-2.1%	3	2808
7/30/02	17	2,211	3,685	84	26	3,659	83	-0.7%	-1.3%	2	1606
8/14/02	13	2,651	3,800	93	29	3,771	88	-0.8%	-6.2%	8	6466
8/14/02	14	2,684	3,874	103	34	3,840	96	-0.9%	-7.1%	8	8423
8/14/02	15	2,700	3,878	137	40	3,838	126	-1.0%	-8.2%	8	12845
8/14/02	16	2,696	3,912	150	30	3,882	141	-0.8%	-6.2%	8	11123
8/14/02	17	2,668	3,855	101	25	3,830	96	-0.6%	-5.2%	8	6129
Hourly Average		**2,445**	**3,806**	**92** #	**30**	**3,776**	**87**	**-0.8%**	**-4.4%**	**5**	**5,562**
Total		**24,452**	**38,060**		**305**	**37,755**					**55,622**

Table 6-1D. April 2002 Value of Expected Un-served Energy, 5% Load at Risk

Reduction in LOLP	Outage Cost $1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	($1,000's)			
0.05	$ 303	$ 455	$ 759	$ 1,517
0.10	$ 607	$ 910	$ 1,517	$ 3,034
0.15	$ 910	$ 1,366	$ 2,276	$ 4,552
0.20	$ 1,214	$ 1,821	$ 3,034	$ 6,069
0.25	$ 1,517	$ 2,276	$ 3,793	$ 7,586
0.50	$ 3,034	$ 4,552	$ 7,586	$ 15,172

EDRP Payments = $216,853

Table 6-2D. April 2002 Value of Expected Un-served Energy, 100% of Load at Risk

Reduction in LOLP	Outage Cost $1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	($1,000's)			
0.05	$ 6,069	$ 9,103	$ 15,172	$ 30,345
0.10	$ 12,138	$ 18,207	$ 30,345	$ 60,690
0.15	$ 18,207	$ 27,310	$ 45,517	$ 91,034
0.20	$ 24,276	$ 36,414	$ 60,690	$ 121,379
0.25	$ 30,345	$ 45,517	$ 75,862	$ 151,724
0.50	$ 60,690	$ 91,034	$ 151,724	$ 303,448

EDRP Payments = $216,853

Table 6-3D. Summer 2002 Value of Expected Un-served Energy, 5% of Load at Risk

Reduction in	Outage Cost			
LOLP	$1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	---------------------------- ($1,000's) --------------------------------			
0.05	$ 339	$ 509	$ 849	$ 1,697
0.10	$ 679	$ 1,018	$ 1,697	$ 3,394
0.15	$ 1,018	$ 1,528	$ 2,546	$ 5,092
0.20	$ 1,358	$ 2,037	$ 3,394	$ 6,789
0.25	$ 1,697	$ 2,546	$ 4,243	$ 8,486
0.50	$ 3,394	$ 5,092	$ 8,486	$ 16,972

EDRP Payments = $3,318,381

Table 6-4D. Summer 2002 Value of Expected Un-served Energy, 100% of Load at Risk

Reduction in LOLP	Outage Cost $1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	($1,000's)			
0.05	$ 6,789	$ 10,183	$ 16,972	$ 33,945
0.10	$ 13,578	$ 20,367	$ 33,945	$ 67,889
0.15	$ 20,367	$ 30,550	$ 50,917	$ 101,834
0.20	$ 27,156	$ 40,733	$ 67,889	$ 135,778
0.25	$ 33,945	$ 50,917	$ 84,861	$ 169,723
0.50	$ 67,889	$ 101,834	$ 169,723	$ 339,446

EDRP Payments = $3,318,381

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002

			With DADRP			Simulated		% Change in Due to DADRP				
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Arc Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
6/11	17	1,716	1,317	57.2	1	1,318	57.2	0.1%	0.1%	1.2	71	43
6/25	17	1,689	1,638	69.4	5	1,643	70.0	0.3%	0.9%	3.1	1,074	644
6/25	18	1,654	1,599	67.2	10	1,609	68.5	0.6%	1.9%	3.1	2,086	1,252
6/25	20	1,599	1,579	61.1	5	1,584	61.7	0.3%	1.0%	3.1	946	567
6/25	21	1,608	1,580	63.7	10	1,590	64.9	0.6%	2.0%	3.1	1,977	1,186
6/25	23	1,308	1,307	40.2	5	1,312	40.4	0.4%	0.5%	1.2	250	150
6/26	0	1,200	1,148	39.2	10	1,158	39.6	0.9%	1.1%	1.2	488	293
6/26	2	1,108	1,035	36.6	5	1,040	36.8	0.5%	0.6%	1.2	228	137
6/26	3	1,085	1,010	36.1	10	1,020	36.5	1.0%	1.2%	1.2	450	270
6/26	5	1,132	1,064	36.8	5	1,069	37.1	0.5%	0.6%	1.2	230	138
6/26	6	1,261	1,240	37.9	10	1,250	38.2	0.8%	1.0%	1.2	472	283
6/26	8	1,574	1,422	47.2	5	1,427	47.4	0.4%	0.4%	1.2	294	177
6/26	9	1,685	1,496	60.6	10	1,506	61.1	0.7%	0.8%	1.2	756	453
6/26	11	1,869	1,600	71.2	5	1,605	71.9	0.3%	1.0%	3.1	1,101	661
6/26	12	1,912	1,613	72.5	22	1,635	75.6	1.4%	4.3%	3.1	4,994	2,996
6/26	14	1,951	1,647	76.6	17	1,664	79.1	1.0%	3.2%	3.1	4,063	2,438
6/26	15	1,957	1,651	67.9	34	1,685	72.3	2.1%	6.5%	3.2	7,277	4,366
6/26	17	1,913	1,600	62.0	5	1,605	62.6	0.3%	1.0%	3.1	960	576
6/26	18	1,822	1,538	64.5	10	1,548	65.8	0.7%	2.0%	3.1	2,003	1,202
6/26	20	1,770	1,439	56.5	5	1,444	56.7	0.3%	0.4%	1.2	352	211
6/26	21	1,739	1,431	50.9	10	1,441	51.3	0.7%	0.9%	1.2	635	381
6/27	0	1,284	1,094	38.7	10	1,104	39.1	0.9%	1.1%	1.2	482	289
6/27	2	1,172	1,011	30.3	5	1,016	30.5	0.5%	0.6%	1.2	189	113
6/27	3	1,152	989	29.9	10	999	30.2	1.0%	1.3%	1.2	373	224
6/27	5	1,213	1,050	32.7	5	1,055	32.8	0.5%	0.6%	1.2	203	122
6/27	6	1,342	1,199	35.4	10	1,209	35.8	0.8%	1.0%	1.2	441	265
6/27	8	1,646	1,384	45.2	5	1,389	45.4	0.4%	0.5%	1.2	282	169
6/27	9	1,732	1,438	54.3	10	1,448	54.7	0.7%	0.9%	1.2	676	406
6/27	11	1,820	1,513	63.7	5	1,518	64.0	0.3%	0.4%	1.2	397	238
7/1	12	1,745	1,644	93.2	10	1,654	94.9	0.6%	1.9%	3.1	2,893	1,736
7/1	14	1,831	1,670	106.8	10	1,680	108.8	0.6%	1.9%	3.1	3,317	1,990

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
7/1	15	1,853	1,689	110.3	20	1,709	114.4	1.2%	3.7%	3.1	6,890	4,134
7/2	12	1,985	1,713	118.7	10	1,723	120.1	0.6%	1.2%	2.1	2,498	1,499
7/2	14	2,042	1,773	159.4	10	1,783	161.3	0.6%	1.2%	2.1	3,364	2,019
7/2	15	2,058	1,775	162.9	20	1,795	166.8	1.1%	2.4%	2.1	6,928	4,157
7/3	0	1,457	1,219	39.4	10	1,229	39.8	0.8%	1.0%	1.2	491	295
7/3	2	1,329	1,110	30.1	5	1,115	30.3	0.5%	0.6%	1.2	188	113
7/3	3	1,310	1,086	29.5	10	1,096	29.8	0.9%	1.1%	1.2	368	221
7/3	5	1,335	1,136	29.5	5	1,141	29.6	0.4%	0.5%	1.2	184	110
7/3	6	1,465	1,264	35.7	10	1,274	36.0	0.8%	1.0%	1.2	444	267
7/3	8	1,801	1,468	58.2	5	1,473	58.5	0.3%	0.4%	1.2	363	218
7/3	9	1,893	1,550	86.0	10	1,560	87.7	0.6%	2.0%	3.1	2,670	1,602
7/3	11	2,033	1,688	125.2	5	1,693	126.4	0.3%	0.9%	3.1	1,937	1,162
7/3	12	2,048	1,719	134.8	22	1,741	139.6	1.3%	3.6%	2.8	8,283	4,970
7/3	14	2,077	1,755	174.1	17	1,772	178.8	1.0%	2.7%	2.8	8,234	4,940
7/3	15	2,079	1,745	161.4	34	1,779	170.1	1.9%	5.4%	2.8	15,287	9,172
7/3	17	2,030	1,704	161.4	17	1,721	166.4	1.0%	3.1%	3.1	8,552	5,131
7/3	18	1,986	1,596	106.9	5	1,601	107.9	0.3%	1.0%	3.1	1,654	992
7/8	12	1,711	1,515	60.2	10	1,525	60.7	0.7%	0.8%	1.2	750	450
7/8	14	1,783	1,542	68.2	9	1,551	69.4	0.6%	1.8%	3.1	1,905	1,143
7/8	15	1,820	1,549	67.2	18	1,567	69.6	1.2%	3.6%	3.1	3,777	2,266
7/8	17	1,870	1,537	62.3	1	1,538	62.5	0.1%	0.2%	3.1	192	115
7/8	18	1,829	1,505	59.0	2	1,507	59.1	0.1%	0.2%	1.2	147	88
7/9	12	1,804	1,435	59.9	10	1,445	60.4	0.7%	0.9%	1.2	747	448
7/9	14	1,750	1,498	67.8	9	1,507	68.3	0.6%	0.7%	1.2	760	456
7/9	15	1,702	1,524	68.0	18	1,542	69.0	1.2%	1.5%	1.2	1,526	915
7/9	17	1,632	1,537	63.3	1	1,538	63.4	0.1%	0.2%	3.1	195	117
7/9	18	1,572	1,506	60.6	2	1,508	60.7	0.1%	0.2%	1.2	151	91
7/16	17	1,624	1,783	53.3	5	1,788	53.7	0.3%	0.8%	2.9	772	463
7/17	11	1,623	1,736	55.1	5	1,741	55.8	0.3%	1.1%	3.9	1,072	643
7/17	12	1,644	1,762	59.6	23	1,785	62.6	1.3%	5.0%	3.9	5,283	3,170

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
		Load in	Day-Ahead	Day-Ahead	DADRP	Day-Ahead	Day-Ahead			Price	Collateral	Bill
Date	Hr.	the RTM	Load (MW)	LBMP ($/MW)	Load (MW)	Load (MW)	LBMP ($/MW)	Load	LBMP	Flexibility*	Benefits ($)**	Savings ($)***
7/17	14	1,742	1,808	62.6	18	1,826	64.4	1.0%	2.9%	2.9	3,285	1,971
7/17	15	1,796	1,824	64.5	36	1,860	68.3	2.0%	5.9%	3.0	6,980	4,188
7/17	17	1,858	1,787	59.6	5	1,792	60.0	0.3%	0.8%	3.0	888	533
7/17	18	1,826	1,753	57.1	10	1,763	58.2	0.6%	2.0%	3.6	2,048	1,229
7/22	11	1,852	1,602	58.9	5	1,607	59.4	0.3%	1.0%	3.1	911	546
7/22	12	1,883	1,622	59.3	10	1,632	60.4	0.6%	1.9%	3.1	1,840	1,104
7/22	14	1,948	1,672	64.7	5	1,677	65.3	0.3%	0.9%	3.1	1,001	601
7/22	15	1,997	1,697	66.6	10	1,707	67.8	0.6%	1.8%	3.1	2,067	1,240
7/22	17	2,042	1,712	64.6	5	1,717	65.3	0.3%	1.1%	3.6	1,174	704
7/22	18	1,998	1,685	59.0	10	1,695	60.1	0.6%	1.8%	3.1	1,831	1,098
7/22	20	1,940	1,607	51.9	1	1,608	52.0	0.1%	0.2%	3.1	160	96
7/23	11	2,086	1,623	53.2	1	1,624	53.3	0.1%	0.2%	3.1	164	98
7/23	12	2,040	1,635	55.7	2	1,637	55.9	0.1%	0.4%	3.1	344	207
7/23	14	1,801	1,647	61.2	1	1,648	61.3	0.1%	0.2%	3.1	189	113
7/23	15	1,761	1,634	61.5	2	1,636	61.8	0.1%	0.4%	3.1	380	228
7/23	17	1,744	1,563	56.7	1	1,564	56.8	0.1%	0.2%	3.1	175	105
7/23	18	1,689	1,501	54.7	2	1,503	54.8	0.1%	0.2%	1.2	136	82
7/23	20	1,657	1,430	59.1	1	1,431	59.1	0.1%	0.1%	1.2	74	44
7/24	6	1,257	1,174	28.4	4	1,178	28.5	0.3%	0.4%	1.2	142	85
7/24	8	1,458	1,311	34.7	2	1,313	34.8	0.2%	0.2%	1.2	87	52
7/24	9	1,516	1,366	38.3	4	1,370	38.4	0.3%	0.4%	1.2	191	114
7/24	11	1,561	1,418	44.6	2	1,420	44.6	0.1%	0.2%	1.2	111	67
7/24	12	1,538	1,428	47.0	4	1,432	47.2	0.3%	0.3%	1.2	234	141
7/24	14	1,556	1,439	51.8	2	1,441	51.9	0.1%	0.2%	1.2	129	77
7/24	15	1,557	1,439	51.6	4	1,443	51.8	0.3%	0.3%	1.2	257	154
7/24	17	1,550	1,405	44.4	2	1,407	44.5	0.1%	0.2%	1.2	111	66
7/24	18	1,509	1,362	40.0	4	1,366	40.1	0.3%	0.4%	1.2	199	120
7/24	20	1,493	1,324	42.8	2	1,326	42.9	0.2%	0.2%	1.2	107	64
7/24	21	1,493	1,315	40.9	4	1,319	41.0	0.3%	0.4%	1.2	204	122
7/24	23	1,221	1,138	34.8	2	1,140	34.8	0.2%	0.2%	1.2	87	52
7/25	0	1,126	1,005	34.4	4	1,009	34.6	0.4%	0.5%	1.2	171	103

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP				
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Arc Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
7/25	2	1,047	899	28.1	2	901	28.2	0.2%	0.3%	1.2	70	42
7/25	6	1,196	1,067	25.4	4	1,071	25.5	0.4%	0.5%	1.2	127	76
7/25	8	1,447	1,277	30.9	2	1,279	31.0	0.2%	0.2%	1.2	77	46
7/25	9	1,507	1,351	41.0	4	1,355	41.1	0.3%	0.4%	1.2	204	122
7/25	11	1,579	1,408	40.8	2	1,410	40.9	0.1%	0.2%	1.2	102	61
7/25	12	1,558	1,416	41.7	4	1,420	41.8	0.3%	0.4%	1.2	208	125
7/25	14	1,582	1,427	42.0	2	1,429	42.1	0.1%	0.2%	1.2	105	63
7/25	15	1,580	1,424	43.0	4	1,428	43.2	0.3%	0.3%	1.2	215	129
7/25	17	1,587	1,384	40.4	2	1,386	40.5	0.1%	0.2%	1.2	101	60
7/25	18	1,543	1,340	39.6	4	1,344	39.7	0.3%	0.4%	1.2	197	118
7/25	20	1,518	1,298	38.4	2	1,300	38.5	0.2%	0.2%	1.2	96	57
7/25	21	1,500	1,310	40.6	4	1,314	40.8	0.3%	0.4%	1.2	203	122
7/25	23	1,238	1,149	36.8	2	1,151	36.9	0.2%	0.2%	1.2	92	55
7/29	9	1,838	1,597	62.1	1	1,598	62.2	0.1%	0.2%	3.1	192	115
7/29	11	1,944	1,734	78.6	1	1,735	78.8	0.1%	0.2%	3.9	310	186
7/29	17	2,082	1,844	89.9	1	1,845	90.1	0.1%	0.2%	3.3	300	180
7/29	18	2,035	1,803	79.6	2	1,805	79.9	0.1%	0.4%	3.3	533	320
7/30	9	1,885	1,710	68.1	1	1,711	68.3	0.1%	0.2%	3.8	257	154
7/30	11	2,010	1,812	86.0	1	1,813	86.2	0.1%	0.2%	3.7	318	191
7/30	17	1,963	1,798	105.8	1	1,799	106.0	0.1%	0.2%	3.8	399	239
7/30	18	1,918	1,745	88.9	2	1,747	89.3	0.1%	0.4%	3.8	672	403
7/31	9	1,842	1,713	83.5	10	1,723	85.7	0.6%	2.7%	4.7	3,902	2,341
7/31	11	1,923	1,838	107.0	5	1,843	108.0	0.3%	1.0%	3.6	1,941	1,165
7/31	17	2,041	1,812	126.2	5	1,817	127.4	0.3%	1.0%	3.7	2,318	1,391
7/31	18	2,005	1,745	105.2	10	1,755	107.4	0.6%	2.2%	3.8	3,981	2,388
7/31	20	1,941	1,677	85.7	5	1,682	86.5	0.3%	0.9%	3.1	1,326	796
8/2	11	1,926	1,795	102.5	1	1,796	102.9	0.1%	0.4%	7.9	804	483
8/2	12	1,891	1,797	120.8	2	1,799	121.9	0.1%	0.9%	7.8	1,882	1,129
8/2	14	1,795	1,797	156.0	1	1,798	156.7	0.1%	0.4%	7.3	1,134	680
8/2	15	1,750	1,780	145.3	2	1,782	146.5	0.1%	0.8%	7.3	2,118	1,271
8/2	17	1,653	1,726	106.8	1	1,727	107.3	0.1%	0.5%	7.8	833	500

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
8/2	18	1,601	1,666	93.1	2	1,668	93.4	0.1%	0.4%	3.1	575	345
8/12	9	1,738	1,633	56.5	2	1,635	56.7	0.1%	0.4%	3.1	349	209
8/12	11	1,915	1,759	76.2	1	1,760	76.5	0.1%	0.4%	6.7	509	305
8/12	12	1,949	1,794	79.1	4	1,798	80.2	0.2%	1.4%	6.1	1,925	1,155
8/12	14	2,002	1,833	105.9	2	1,835	106.6	0.1%	0.7%	6.2	1,319	791
8/12	15	2,016	1,852	108.9	4	1,856	110.3	0.2%	1.3%	6.2	2,718	1,631
8/12	17	2,029	1,889	98.6	2	1,891	99.2	0.1%	0.7%	6.3	1,234	740
8/12	18	1,997	1,838	77.4	4	1,842	78.5	0.2%	1.5%	6.9	2,127	1,276
8/12	20	1,932	1,766	68.2	1	1,767	68.5	0.1%	0.4%	6.9	472	283
8/12	21	1,889	1,732	60.3	2	1,734	60.9	0.1%	0.9%	7.5	911	546
8/13	9	1,798	1,689	45.3	2	1,691	45.5	0.1%	0.4%	3.1	280	168
8/13	11	1,957	1,813	72.9	1	1,814	73.1	0.1%	0.3%	5.9	432	259
8/13	12	2,007	1,831	76.4	4	1,835	77.3	0.2%	1.2%	5.4	1,662	997
8/13	14	2,064	1,858	104.6	2	1,860	105.2	0.1%	0.6%	5.6	1,170	702
8/13	15	2,083	1,864	109.4	4	1,868	110.8	0.2%	1.2%	5.6	2,454	1,473
8/13	17	2,093	1,850	88.9	2	1,852	89.4	0.1%	0.6%	5.5	978	587
8/13	18	2,041	1,796	72.4	4	1,800	73.4	0.2%	1.4%	6.2	1,786	1,072
8/13	20	1,992	1,718	60.6	1	1,719	60.8	0.1%	0.4%	6.0	365	219
8/14	9	1,873	1,633	50.3	2	1,635	50.5	0.1%	0.4%	3.1	311	187
8/14	18	1,887	1,793	95.5	4	1,797	97.1	0.2%	1.6%	7.3	2,793	1,676
8/14	20	1,883	1,733	73.4	1	1,734	73.7	0.1%	0.4%	7.3	539	323
8/14	21	1,853	1,702	68.6	2	1,704	68.8	0.1%	0.4%	3.1	424	254
8/15	11	2,033	1,771	83.6	5	1,776	85.4	0.3%	2.2%	7.7	3,212	1,927
8/15	17	1,962	1,728	122.8	5	1,733	125.3	0.3%	2.1%	7.1	4,364	2,619
8/15	18	1,915	1,668	89.8	10	1,678	91.5	0.6%	1.9%	3.1	2,787	1,672
8/16	12	2,114	1,833	104.9	8	1,841	108.1	0.4%	3.1%	7.1	5,959	3,575
8/16	14	2,069	1,862	185.3	8	1,870	191.0	0.4%	3.1%	7.2	10,732	6,439
8/16	15	1,904	1,836	213.5	16	1,852	227.2	0.9%	6.4%	7.3	25,099	15,059
8/19	12	1,797	1,712	49.5	8	1,720	50.5	0.5%	2.1%	4.5	1,789	1,073
8/19	14	1,836	1,741	108.0	8	1,749	110.3	0.5%	2.1%	4.6	3,939	2,363
8/19	15	1,855	1,759	76.9	16	1,775	80.1	0.9%	4.2%	4.6	5,637	3,382

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
8/20	11	1,626	1,470	58.6	7	1,477	58.9	0.5%	0.6%	1.2	511	307
8/23	12	1,559	1,355	42.7	10	1,365	43.1	0.7%	0.9%	1.2	532	319
8/23	14	1,555	1,384	48.5	10	1,394	48.9	0.7%	0.9%	1.2	604	362
8/23	15	1,565	1,397	48.1	20	1,417	49.0	1.4%	1.8%	1.2	1,201	721
Hourly Avg.		1,733	1,553	70	7	1,559	71	0.4%	1.1%	3.0	1,696	1,018
Total		273,842	245,322		1,046	246,368					267,963	160,778

*As with most mathematical relations of this kind, the supply price flexibilities in the tables above are only vaild for small changes in load. Here the supply models are calibrated to the observed prices, and in mathematical terms, the load response was large. The average "arc" flexibilities only approximate the averages from the tables.

**The collateral benefits are equal to the difference in actual and simulated LBMP multiplied by load served.

*** The bill savings are estimated to be 0.6 of the total collateral benefits. This assumes that an average of 40% of load is purchased through bilaterals. Thus, this net amount is the savings to customers buying load in the DAM.

Table 6-2E. Daily Effect of DADRP Scheduled Bids in the Western Superzone, Summer, 2002

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
7/1	11	8,502	7,884	57.3	10	7,894	57.4	0.1%	0.1%	1.2	662	397
7/1	12	8,615	7,969	60.0	20	7,989	60.2	0.3%	0.3%	1.4	1,648	989
7/1	14	8,851	8,069	63.6	10	8,079	63.7	0.1%	0.2%	1.6	1,029	618
7/1	15	8,807	7,986	55.1	20	8,006	55.4	0.3%	0.4%	1.7	1,905	1,143
7/1	17	8,707	7,606	51.3	10	7,616	51.4	0.1%	0.2%	1.8	903	542
7/4	12	7,802	6,027	45.1	20	6,047	45.4	0.3%	0.8%	2.3	2,088	1,253
7/4	14	7,687	6,020	45.1	10	6,030	45.3	0.2%	0.4%	2.3	1,044	626
7/4	15	7,627	6,027	45.0	20	6,047	45.3	0.3%	0.8%	2.3	2,084	1,250
7/4	17	7,436	6,068	37.9	10	6,078	38.1	0.2%	0.4%	2.3	877	526
7/4	18	7,259	5,991	37.9	20	6,011	38.2	0.3%	0.8%	2.3	1,753	1,052
7/5	12	6,541	6,151	46.6	14	6,165	46.9	0.2%	0.5%	2.3	1,511	906
7/5	14	6,499	6,132	47.1	7	6,139	47.3	0.1%	0.3%	2.3	763	458
7/5	15	6,474	6,052	48.0	14	6,066	48.2	0.2%	0.5%	2.3	1,555	933
7/5	17	6,223	5,893	46.9	7	5,900	47.0	0.1%	0.3%	2.3	758	455
7/5	18	6,114	5,746	45.2	14	5,760	45.5	0.2%	0.6%	2.3	1,466	879
8/12	9	7,933	7,618	53.6	6	7,624	53.8	0.1%	0.4%	5.2	1,680	1,008
8/12	11	8,671	8,213	73.2	3	8,216	73.4	0.0%	0.2%	5.7	1,245	747
8/12	12	8,861	8,345	75.8	6	8,351	76.1	0.1%	0.4%	5.4	2,472	1,483
8/12	14	9,138	8,564	101.2	3	8,567	101.4	0.0%	0.2%	5.9	1,793	1,076
8/12	15	9,150	8,543	103.8	7	8,550	104.3	0.1%	0.5%	6.0	4,364	2,618
8/12	17	8,969	8,414	93.6	4	8,418	93.9	0.0%	0.3%	6.1	2,287	1,372
8/12	18	8,736	8,203	73.6	8	8,211	74.1	0.1%	0.6%	6.3	3,717	2,230
8/12	20	8,579	7,915	65.1	4	7,919	65.3	0.1%	0.3%	6.0	1,553	932
8/12	21	8,373	7,804	57.5	8	7,812	57.8	0.1%	0.6%	6.2	2,830	1,698
8/13	11	8,907	7,884	67.1	3	7,887	67.2	0.0%	0.2%	5.4	1,078	647
8/13	12	9,146	7,964	70.1	6	7,970	70.4	0.1%	0.4%	5.2	2,176	1,306
8/13	14	9,382	8,118	91.0	3	8,121	91.2	0.0%	0.2%	5.6	1,524	914
8/13	15	9,347	8,094	95.6	7	8,101	96.0	0.1%	0.5%	5.6	3,773	2,264
8/13	17	9,167	7,861	80.8	4	7,865	81.1	0.1%	0.3%	5.5	1,780	1,068
8/13	18	8,954	7,642	66.3	8	7,650	66.7	0.1%	0.6%	5.8	3,061	1,837
8/13	20	8,747	7,533	56.4	4	7,537	56.6	0.1%	0.3%	5.2	1,178	707

Table 6-2E. Daily Effect of DADRP Scheduled Bids in the Western Superzone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP				
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Arc Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
8/14	11	9,197	8,264	73.9	3	8,267	74.1	0.0%	0.2%	6.3	1,386	831
8/14	12	9,332	8,397	85.6	6	8,403	85.9	0.1%	0.4%	5.9	3,051	1,831
8/14	14	9,354	8,606	129.9	3	8,609	130.2	0.0%	0.2%	6.4	2,504	1,502
8/14	15	9,092	8,590	138.5	7	8,597	139.2	0.1%	0.5%	6.5	6,291	3,775
8/14	17	9,000	8,358	112.4	4	8,362	112.7	0.0%	0.3%	6.4	2,878	1,727
8/14	18	8,880	8,137	88.2	8	8,145	88.8	0.1%	0.7%	6.7	4,704	2,822
8/14	20	8,825	7,802	68.3	4	7,806	68.6	0.1%	0.3%	6.3	1,727	1,036
8/14	21	8,675	7,809	64.2	8	7,817	64.6	0.1%	0.7%	6.6	3,371	2,023
8/15	11	8,820	8,166	76.8	3	8,169	77.0	0.0%	0.2%	6.6	1,523	914
8/15	12	8,906	8,233	84.1	6	8,239	84.5	0.1%	0.5%	6.3	3,205	1,923
8/15	14	9,003	8,335	139.7	3	8,338	140.0	0.0%	0.2%	6.7	2,819	1,691
8/15	15	8,964	8,296	139.7	7	8,303	140.5	0.1%	0.6%	6.7	6,574	3,944
8/15	17	8,799	8,057	112.3	4	8,061	112.6	0.0%	0.3%	6.3	2,827	1,696
8/15	18	8,525	7,881	82.5	8	7,889	83.1	0.1%	0.7%	6.5	4,298	2,579
8/15	20	8,399	7,632	65.2	4	7,636	65.4	0.1%	0.3%	6.1	1,591	954
8/16	9	8,413	7,557	55.9	6	7,563	56.2	0.1%	0.5%	6.5	2,179	1,307
8/16	11	8,998	8,088	79.5	3	8,091	79.7	0.0%	0.2%	6.5	1,541	925
8/16	12	9,108	8,176	83.3	6	8,182	83.7	0.1%	0.5%	6.3	3,131	1,879
8/16	14	9,246	8,237	131.4	3	8,240	131.8	0.0%	0.2%	6.8	2,678	1,607
8/16	15	9,096	8,096	125.2	6	8,102	125.8	0.1%	0.5%	6.8	5,079	3,048
8/16	17	8,776	7,845	92.8	3	7,848	93.0	0.0%	0.2%	6.4	1,794	1,077
8/16	18	8,515	7,597	59.0	6	7,603	59.3	0.1%	0.5%	6.4	2,281	1,369

Table 6-2E. Daily Effect of DADRP Scheduled Bids in the Western Superzone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
8/16	20	8,382	7,196	47.4	3	7,199	47.5	0.0%	0.1%	2.5	353	212
8/17	11	7,999	6,723	41.8	2	6,725	41.8	0.0%	0.1%	2.3	193	116
8/17	12	8,057	6,814	51.8	6	6,820	51.9	0.1%	0.2%	2.3	719	431
8/17	14	8,025	6,827	59.5	3	6,830	59.5	0.0%	0.1%	2.3	412	247
8/17	15	7,944	6,872	60.6	5	6,877	60.7	0.1%	0.2%	2.3	701	420
8/17	17	7,848	6,920	53.0	2	6,922	53.1	0.0%	0.1%	2.3	245	147
Hourly Avg.		8,464	7,591	74	7	7,598	74	0%	0%	5	2,146	1,288
Total		499,382	447,847		422	448,269					126,611	75,967

*As with most mathematical relations of this kind, the supply price flexibilities in the tables above are only vaild for small changes in load. Here the supply models are calibrated to the observed prices, and in mathematical terms, the load response was large. The average "arc" flexibilities only approximate the averages from the tables.

**The collateral benefits are equal to the difference in actual and simulated LBMP multiplied by load served.

*** The bill savings are estimated to be 0.6 of the total collateral benefits. This assumes that an average of 40% of load is purchased through bilaterals. Thus, this net amount is the savings to customers buying load in the DAM.