Chapter 1

Evaluation of the Effects of the NYISO's Price Responsive Load Programs on New York's Day-Ahead and Real-Time Markets for Electricity

The NYISO, in efforts to expand customer access to wholesale electricity markets in New York and to insure system security, designed two price-responsive load (PRL) programs that were implemented during the summer of 2001. One program, called the Day-Ahead Demand Response Program (DADRP), allows industrial, commercial, and residential customer aggregates to offer demand reduction bids into New York's day-ahead electricity market to help reduce system demand and receive market prices for scheduled load reductions. The second program is named the Emergency Demand Response Program (EDRP). Participants in EDRP are notified at least two hours in advance of when emergency system conditions are imminent, and they are guaranteed a minimum price for any load curtailment during that period (Figure 1.1).[1]

Many believe these types of PRL programs will bring additional "discipline" to the New York electricity markets. For some, the yardstick by which the success of PRL programs will be measured is their effect on the Locational Based Marginal Prices (LBMPs) in the Day-Ahead Market (DAM) and Real-Time Market (RTM), particularly their effectiveness in mitigating extreme price spikes.[2] This is especially true for

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[1] While under contract to the NYISO during the fall of 2000, Neenan Associates helped both to examine the feasibility of these PRL programs in New York market for electricity and in the programs' designs.

[2] The theory of how prices are determined in the DAM and RTM is developed in detail by Neenan Associates, 2000.

DADRP. The EDRP program is predicated mainly on the reliability benefits it can provide.

As part of the comprehensive evaluation of the performance of NYISO's two price-responsive load (PRL) programs it is essential to understand how load bids accepted in DADRP or load offered in EDRP will affect LBMPs in both the DAM and RTM. Estimates of these price effects provide a basis for quantifying the reliability benefits; they also help determine the over-arching, long-term value of PRL programs to customers, LSE's, and generators that comprise the NYISO membership. These effects have implications for market participation and for recruiting customers into the programs.

This first chapter of the report contains one of the three major elements of the program evaluation: an assessment of the market effects of the PRL programs during the summer of 2001. One major component of this analysis involves determining the effects of electricity prices in the two markets. It is also essential to document the collateral benefits to all customers from any price reductions due to load curtailments or program related on-site generation. The PRL programs can also affect average prices and price variability in both markets, and in external, bilateral markets for electricity. The implications of these changes for the price of contracts to hedge load are discussed. Finally, the implications of EDRP load for system security are discussed.

In what follows, we begin with some descriptive data that characterize the nature of LBMPs in both the DAM and RTM in several of the major zones for which separate hourly prices are determined. Next, we provide a detailed development of the supply model, including a discussion of the variables to be incorporated into the model and the "spline" formulation 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. The estimated models and supply flexibilities for individual zones or zonal aggregates are presented next. Emphasis is placed on the supply flexibility estimates for the afternoon hours of the summer months of 2001 since these hours are most likely to produce conditions that will trigger curtailments by PRL participants. Next, the data on the performance of customers in both EDRP and DADRP are presented and are used to estimate the effects of the program on electricity markets. Finally, some conclusions are drawn.

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

To understand the issues surrounding the estimation of zonal short-run supply curves for electricity in New York, it is helpful to examine some summary statistics on hourly LBMPs and demand during the summer 2001, the summer in which NYISO's new PRL programs were implemented. We focus on the afternoon hours (1pm through 7pm) 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.[3] These circumstances would suggest that the two PRL programs would be most active during this time of the day. Second, 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. At some point it may be useful to estimate supply functions for these other times

[3] The charts in Appendix 1A show that 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.

of the day, but such an extended analysis is not critical to the evaluation of the current PRL programs, and it is beyond the scope of this particular research effort.[4]

Table 1.1 contains summary statistics on LBMPs in the day-ahead market (DAM) and the real-time market (RTM) for the three summer months of 2001, as well as for fixed bid load in the DAM[5] and actual load served in the RTM. In the supply analysis below, the Capital zone is modeled separately, as are the NYISO pricing zones for New York City and Long Island. 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.[6]

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).[7] By combining zones in which prices seem to be similar, we facilitate the analysis and improve the ability to estimate the short-run

[4] Since DADRP allows customers to bid curtailments in any hour, PRL program curtailments actually are not confined to high afternoon hours.
[5] 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.
[6] Individual zonal results are provided in either an appendix or under a separate cover.
[7] 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.

supply relationships. Map 1.1 contains the boundaries of these aggregate zones in relation to the boundaries of the 11 individual pricing zones.

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.

Comparisons Across Markets

During the afternoon hours of the summer of 2001, total load served in real time in the New York State electricity market averaged nearly 23,988 MW, ranging from a low of 17,747 MW to a new system peak of 30,982 MW on August 9, 2001 (Table 1.1, last data set, third column). This new peak is 1.75 times higher than the State's minimum hourly demand, and it surpassed the previous system peak of 30,311 MW, reached July 6, 1999 by over 2% (NYISO Press Release, Aug. 10 2001). Statewide, the average fixed bid load in the day-ahead market, including bilaterals and energy purchased in the day-ahead market, averaged 22,720 MW, about 95% of the actual load served in real time. Fixed bid load ranged from a low of 16,978 MW to a high of 29,499 MW (Table 1.1, last data set, first column). The relative variation in load, as measured by the standard deviation divided by the mean is nearly identical in both markets.

To serve this electricity demand, generators throughout the State and in neighboring markets have pledged 36,132 MW of installed capacity (ICAP) to the New York market (NYISO Web Site). Generators are required to bid all ICAP into both day-ahead and real-time markets, but for a variety of reasons (some planned and others not), the amount available on any given day can fall short of this total. During the three summer months of 2001, generator bids into the day-ahead market averaged 90% of ICAP. Although not given in the table above, our analysis of these data indicate that this measure of supply availability ranged from a low of 85% to a high of 93%.[8] Clearly the availability and location of this capacity, particularly relative to transmission constraints, and the prices at which it is offered, affect the shape of the supply curves in the pricing zones.

This distribution of demand by zone also affects the prices at which demand is served. During afternoons this past summer, about 49% of average system-wide demand in real time came from downstate customers in New York or Long Island. These two downstate pricing zones are slightly more important in the DAM, accounting for about 52% of the average fixed bid load. Although not evident from the aggregate data in Table 1.1, this difference is due almost entirely to the somewhat larger demand in the DAM from New York City. In contrast, the western pricing zones account for a slightly larger share of average statewide demand in real time (32%) than they do in the DAM (29%). In the Capital zone, average demand in real time accounts for about 1% more of the statewide average than its share of what is scheduled statewide in the DAM. The shares of average demand in each market in the Hudson River "super" zone are nearly identical.

There are also differences by zone in terms of the proportion of load served in real time that is also scheduled in the DAM. Statewide, load scheduled in the DAM averages just under 95% of load served in real time. For New York and Long Island combined,

[8] Summary statistics on this variable are found in the tables that report the estimated supply flexibilities in which this variable is included as an explanatory variable (Tables 1.2 and 1.3)

load scheduled in the DAM averages just over one percent above load served in real time, while in both the Capital zone and western New York, load scheduled in the DAM is only about 85% of real time demand.

It is difficult to ascertain the proportion of demand in real time that is actually settled at real-time prices from the average load values reported in Table 1.1 alone. A somewhat more accurate measure can be derived by first taking the differences in load scheduled in the DAM and served in the RTM, and then calculating the average percentage difference. We return to this issue below, as the amount of load settled in the real-time market does affect the size of the immediate benefits of EDRP to participants in the wholesale market. The amount of load settled in the DAM, relative to the size of bilateral contracts, also affects the immediate benefits in the DAM due to DADRP.

Statewide, LBMP in the day-ahead market during the summer of 2001 averaged $75/MW, just $1 less than the average LBMP of $76/MW in the real-time market (Table 1.1). The range in real-time prices and the standard deviation was slightly larger as well. In both New York City and Long Island average prices in the DAM are below those in the RTM, substantially so in Long Island. In contrast, the reverse is true in the Capital zone and in Western New York.

Throughout the afternoon hours of the summer, not only are statewide average prices in the two markets (the DAM and the RTM) somewhat different, the variability in weighted average zonal prices was slightly higher in relative terms in the real-time market. The same conclusions, however, do not hold for the five regions for which separate supply functions are estimated below. This fact can help formulate hypotheses about how the two short-run electricity supply functions in each of the various zones might differ, as we discuss below.

When comparing the DAM and RTM within each region, one might expect the price response flexibility of supply (e.g. the percentage change in price as load is changed by one percent) to be higher in the market with: 1) higher average prices, 2) greater price variability, and 3) less variability in load. This tentative hypothesis is tested formally in the econometric analysis below. If the hypothesis is substantiated by the data, one would expect that the price flexibility of supply in the RTM would be greater than in the DAM in New York City and Long Island. The reverse would be true for the Hudson River and Western New York "super" zones and for the Capital zone.

This short review of the characteristics of prices and demand in New York electricity markets by zone highlights the fact that short-run supply schedules for some of the various pricing zones must be estimated separately. This necessity is further underscored by simply looking at scatter diagrams of the LBMPs plotted against fixed bid load or actual load. These scatter diagrams for each of the zones (with New York City and Long Island aggregated together) for the summer of 2001 are contained in Charts 1.1 through 1.8. One can see from these charts that the supply functions appear to be quite different for the zones. The basic "hockey stick" shape is evident, but in some zones there are cases where prices are low, even if demand is high. Alternatively, there are observations where prices are high despite less than peak demand. These situations are likely to be the result of different system conditions. These issues, and how to model them are discussed below.

The Econometric Model of Supply

Since these PRL programs essentially affect the amount of load to be purchased in the DAM and/or served in real time, the process of estimating the effects of these programs on prices involves two separate steps:

1. quantifying the PRL load response to changes in prices in the DAM and the RTM (the demand side) or changes in program payments offered for curtailments; and

2. quantifying the change in price due to changes in the amount of PRL load bought or sold (the supply side).

This chapter focuses on the second of these two steps. Our work to quantify participants' price responsiveness is reported in Chapter 2.

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 a little over 2 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, including two full summers.[9] Given that the markets are so new, it remains to be seen if the data are sufficiently robust to identify the empirical supply relationships with any degree of statistical precision, particularly in terms of there being sufficient variation in the load and price data to support confidence in the parameter estimates. Our task is complicated further since we were unable to employ data on generator bids or their bid curves, which may be critical to precisely identifying the supply function in the DAM. However, for the RTM, we do have access to data on transmission constraints and net imports of electricity which proved to be essential in identifying the supply function in the RTM. More is said about the data below.

There are essentially three issues to be discussed in defining the appropriate specification for the short-run supply functions in both the DAM and the RTM. They relate to:

- the way in which equilibrium prices and quantities are determined in the markets;
- the appropriate model specification and selection of explanatory variables; 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

As stated above, the form of the econometric specification of supply and demand models depends importantly on how the particular markets of interest function (Tomek and Robinson, 1981). In the markets for many commodities, for example, economists

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[9] 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.

often assume that equilibrium prices and quantities are determined simultaneously, and, therefore, supply and demand relationships are modeled and estimated together using simultaneous equation estimation techniques (e.g. Tomek and Robinson, 1981; Chambers, 1988). In other markets, such as some agricultural markets, quantity supplied is often thought to be determined in response to some expected or forecasted price at the time when production decisions are made, but long before actual output is realized (Tomek and Robinson, 1981). Explicit recognition of this decision process leads to the specification of a recursive modeling strategy brought about in large measure because of the biological nature of agricultural production. A production decision must be made long before its consequences are realized.

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.[10]

[10] Estimating these electricity supply relationships is nearly identical to the pseudo-data methods developed by both 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 models. Griffin, for example, used pseudo-data arising from LP solutions to estimate a summary electricity cost function for later incorporation into the Wharton econometric model. In Preckel and Hertel's application, a complete system of output supply and input demand functions for agricultural commodities and inputs was estimated. The observations on quantities were the optimal output levels of several products determined by the successive solutions to the programming model. The prices were those assumed for each of the corresponding programming solutions. To map out the entire supply surface, the authors developed a complex sampling design to generate a wide range of relative input and output price differentials. In turn, these simulated data were used to estimate econometrically a smooth supply and input demand surface assuming a translog flexible functional form.
Viewed from a very practical perspective, this pseudo-data exercise is strictly a convenient way to summarize the relationships between the input data and the solutions to complex programming models. This is accomplished by regressing the solutions of the programming models on the input data to the programming models themselves. In a very real sense, the LBMPs from the DAM and the RTM are generated in exactly the same way as the data used in these "pseudo-data" exercises. The major difference is that the supply and demand quantities are used as input data in the SCUC and SCD models, and it is the prices that are determined by the solution to the model. Because of the way in which the data are generated, we identify the price-dependent supply curve.

If there were no shifts in supply due to different generator availability or general level of prices bid, there would be no need for generator bid data to identify the supply response flexibilities. However, these factors, and others as well, 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 a number of explanatory variables other than load.

The Econometric Model Specification for Short-Run Electricity Supply Relationships

In what follows, we outline briefly, and in a most general form, separate short-run supply specifications for both the DAM and the RTM market supply curves. The appropriate price variables to be used as dependent variables in the regressions are defined, as are the appropriate load variables reflecting the level of demand. As suggested above, some other variables are also hypothesized to affect LBMPs, and they are listed in general terms. The form in which these other variables enter the supply functions will depend of the availability of data.

Short-Run Supply in the DAM. To specify this model in a most general form, we define, for month or season i, zone j, and the t^{th} hour of the day:

$LBMPA_{ijt}$ = locational based marginal price in day-ahead market;

$BLKWA_{ijt}$ = zonal bid load day ahead;

ADJ_BLKWA_{ijt} = bid load day ahead in zones adjacent to zone j;

$FLKWA_{ijt}$ = ISO forecast of system load in day-ahead market;

ADJ_FLKWA_{ijt} = ISO forecast system load day-ahead in zones adjacent to j;

$GENAV_{ijt}$ = a measure of zonal generator availability; and

$SUPPRICE_{ijt}$ = a measure of zonal supply prices for power, particularly the high priced units;

ADJ_GENAV_{ijt} = a measure of generator availability in adjacent zones;

$ADJ\_SUPPRICE_{ijt}$ = a measure of supply prices for power of high priced units in adjacent zones;

u_{ijt} = an error term.

In functional notation, the general model of price determination in the DAM is:

$$LBMPA_{ijt} = F(BLKWA_{ijt}, FLKWA_{ijt}, ADJ\_BLKWA_{ijt}, ADJ\_FLKWA_{ijt}, GENAV_{ijt}, SUPPRICE_{ijt}, ADJ\_GENAV_{ijt}, ADJ\_SUPPRICE_{ijt}, u_{ijt}).$$

Short-Run Supply in the RTM. To specify this model in a most general form, we again define, for month or season i, zone j, and the t^{th} hour of the day:

$LBMPR_{ijt}$ = locational based marginal price in real-time market;

$ALKWA_{ijt}$ = zonal actual load served in the real-time market;

ADJ_ALKWA_{ijt} = actual load served in real-time in zones adjacent to zone j;

$NIMPKW_{ijt}$ =net imports of electricity by the NY electricity market;

$CWBTC_{ijt}$ = capacity weighted part of an hour when transmission constraints bind in j;

v_{ijt} = an error term.

In functional notation, the general model of price determination in the RTM is:

$$LBMPR_{ijt} = F(ALKWA_{ijt}, NIMPKW_{ijt}, ADJ\_ALKWA_{ijt}, CWBTC_{ijt}, v_{ijt}).$$

Some Modeling Issues

From a careful examination of the data for the operation of New York's day-ahead wholesale electricity market, it is clear that the prices (LBMPs) are an increasing function of fixed bid load (Neenan Associates, 2001). Further, it appears that this function is relatively flat for low and modest levels of fixed bid load, but then rises sharply as bid load approaches available system capacity. Thus, it is reasonable to expect that the supply price flexibilities (the percentage change in price resulting from a percentage change in bid load) are not constant, but are a function of bid load or actual load served.

To capture this relationship with any large degree of precision, we need to use an extremely "flexible" functional form (Boisvert, 1982; Chambers, 1988, Diewert, 1974, Tishler and Lipovetsky, 1997), such as a general higher order polynomial or a polynomial in the logarithms of the dependent and independent variables.[11] Unfortunately, given that the size of the bid loads are normally an order of magnitude larger than LBMPs, except at the extremes of the data, it is difficult to capture such marked differences with a single polynomial function. This situation is illustrated in Exhibit 1.1. It is almost as though the relationships between bid load and LBMPs are structurally different (representing different regimes or states of the system) at the extremes of the data, each of which is different still from the middle range. These separate regimes are illustrated in Exhibit 1.2.

To capture these differences in the structure of economic relationships over time or in the cross-section, supply models are often specified as piece-wise "spline" functions, so that the intercepts and slopes of the functions can change at specified intervals (Exhibit 1.3). Ando (1998), for example, uses a "spline" specification to allow

[11] The term "flexible" functional form was originally defined by Diewert (1974) and is most often used in the context of indirect cost and profit functions, from which output supply functions are derived. In general, the requirement for a function to be "flexible" (not to be confused with the supply price response flexibilities to be calculated in this analysis) precludes the simple imposition of global concavity on the cost function. This means that there could be multiple profit maximizing or cost minimizing optima. This is not serious in our case. Our primary reason for initially trying to use a "flexible" functional form specification was to identify a mathematical

for a piece-wise linear trend in economic data, while Schenkel and Boisvert (1994) use a complex "spline" specification to model the 24-hour electricity load shape for dairy farms, and Poirier (1976, 1977) applied a similar specification to estimating electricity demand by season and by time-of day.

In addition to accommodating these separate regimes, the supply model must also be able to reconcile what appears to be conflicting observations in the data: situations where high demands lead to extremely high prices and other situations with equally high demands but very low prices. There are also situations in which modest demand can be served only at relatively high prices. The high prices associated with the high demands are consistent with a continuous supply formulation and are to be expected. These points are at the extreme range of regime 3 in Exhibit 1.4. The other situations are characterized by the points circled in Exhibit 1.4, and must be explained by differences in system conditions, e.g. transmission line congestion, unexpected generator outages and other reasons why generator bids fall short of installed capacity, or demand conditions in adjacent zones.

These circumstances can be expected to affect the slope of the supply function in one or more of the regimes, as shown in Exhibit 1.5. When system conditions are normal, the supply curve is S1. A large load (greater than the load, represented by knot 2, at which regime 3 begins) can be served at modest prices. Moreover, a small increase in load leads to a modest increase in price; the supply flexibility is low. Curves S2 and S3 are the supply schedules representative of states where system conditions deteriorate, or as demands in adjacent zones increase. Under these conditions, an initial load (greater

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function that can accommodate the hypothesized extremely non-linear nature of electricity supply.

than knot 2) can be served only at respectively higher prices than for supply curve S1. Further, to serve incremental load, prices must increase by more than under normal conditions. Thus, as the supply curve shifts to the left and becomes steeper (as depicted by S2 and S3 in Exhibit 1.5), the supply flexibilities increase as well.

By including variables in addition to load that explain how these alternative states evolve the model specifications, it is possible to capture these changes in system conditions. By including them as separate variables, each of them would shift the supply functions in each regime up or down in a parallel fashion. Another alternative is to form "interaction" variables by multiplying them by load served. In this way, these interaction variables effectively change the slope of the function in one or more of the regimes. In the derivations that follow, we illustrate how the "spline" function can be estimated using ordinary least squares (OLS) through variable transformations involving the introduction of dummy variables for each regime. We demonstrate how these "interaction" variables can be accommodated as well to provide sufficient flexibility in the model to capture these complex effects.

In the empirical analyses below, the supply models for both the DAM and the RTM are specified as "spline" functions including several variables. In each case, however, the "splines" are defined in terms of ranges on fixed bid load in the DAM, or actual load in the RTM. Therefore, to develop the models and demonstrate how they can be manipulated for econometric estimation, it is sufficient to illustrate using the model for the DAM. It is also sufficient to assume there is only one independent variable other than fixed bid load. The analysis then can be similarly applied to the RTM and expanded to include additional independent "shifter" variables in a straightforward fashion.

<u>The "Spline" Formulation of the Supply Curve</u>

To develop the "spline" formulation of supply, we must identify the points (often called knots) at which the supply relationship changes its structure. For our purposes, these "knots" are defined to isolate the ranges over fixed bid load for which the supply envelope is functionally different. We hypothesized that three regimes should be sufficient, and as is seen below, 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 bid load measured in logarithmic terms (lnFBL):

(1) $D_1 = 1$ if $\ln FBL \leq \ln FBL_1^*$, otherwise $D_1 = 0$;

(2) $D_2 = 1$ if $\ln FBL_1^* < \ln FBL \leq \ln FBL_2^*$, otherwise $D_2 = 0$;

(3) $D_3 = 1$ if $\ln FBL > \ln FBL_2^*$, otherwise $D_3 = 0$.

where FBL = fixed bid load and the subscripts indicate specific MW loads

<u>The Linear "Spline" Function.</u> Now, for a linear "spline" specification, the inverse supply relation is given by:[12]

(4) $\ln LBMP = \alpha_1 D_1 + \alpha_2 D_2 + \alpha_3 D_3 + \beta_1 D_1 \ln FBL + \beta_2 D_2 \ln FBL$

$+ \beta_3 D_3 \ln FBL.$

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:

(5) $\alpha_1 + \beta_1 \ln FBL_1^* = \alpha_2 + \beta_2 \ln FBL_1^*$ or

$\alpha_1 = - \beta_1 \ln FBL_1^* + \alpha_2 + \beta_2 \ln FBL_1^*$.

(6) $\alpha_2 + \beta_2 \ln FBL_2^* = \alpha_3 + \beta_3 \ln FBL_2^*$ or

$\alpha_3 = - \beta_3 \ln FBL_2^* + \alpha_2 + \beta_2 \ln FBL_2^*$.

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) $\ln LBMP = \alpha_2 \{ D_1 + D_2 + D_3\} + \beta_1 \{ D_1 [\ln FBL - \ln FBL_1^*]\}$

$+ \beta_2 \{ D_1 \ln FBL_1^* + D_2 \ln FBL + D_3 \ln FBL_2^*\}$

$+ \beta_3 \{ D_3 [\ln FBL - \ln FBL_2^*]\}$.

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 FBL are:

(8) $\partial \ln LBMP / \partial \ln FBL = \beta_1$, if $\ln FBL \leq \ln FBL_1^*$;

[12] 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.

(9) $\partial \ln LBMP / \partial \ln FBL = \beta_2$, if $\ln FBL_1^* < \ln FBL \leq \ln FBL_2^*$;

(10) $\partial \ln LBMP / \partial \ln FBL = \beta_3$, if $\ln FBL > \ln FBL_2^*$.

Thus, while these supply price flexibilities are constant over the corresponding ranges in fixed bid 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 fixed bid load rises—that is $\beta_1 < \beta_2 < \beta_3$. We constrain the calculated value of lnLBMP at the three "knots" to be equal in approaching the "knot" from either direction; it is these constraints that allow the flexibilities to differ. From equation (5) we see that $\beta_1 < \beta_2$, as long as $\alpha_1 > \alpha_2$. Likewise, $\beta_2 < \beta_3$ as long as $\alpha_2 > \alpha_3$.

***A Non-Linear "Spline" Formulation*.** This linear "spline" formulation adds tremendous flexibility to the supply model, but it still requires that the price flexibility is constant within a particular interval of FBL. To relax this restriction, we need only make this formulation non-linear in the logarithm of FBL. For the same ranges in FBL as specified in equations (1) through (3), we can write:

(11) $$\ln LBMP = \alpha_1 D_1 + \alpha_2 D_2 + \alpha_3 + \beta_1 D_1 \ln FBL + \beta_2 D_2 \ln FBL + \beta_3 D_3 \ln FBL + \gamma_1 D_1 [\ln FBL]^2 + \gamma_2 D_2 [\ln FBL]^2 + \gamma_3 D_3 [\ln FBL]^2.$$

For this model, we must impose constraints at the "knots" similar to those above:

(12) $$\alpha_1 + \beta_1 \ln FBL_1^* + \gamma_1 [\ln FBL_1^*]^2 = \alpha_2 + \beta_2 \ln FBL_1^* + \gamma_2 [\ln FBL_1^*]^2$$

(13) $$\alpha_2 + \beta_2 \ln FBL_2^* + \gamma_2 [\ln FBL_2^*]^2 = \alpha_3 + \beta_3 \ln FBL_2^* + \gamma_3 [\ln FBL_2^*]^2.$$

By solving for α_1 and α_3 in equation (12) and (13), we can also transform the variables in equation (11) and estimate it using OLS. The estimating equation becomes:

(14) $$\ln LBMP = \alpha_2 \{ D_1 + D_2 + D_3 \} + \beta_1 \{ D_1 [\ln FBL - \ln FBL_1^*] \} + \beta_2 \{ D_1 \ln FBL_1^* + D_2 \ln FBL + D_3 \ln FBL_2^* \}$$

$$+ \beta_3 \{ D_3 [\ln FBL - \ln FBL_2^*] \}$$

$$+ \gamma_1 \{ D_1 [(\ln FBL)^2 - (\ln FBL_1^*)^2] \}$$

$$+ \gamma_2 \{ D_1 (\ln FBL_1^*)^2 + D_2 (\ln FBL)^2 + D_3 (\ln FBL_2^*)^2 \}$$

$$+ \gamma_3 \{ D_3 [(\ln FBL)^2 - (\ln FBL_2^*)^2] \}.$$

Again, the first term in this expression reduces to a standard constant term, and the other intercept coefficients are identified from equations (12) and (13). Further, the partial logarithmic partial derivatives of equation (11) with respect to the logarithm of FBL are:

(15) $\partial \ln LBMP / \partial \ln FBL = \beta_1 + 2 \gamma_1 [\ln FBL]$, if $\ln FBL \leq \ln FBL_1^*$;

(16) $\partial \ln LBMP / \partial \ln FBL = \beta_2 + 2 \gamma_2 [\ln FBL]$, if $\ln FBL_1^* < \ln FBL \leq \ln FBL_2^*$;

(17) $\partial \ln LBMP / \partial \ln FBL = \beta_3 + 2 \gamma_3 [\ln FBL]$, if $\ln FBL > \ln FBL_2^*$.

The supply price flexibilities now differ by interval, but within each interval, the flexibility in turn depends on the level of fixed bid load. That is, if one wants to use these flexibilities to estimate the percentage reduction in price due to a reduction in load served, that percentage change depends on the initial load to be served before any load is shed.

We would expect that all the supply price flexibilities to be positive, and that the one in equation (15) would be smaller than the one in (16), and the one in (17) to be larger than the one in (16). A sufficient, but not necessary, condition for them all to be positive is that all the γ coefficients be positive. The extent to which the γ's rise in moving from the left to right across the intervals is also an empirical question, and to some extent depends on the selection of the "knots".

A "Spline" Model with Selective Restrictions on the Parameters. The above specification may be too "flexible" to provide precise results and may lead to extreme problems of multicollinearity because of the high correlation between a variable and its squared value. In these cases, one will not be able to identify the separate effects of these variables. However, it is reasonable to expect that prices would most often be too low for there to be any PRL (particularly EDRP) to be called when fixed bid load is in the low to middle range. Thus, it is most important to specify a model in which the price flexibility can vary with fixed bid load when fixed bid load is approaching its maximum or approaching available system capacity. We can accommodate this specification by merely restricting γ_1 and γ_2 to be zero in equation (11). By so doing, the specification of the constraints and the estimating equation becomes:

$$\text{(11a)}\quad \ln LBMP = \alpha_1 D_1 + \alpha_2 D_2 + \alpha_3 + \beta_1 D_1 \ln FBL + \beta_2 D_2 \ln FBL + \beta_3 D_3 \ln FBL + \gamma_3 D_3 [\ln FBL]^2.$$

For this model, we must still impose constraints at the “knots” similar to those above:

$$\text{(18)}\quad \alpha_1 + \beta_1 \ln FBL_1^* = \alpha_2 + \beta_2 \ln FBL_1^*$$

$$\text{(19)}\quad \alpha_2 + \beta_2 \ln FBL_2^* = \alpha_3 + \beta_3 \ln FBL_2^* + \gamma_3 [\ln FBL_2^*]^2.$$

By solving for α_1 and α_3 in equation (18) and (19), we can also transform the variables in equation (11) and estimate it using OLS. The estimating equation becomes:

$$\text{(20)}\quad \ln LBMP = \alpha_2 \{ D_1 + D_2 + D_3\} + \beta_1 \{ D_1 [\ln FBL - \ln FBL_1^*]\} + \beta_2 \{ D_1 \ln FBL_1^* + D_2 \ln FBL + D_3 \ln FBL_2^*\} + \beta_3 \{ D_3 [\ln FBL - \ln FBL_2^*]\} + \gamma_3 \{ D_3 [(\ln FBL)^2 - (\ln FBL_2^*)^2]\}.$$

Again, the first term in this expression reduces to a standard constant term, and the other intercept coefficients are identified from equation (18) and (19). Further, the partial logarithmic partial derivatives of equation (11a) with respect to the logarithm of FBL are:

(21) $\partial \ln LBMP / \partial \ln FBL = \beta_1$, if $\ln FBL \leq \ln FBL_1^*$;

(22) $\partial \ln LBMP / \partial \ln FBL = \beta_2$, if $\ln FBL_1^* < \ln FBL \leq \ln FBL_2^*$;

(23) $\partial \ln LBMP / \partial \ln FBL = \beta_3 + 2\,\gamma_3\,[\ln FBL]$, if $\ln FBL > \ln FBL_2^*$.

The supply price flexibilities now still differ by interval, but it is only within the last interval that the flexibility depends on the level of fixed bid load. In this last interval, if one wants to use these flexibilities to estimate the percentage reduction in price due to a reduction in load served, then that percentage change depends on the initial load to be served before any load is shed. This model is a hybrid between the model in equation (7) and the model in equation (11).

<u>A "Spline" Model with Interaction Terms</u>. The final important modification of the "spline" model is one that allows for interactions between the variable over which the "spline" is defined and other continuous or discrete variables. This formulation follows. The model includes a variable X that shifts all segments of the function in the same fashion and an interaction term, X lnFBL (e.g, X multiplied by lnFBL), whose slope differs between the "knots". The "spline" equation becomes:

(24) $$\ln LBMP = a_1D_1 + b_1D_1X + c_1D_1 \ln FBL + d_1D_1\,X \ln FBL$$
$$+ a_2D_2 + b_2D_2X + c_2D_2 \ln FBL + d_2D_2\,X \ln FBL$$
$$+ a_3D_3 + b_3D_3X + c_3D_3 \ln FBL + d_3D_3\,X \ln FBL$$

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

(25) $$a_1 + b_1X + c_1 \ln FBL_1^* + d_1X \ln FBL_1^* = a_2 + b_2X + c_2 \ln FBL_1^* + d_2X \ln FBL_1^*$$

(26) $$a_3 + b_3X + c_3 \ln FBL_2^* + d_3X \ln FBL_2^* = a_2 + b_2X + c_2 \ln FBL_2^*$$

$+ d_2X \ln FBL_2^*$.

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 lnFBL on lnLBMP to be higher for values of lnFBL across successive knots. A sufficient, but certainly not a necessary condition, for this to happen is for $c_3 > c_2 > c_1$; $d_3 > d_2 > d_1$; and $a_1 > a_2 > a_3$. If this were merely a linear “spline” function in lnFBL, 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:

(27) $a_1 = a_2 + b_2X + c_2 \ln FBL_1^* + d_2X \ln FBL_1^*$
$-[b_1X + c_1 \ln FBL_1^* + d_1X \ln FBL_1^*]$; and

(28) $a_3 = a_2 + b_2X + c_2 \ln FBL_2^* + d_2 \ln FBL_2X^*$
$-[b_3X + c_3 \ln FBL_2^* + d_3X \ln FBL_2^*]$.

Substituting these expressions into equation (24), we have;

(29) $\ln LBMP = D_1 \{a_2 + b_2X + c_2 \ln FBL_1^* + d_2X \ln FBL_1^*$
$- [b_1X + c_1 \ln FBL_1^* + d_1X \ln FBL_1^*]\}+ b_1D_1X + c_1D_1 \ln FBL$
$+ d_1XD_1 \ln FBL + a_2D_2 + b_2D_2X + c_2D_2 \ln FBL + d_2D_2X \ln FBL$
$+ D_3 \{ a_2 + b_2X + c_2 \ln FBL_2^* + d_2X \ln FBL_2^* - [b_3X + c_3 \ln FBL_2^*$
$+ d_3X \ln FBL_2^*]\}+ b_3D_3X + c_3D_3 \ln FBL + d_3D_3X \ln FBL$.

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

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

$+b_3\ [D_3X\text{-}D_3X]$

$+\ c_1\ [D_1\ \ln FBL\ \ – D_1\ \ln FBL_1^*]$

$+\ c_2\ [D_1\ \ln FBL_1^* + D_2\ \ln FBL\ \ + D_3\ \ln FBL_2^*]$

$+\ c_3\ [D_3\ \ln FBL\ \ – D_3\ \ln FBL_2^*]$

$+\ d_1\ [D_1X\ \ln FBL – D_1X\ \ln FBL_1^*]$

$+\ d_2\ [D_1X\ \ln FBL_1^* + D_2X\ \ln FBL\ \ + D_3X\ \ln FBL_2^*]$

$+\ d_3\ [D_3\ \ln FBL – D_3\ \ln FBL_2^*]$

Again, since the sum of the zero-one variables, $[D_1+ D_2+ D_3]$ is unity, and the terms associated with b_1 and b_3 are zero, a_2 becomes an intercept term, and X, the variable that shifts the function in the same way across “knots”, becomes a standard level term in the regression. This means that a_2, the intercept for the second segment, is identified directly in the regression along with the other coefficients, but a_1 and a_3 must be evaluated using equations (25) and (26). 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 lnFBL, 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 lnFBL.

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 (24) the marginal effects of lnFBL and X on lnLBMP. Taking the partial derivatives of lnLBMP with respect to lnFBL for the three segments, we have:

(31) $\partial\ \ln LBMP / \partial\ \ \ln FBL = c_1 +\ [d_1X]$, if $\ln FBL\ \le\ \ln FBL_1^*$;

(32) $\partial\ \ln LBMP / \partial\ \ \ln FBL = c_2 +\ [d_2X]$, if $\ln FBL_1^* <\ \ln FBL\ \le\ \ln FBL_2^*$;

(33) $\partial\ \ln LBMP / \partial\ \ \ln FBL = c_3 +\ [d_3X]\ [\ \ln FBL]$, if $\ln FBL\ >\ \ln FBL_2^*$.

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 lnFBL if it were not for the interaction terms between X and lnFBL. Because of the interaction, the partial derivatives of lnLBMP with respect to X are:

(14a) $\partial \ln LBMP / \partial X = b_2 + d_1[\ln FBL]$, if $\ln FBL \leq \ln FBL_1^*$;

(15a) $\partial \ln LBMP / \partial X = b_2 + d_2[\ln FBL]$, if $\ln FBL_1^* < \ln FBL \leq \ln FBL_2^*$;

(16a) $\partial \ln LBMP / \partial X = b_2 + d_3[\ln FBL]$, if $\ln FBL > \ln FBL_2^*$.

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

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. The results for the day-ahead market are in Tables 1.2 through 1.6, while those for the real-time market are in Tables 1.7 thorough 1.11. In each table, the estimated coefficients for each of the explanatory variables are reported, along with the t-ratios.[13] For the most

[13] 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).
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

part, the supply models are specified entirely in logarithmic form so that the supply flexibilities are calculated according to equations (8-10), (21-23), and (31-33), respectively, if there are no interaction terms with load, if load squared is in the model, and if there are other interaction terms with load.[14]

Before discussing the specific results in detail, some general comments are in order. Overall, the performance of the supply models is quite remarkable. In most cases at least half (or nearly so) of the variation in the dependent variable is explained. For the day-ahead market, upwards of 80% of the variation in LBMP 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 performance of the real-time models is not as good as for the day-ahead models in terms of overall explanatory power. This is to be expected. LBMPs in the DAM are determined analytically by the solution of the day-ahead scheduling algorithm,

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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.

[14] 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

SCUC, that determines the minimum-cost generation schedule to meet fixed bid load in the DAM. The scheduling algorithm in the real-time market, SCD, also minimizes the cost of meeting load, but 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 lead to greater variation in LBMP than would occur in the DAM. 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. It is also less likely that the effects of these actions on the LBMP in real time could be explained 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 from DADRP or 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

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, as well as the average values, are reported in the bottom

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advantages of the logarithmic specification (goodness of fit, flexibility as a functional form, and sections of Tables 1.2 through 1.11. The formulas for calculating them are provided in Appendix 1B, as are the definitions of the variables used in the regressions.

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 Exhibits 1.1 through 1.5). 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.

Above, 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. In markets where at least two of these conditions hold in comparing the DAM with the RTM in a given zone, our hypothesis, formulated from examining the summary data in Table 1.1, is supported by the empirical evidence. Supply price flexibilities are indeed larger in the RTM than in the DAM in New York City, Long Island and the Hudson “super” zone. The reverse is true in the Capital zone, and in Western New York.

Zonal Comparisons

In the RTM, the price flexibility is highest in New York City (14.52), followed by Long Island (10.40) and the Hudson region (8.62). Although still substantial, the flexibility in the Capital zone of about 8.4 is only 58% of that in the City. In western New York (6.44), the supply price flexibility is only 44% of that in the City.

In the DAM, the situation is somewhat different. Here, the supply price flexibility of 11.77 in the Capital zone is about one-quarter higher than it is in New York City

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the ease in calculating supply price flexibilities) clearly outweighed this slight disadvantage.

(9.42). Somewhat surprisingly, the supply price flexibility in the DAM for western New York (9.32) is nearly as high as it is in the City. Given the relatively high price flexibilities in the RTM, the relatively low flexibilities for both Long Island (5.05) and the Hudson region (5.08) defy easy explanation. In these study regions, the LBMPs in the DAM are less than half as responsive to load changes as they are in the Capital zone. While these results were unexpected, the statistical performance of these two models was also rather disappointing relative to the other models. Since there is little or no participation in DADRP in these regions, these rather disappointing results will not affect the DADRP program evaluation below in any significant way. However, if these regions are to become targeted in future DADRP subscription efforts, resolving these ambiguities is important

Supply Shifters

Although hourly data on system conditions by zone are relatively limited, there were several variables that performed well statistically and their effects on LBMPs and supply flexibilities were as expected. For example, in the RTM, the extent of congestion on major transmission lines increased the supply price flexibility for both New York and Long Island. Load served in adjacent zones affects the level of LBMP in both New York and Long Island, but not the supply flexibilities. The fact that lagged load and lagged forecast load positively affect the supply price flexibilities in the Capital zone in the current hour could help predict those times when load relief would put significant downward pressure on LBMP.

In the DAM, increases in adjacent zonal load do lead to increases in the supply price flexibilities in New York, Long Island, and the Hudson “super” zone. Higher lagged load also leads to higher supply price flexibilities in the Hudson “super” zone and on Long Island. Finally, the amount of load scheduled in DADRP would lead to higher supply price flexibilities in both the Capital zone and in western New York. It is difficult to know if this effect will be sustained over time. Due to the small number of hours in which DADRP load is scheduled, this effect could merely reflect the fact that prices need to be relatively high before any DADRP load is scheduled.

In eight of the 10 models, the supply price flexibility falls as the amount of available generation (relative to ICAP) rises system wide. This is certainly the effect one would expect. However, in the RTM for the Capital zone and Long Island no significant relationship between this variable and LBMP was found, which is somewhat perplexing but explainable. There are mitigating zonal forces, like transmission line constraints, which render an increase in state-wide generation levels ineffective at lowering prices in these regions. This is all the more reason to focus PRL programs here.

Overall Strategy for Evaluating the Effects of the PRL Programs

These estimates of the supply flexibilities are a critical element in calculating the effects of PRL load reduction on electricity prices, and in the overall program evaluation. The Day-Ahead Demand Response Program (DADRP) allows industrial, commercial, and large residential customers to offer demand reduction bids into New York’s day-ahead electricity market to help reduce system demand and receive market prices for any load reduction. Participants in the Emergency Demand Response Program (EDRP) are notified at least two hours in advance of when emergency system conditions are imminent, and they are guaranteed a minimum price for any load curtailment.

The overall strategy for evaluating both the DADRP and the EDRP, and a list of the major market effects are given in Exhibit 1.6. Each of the programs is evaluated in turn, and the quantitative estimates of the major market effects are discussed. We begin with an evaluation of EDRP.

The EDRP Evaluation

Market Effects of EDRP

The theory underlying the effect of load reduction or on-site generation during an EDRP event is developed in detail in an earlier report to the NYISO by Neenan Associates (2001). The major components of this theory are illustrated simply in Exhibits 1.7a and 1.7b. In developing this theory, it is assumed that demand is initially at Q2 in Exhibit 1.7a. When the event is called, demand is reduced to Q1 due to the load reduction and on-site generation, and the LBMP in the RTM falls from P2 to P1. When an event is called, the situation could in fact be worse than the one in the Exhibit. Demand could initially be well beyond Q2, *not* intersecting the supply curve at all.

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

To assess the effects of actual EDRP events, one must essentially view things in reverse order. That is, once an EDRP event is called, the market equilibrium is at point 1 in Exhibit 1.7a. The observed price and quantity are P1 and Q1, respectively. Now, using the estimated supply price flexibilities from above (combined with data on actual EDRP load response), one must simulate what LBMP would have been had the event not been called—in this case simulate point 2 in Exhibit 1.7a. As indicated in Exhibit 1.6, the most significant market effects are:

1. Reduction in RT-LBMP;
2. EDRP Payments (the shaded area 3 in both Exhibits 1.7a and 1.7b);
3. Collateral Benefits, or Savings to Customers (shaded area 4 in Exhibit 1.7b);
4. Any Reduction in Average Price or Price Variability; and
5. Effects on System Reliability.

After first describing the August 2001 EDRP events, empirical estimates of these various market effects are provided. In most cases, these effects are broken out by pricing zone or "super" zone. Since the pricing zones were established for reasons other that overall system security, the discussion of this latter issue is most effectively done at the system level.

August 2001 EDRP Events

In August of 2001, the NYISO called EDRP events on August 7, 8, 9, and 10—the days during which the New York Electricity market reached a new historic system peak. The events differed in duration:

- August 7--3:00 p.m. through 6:00 p.m.;
- August 8--1:00 p.m. through 6:00 p.m.;
- August 9--11:00 a.m. through 6:00 p.m.; and
- August 10--1:00 p.m. through 5:00 p.m[15].

[15] Although the NYISO called the August 10th EDRP event to start at 1:30 PM, for settlement purposes, the event was considered to have begun at 1:00 PM.

Combined, these events spanned 23 hours. On the final day, the event was called only for selected pricing zones—the Capital zone, Hudson "super" zone, New York City, and Long Island. The event was not called for any of the pricing zones in our western New York "super" zone.

At the time the events were called, there were a total of 292 end-use customers enrolled in EDRP (Table 1.12). Of this total, 72% subscribed to EDRP through an LSE, while another 25% subscribed through a CSP. Some of the customers in the "other" category are direct serve customers from the NYISO. One quarter of the customers have also participated in either PON 577 or PON 585, NYSERDA's Peak Load Reduction and Enabling Technology programs, respectively. These programs offered financial assistance to firms for the purchase of load reduction or load shifting technology, and/or metering and communications equipment that could well have been an integral part of customers' decisions to participate in EDRP. The effect of these programs on participation is discussed in Chapters 3 and 4.

Customers enrolled in EDRP are also scattered throughout the State. Roughly 40% of these customers are in the western New York "super" zone. Another 10% of the total participants are in the Capital zone, while roughly 36% of them are in New York City and Long Island. The three pricing zones that make up the Hudson "super" zone contain 15% of the customers enrolled in EDRP.

One can gain a visual perspective of the EDRP loads provided during the events by examining Charts 1.9 through 1.12. Since western New York has the largest number of EDRP participants, it is not surprising that this study region provided the largest shares of the EDRP response. The Capital zone, with 10% of the participants, provided a proportionately larger share of the EDRP load (18%). During the last event day, of course, western New York provided no load reduction because the event was called only in selected pricing zones (Chart 1.12).

LBMPs in the real-time market during the event hours are displayed in Charts 1.13 through 1.16. There are a couple of observations worth noting with respect to these LBMPs. The first is that the trends in prices across the event hours are remarkably consistent across zones, with one or two exceptions. There was also some general downward trend in prices about midway through the events, but it is difficult to explain why prices spiked in the last event hour on the first two event days.

At one point during the EDRP events, 30-minute reserves system wide fell to less than 34% of required reserves (NYISO-supplied data). Without the help of EDRP and other emergency measures (including voluntary load reduction through public appeals, NYS government agency reduction, TO program load reduction, and voltage reduction), the likelihood of an outage somewhere in the system would probably have been very high. The NYISO has estimated that the EDRP and Special Case Resource Programs accounted for just over one-third of the 1,580 MW of total emergency load relief system wide (REF).

Empirical Estimates of Market Effects from EDRP Events

A summary of the empirical estimates of the market effects of the August 2001 EDRP events is contained in Table 1.13. More detailed results by hour are in the tables in Appendix 1C.

EDRP Load. Over the 23 event hours, the EDRP customers delivered 8,159 MWH of EDRP load. Nearly 93% of it was delivered during the first three event days, reflecting the fact that western pricing zones, which contain the largest share of enrolled customers, were not included in the final event day (derived from Tables 1.1C through 1.5C in Appendix 1C).

There was a small variation in the hourly EDRP load contributed by all customers, and slightly more variation by event day. For example, average hourly EDRP statewide load curtailments over event hours ranged from a low of 87 MW on August 10 to a high of 454MW on August 8. On August 9, the average hourly load curtailment was only 7 MW less than on the August 8, and average hourly EDRP load on August 7 was about 35 MW less than on August 8.

During the first three event days with the exception of a single hour, the hourly EDRP load statewide was never above or below the average contribution by more than 5%. Once customers had reduced load, they seemed committed to that reduction over the duration of the events. In the first event hour of the final day, EDRP load statewide was only 75% of the average across that day's 4-hour event. EDRP load increased substantially in the second hour, and remained about at this higher level for the remaining two hours (derived from Tables 1.1C through 1.5C in Appendix 1C).

Given the large number of enrolled customers in the western pricing zones, it is not surprising that it is this region that contributed about 65% of the total EDRP load during the four event days, despite the fact that they only were called during the first three (Table 1.13). The Capital zone was the next largest contributor (18%), while New York City customers accounted for 11% of the total. The remaining amount came from the Hudson region and Long Island.

In percentage terms, both the Capital zone and western New York zone EDRP load reduction constituted over 3% of actual load served during the event hours. In the other three study regions, the EDRP load accounted for no more than half of one percent of actual load served.

Effects on LBMP. Given the "hockey" stick shape of the short-run electricity supply curves (Exhibits 1.1, 1.2, and 1.3), it is anticipated that EDRP would have an important effect on LBMPs. This is indeed the case.

Without the EDRP load, it is estimated that LBMPs in the event hours would have been approximately 21.5% higher in western New York, and 28.8% higher in the Capital zone (Table 1.13, Column 9). Although the EDRP load reduction was greater in western New York, the price reduction brought about by the EDRP load reduction was less than for the Capital zone. This is primarily due to the fact that the estimated real-time supply price flexibility in western New York is nearly 2.6 percentage points below that for the Capital zone (Table 1.13, Column 10). Similarly, because of the relatively high real-time supply flexibility in New York City (11.2 in Table 1.13, Column 10), the small EDRP load reduction still led to a 4.1% price reduction (Table 1.13, Column 10).

EDRP Program Payments. Program payments for EDRP load are set at $500/MW or the RT-LBMP, which ever is higher. Accordingly, total program payments for the four event days were just over $4.1 million (Table 1.14). Slightly less than $ 2.7 million in benefits were paid to customers in western New York, while nearly $750,000 was paid to the Capital zone (Table 1.14). Customers in the other zones would receive lesser amounts, nearly in proportion to their contributions to EDRP load. These payments, nearly proportional to load reductions, are in large measure due to the fact that during the event hours, there were only two hours in every zone in which real-time LBMPs exceeded $500/MW.[16] Thus, in 21 of the 23 hours, customers received the minimum $500/MW payment; total payments were naturally nearly proportional to load.

Collateral Benefits. As mentioned above, there are several effects on the electricity markets stemming mostly from the reduction in market prices due to EDRP load reductions. The first of these is termed collateral benefits. These benefits are shown in Table 1.13 and are defined as: the difference between actual and simulated LBMPs multiplied by all of the actual load served in real time. If all load were purchased in the RTM, this would be the savings to wholesale buyers, and as one could predict from Exhibit 1.7b, these benefits would be substantially above program costs. During the events of August 2001, these potential "benefits" were estimated to be nearly 3 times program costs (Tables 1.13 and 1.14).

Effects on Average LBMP and its Variability. In a real sense, the collateral benefits arising from load curtailments 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. From the data in Table 1.15, one can clearly see this is the case. From just these four events, the average LBMP for the hours from 6:00 a.m. to 10:00 p.m. during week days in August, fell by as much as $4/MW in the Capital zone, and by nearly $2/MW in western New York (Table 1.15, Column 8). The variability in prices fell proportionally

[16] To meet project deadlines, it was necessary to estimate short-run supply curves as soon as LBMP information for both markets became available for the month of August. Further, to be consistent with these supply models, our simulations of the supply price effects due to PRL load were based on this same dataset. Due to market mitigation actions and the true-up process for final settlement, it is possible that in a small number of hours the LBMPs currently posted on the NYISO website may differ from those used in this analysis.

more, as evidenced by the reductions in the coefficients of variation in prices with and without EDRP (Table 1.15, Columns 4 and 7). Although these effects are relatively modest, 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.

In theory, one would ultimately expect the price of hedging contracts to reflect both average price reductions and reductions in price variability.[17] It is easy to calculate the cost reduction due to lower average prices simply by accounting for the differences in average prices. This is what has been done in the last column in Table 1.15. From this standpoint alone, the long-term benefits appear substantial, if these average price reductions are eventually reflected in the bilateral contracts under which about 40% of load in the DAM is now purchased. In total, the cost reductions would be about $ 3.9 million (Table 1.15, Column 9), the largest portion of which would accrue to the Capital zone (22%) and to western New York (48%). Note that these benefits reflect the available PRL load. If more load participates, 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 necessary to have information about

[17] 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.

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.

Effect of EDRP on System Reliability. Load reduction during EDRP events will also affect the reliability of New York's entire electricity system. Some might argue that this purpose, and this purpose alone, justifies an emergency program and dictates how it should be deployed and participants 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 then are the collateral benefits 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). On August 7th – 10th, 2001, when more conventional actions, such as voltage reduction and external emergency energy purchases, were undertaken by the NYISO to abate real-time operating reserve shortages, EDRP and Special Case Resources were also deployed, in effect confirming that at least one of their roles is to provide the system with emergency operating reserves (NYISO Press Release, August 9, 2001).

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.[18]

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:

(34) 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 transaction data.[19] Nationwide, only a few 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,

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

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. This broad range in values was used because of the subjectivity associated with the initial outage cost estimates. The British PoolCo model, which required a value for lost load, adopted a value of approximately $2,500/MWh.[20]

In order to evaluate equation (34), we need to generate values for the change in LOLP, which are implied by solutions to the production cost models used to establish reserve requirements for LSEs, but are not easily determined for a specific period such as when a curtailment is called. To circumvent this problem, we begin the analysis by solving equation (34) for the change in LOLP that will equate ΔVEUE with EDRP program payments to customers. Then, we look at actual market conditions when the EDRP events were declared and ascertain if such changes are likely to have been achieved as a result of the EDRP load reduction made available by EDRP participants.

To begin the analysis, we solve equation (34) for the change in LOLP:

(35) Δ LOLP = [ΔVEUE] / [(Outage Cost/MW)* (Un-Served Load)].

We then solve this equation for the change in LOLP based on an estimate of outage costs. To illustrate the methodology, we will look at two values for outage costs, $1,500 and

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

[20] 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 L/MWh (approximately $2.50/kWh), and that is increased steadily in subsequent years with the growth of the Index of Retail Prices. In 2001, Britain converted from central pool pricing to a bilateral markets, and as a result the value of lost load is no longer used directly to set market prices.

\$2,500/MWH.[21] We conduct the analysis on an hourly basis by dividing the total EDRP program payments of \$4.3 million (Table 1.1) by 23 hours, the number of hours the EDRP events spanned. Assuming that any system outage would affect about 5% of the system, the amount of un-served load used in the calculation is set equal to 5% of average load served in real time during the event hours (Table 1.13). Using these assumptions, we can establish a range for the change in LOLP needed to equate EDRP program payments with ΔVEUE as follows:

(36) Δ LOLP = (181,177) / [2,500* (0.05*27,871)] = 0.052,

if Outage Cost = \$2,500/MW;

(37) Δ LOLP = (181,177) / [1,500* (0.05*27,871)] = 0.087,

if Outage Cost = \$1,500/MW.

Now, for this measure of benefits to be at least as large as program payments to customers, one must ask the following question. Did EDRP load reduce the probability of a system outage by at least 0.087 if outage costs are put at \$1,500/MW, or by at least 0.052 if outage costs are more in the neighborhood of \$2,500? Put another way, if the EDRP curtailments reduced the system LOLP by at least 5.2% during the curtailment periods, then the EDRP payments are justified if outage cost is at least \$2,500/MWH. If the LOLP was reduced by at least 9%, then the program payments are justified if outage costs are at least \$1,500/MWH, and it produces substantial net benefits if outage costs are \$2,500/MWH.[22]

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[21] To develop an initial value of the contribution of EDRP load to system security, we used a lower bound outage cost estimate of \$1,500/MWh as a compromise between the British and Niagara Mohawk estimates, \$2,500/MWH and \$500/MWH respectively.

[22] If outage costs were set equal to the current price cap of \$1,000/MW, the reduction in LOLP needed to equate VEUE to program costs would be just under 0.14.

To complete this exercise, we assume that the loss of load probability function for the NYCA resembles that shown in Exhibit 1.8. In that representation, as system reserves approach zero, the probability of an outage approaches unity, and as the reserve margin increases from a level of zero, there is initially a large reduction in the probability of loss of load. As reserves continue to increase, the system security continues to increase, but it does so at a much slower rate. Finally, when system reserves equal 18%, we assume that the LOLP is effectively zero; additional reserves provide no additional security over what is already available at 18%. This latter assumption is consistent with system security planning criteria that dictate adding generation capacity until the expectation is one outage day in ten years; both in effect assume that at some level additional capacity is not worth the costs of providing it.

Beginning at the other extreme, at 100% of the required reserve margin, and moving in the opposite direction (from right to left), one critical point is the level of reserves below which the loss of load probability begins to rise sharply. Based on the experience of Neenan Associates in designing real-time pricing programs, we estimate that when reserves are only 50% of those required, the associated probability of an outage would be about 0.25.[23] Thus, when reserve margins fell to only 34% of required reserves during the August events, using the relationship depicted in Exhibit 1.8 if no emergency actions had been taken the probability of an outage would have been well in excess of 0.25 (e.g., the point with the **?** in Exhibit 1.8.).

[23] 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 an value of one the two dollars per kWh.

The data provided by the NYISO suggests that the combined emergency efforts resulted in a substantial reduction in system demand. EDRP and Special Case resources were deployed and accounted for just about one-third of the total emergency load relief of nearly 1,600 MW. If we assume that this load relief has a similar effect on system reliability as increases in reserves, then, if only EDRP and Special Case resources had been called, the effect would have been as though reserves increased from about 34% to at least 50%, if not higher. Conservatively, this would imply that the loss of load probability (LOLP) would fall at least to 0.25, the point at which the curve begins to flatten out. For the VEUE to be at least equal to program payments, the loss of load probability at 34% reserves (the point at the **?** in Exhibit 1.8) would only have had to have been 0.294 if outage costs approach $2,500/MW or only 0.340 if outage costs are instead only $1,500/MW. Given that these changes are in the steep part of the curve in Exhibit 1.8, neither of these values would seem unreasonable. This conclusion, of course, is valid only if the position of this loss of load probability curve is correct. If the actual probability of an outage when reserves fall to 34% of required reserves is actually higher than 0.340, then the value of EDRP to system security clearly outweighed program payments to customers.

As reasonable and compelling as these results are, one would clearly need to estimate the relationship between reserve levels and the loss of load probability (e.g., the relationship in Exhibit 1.8) 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. Through such an analysis, one could then make a direct application of equation (34) for estimating the change in the expected value of un-served energy due to an EDRP load reduction.

This type of analysis was clearly beyond the scope of this research, but in addition to the analysis above, we can examine the tradeoff between the reduction in the loss of load probability and outage costs needed to keep the benefits in terms of restoring system security of EDRP above program costs. This is accomplished by evaluating equation (34) for alternative values of the change in LOLP and the outage costs. We also can examine a couple of different views of the amount of load assumed to be at risk.

The two tables at the bottom of Exhibit 1.8 contain the results of this analysis. As above, the analysis is performed for the "average" EDRP event hour.

If one assumes that the benefits are defined in terms of the entire market load, as is most often assumed in production system simulation analyses, the system benefits outstrip EDRP payments by a very large margin regardless of the level of LOLP reduction assumed, and even if outage costs are assumed equal to the existing market price cap of $1,000/MW (table in the lower right corner of Exhibit 1.8). Although not reported in the figure, one would reach the same conclusion if the load at risk were assumed equal to the 18% reserve margin.

If, on the other hand, one were to take a much more conservative approach to benefit estimation (e.g. assume only 5% of the system's load is at risk of an outage), the benefits fall short of program costs in *only* four of the 16 cases displayed (the shaded area of the table in the lower left corner of Figure 1.8). For program costs to outweigh system security benefits in this case, the reduction in LOLP caused by the EDRP load reduction would have to be no greater than 0.05 if outage costs are under $2,500/MW. This is a small number indeed, and it is difficult to imagine that system operators would call an EDRP event if they weren't quite sure that there would be a "significant" improvement (at least 0.05, and most likely much greater) in system reliability due to the EDRP load reduction.

The DADRP Evaluation

The market effects and evaluation of DADRP are also developed systematically following the flow chart in Exhibit 1.6. The market effects are similar to those discussed with regard to the EDRP, although any effect on system security would come about only indirectly. That is, if sufficient load were accepted in DADRP that is not served in real time, there may be fewer occurrences of system emergencies that would necessitate EDRP events. However, actual participation in DADRP is too small in this first year to shed much light on this issue.

Simulations of greater participation in DADRP could certainly be useful in a longer-term program evaluation, but they are beyond the scope of this immediate evaluation.

Markets Effects of DADRP

The theory underlying the effect of load reduction bids in the DAM through DADRP is also developed in detail in an earlier report to the NYISO by Neenan Associates (2001). The major components of this theory are illustrated simply in Exhibit 1.9. The detailed discussion of similar diagrams for EDRP provided above applies to the circumstances involving DADRP. The primary differences in the theory underlying the two programs relate to the mechanisms by which the DADRP load reduction is scheduled. The DADRP load reduction is scheduled according to customers' bid prices, while EDRP's load reduction is called by the system's operators. Once load is scheduled, the effects on the markets can be traced in similar fashions, except the effect of EDRP is obviously in the RTM, while the primary effect of DADRP is in the DAM.[24] As indicated in Exhibit 1.6, the most significant market effects of DADRP are:

1. Reduction in DAM-LBMP;
2. DADRP Payments to Customers (the area [Q1-Q2]*P2 in Exhibit 1.9);
3. Collateral Benefits, or Savings to Customers (shaded area 5 Exhibit 1.9); and
4. Any Reduction in Average Market Price or Price Variability.

DADRP Scheduled Bids

There were only 16 participants in DADRP statewide for this first year of the program. Surprisingly, not all of the DADRP participants actually submitted bids. Only participants in the Capital zone and in the Western NY "super" zone offered bids and had them accepted.[25] In contrast to EDRP, where events were called only in August, DADRP bids were accepted in both July and August. However, in July, DADRP bids were scheduled only in the Capital zone, while bids were scheduled in both the Capital zone and western New York in August.

Empirical Estimates of Market Effects from DADRP Events

A summary of the empirical estimates of the market effects DADRP is found in Table 1.16. More detailed results by hour are in the tables in Appendix 1D.

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

[25] Because the only customers bidding in western New York were in pricing zone C, we applied the supply price flexibilities estimated for the Western NY "super" zone to the data for pricing zone C to calculate the price effects.

DADRP Load Scheduled. In these two zones, there was a total of 2,694 MWH of load for which the DADRP bids were accepted, 46% was in the Capital zone and 54% was in NYISO's Central zone (Zone C), one of the component zones of the western New York "super-zone" (Table 1.16, Column 5).[26] This is the only point in the analysis where it was necessary to examine one of the component zones of the aggregated zones. In the Capital zone, 45% of the MWs were for bids accepted in July, while 55% were for bids accepted August (Table 1.1D in Appendix 1D). All of the bids accepted for customers in western New York were in the month of August (Table 1.2D in Appendix 1D). On an hourly basis, the average load for the bids accepted was 5 MW in western New York; they ranged in size from 1 MW to 20 MW (Table 1.2D in Appendix 1D). In the Capital zone, the average hourly load accepted in any hour was 3 MW, ranging from 1 MW to 20 MW. (Table 1.1D in Appendix 1D)

In the Capital zone, DADRP bids were accepted in 370 separate hours, while in the western New York zone, DADRP bids were accepted in 279 separate hours. A significant portion of the accepted bids came in the early morning or late evening hours, and as would have to be the case, they were bid in at very low prices.[27] The early morning hour bids in western New York were generally for higher loads than those in the early morning bids in the Capital zone.

[26] 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.
[27] DADRP customers are essentially allowed to bid start-up (more appropriately outage) costs, along with the energy price. Their bids are evaluated on an equal footing with generators' bids in the dynamic programming part of SCUC. When both start-up costs and energy costs are considered jointly, they clearly were a cheaper source of energy than competing generators for these relatively small amounts of load.

As one might expect, there were some DADRP bids accepted on the four EDRP-event days in August. For the Capital zone, about 26% of the total DADRP load bids accepted were on the EDRP event days, but only 7% were during the EDRP event hours (Table 1.1D). Some of the bids were accepted earlier in the month, while others came after the EDRP events. In the Western NY "super" zone, about 24% of the total DADRP load bids accepted were on the EDRP event days, but only 5% were during the EDRP event hours (Table 1.2D). The remaining load bids accepted into DADRP were all accepted later in the month.

Effects of DADRP on LBMP. Because of the relatively small number of customers actively bidding in the DADRP, one would expect that the effects of accepted bids on LBMP in the DAM would be smaller than for EDRP. This is indeed the case, as in those hours where bids were accepted, they accounted for on average less than one-half of one percent of the load served in the DAM. Although the percentage reduction in load was just slightly smaller on average in the western zone, the effect on LBMP in the Capital zone (0.9%) was over three times as large as the effect on LBMP in the Western NY zone (0.3%) This difference is primarily due to the fact that during the hours in which bids were accepted, the price flexibility of supply was on average somewhat larger in the Capital zone than in the Western NY zone (Tables 1.1D and 1.2D); bids were better aligned with market conditions.

DADRP Program Payments. In contrast to EDRP, participants in DADRP are paid their bid amount (including start-up cost) or LBMP in the DAM, whichever is higher. In Table 1.17, the estimates of program payments are based on the assumption that all accepted bids are paid at the LBMP in the DAM. From the bid data provided by the NYISO, it was impossible to disentangle the start-up costs from the energy bids on a bid-by-bid basis, particularly when bids were submitted for a minimum run time.

Based on these data, the total payments were $217,487 (Table 1.17), or about $81/MW. While 46% of the scheduled load was in the Capital zone, that load accounted for 62% of the total payments, averaging $109/MW.[28] In contrast, the payments averaged $57/MW in western New York. This difference, of course is due to the higher average price ($78/MW vs. $66/MW) in the Capital zone on days when bids were accepted. Although the significant price differences explain the differential in payments, there is no way to explain why the difference persisted because bids were obviously not scheduled on exactly the same days in each zone.

Collateral Benefits. As mentioned above, there are several effects on the electricity markets stemming mostly from the reduction in market prices due to the scheduling of DADRP load reductions. The first of these is termed collateral benefits, and as in the case of EDRP, these benefits are defined as: the difference between actual and simulated LBMPs multiplied by all of the actual load scheduled in the Day-Ahead Market (Table 1.16). In this case, however, the benefits are due to the difference in the LBMPs in the DAM multiplied by the load that is scheduled in the DAM. If all load scheduled in the DAM were settled at the DAM LBMP, these collateral benefits would be equal to the customers' savings on the wholesale cost of electricity. For the two regions in which

[28] At the time this analysis was completed, the settlement data for DADRP had not been processed by NYISO and made available to us. Therefore, these program costs assume that DADRP payments were at LBMPs in the DAM, and for this reason, they exclude any start up costs included in customers bids that were accepted. Based on conversations with NYISO, it is estimated that these costs, and payment rates would be about 30% higher if these costs had been included.

DADRP bids were accepted, these collateral benefits exceeded program payments to customers by a wide margin—potential collateral savings are 7 times payments.[29]

Effects on Average LBMP and its Variability. As is the case of EDRP, the collateral benefits to the market are transfers between buyers and sellers. By affecting the number of extreme prices, one might also expect DADRP load also to reduce both average LBMPs and the variability in LBMPs. From the data in Table 1.18, one can clearly see this is the case, although the effects are not as dramatic as in the real time market due to EDRP load reduction. From these small average loads scheduled rather frequently in the DAM in these two zones, the average LBMP in the DAM for the hours from 6:00 a.m. to 10:00 p.m. during week days in July and August fell by $1.42/MW in the Capital zone and by $0.51/MW in the western zone. The variability in prices also fell proportionally more, as evidenced by the reductions in the coefficients of variation in prices with and without DADRP load scheduled.

Although these effects are extremely modest, if these programs persist in the long run, and market participants come to expect that LBMPs in the DAM are likely to be modestly lower and less variable, these changes will eventually be reflected in the prices at which customers can hedge load. If reflected in the price of hedging load, the cost saving to hedgers would be over $680,000. It would be substantially more if the effect of the lower price variability were also reflected in these estimates. Finally, and perhaps most important, if active participation in the day-ahead wholesale market for electricity

[29] One can also argue that if DADRP customers fully comply with their obligations to reduce load by the amount of DADRP load scheduled in the DAM, then this load will not need to be served in real time, and there would be additional collateral savings in real time. We made no attempt to estimate these additional collateral savings for a couple of reasons. First, in contrast to EDRP, at the time this analysis was completed, we had no data on actual compliance or performance for the

were expanded significantly beyond the small number of first-year participants, they could contribute importantly to the discipline of the day-ahead market—both in terms of lowering the average price, as well as price volatility. Some of this discipline would surely extend to the real-time market if participants comply, and the loads scheduled in DADRP need not be served in real time.

DADRP bids. Second, the amount bid in any hour was quite small, and it would have not been distinguishable separately from the load reduction in EDRP.

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Table 1.1. Summary Data for Hourly LBMP and Load by Zonal Aggregates for Which Separate Supply Functions are Estimated (Summer, Afternoon Hours, 2001)*

	Capital (Zone F)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	1,011	$23	1,242	-$21
Maximum	1,887	$976	2,107	$962
Mean	1,386	$68	1,647	$60
Standard Deviation	194	$87	212	$79
	New York City (Zone J)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum		$39		$15
Maximum		$1,025		$1,071
Mean		$82		$86
Standard Deviation		$90		$116
	Long Island (Zone K)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum		$37		$27
Maximum		$831		$1,060
Mean		$87		$114
Standard Deviation		$80		$119
	West of Total East (Zones A, B, C, D, & E)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	4,692	$23	5,597	-$41
Maximum	8,637	$915	9,328	$937
Mean	6,560	$59	7,563	$48
Standard Deviation	737	$79	778	$61
	Hudson River (Zones G, H, & I)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	2,016	$31	2,104	$15
Maximum	4,091	$1,015	4,319	$1,039
Mean	2,857	$76	3,054	$77
Standard Deviation	451	$90	509	$100
	New York City & Long Island (Zones J & K)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	8,508	$40	8,184	$22
Maximum	15,378	$966	15,502	$1,068
Mean	11,917	$84	11,724	$95
Standard Deviation	1,539	$86	1,486	$116
	New York State (Zones A - K)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	16,978	$35	17,747	$18
Maximum	29,499	$958	30,982	$1,018
Mean	22,720	$75	23,988	$76
Standard Deviation	2,755	$84	2,865	$87

*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 1 2. Estimated Day-Ahead Electricity Supply Function, Capital Region, Summer 2001

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Variables*	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.
FB-Load	1,298	135	1,550	37	1,712	92
Min.	1,011		1,493		1,607	
Max.	1,492		1,600		1,887	
DAM-LBMP	47	10	74	29	189	207
Min.	23		47		56	
Max.	124		151		976	
FB-Load-2L	0.12	0.77	3.03	7.84	3.31	6.13
Min.	0.00		0.00		0.00	
Max.	8.00		40.00		32.00	
Avail. Gen./ ICAP	0.90	0.02	0.90	0.02	0.92	0.01
Min.	0.85		0.85		0.89	
Max.	0.93		0.93		0.93	
DADRP Sch.	0.12	0.68	3.09	7.86	3.62	6.05
Min.	0.00		0.00		0.00	
Max.	7.00		40.00		32.00	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-20.6940	-11.1348		
FB-Load	1.6249	27.9403	3.3584	13.1959	-15.2478	-8.9032
FB-Load-2L					-0.0341	-2.3540
Avail. Gen./ ICAP			-0.2309	-5.8080	-305.9179	-14.9842
DADRP Sch.					0.1132	4.5008
ARCH(0)	0.0062	10.2008				
ARCH(1)	0.9130	6.6707				
ARCH(2)						
R^2 =	0.8286					
		Knots (Load in MW)				
Price Flexibilities**		1493		1602		
Minimum	1.62		3.38		5.31	
Maximum	1.62		3.39		20.92	
Mean	1.62		3.38		11.77	
At the Mean of Data	1.62		3.38		11.77	

* Variables are defined in Appendix Table B1; All are in logarithms, except where noted.
The model estimated is from equation (24), and the coefficients are those associated with intercept shifter (if the same coefficients appear in all segments of the spline.
The other intercept 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 (31-33) 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 1.3. Estimated Day-Ahead Electricity Supply Function, New York City Region, Summer 2001

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Variables*	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.
DAM-LBMP	57	13	89	39	235	224
Min.	39		54		90	
Max.	105		358		1,025	
Avail. Gen./ ICAP	0.90	0.02	0.91	0.02	0.91	0.01
Min.	0.85		0.85		0.89	
Max.	0.93		0.93		0.93	
Adj. Load	4,011	473	4,755	300	5,370	229
Min.	2,961		4,071		4,826	
Max.	5,079		5,596		5,738	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-34.7228	-18.9078		
FB-Load	1.1861	17.2065	4.2774	21.2517	-1206.1788	-9.5309
Avail. Gen./ ICAP					-97.2021	-2.7537
Adj. Load					140.5366	9.4951
ARCH(0)	0.0092	10.3971				
ARCH(1)	0.7912	5.9809				
ARCH(2)						
R^2 =	0.7665					
			Knots (% Max.Load)			
Price Flexibilities**		55%		78%		
Minimum	1.19		4.28		-5.15	
Maximum	1.19		4.28		18.47	
Mean	1.19		4.28		9.42	
At the Mean of Data	1.19		4.28		9.42	

* Variables are defined in Appendix Table B1; All are in logarithms, except where noted.
The model estimated is from equation (24), and the coefficients are those associated
with intercept shifter (if the same coefficients appear in all segments of the spline.
The other intercept 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 (31-33)
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 1.4. Estimated Day-Ahead Electricity Supply Function, Long Island Region, Summer 2001

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Variables*	Mean	Std. Dev.	Mean	Std. Dev.
DAM-LBMP	70	32	240	166
Min.	37		129	
Max.	400		831	
Avail. Gen./ ICAP	0.90	0.02	0.91	0.01
Min.	0.85		0.89	
Max.	0.93		0.93	
Adj. Load	8,234	948	10,205	554
Min.	6,108		8,769	
Max.	10,750		11,075	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-37.1482	-6.5964
FB-Load	-35.4966	-8.3636	4.2697	6.4024
Avail. Gen./ ICAP			-0.2009	-3.1258
Adj. Load			0.0826	5.2299
FB-Load-2L	4.7948	8.7808		
ARCH(0)	0.0290	13.7445		
ARCH(1)	0.4697	4.5337		
ARCH(2)				
R^2 =	0.7980			
	Knots (% of Max. Load)			
Price Flexibilities**	80%			
Minimum	1.83		5.04	
Maximum	4.81		5.06	
Mean	3.43		5.05	
At the Mean of Data	3.43		5.05	

* Variables are defined in Appendix Table B1; All are in logarithms, except where noted.
The model estimated is from equation (24), and the coefficients are those associated with intercept shifter (if the same coefficients appear in all segments of the spline.
The other intercept 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 (31-33) 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.
Note: This supply function has only two regimes; there is only one knot.

Table 1.5. Estimated Day-Ahead Electricity Supply Function, Western New York Region, Summer 2001

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Variables*	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.
FB-Load	6,070	467	7,076	287	7,970	277
Min.	4,692		6,667		7,658	
Max.	6,663		7,637		8,637	
DAM-LBMP	38	8	63	26	205	235
Min.	23		40		70	
Max.	81		186		915	
Avail. Gen./ ICAP	0.90	0.02	0.91	0.02	0.92	0.01
Min.	0.85		0.85		0.89	
Max.	0.93		0.93		0.93	
DADRP Sch.	0	3	1	4	1	3
Min.	0		0		0	
Max.	40		40		9	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-22.7742	-28.9081		
FB-Load	2.0684	40.5315	2.9968	33.8062	7.8174	9.4466
Avail. Gen./ ICAP			-0.2062	-9.5507		
DADRP Sch.					1.1405	10.8291
ARCH(0)	0.0036	10.0050				
ARCH(1)	0.9429	8.1151				
ARCH(2)						
R^2 =	0.7260					
	Knots (Load in MW)					
Price Flexibilities**	6665		7651			
Minimum	2.07		3.01		7.82	
Maximum	2.07		3.03		18.08	
Mean	2.07		3.02		9.38	
At the Mean of Data	2.07		3.02		9.38	

* Variables are defined in Appendix Table B1; All are in logarithms, except where noted.
The model estimated is from equation (24), and the coefficients are those associated
with intercept shifter (if the same coefficients appear in all segments of the spline.
The other intercept 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 (31-33)
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 1.6. Estimated Day-Ahead Electricity Supply Function, Hudson River Region, Summer 2001

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Variables*	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.
FB-Load	2,519	227	3,105	175	3,645	164
Min.	2,016		2,847		3,428	
Max.	2,846		3,415		4,091	
DAM-LBMP	49	10	73	25	204	206
Min.	31		42		69	
Max.	101		155		1,015	
Avail. Gen./ ICAP	0.90	0.02	0.90	0.02	0.91	0.01
Min.	0.85		0.85		0.89	
Max.	0.93		0.93		0.93	
Adj. Load	12,996	1,118	14,940	1,057	16,890	1,175
Min.	10,374		12,010		13,592	
Max.	15,171		17,330		18,280	
FB-Load-2L	2,543	230	3,104	205	3,608	199
Min.	2,109		2,754		3,261	
Max.	3,024		3,591		4,091	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-4.3383	-14.8719		
FB-Load	-20.9693	-5.9201				
Avail. Gen./ ICAP					-30.2986	-3.1112
Adj. Load	2.3109	6.1121	0.1099	28.6155	17.2175	5.4637
FB-Load-2L	0.0000	0.0000	0.0000	0.0000	-20.1706	-5.3605
ARCH(0)	0.0052	17.4432				
ARCH(1)	0.9915	8.3563				
ARCH(2)						
R^2 =	0.6683					
	Knots (Load in MW)					
Price Flexibilities**			2846		3417	
Minimum	0.40		1.03		1.46	
Maximum	1.28		1.07		7.49	
Mean	0.91		1.06		5.08	
At the Mean of Data	0.91		1.06		5.08	

* Variables are defined in Appendix Table B1; All are in logarithms, except where noted.
The model estimated is from equation (24), and the coefficients are those associated with intercept shifter (if the same coefficients appear in all segments of the spline.
The other intercept 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 (31-33) 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 1.7. Estimated Real-Time Electricity Supply Function, Capital Region, Summer 2001

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Variables*	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.
RT-Load	1,406	91	1,698	78	1,973	76
Min.	1,242		1,545		1,849	
Max.	1,544		1,846		2,107	
RT-LBMP	36	13	51	37	136	162
Min.	8		-21		23	
Max.	81		476		962	
Trans. Const.-L	1	4	1	4	6	7
Min.	0		0		0	
Max.	17		19		17	
Forecast Load-2L	1,469	113	1,712	111	2,037	124
Min.	1,246		1,540		1,779	
Max.	1,682		2,142		2,318	
RT-Load-2L	1,421	90	1,708	79	1,976	79
Min.	1,250		1,559		1,828	
Max.	1,594		1,895		2,107	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-20.2579	-4.9949		
Forecast Load-2L	0.3850	2.5950	0.3850	2.5950	0.3850	2.5950
RT-Load	2.5871	5.0960	4.2504	4.1681		
Trans. Const.-L			0.0004	1.8458		
RT-Load-2L			-0.1878	-2.4641	1.1091	13.2391
ARCH(0)	0.0210	7.0316				
ARCH(1)	1.0991	11.6329				
ARCH(2)	0.4250	7.1416				
ARCH(3)	0.0816	2.9456				
R^2 =	0.4464					
	Knots (Load in MW)					
Price Flexibilities**		1545		1848		
Minimum	2.59		2.83		8.33	
Maximum	2.59		2.87		8.49	
Mean	2.59		2.85		8.41	
At the Mean of Data	2.59		2.85		8.41	

* Variables are defined in Appendix Table B1; All are in logarithms, except where noted.
The model estimated is from equation (24), and the coefficients are those associated with intercept shifter (if the same coefficients appear in all segments of the spline).
The other intercept 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 (31-33) 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 1.8. Estimated Real-Time Electricity Supply Function, New York City Region, Summer 2001

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Variables*	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.
RT-LBMP	36	15	61	52	214	202
Min.	15		26		47	
Max.	104		450		1,071	
Adj. Load	3,553	253	4,475	374	5,509	454
Min.	2,990		3,533		4,755	
Max.	4,195		5,373		6,252	
Trans. Const.-L	1	2	1	3	4	4
Min.	0		0		0	
Max.	8		16		15	
Avail. Gen./ ICAP	0.89	0.01	0.90	0.02	0.91	0.02
Min.	0.87		0.85		0.85	
Max.	0.92		0.93		0.93	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-14.5442	-11.1628		
RT-Load	1.6551	3.9643	2.0523	14.1770	277.2406	5.5231
Adj. Load					-31.9513	-5.6182
Trans. Const.-L					0.6763	8.5458
Avail. Gen./ ICAP					-101.8281	-5.1664
ARCH(0)	0.0342	10.4627				
ARCH(1)	1.2251	11.3805				
ARCH(2)	0.2464	5.6140				
ARCH(3)						
R^2 =	0.5428					

	Knots (% of Max. Load)		
Price Flexibilities**	30%	65%	
Minimum	1.66	2.05	6.26
Maximum	1.66	2.05	27.57
Mean	1.66	2.05	14.52
At the Mean of Data	1.66	2.05	14.52

* Variables are defined in Appendix Table B1; All are in logarithms, except where noted.
The model estimated is from equation (24), and the coefficients are those associated
with intercept shifter (if the same coefficients appear in all segments of the spline.
The other intercept 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 (31-33)
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 1.9. Estimated Real-Time Electricity Supply Function, Long Island Region, Summer 2001

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Variables*	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.
RT-LBMP	73	40	158	134	294	207
Min.	27		47		90	
Max.	375		752		1,060	
Adj. Load	7,691	714	8,836	360	9,825	408
Min.	5,798		7,966		9,024	
Max.	9,032		9,636		10,602	
Trans. Const.-L	2	3	4	5	6	5
Min.	0		0		0	
Max.	21		21		17	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-18.4110	-5.9812		
Adj. Load	2.5364	7.4738	2.5364	7.4738	2.5364	7.4738
RT-Load	0.7400	2.1560				
RT-Load-Sq.					0.6164	7.7107
Trans. Const.-L	0.1423	2.0817	0.0035	7.0281		
ARCH(0)	0.1054	14.3426				
ARCH(1)	0.4933	3.7328				
ARCH(2)						
R^2 =	0.5805					
	Knots (% of Max. Load)					
Price Flexibilities**		55%		78%		
Minimum	0.74		0.00		10.33	
Maximum	3.74		0.07		10.48	
Mean	1.00		0.02		10.40	
At the Mean of Data	1.00		0.02		10.40	

* Variables are defined in Appendix Table B1; All are in logarithms, except where noted.
The model estimated is from equation (24), and the coefficients are those associated
with intercept shifter (if the same coefficients appear in all segments of the spline.
The other intercept 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 (31-33)
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 1.10. Estimated-Real Time Electricity Supply Function, Western New York Region, Summer 2001

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Variables*	Mean	Std. Dev.	Mean	Std. Dev.
RT-Load	7,420	666	8,956	189
Min.	5,597		8,676	
Max.	8,656		9,328	
RT-LBMP	42	42	104	143
Min.	-41		40	
Max.	671		937	
Adj. Load-2L	3,674	493	4,617	302
Min.	2,747		4,048	
Max.	5,011		4,981	
Forecast Load	7,571	688	9,147	293
Min.	5,927		8,570	
Max.	9,263		9,810	
Avail. Gen./ ICAP	0.90	0.02	0.92	0.01
Min.	0.85		0.89	
Max.	0.93		0.93	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-54.4077	-9.2344
Adj. Load-2L	-0.4711	-1.7064	-0.4711	-1.7064
RT-Load	0.0000	0.0000	6.6588	8.3184
Forecast Load	0.3084	10.3180	0.1021	14.2378
Avail. Gen./ ICAP			-0.1183	-4.2445
ARCH(0)	0.0169	8.3473		
ARCH(1)	1.6114	16.1960		
ARCH(2)	0.2663	4.0402		
R^2 =	0.3571			
	Knots (Load in MW)			
Price Flexibilities**	8675			
Minimum	2.44		6.43	
Maximum	2.63		6.45	
Mean	2.53		6.44	
At the Mean of Data	2.53		6.44	

* Variables are defined in Appendix Table B1; All are in logarithms, except where noted.
The model estimated is from equation (24), and the coefficients are those associated with intercept shifter (if the same coefficients appear in all segments of the spline.
The other intercept 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 (31-33) 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 1.11. Estimated Real-Time Electricity Supply Function, Hudson River Region, Summer 2001

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Variables*	Mean	Std. Dev.	Mean	Std. Dev.
RT-Load	2,915	379	3,981	204
Min.	2,104		3,659	
Max.	3,654		4,319	
RT-LBMP	58	59	204	190
Min.	15		52	
Max.	668		1,039	
Adj. Load	13,947	1,450	17,298	863
Min.	10,238		15,734	
Max.	16,771		18,830	
Avail. Gen./ ICAP	0.90	0.02	0.91	0.01
Min.	0.85		0.89	
Max.	0.93		0.93	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-77.9094	-19.0873
Adj. Load	1.1385	4.0211	1.1385	4.0211
Avail. Gen./ ICAP	-3.4741	-8.1378	-3.4741	-8.1378
RT-Load	0.9561	4.3253	8.6228	15.3949
ARCH(0)	0.0301	10.6947		
ARCH(1)	1.1501	10.8139		
ARCH(2)	0.3701	7.1586		
R^2 =	0.4792			
	Knots (Load in MW)			
Price Flexibilities**	3655			
Minimum	0.96		8.62	
Maximum	0.96		8.62	
Mean	0.96		8.62	
At the Mean of Data	0.96		8.62	

* Variables are defined in Appendix Table B1; All are in logarithms, except where noted.
The model estimated is from equation (24), and the coefficients are those associated
with intercept shifter (if the same coefficients appear in all segments of the spline.
The other intercept 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 (31-33)
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.
Note: This supply function has only two regimes; there is only one knot.

Table 1.12 EDRP Participants by Zone and Subscribing Agency

	Subscribed Through					EDRP Participants also Participating in a NYSERDA PON			
	LSE	CSP	Other	Total		# 577	#585	Both	Total
Zone	No.	No.	No.	No.	%	No.	No.	No.	No.
Western New York*									
A	33	1	4	38	13%	6	4	2	12
B	16	0	0	16	5%	3	0	5	8
C	29	0	2	31	11%	2	18	0	20
D	5	0	0	5	2%	1	2	0	3
E	23	0	0	23	8%	1	3	0	4
Capital Zone									
F	23	1	4	28	10%	4	2	0	6
Hudson River Region**									
G	13	2	0	15	5%	2	0	0	2
H	4	6	0	10	3%	1	5	0	6
I	15	5	0	20	7%	3	2	0	5
New York City									
J	48	20	0	68	23%	17	0	0	17
Long Island									
K	1	37	0	38	13%	0	0	0	0
Totals	**210**	**72**	**10**	**292**		**40**	**36**	**7**	**83**
% of Total	**72%**	**25%**	**3%**	**100%**		**14%**	**12%**	**2%**	**28%**

* These five NYISO zones make up the Western New York "super" zone constructed for analysis (Map 1).
** These three NYISO zones make up the Hudson River "super" zone constructed for analysis (Map 1).

Table 1.13. Average Zonal and Total Effects of EDRP Events on New York Electricity Markets, August, 2001

Zone	Fixed Bid Load in the DAM	With EDRP Real-Time Load (MWH)	With EDRP Real-Time LBMP ($/MW)	EDRP Load (MWH)	Simulated Real-Time Load (MWH)	Simulated Real-Time LBMP ($/MW)	% Change in Due to EDRP Load	% Change in Due to EDRP LBMP	Arc Price Flexibility*	Collateral Benefits ($)**
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Capital										
Hourly Avg.	1,812	2,007	215	63	2,070	280	3.1%	28.8%	9.2	132,009
Total	41,673	46,167		1,446	47,613					3,036,211
% of G. Total	7%	7%		18%	7%					23%
New York										
Hourly Avg.	-	-	273	37	-	284	0.4%	4.1%	11.2	106,044
Total	-	-		860	-					2,439,005
% of G. Total	-	-		11%	-					19%
Long Island										
Hourly Avg.	-	-	311	6	-	313	0.1%	0.6%	4.6	9,274
Total	-	-		148	-					213,294
% of G. Total	-	-		2%	-					2%
Western New York										
Hourly Avg.	8,134	8,969	199	293	9,262	239	3.3%	21.5%	6.6	353,306
Total	146,419	161,441		5,276	166,717					6,359,512
% of G. Total	24%	25%		65%	26%					49%
Hudson Region										
Hourly Avg.	3,660	4,083	250	19	4,101	260	0.5%	3.8%	8.4	39,416
Total	84,170	93,904		430	94,334					906,559
% of G. Total	14%	15%		5%	15%					7%
Grand Total	615,905	641,053		8,159	649,212					12,954,581

*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" f;lexibilities variation in the price flexibility by hour. Thus, these 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.

Table 1.14. EDRP Program Payments on New York Electricity Markets, August, 2001

Zone	Program Payments ($)	Zone	Program Payments ($)
Capital		**Western New York**	
Hourly Avg.	32,474	Hourly Avg.	148,569
Total	746,896	Total	2,674,234
% of G. Total	18%	% of G. Total	64%
New York		**Hudson Region**	
Hourly Avg.	18,300	Hourly Avg.	9,713
Total	420,895	Total	223,401
% of G. Total	10%	% of G. Total	5%
Long Island			
Hourly Avg.	4,420		
Total	101,653	**Grand Total**	**4,167,079**
% of G. Total	2%		

Table 1.15. Effect of EDRP on the Average Level and Variability of Real-Time LBMPs (August, 2001)*

	RT-LBMP ($/MW) (with EDRP)			RT-LBMP ($/MW) (without EDRP)			Difference in Mean LBMPs ($/MW)	Estimated Long-Term *Reduction* in Cost of Hedging Load#
Zone or Region	Mean	Standard Deviation	Coefficient of Variation**	Mean	Standard Deviation	Coefficient of Variation**		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Capital Zone	$72.83	113.09	1.55	$76.89	128.55	1.67	$4.05	$851,778
								22%
New York City	$100.70	147.95	1.47	$101.36	149.43	1.47	$0.66	$831,658
								21%
Long Island Zone	$120.74	146.73	1.22	$120.86	147.02	1.22	$0.12	$61,709
								2%
Western New York	$58.21	82.02	1.41	$60.12	91.32	1.52	$1.91	$1,880,389
								48%
Hudson River Region	$86.35	126.11	1.46	$86.95	127.90	1.47	$0.60	$242,989
								6%
Total								$3,868,525

* 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 368 hours in August week days from 6:00 a.m. through 10:00 p.m.

Table 1.16. Average Zonal and Total Effects of DADRP Scheduled Bids on New York Electricity Markets, Summer, 2001

Zone	Fixed Bid Load in the DAM	With DADRP Day-Ahead Load (MW)	With DADRP Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Simulated Day-Ahead Load (MW)	Simulated Day-Ahead LBMP ($/MW)	% Change in Due to DADRP Load	% Change in Due to DADRP LBMP	Arc Price Flexibility*	Collateral Benefits ($)**
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Capital										
Hourly Avg.	1,536	1,293	77.9	3	1,296	79.5	0.2%	0.9%	3.4	2,781
Total	568,244	478,351		1,231	479,582					1,029,049
% of G. Total	51%	51%		46%	51%					69%
Western New York										
Hourly Avg.	1,995	1,624	66.0	5	1,629	66.9	0.3%	0.3%	3.7	1,641
Total	556,577	453,025		1,463	454,488					457,851
% of G. Total	49%	49%		54%	49%					31%
Grand Total	1,124,821	931,376		2,694	934,070					1,486,900

*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.

Table 1.17. DADRP Program Payments from New York Electricity Markets, Summer, 2001

Zone	Program Payments ($)#	Zone	Program Payments ($)#
Capital		**Western New York**	
Hourly Avg.	363	Hourly Avg.	298
Total	134,232	Total	83,255
% of G. Total	62%	% of G. Total	38%

Grand Total	**217,487**

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%

Table 1.18. Effect of DADRP on the Average Level and Variability of LBMPs in the DAM (August, 2001)*

	DAM-LBMP ($/MW) (with DADRP)			DAM-LBMP ($/MW) (without DADRP)			Difference in	Estimated Long-Term
		Standard	Coefficient		Standard	Coefficient	Mean LBMPs	*Reduction* in Cost of
Zone or Region	Mean	Deviation	of Variation**	Mean	Deviation	of Variation**	($/MW)	Hedging Load#
Capital Zone								
July	$43.41	$12.06	$0.28	$43.52	$12.29	$0.28	$0.11	$31,277
August	$82.22	$102.56	$1.25	$83.64	$107.82	$1.29	$1.42	$446,303
								70%
Western New York								
July	$39.62	$11.19	$0.28	$39.62	$11.19	$0.28	$0.00	$0
August	$71.88	$91.55	$1.27	$72.38	$92.82	$1.28	$0.51	$204,778
								30%
Total								$682,358

* 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 DAM-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 and 368 hours in week days from 6:00 a.m. through 10:00 p.m.in in July and August, respectively.

Chart 1.1. Capital Zone DAM Load vs. LBMP (afternoon hours, summer 2001)

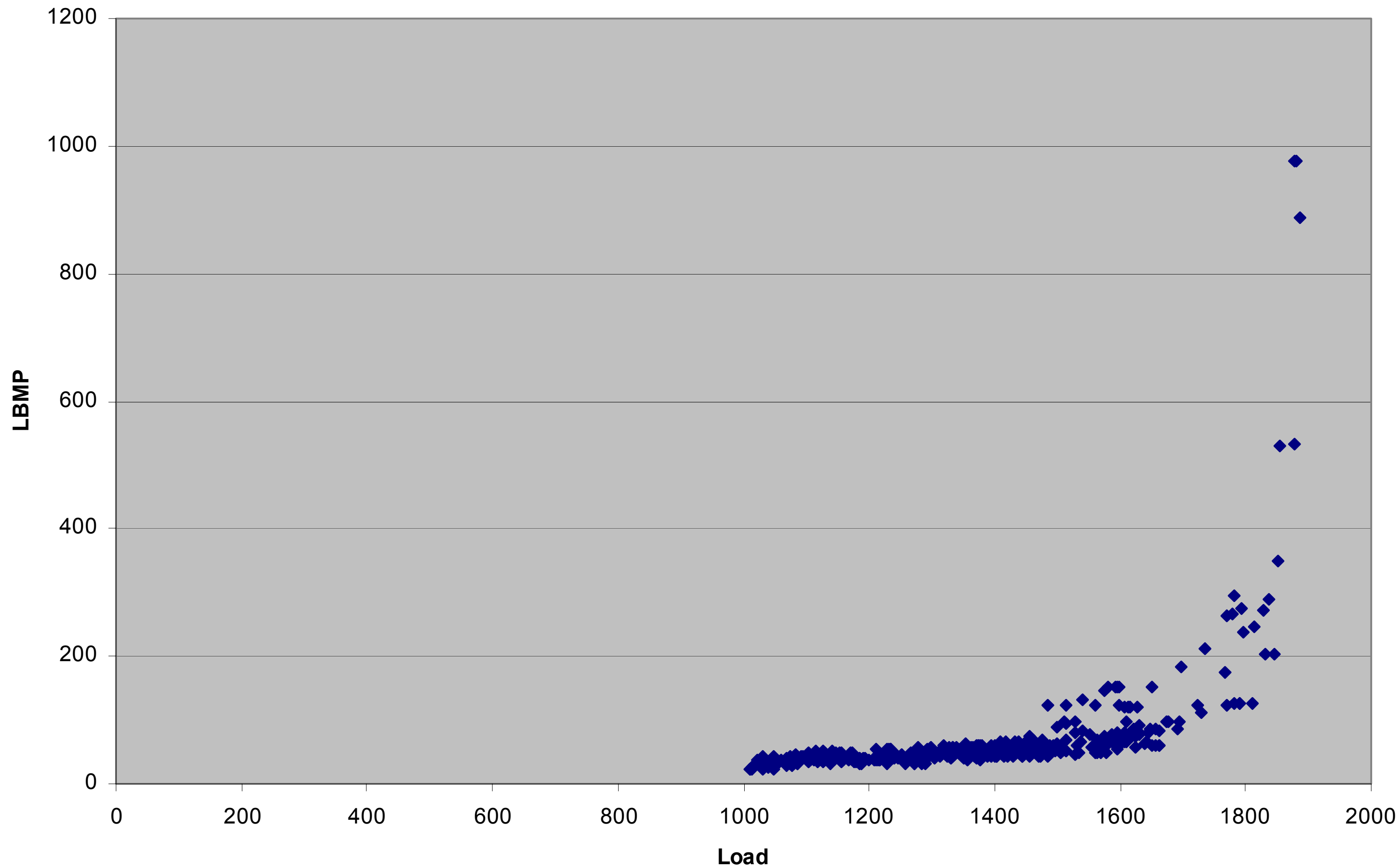


Chart 1.2. NYC/LI DAM Load vs. LBMP (afternoon hours, summer 2001)

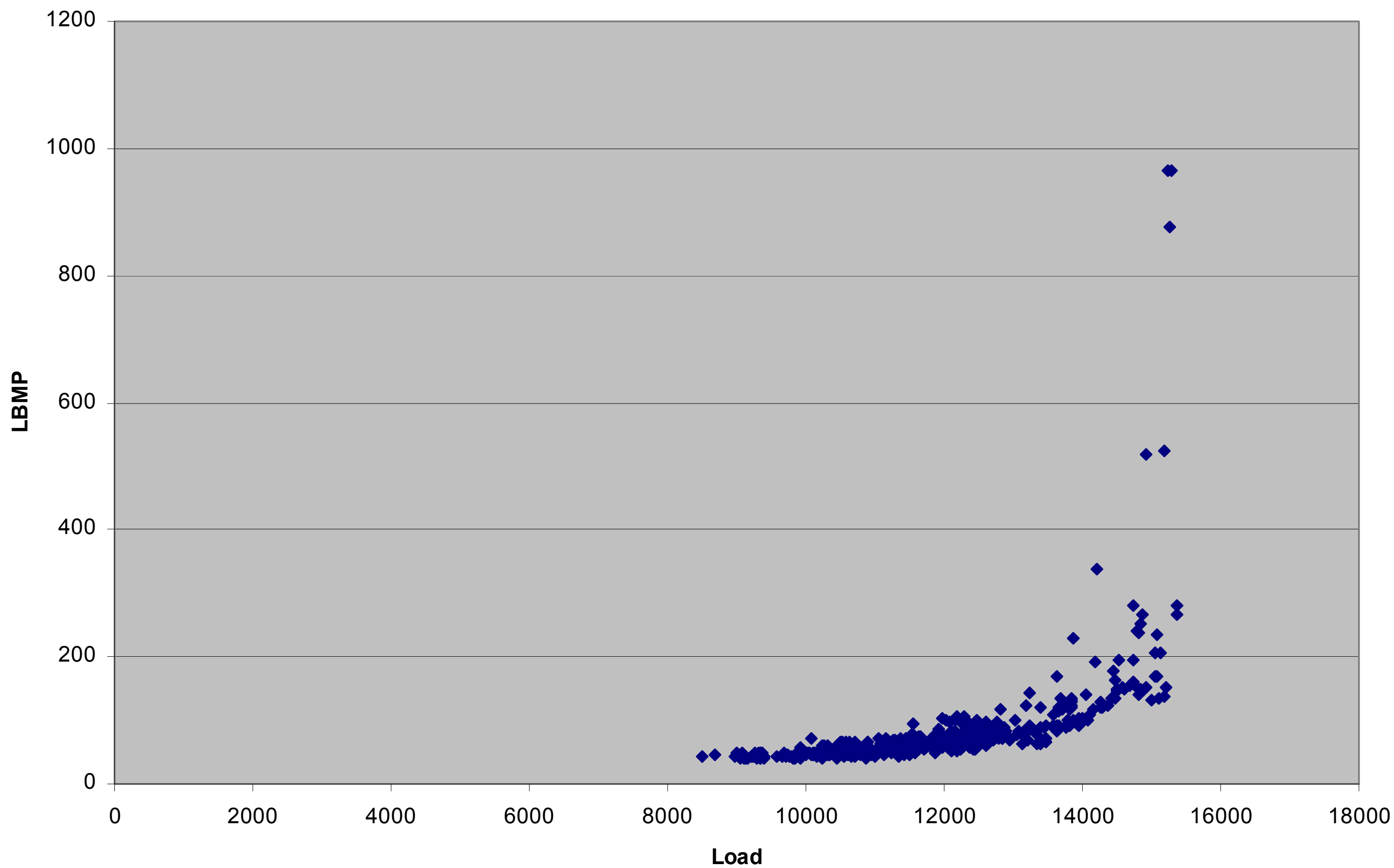


Chart 1.3. West of Total East DAM Load vs. LBMP (afternoon hours, summer 2001)

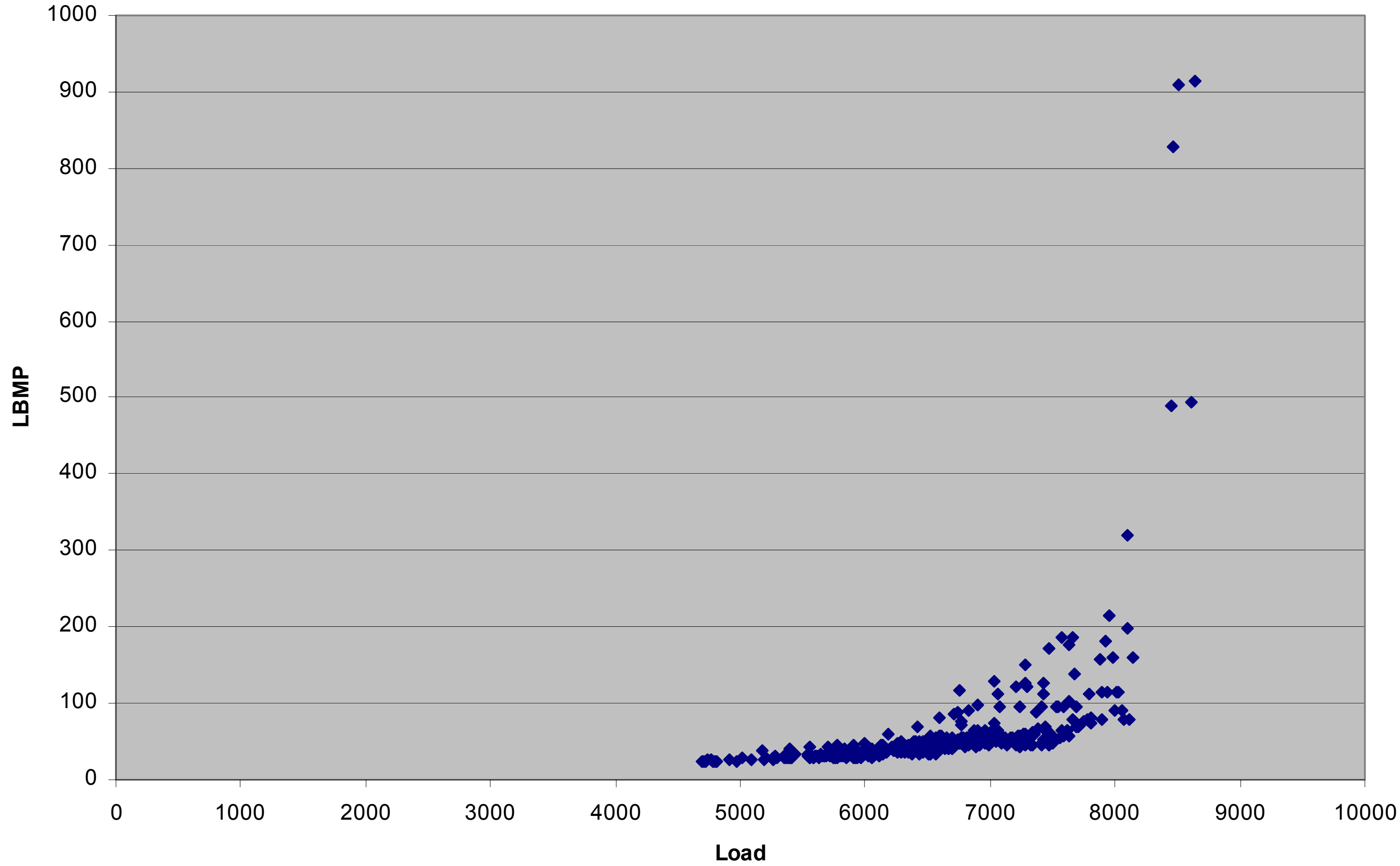


Chart 1.4. Hudson River Superzone DAM Load vs. LBMP (afternoon hours, summer 2001)

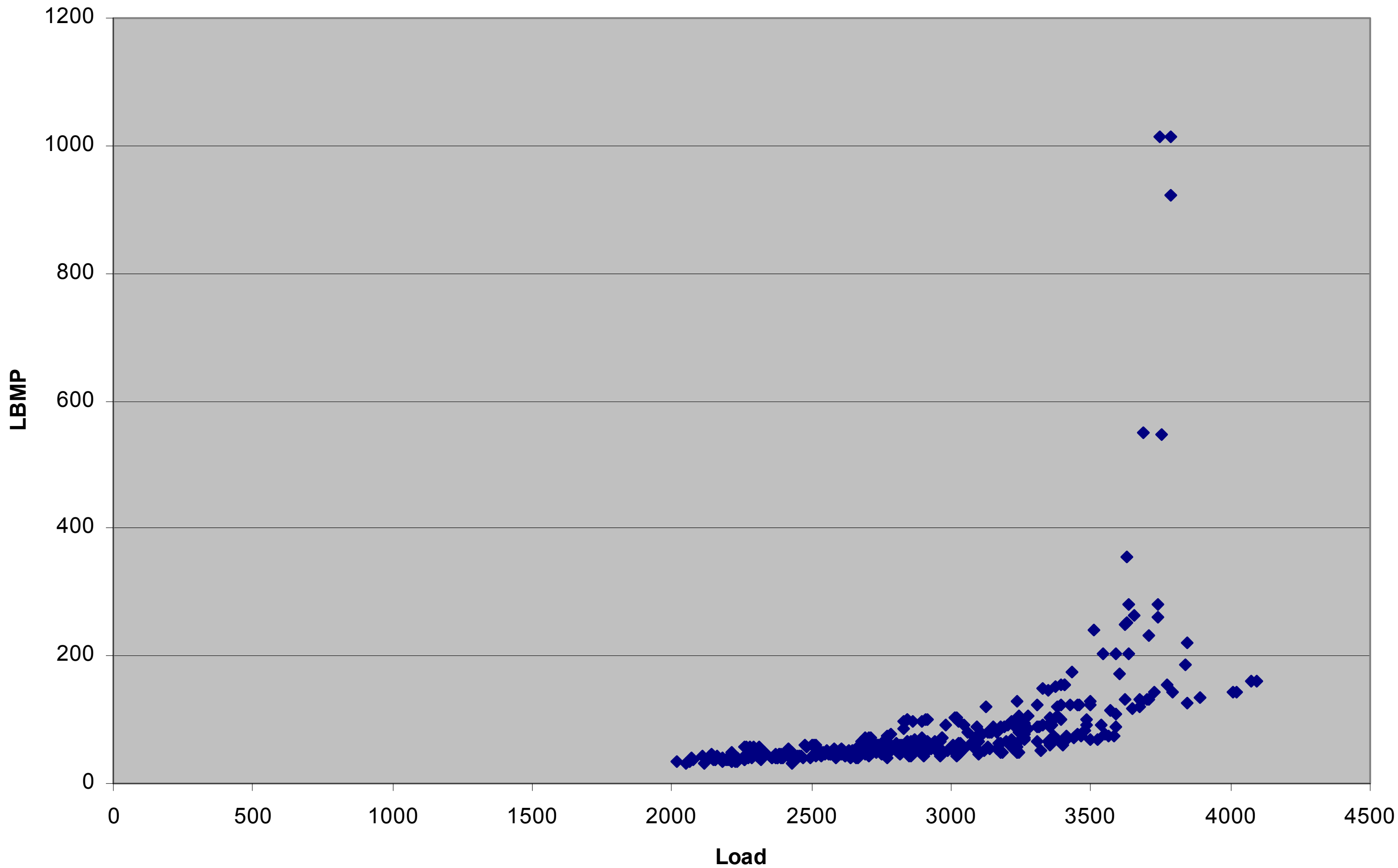


Chart 1.5. Capital Real-Time Market Load vs. LBMP (afternoon hours, summer 2001)

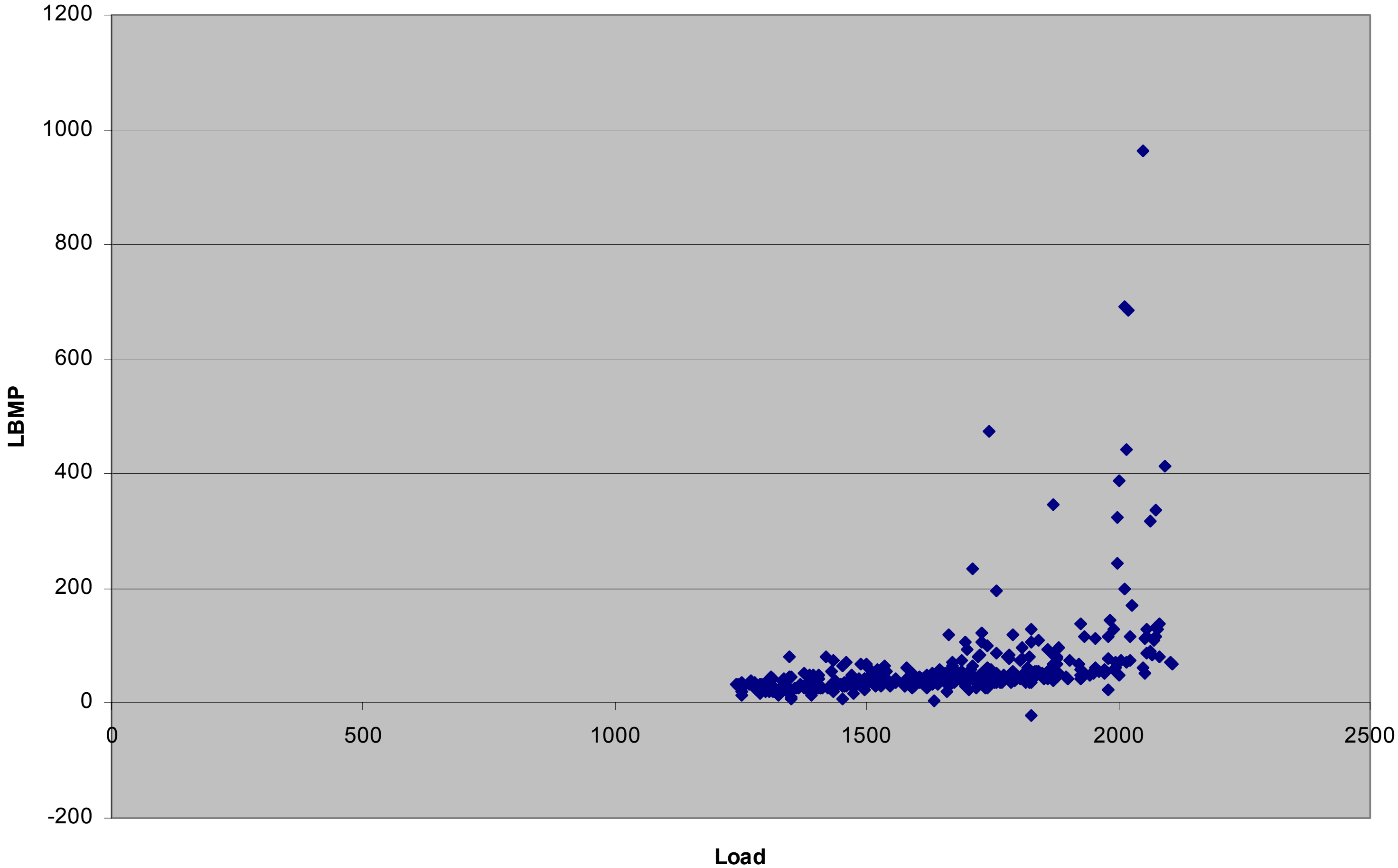


Chart 1.6. NYC/LI Real-Time Load vs. LBMP (afternoon hours, summer 2001)

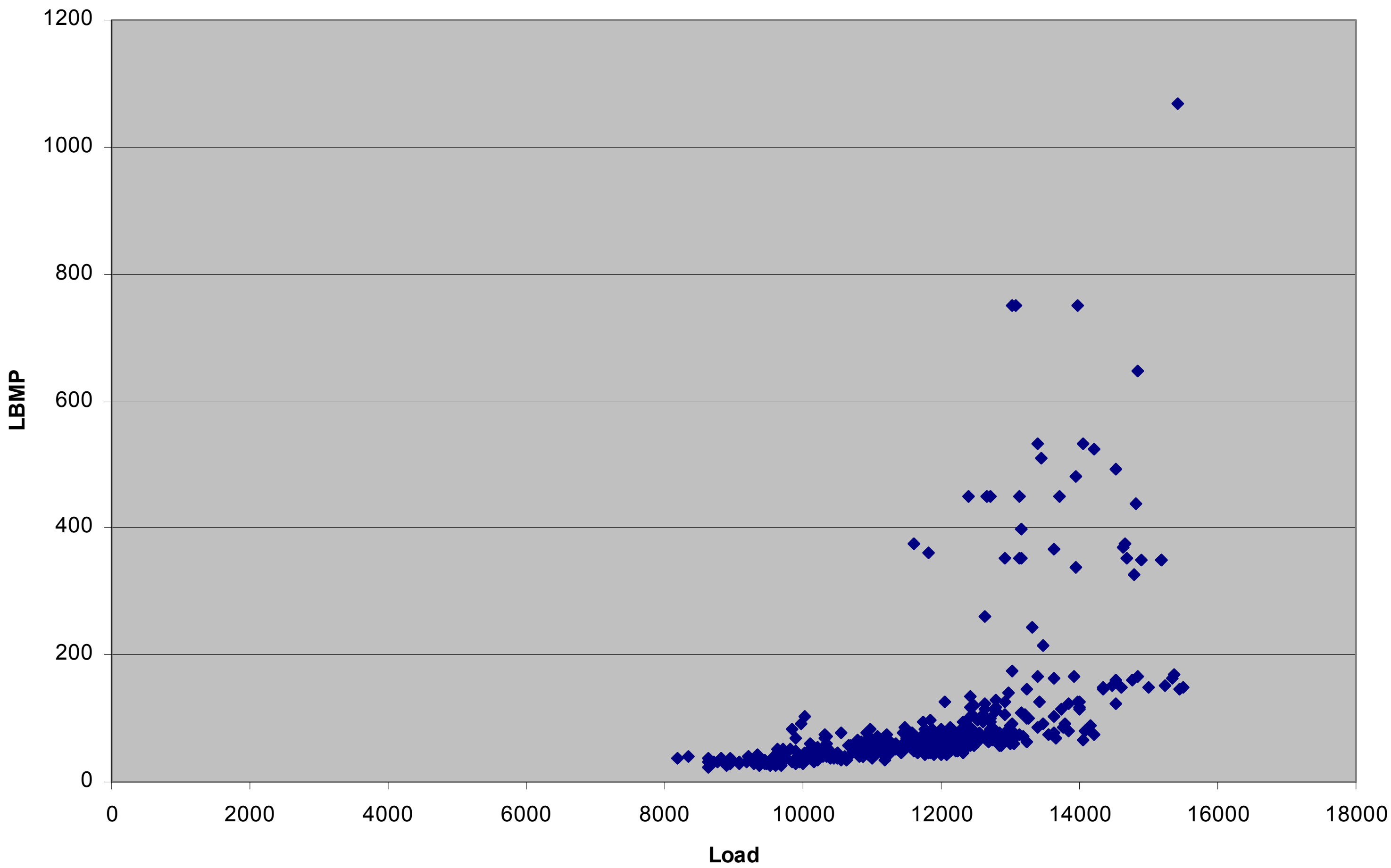


Chart 1.7. West of Total East Real-Time Load vs. LBMP (afternoon hours, summer 2001)

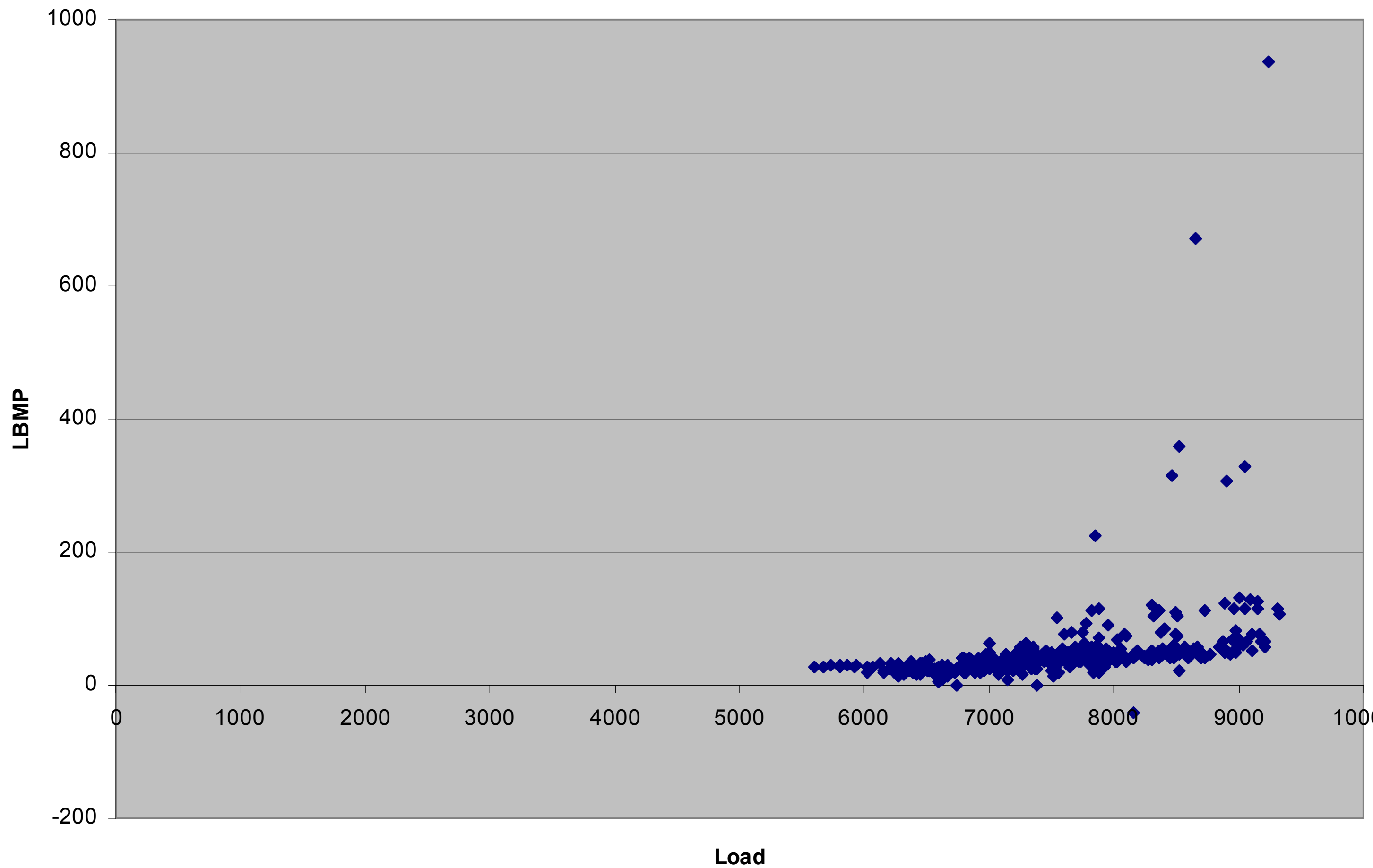


Chart 1.8. Hudson River Superzone Real-Time Load vs. LBMP (afternoon hours, summer 2001)

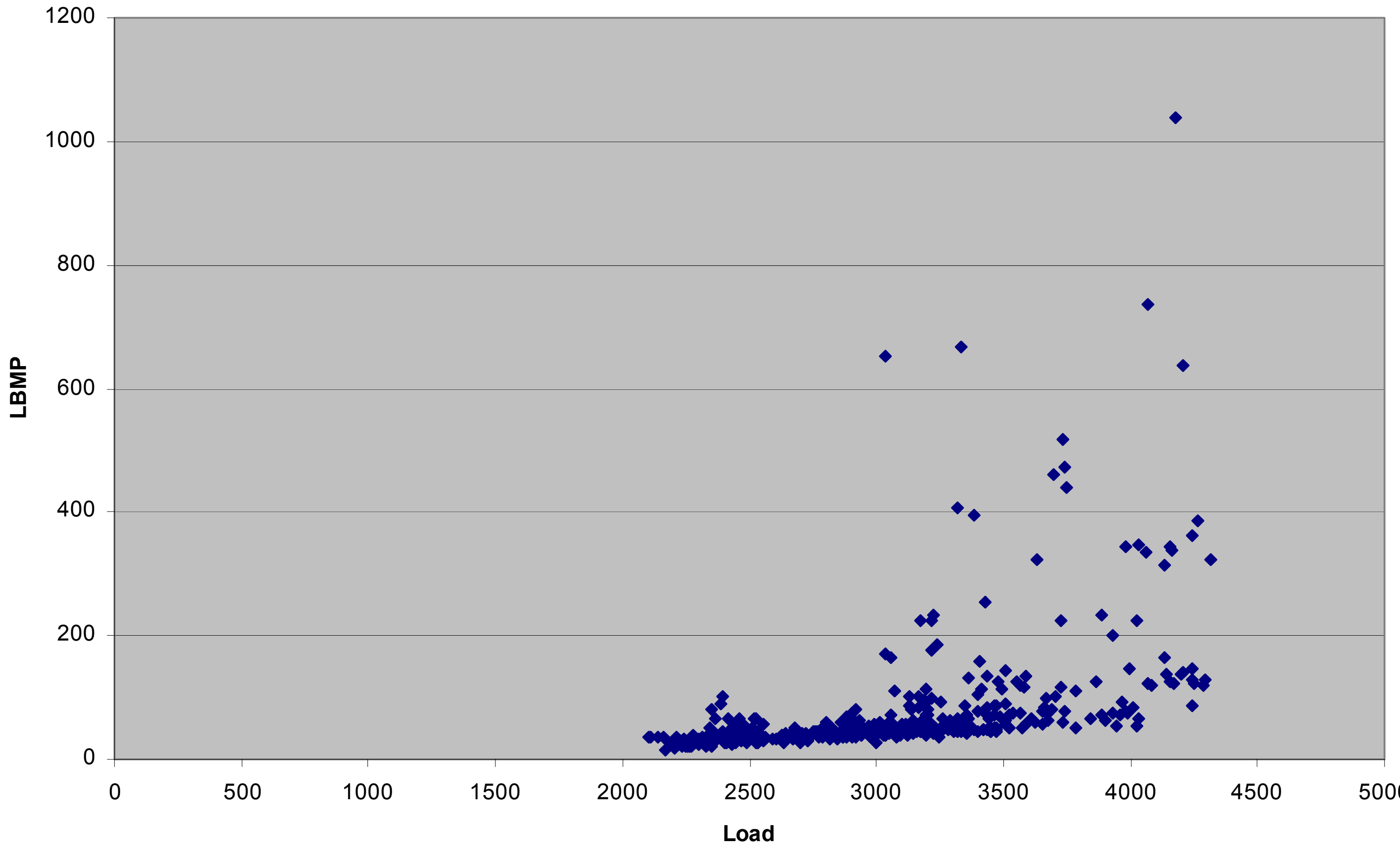


Chart 1.9. NYISO August 7, 2001 EDRP Event: Zonal Performance

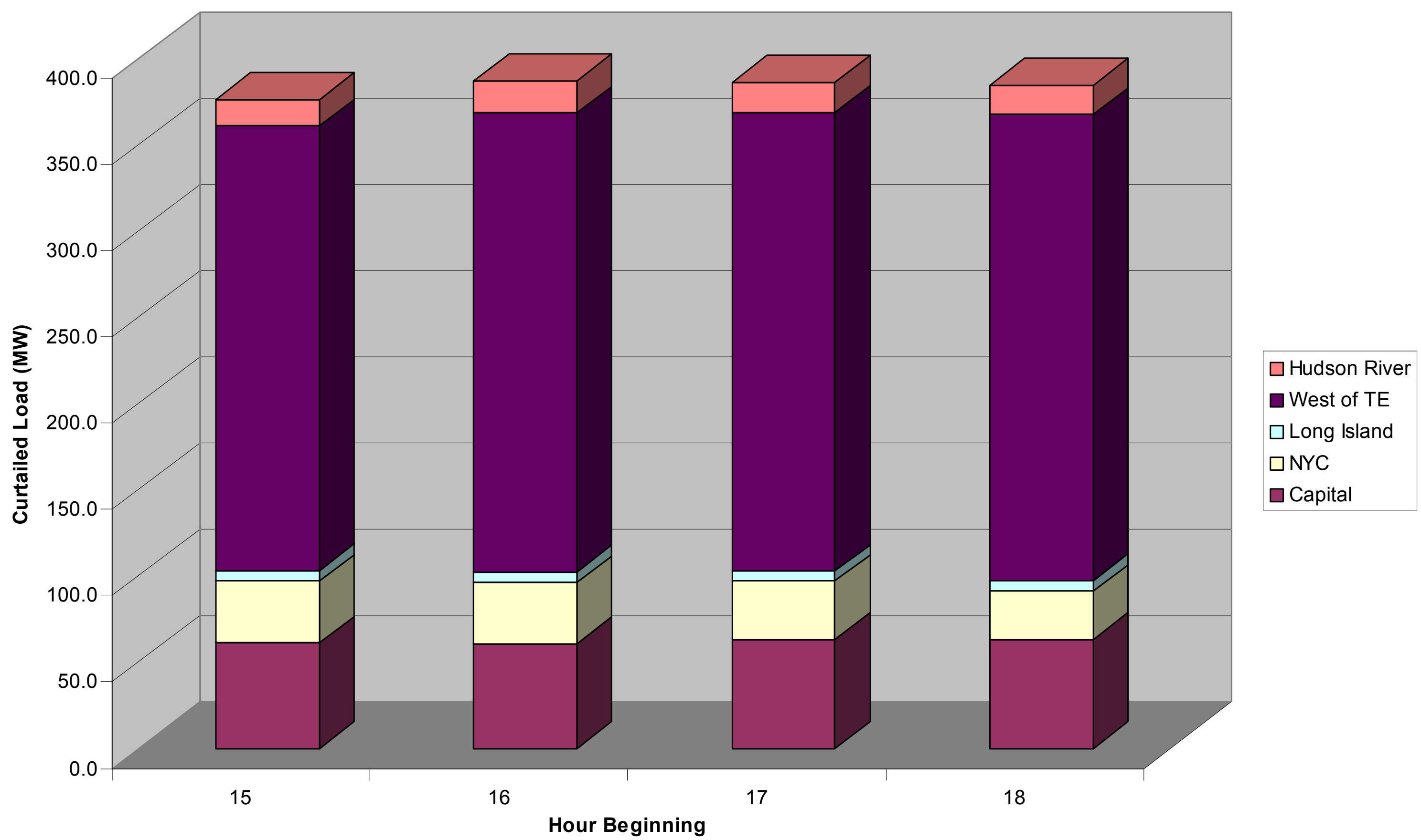


Chart 1.10. NYISO August 8, 2001 EDRP Event: Zonal Performance

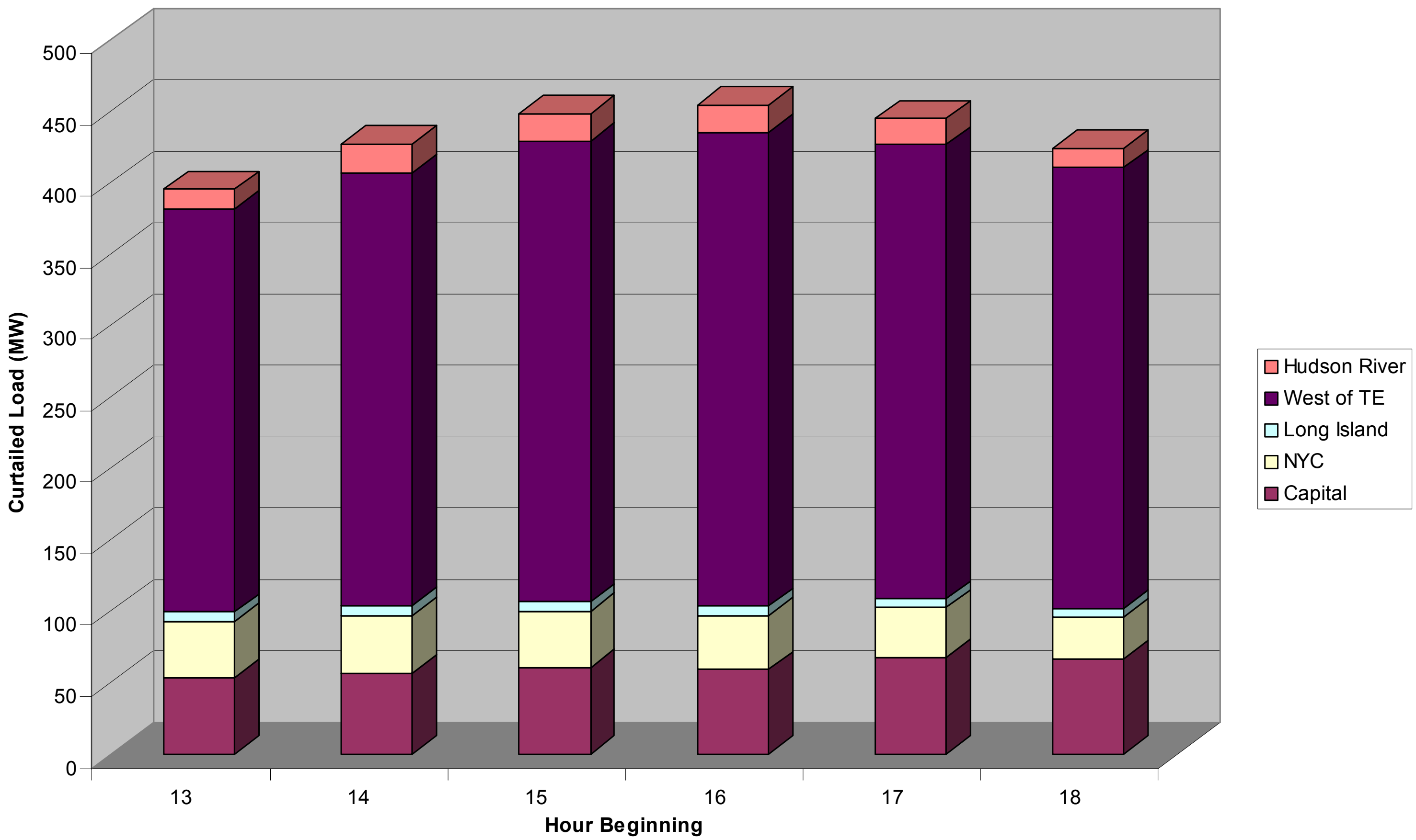


Chart 1.11. NYISO August 9, 2001 EDRP Event: Zonal Performance

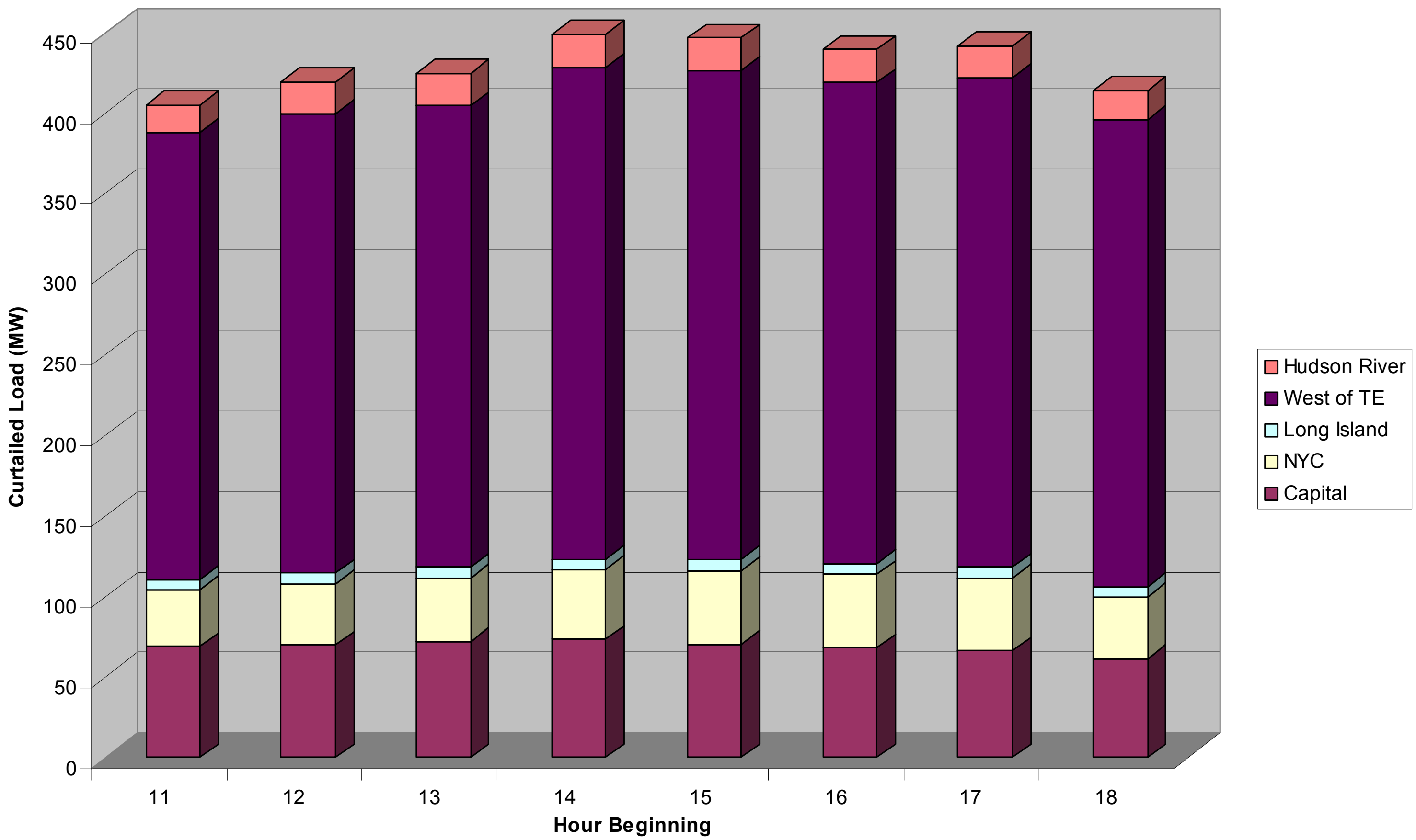


Chart 1.12. NYISO August 10, 2001 EDRP Event: Zonal Performance

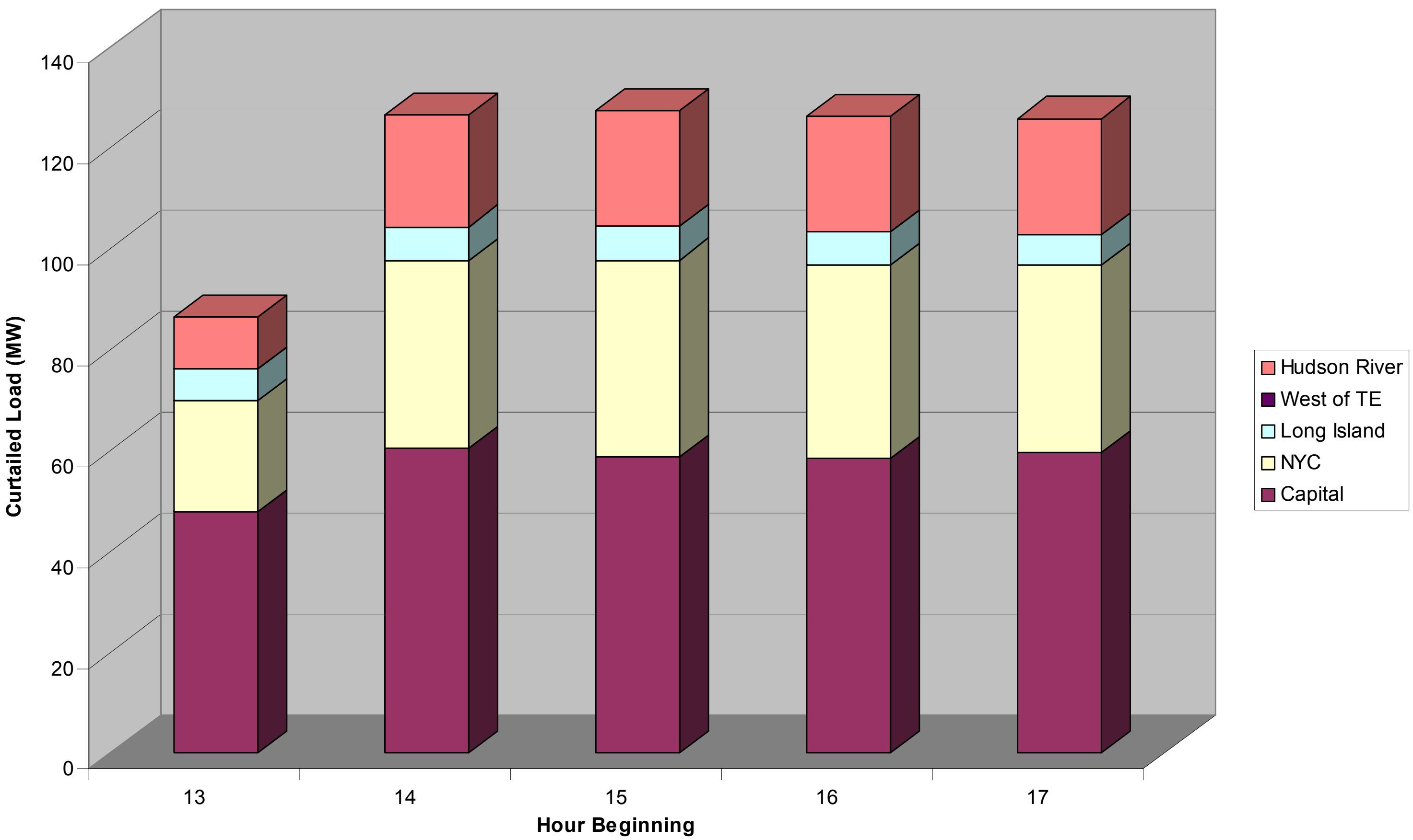


Chart 1.13. NYISO August 7, 2001 EDRP Event: Zonal LBMPs

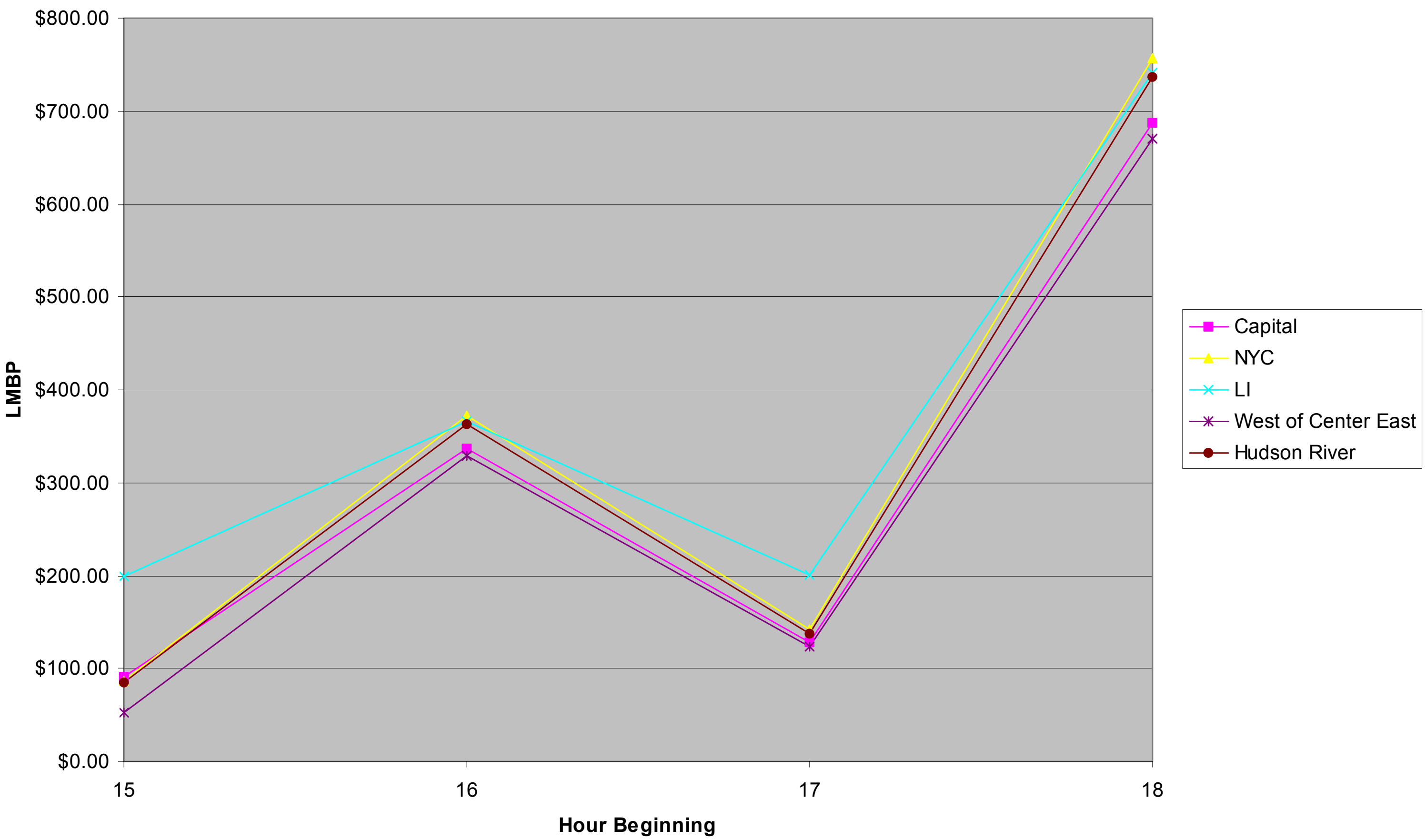


Chart 1.14. NYISO August 8, 2001 EDRP Event: Zonal LBMPs

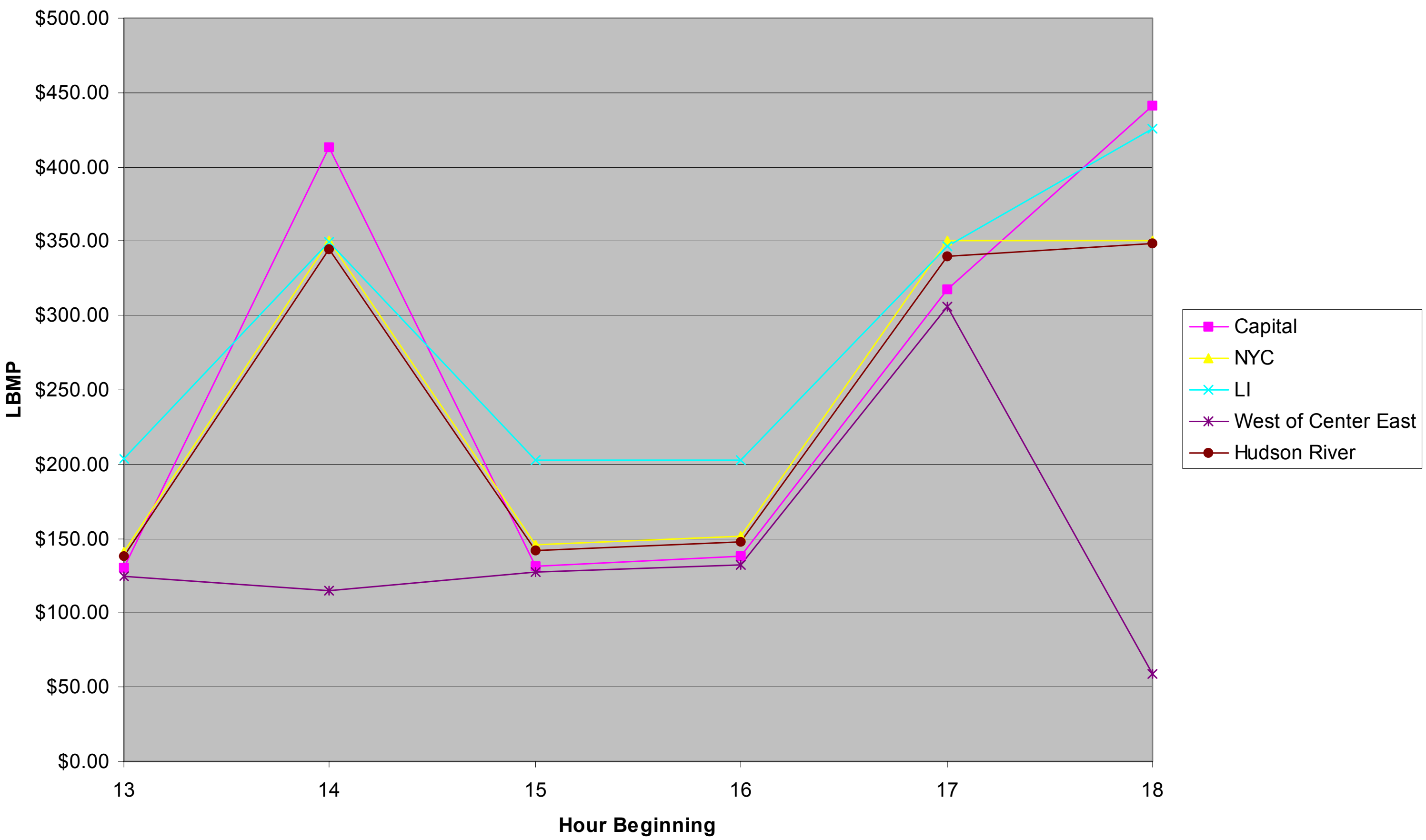


Chart 1.15. NYISO August 9, 2001 EDRP Event: Zonal LBMPs

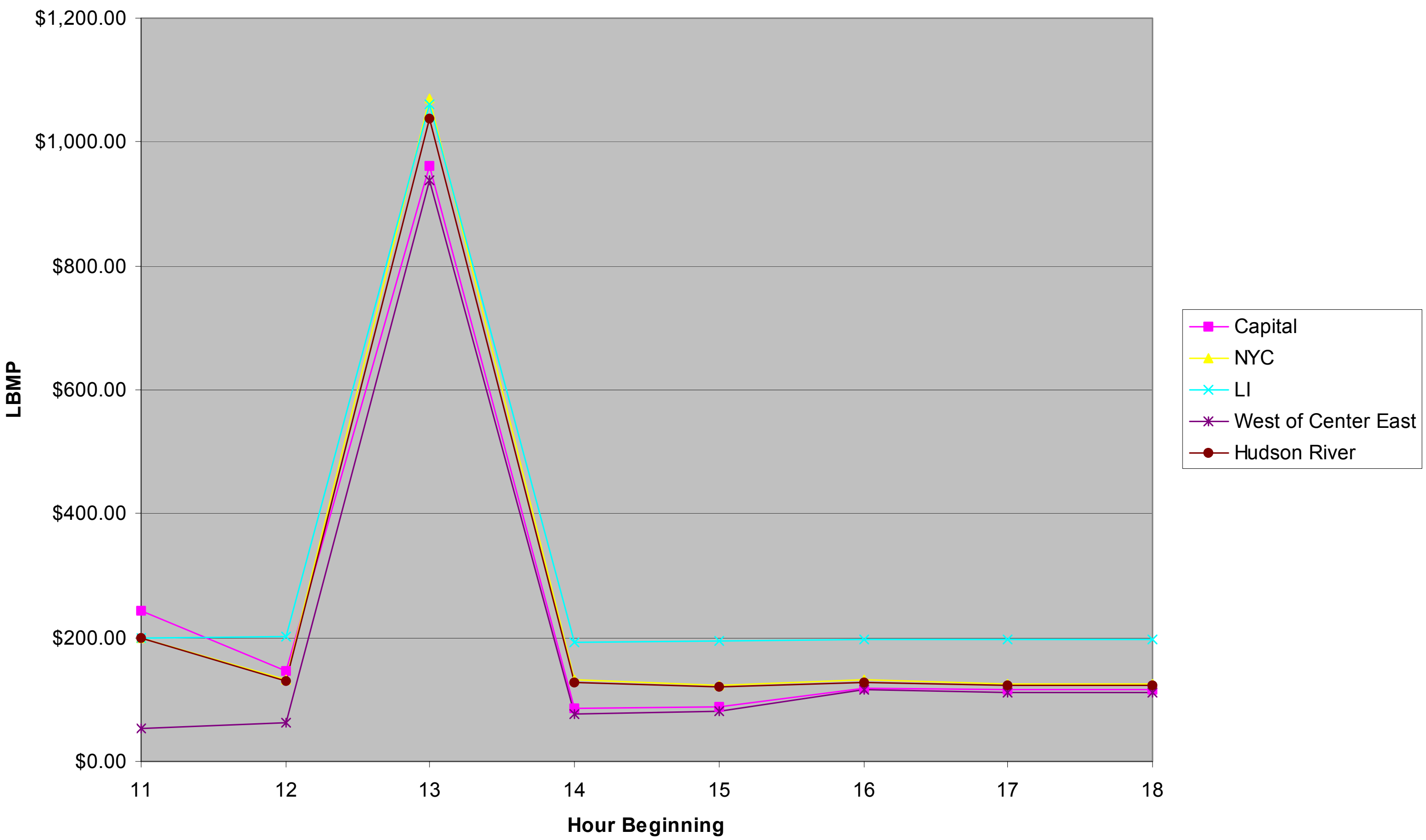


Chart 1.16. NYISO August 10, 2001 EDRP Event: Zonal LBMPs

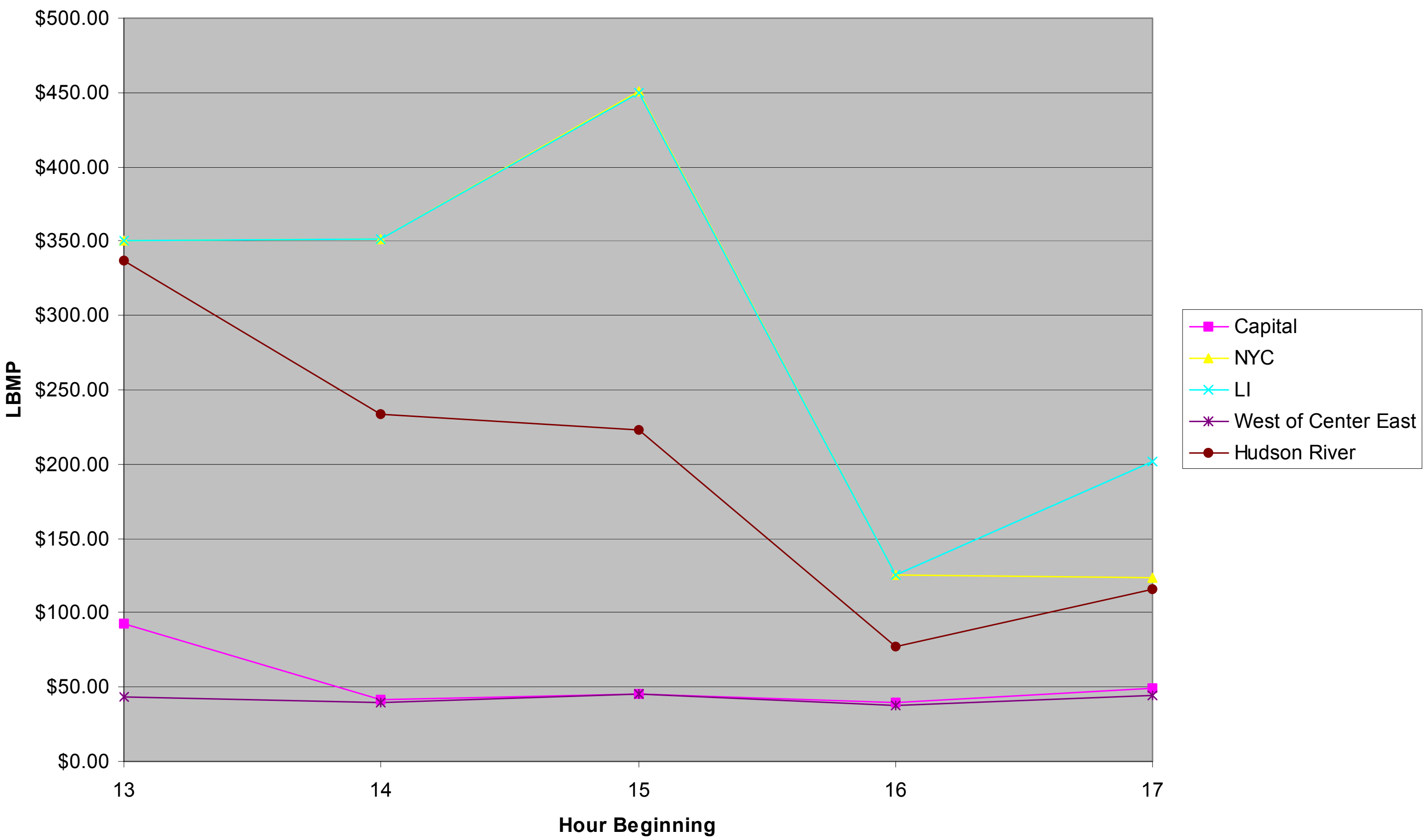


Figure 1.1 Summary of 2001 NYISO Price Responsive Load Programs

Program Feature	**EDRP**	**DADRP**
Curtailment Opportunity	Declared System Emergency	Submitted Curtailment Bid into DAM
Notice	2 Hour Minimum	11 AM Day-Ahead
Penalty	None	1.1 * Higher of DAM or RT LBMP
Performance	Metered Load vs. CBL	Metered Load vs. CBL
Payment	Higher of $500/MWh or RT LBMP	Based on LBMP and Start-Up cost component of scheduled bids
Initial Subscription Limit	100 kW minimum reduction	100 kW minimum reduction
Program Administration	Open to all LSEs and CSPs (Curtailment Service Providers)	LSE's administer program for 2001. CSPs permitted in 2002

Map 1.1: Estimated Price Flexibility Zones

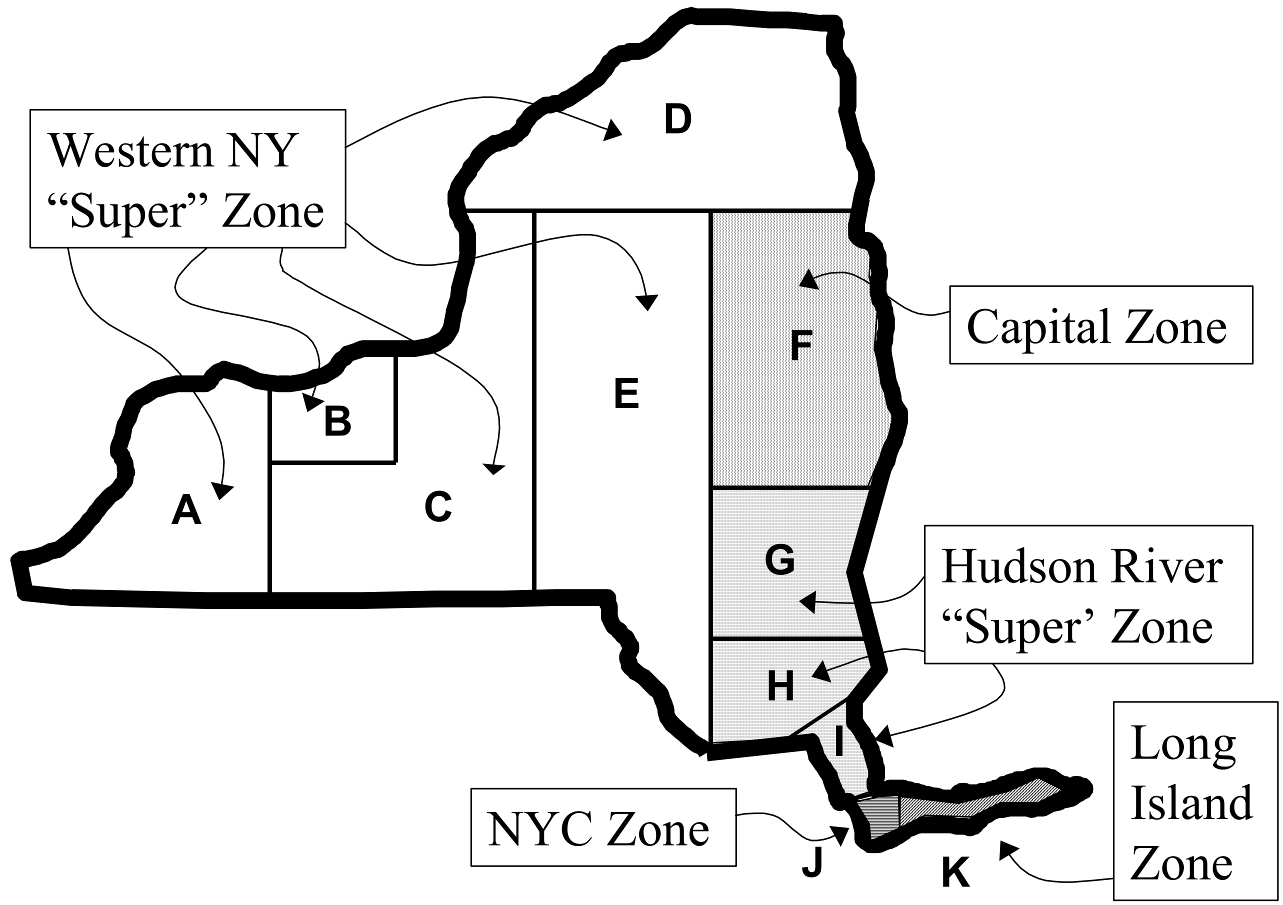


Exhibit 1.1. Scatter Diagram of LBMP vs. Load

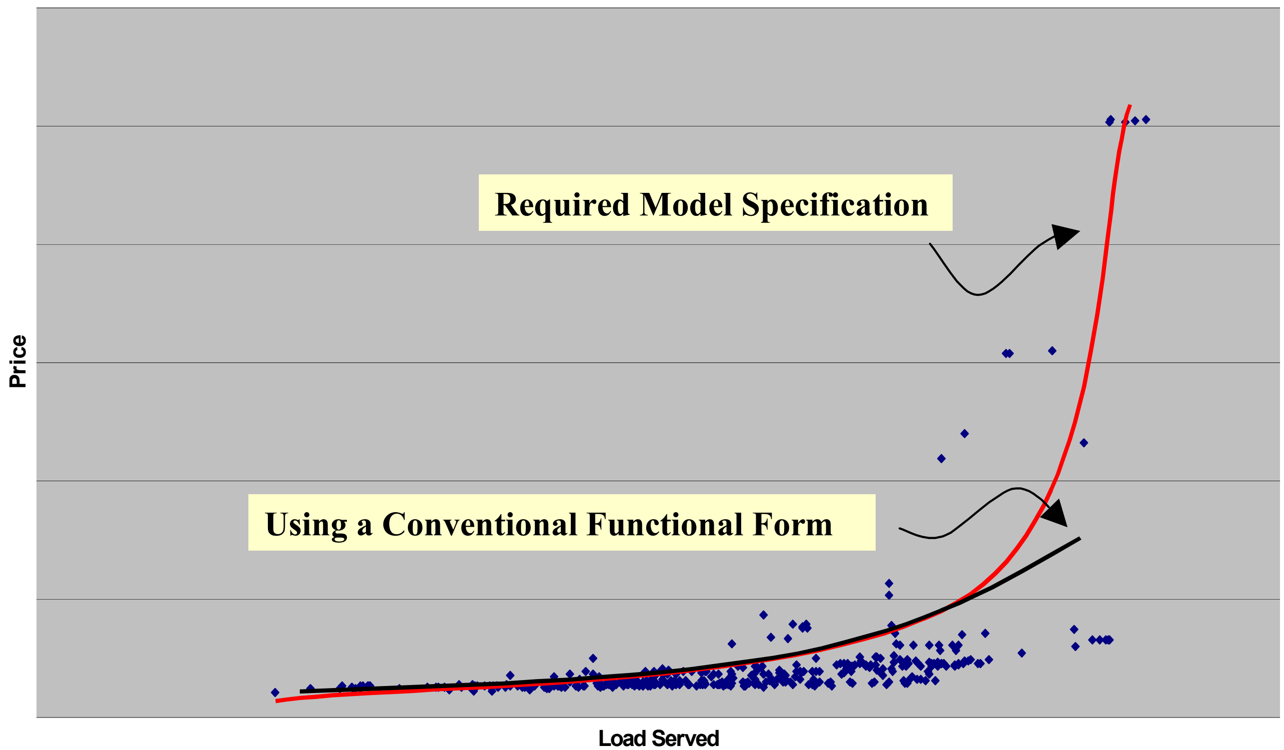


Exhibit 1.2. Different Supply Regimes

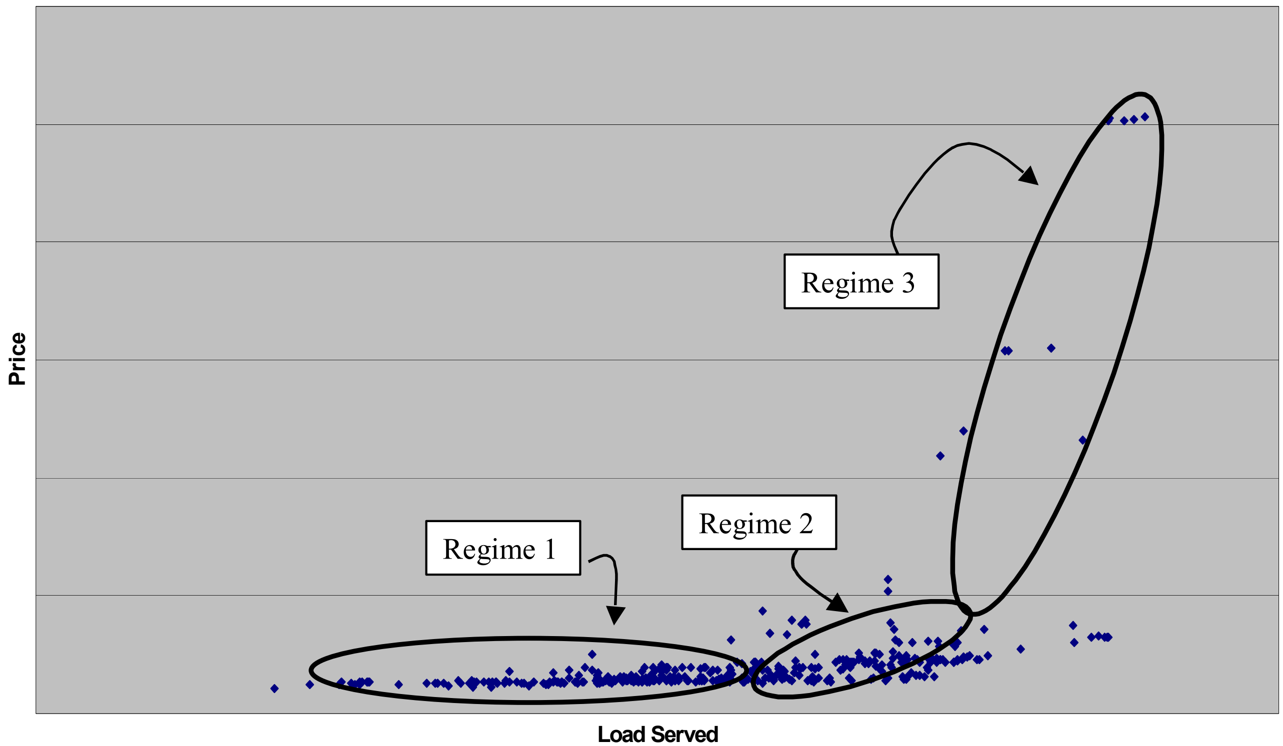


Exhibit 1.3. "Spline" Model Specification

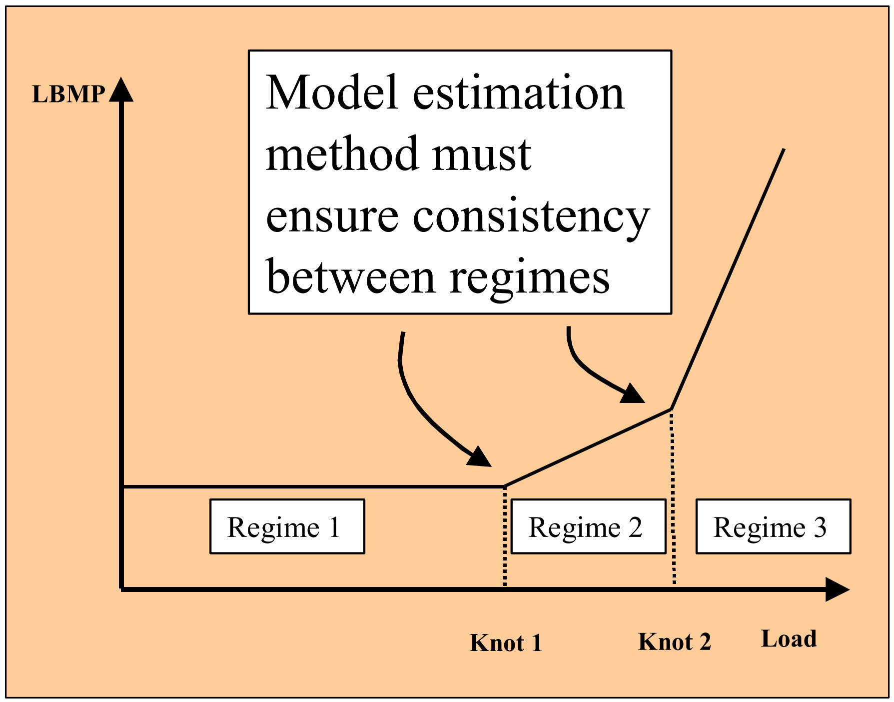


Exhibit 1.4. Modeling Apparent Outliers

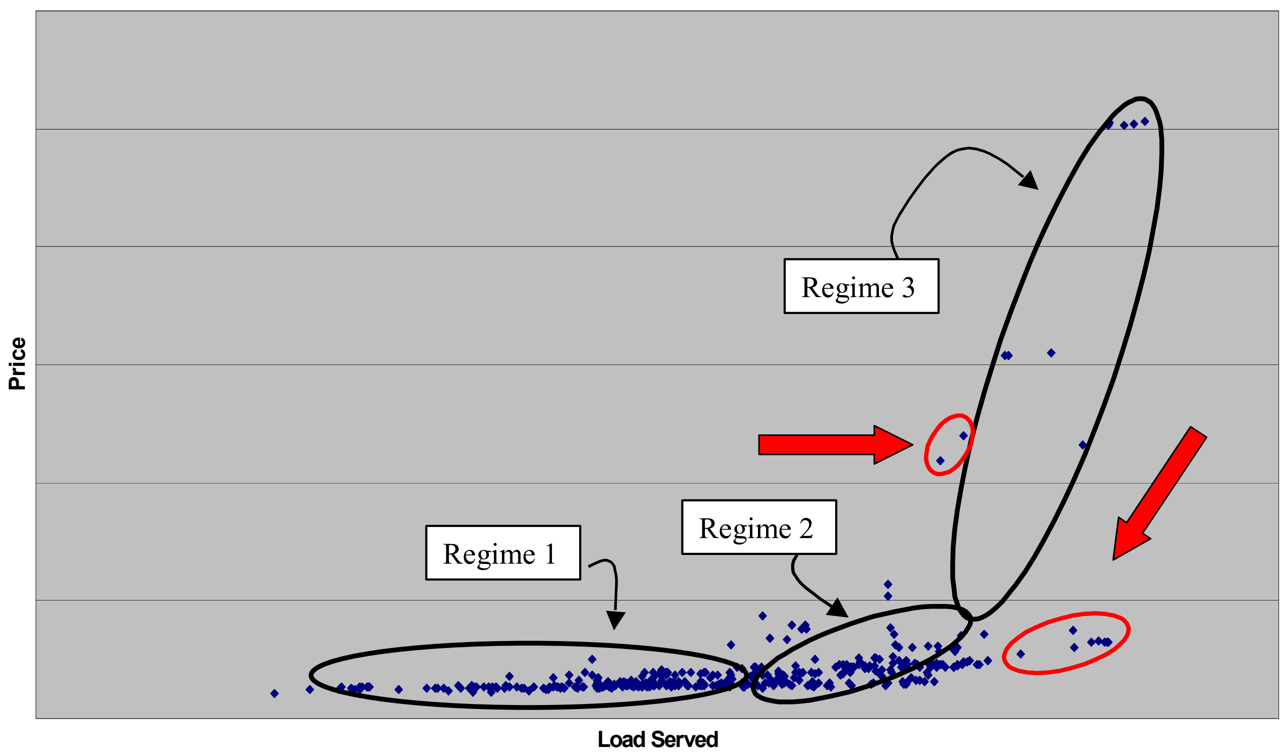
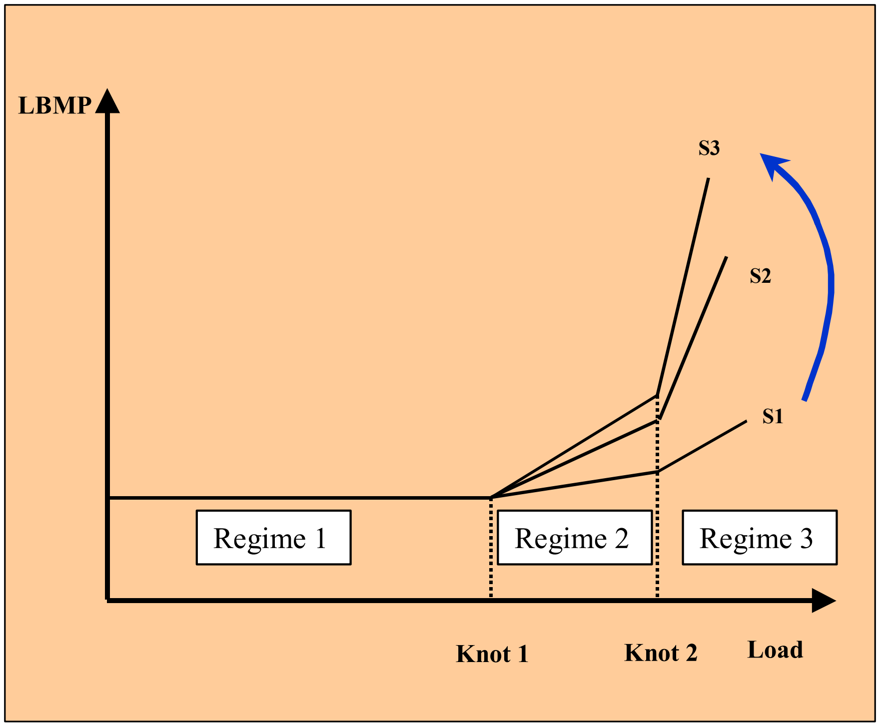


Exhibit 1.5. Final Model Specification



Supply Shift due to:

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

Exhibit 1.6. Simulation of Effects of PRL Reduction

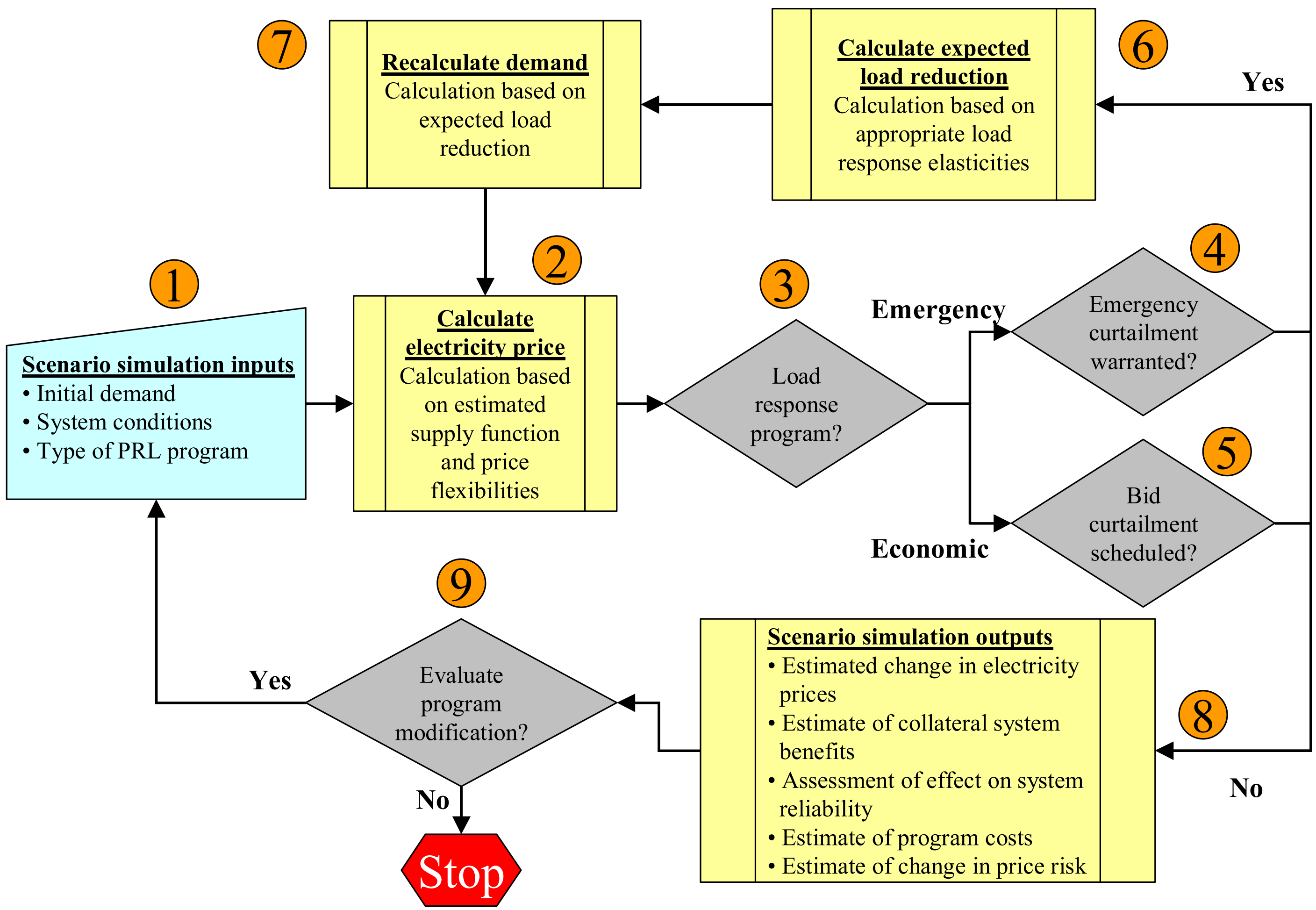
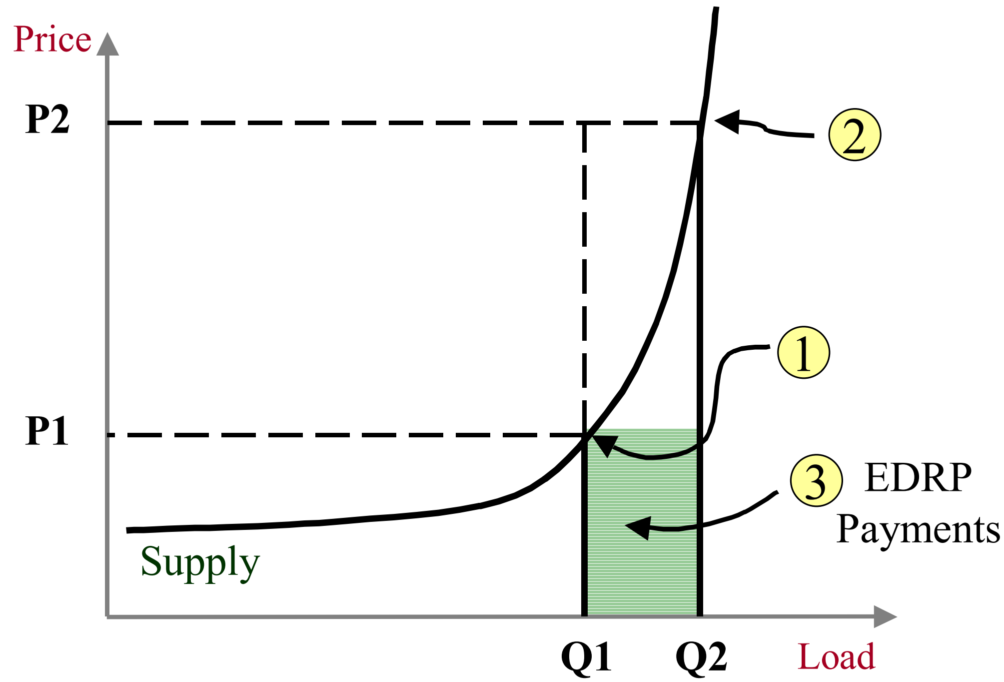


Exhibit 1.7a. Market Adjustments for EDRP

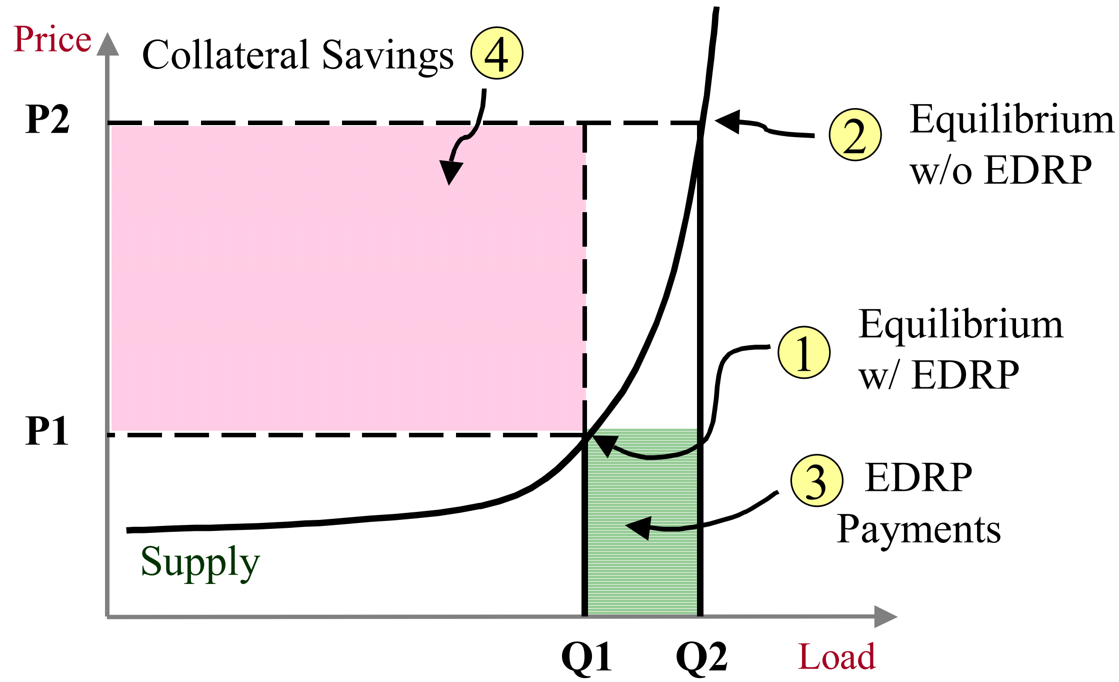


1 Demand and Equilibrium Price, Q1 and P1, after EDRP Event called yielding load reduction of Q2 – Q1, equilibrium observed in the data.

2 Demand and Equilibrium Price without EDRP Load Reduction, Q2 and P2.

3 Program Payments: (Q2 – Q1) x P1 or $500, whichever is higher

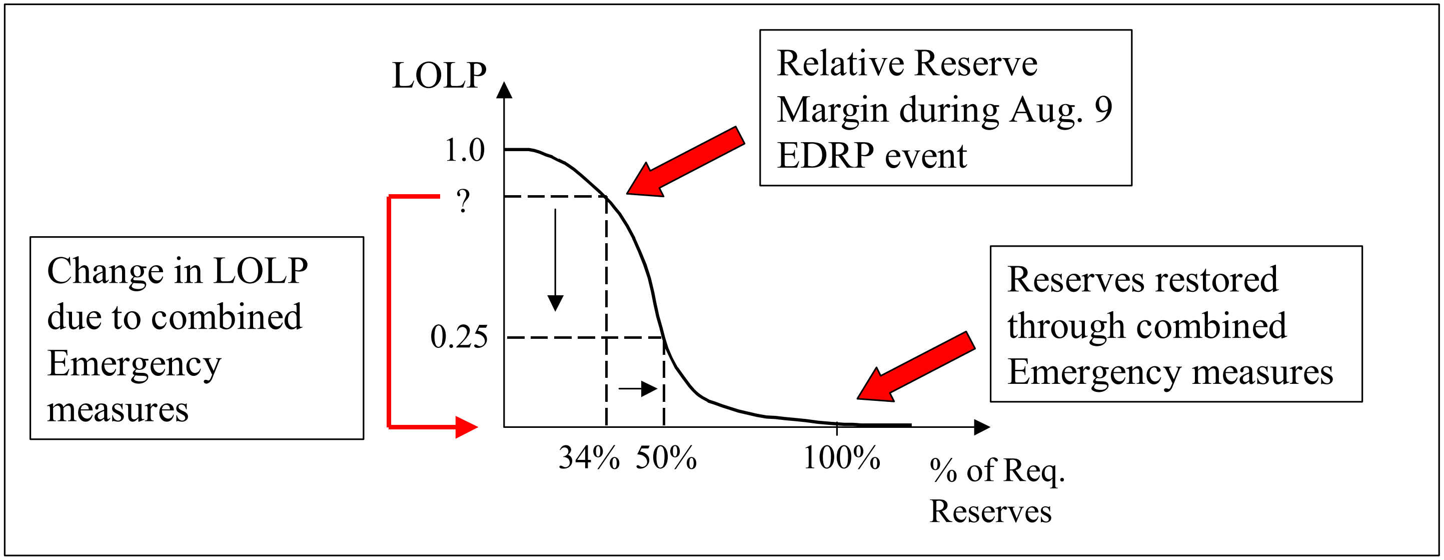
Exhibit 1.7b. EDRP Events Collateral Savings



4 Collateral Savings = Q1 x (P2 – P1) = **$3.2 Million**

These savings equal current market benefits, if all load is purchased in the Real-Time Market.

Exhibit 1.8. EDRP Value of Expected Unserved Energy



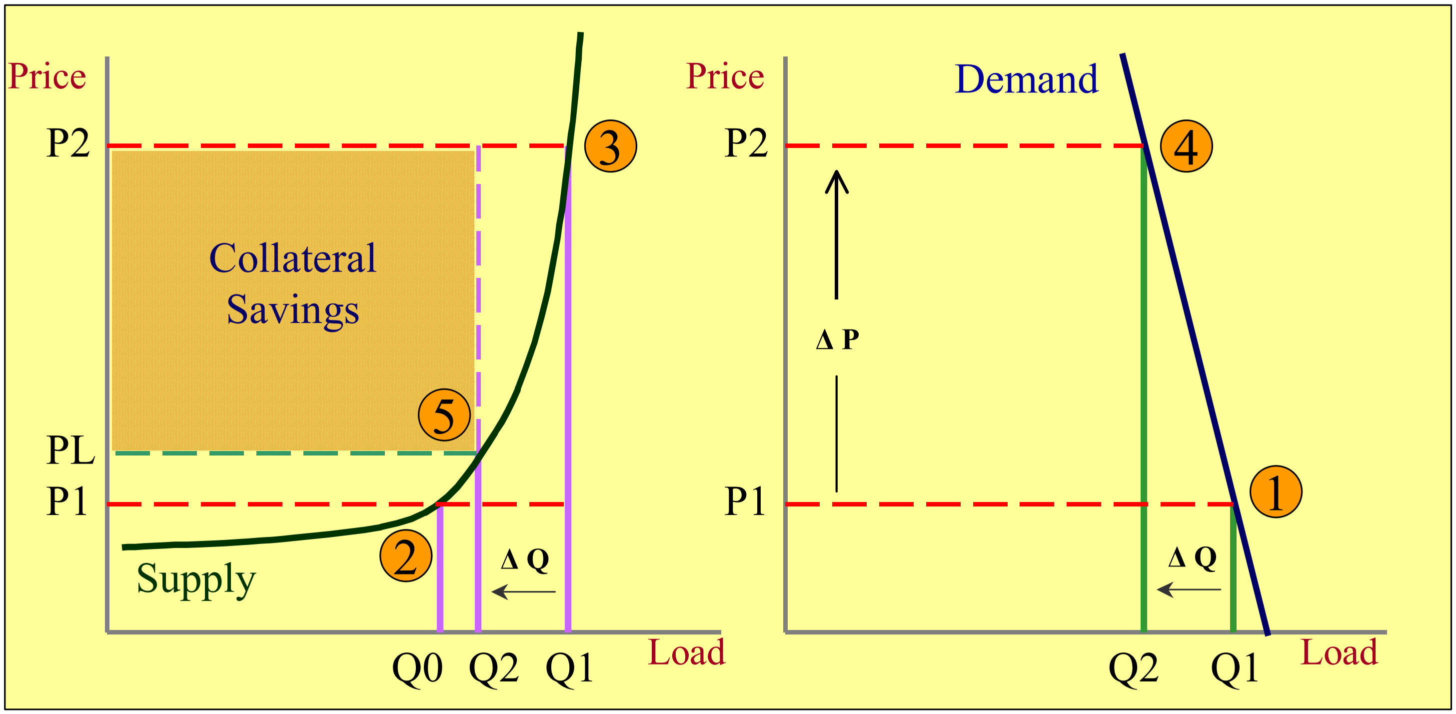
Hourly Value of Expected Un-served Energy, 5% of Load at Risk

Reduction in LOLP	Outage Cost $1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	($1,000's)			
0.05	$ 70	$ 105	$ 174	$ 348
0.10	$ 139	$ 209	$ 348	$ 697
0.25	$ 348	$ 523	$ 871	$ 1,742
0.50	$ 697	$ 1,045	$ 1,742	$ 3,484

Hourly 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	$ 1,394	$ 2,090	$ 3,484	$ 6,968
0.10	$ 2,787	$ 4,181	$ 6,968	$ 13,936
0.25	$ 6,968	$ 10,452	$ 17,419	$ 34,839
0.50	$ 13,936	$ 20,903	$ 34,839	$ 69,678

Exhibit 1.9. The Dynamics of DADRP Price-Responsive Load



1 Retail rate and corresponding demand.

2 Supply offered at retail rate.

3 Retail demand supplied only at higher price.

4 Reduction in retail demand due to higher price.

5 LBMP after scheduled load reduction.

Chart 1.1A. Capital Average DAM vs. Real-Time Load (Summer 2001)

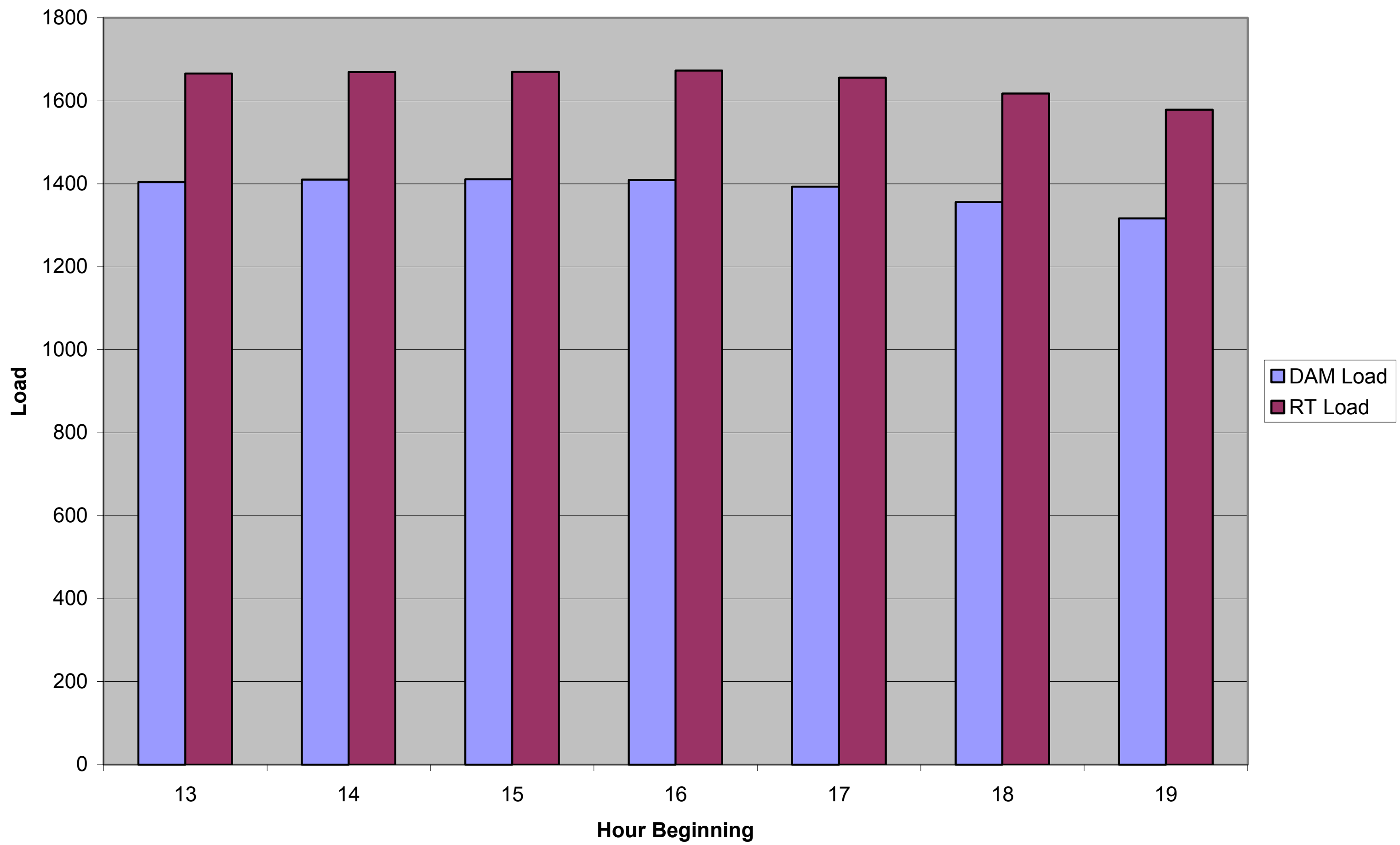


Chart 1.2A. West of Total East Average DAM vs. Real-Time Load (Summer 2001)

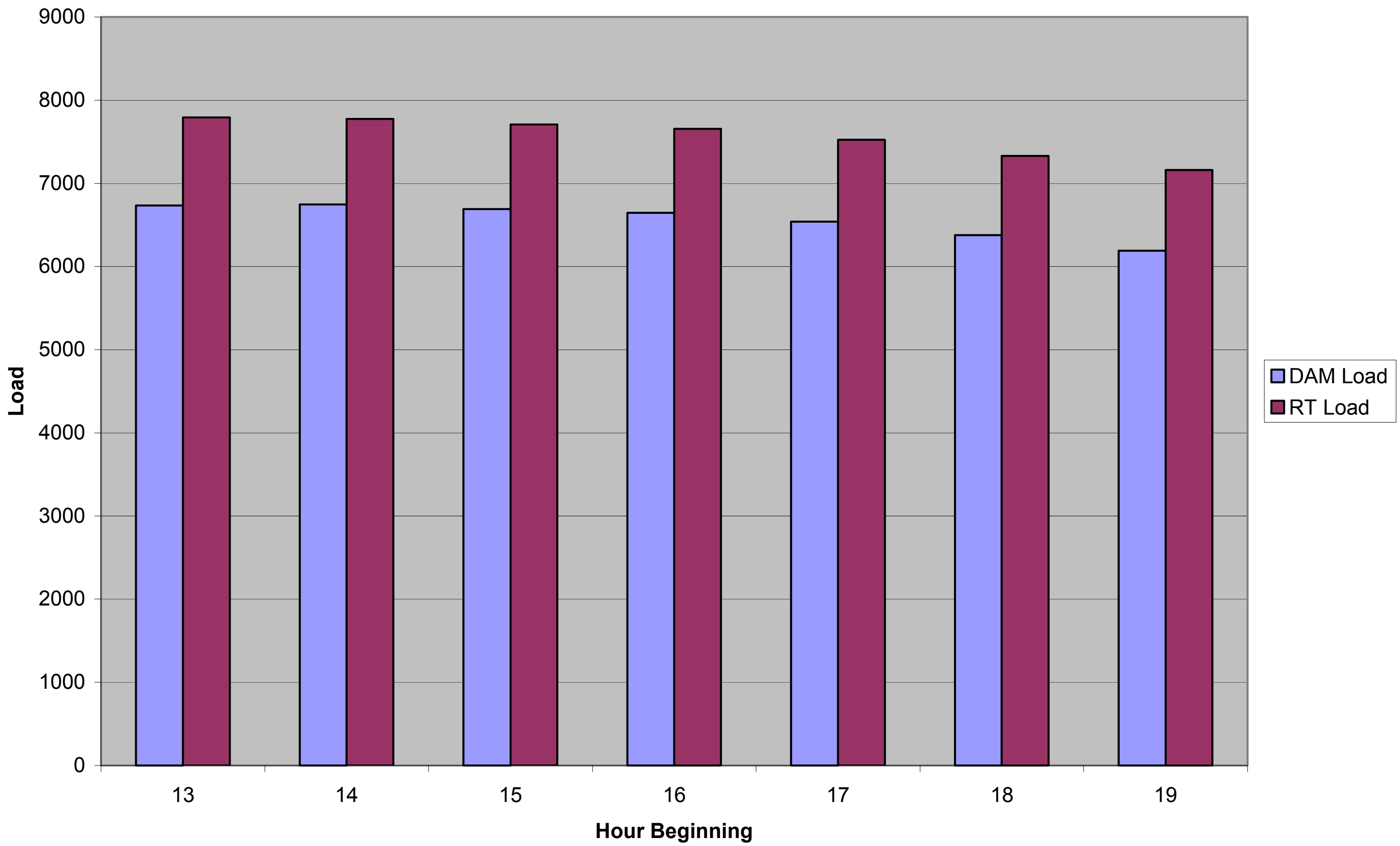


Chart 1.3A. Hudson River Superzone Average DAM vs. Real-Time Load (Summer 2001)

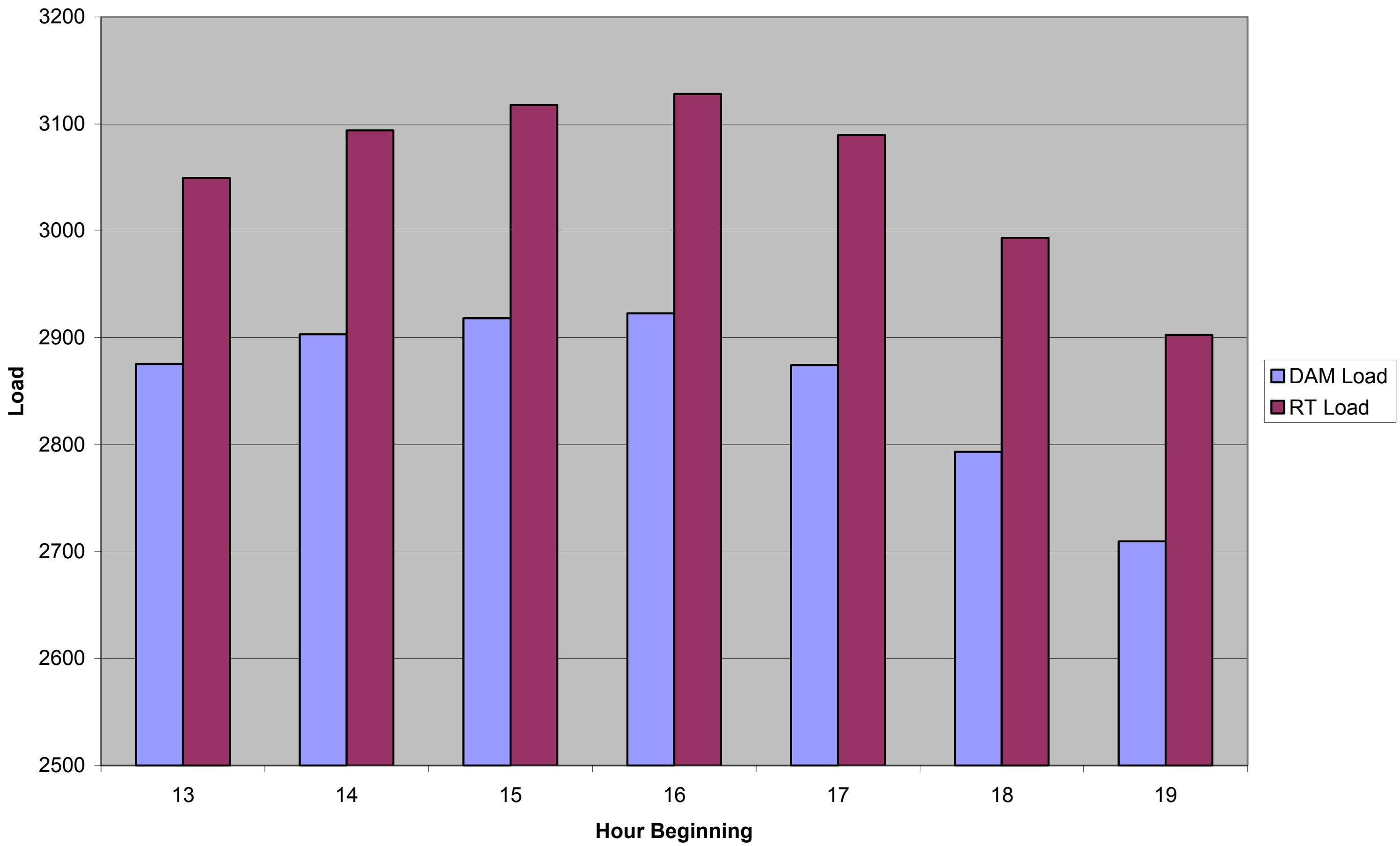


Chart 1.4A. NYC & LI Average DAM vs. Real-Time Load (Summer 2001)

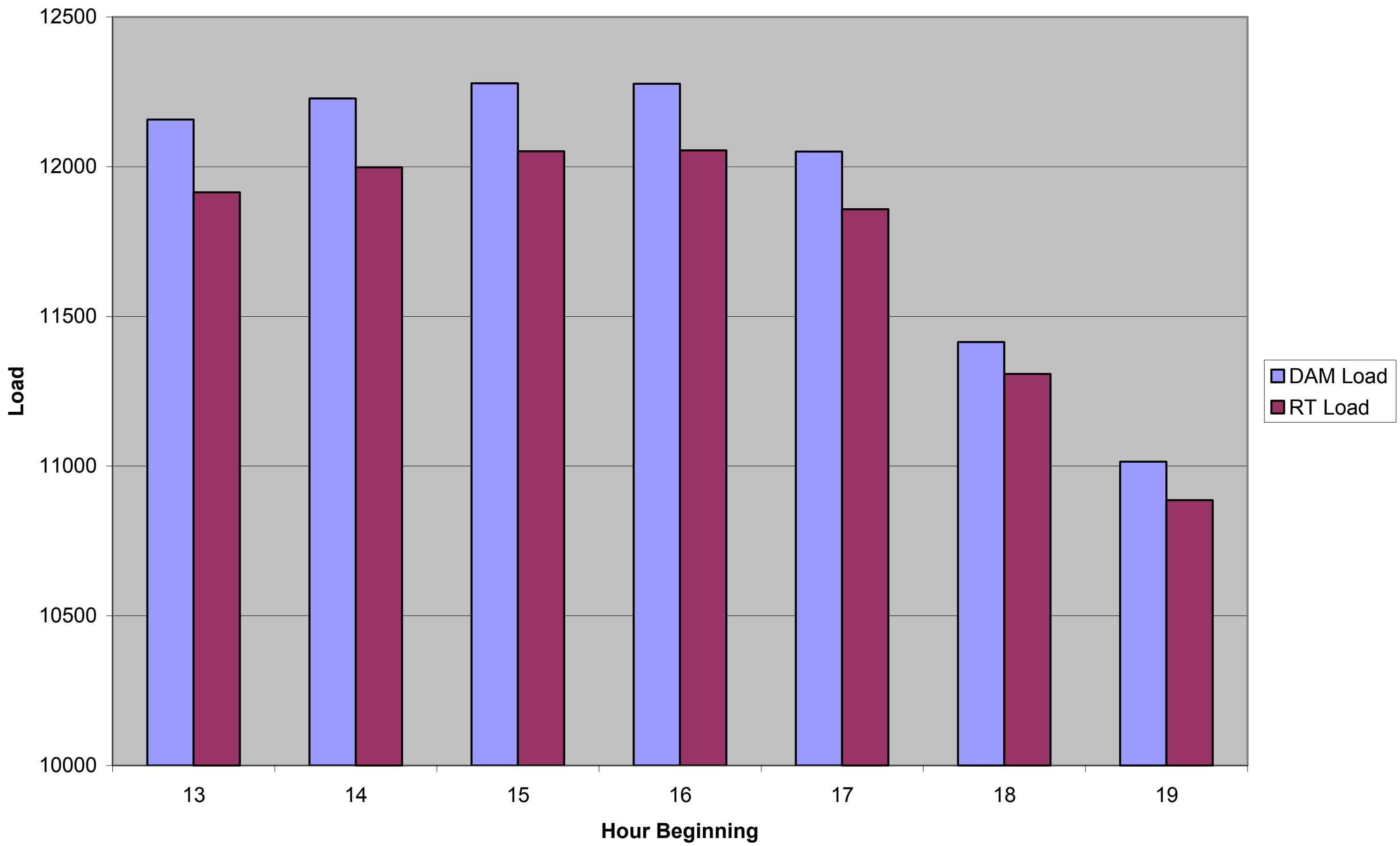


Chart 1.5A. New York State Average DAM vs. Real-Time Load (Summer 2001)

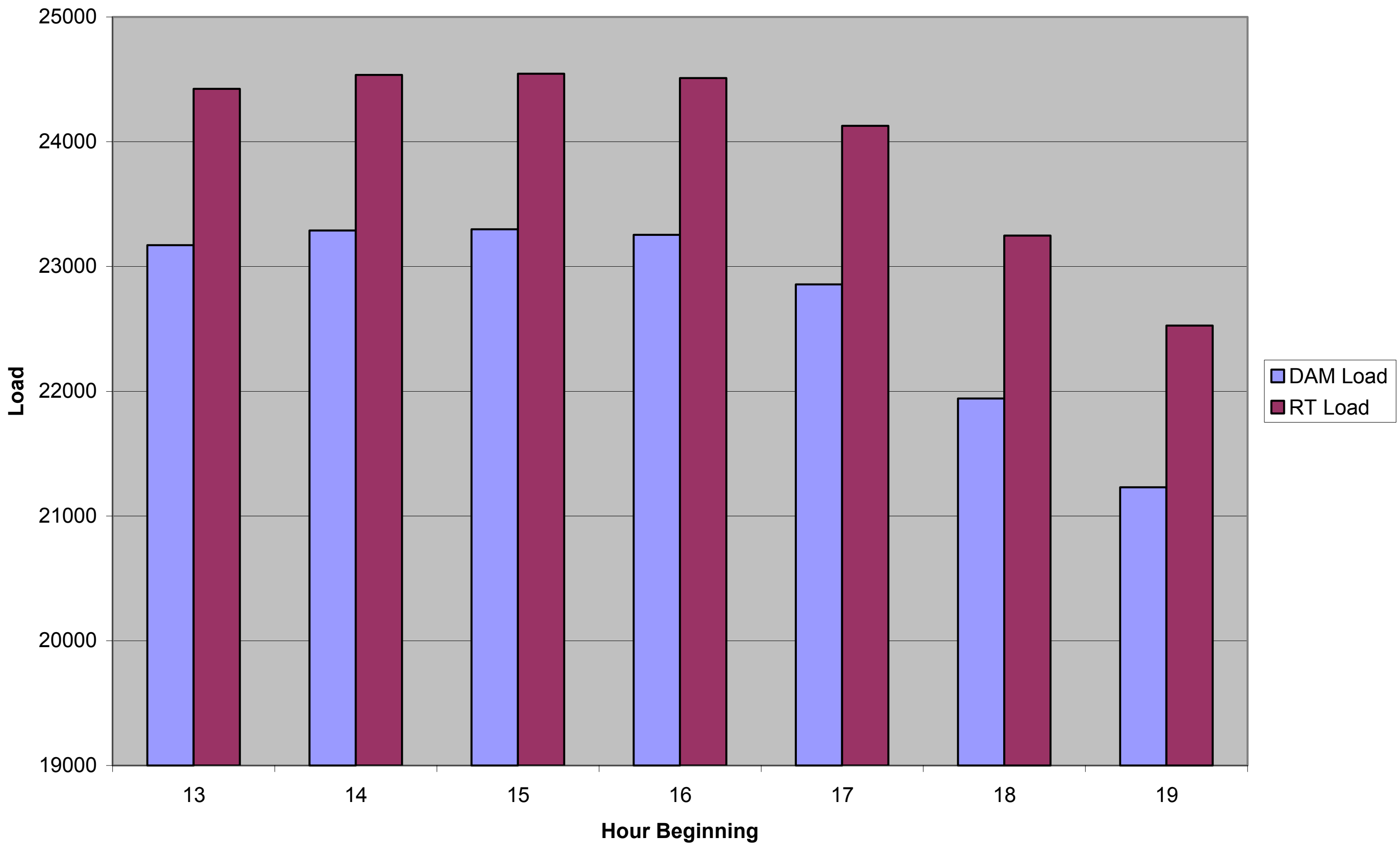


Chart 1.6A. Capital Average DAM vs. Real-Time LBMP (Summer 2001)

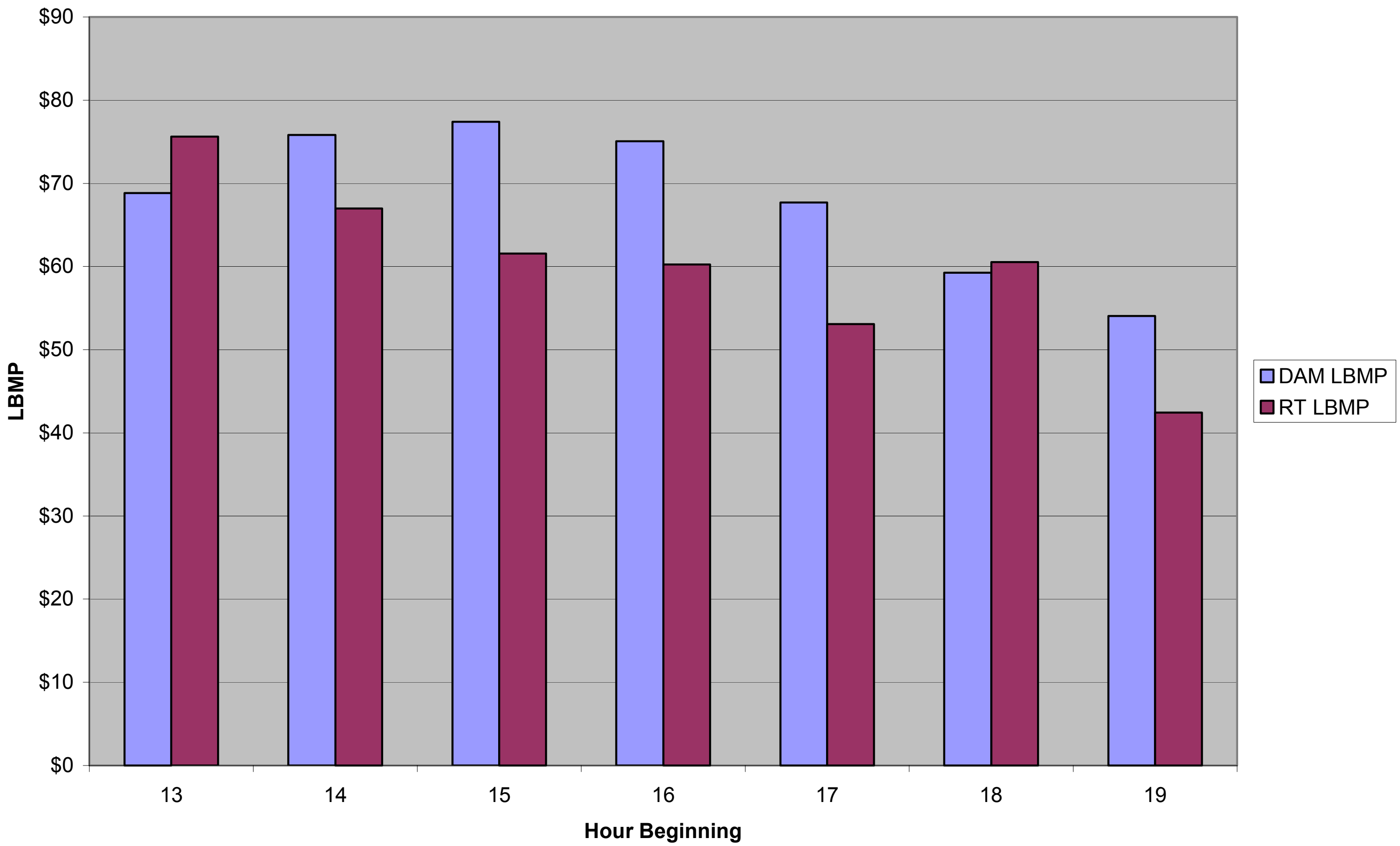


Chart 1.7A. NYC Average DAM vs. Real-Time LBMP (Summer 2001)

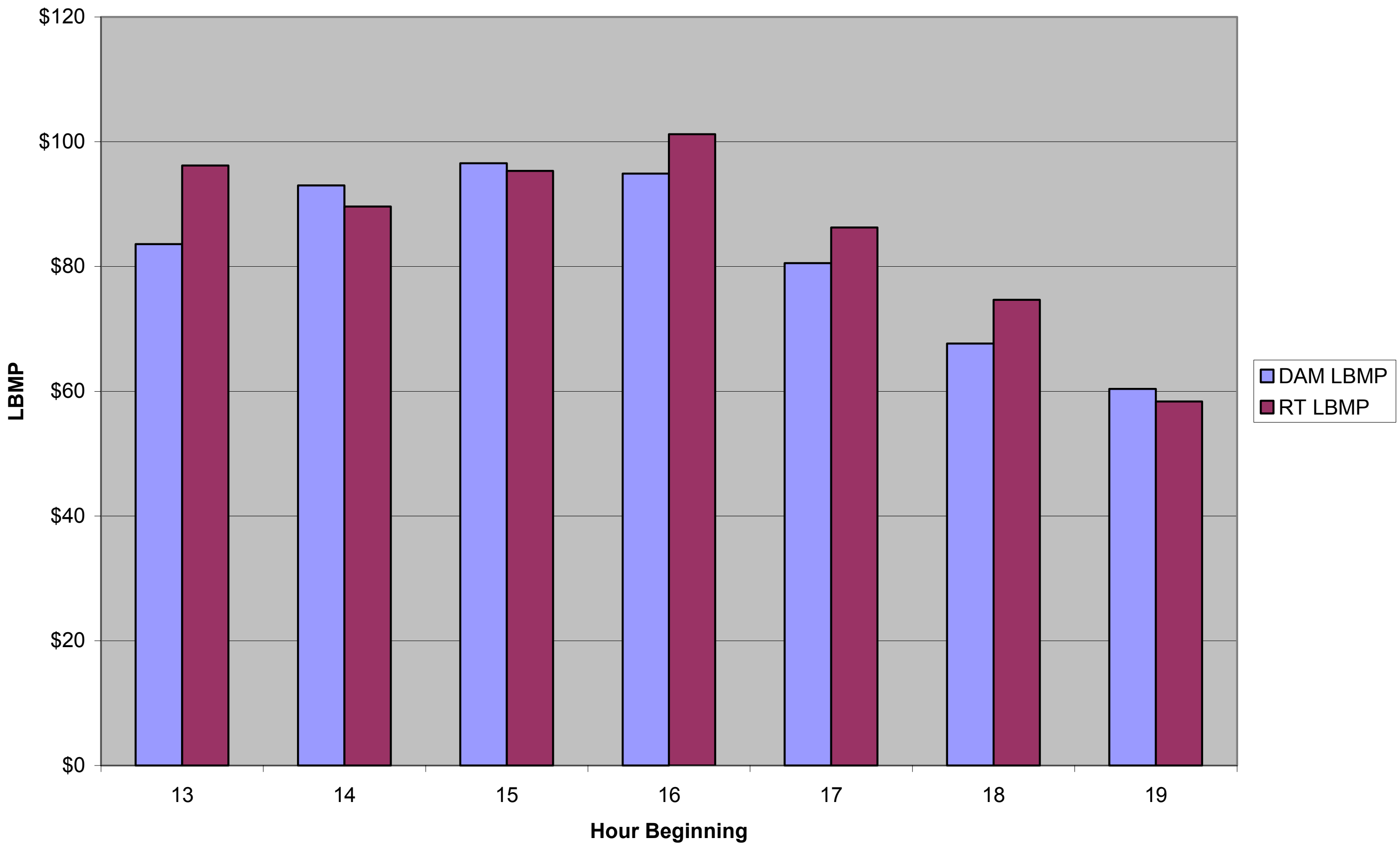


Chart 1.8A. Long Island Average DAM vs. Real-Time LBMP (Summer 2001)

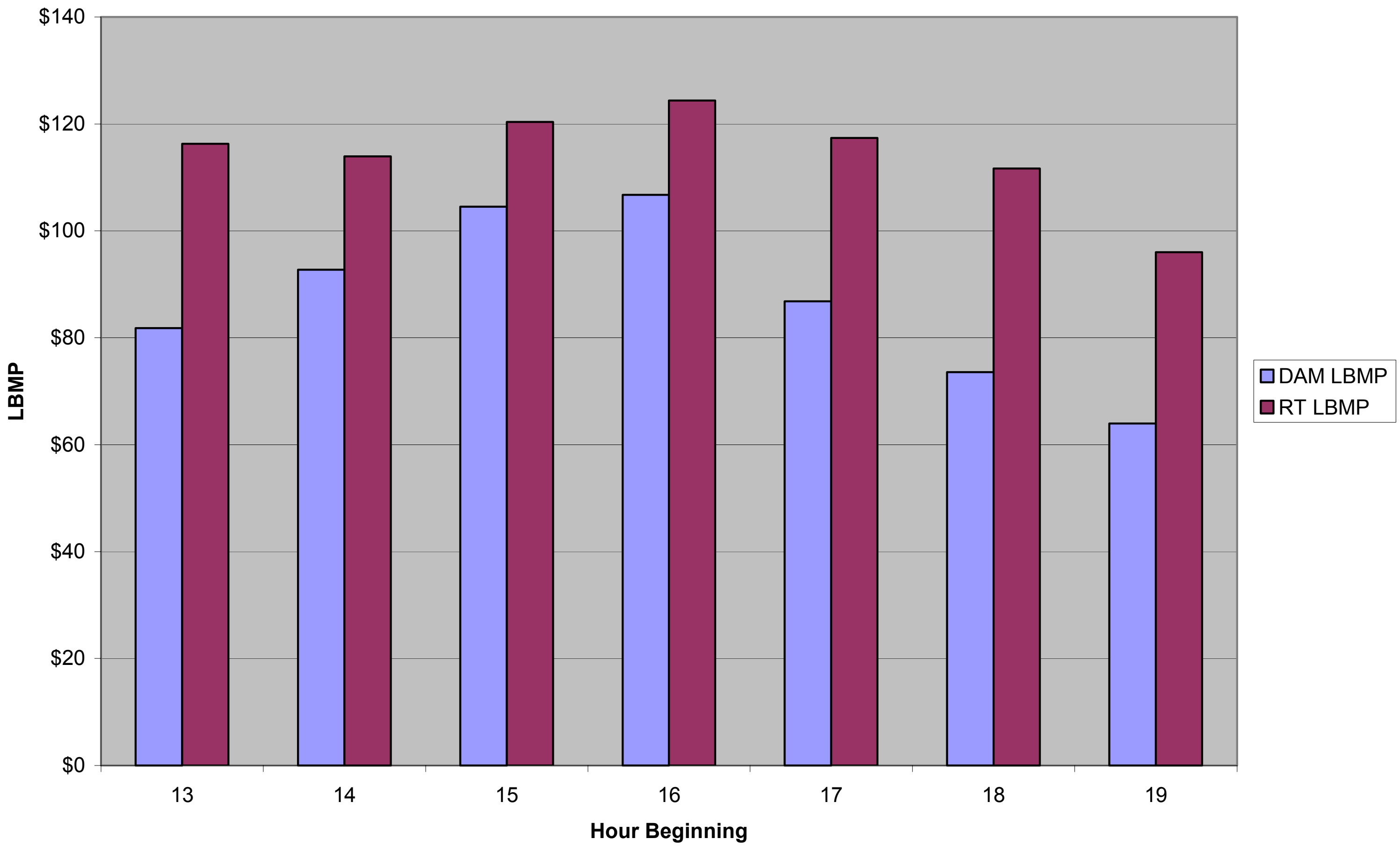


Chart 1.9A. West of Total East Average DAM vs. Real-Time LBMP (Summer 2001)

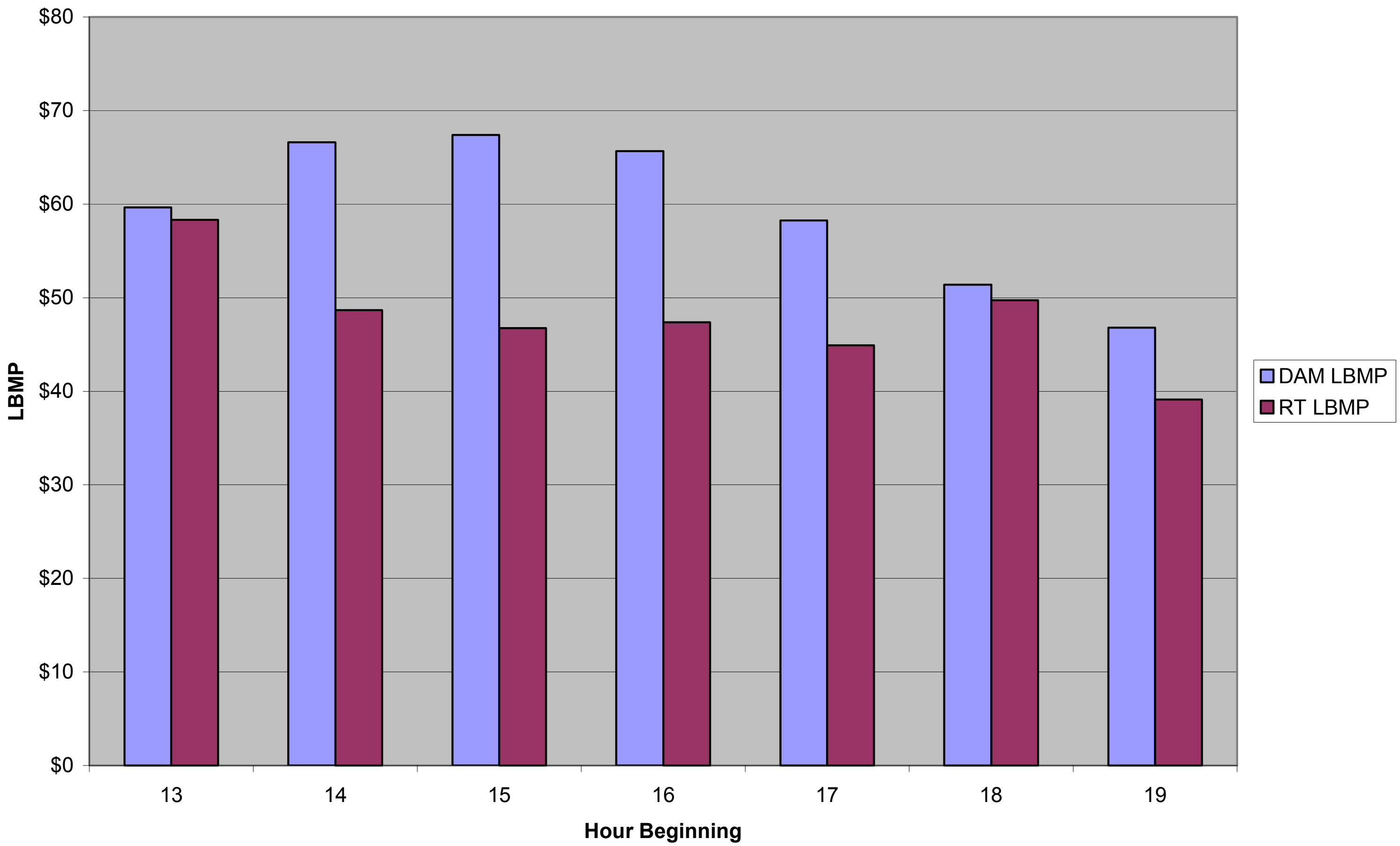


Chart 1.10A. Hudson River Superzone Average DAM vs. Real-Time LBMP (Summer 2001)

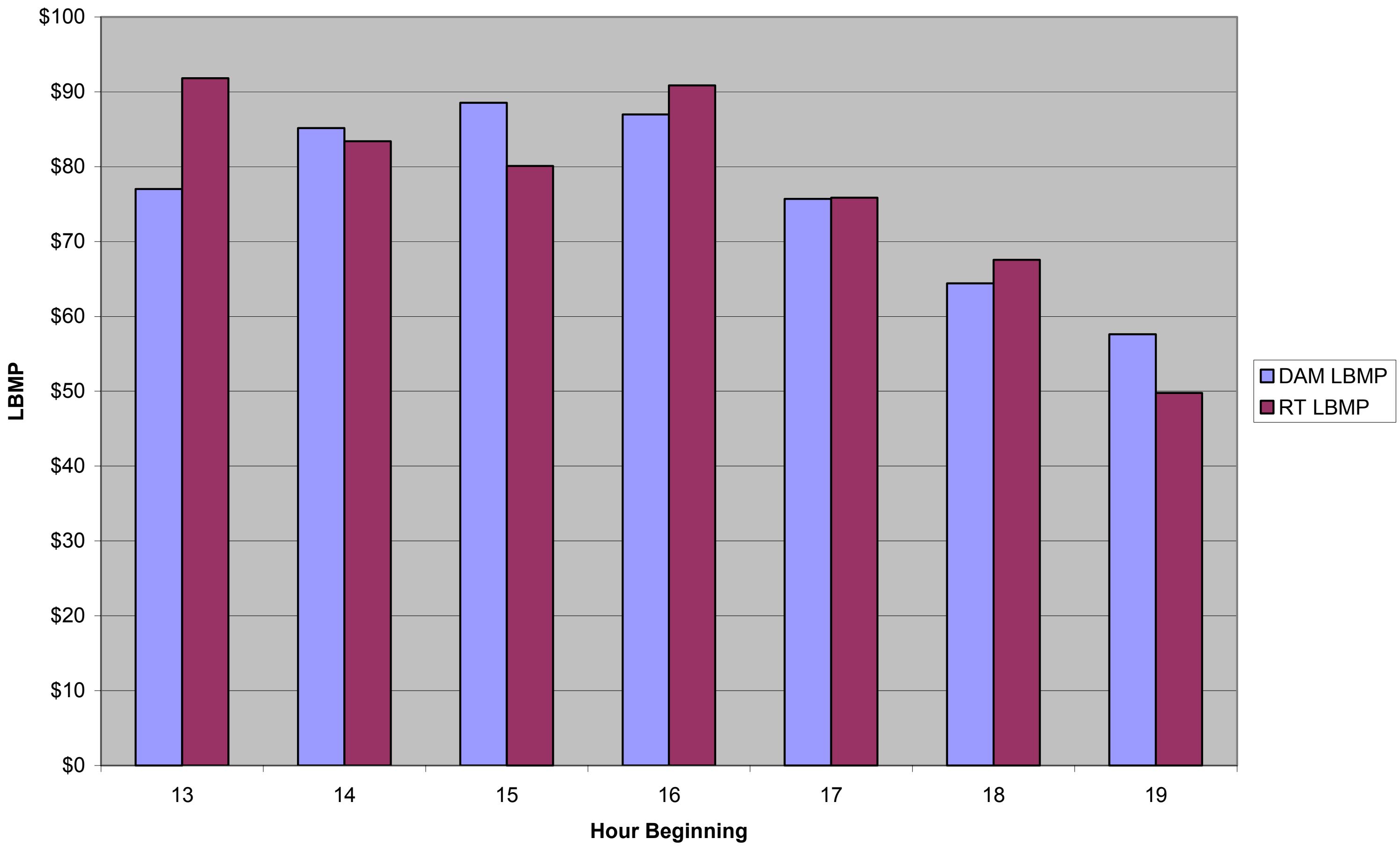
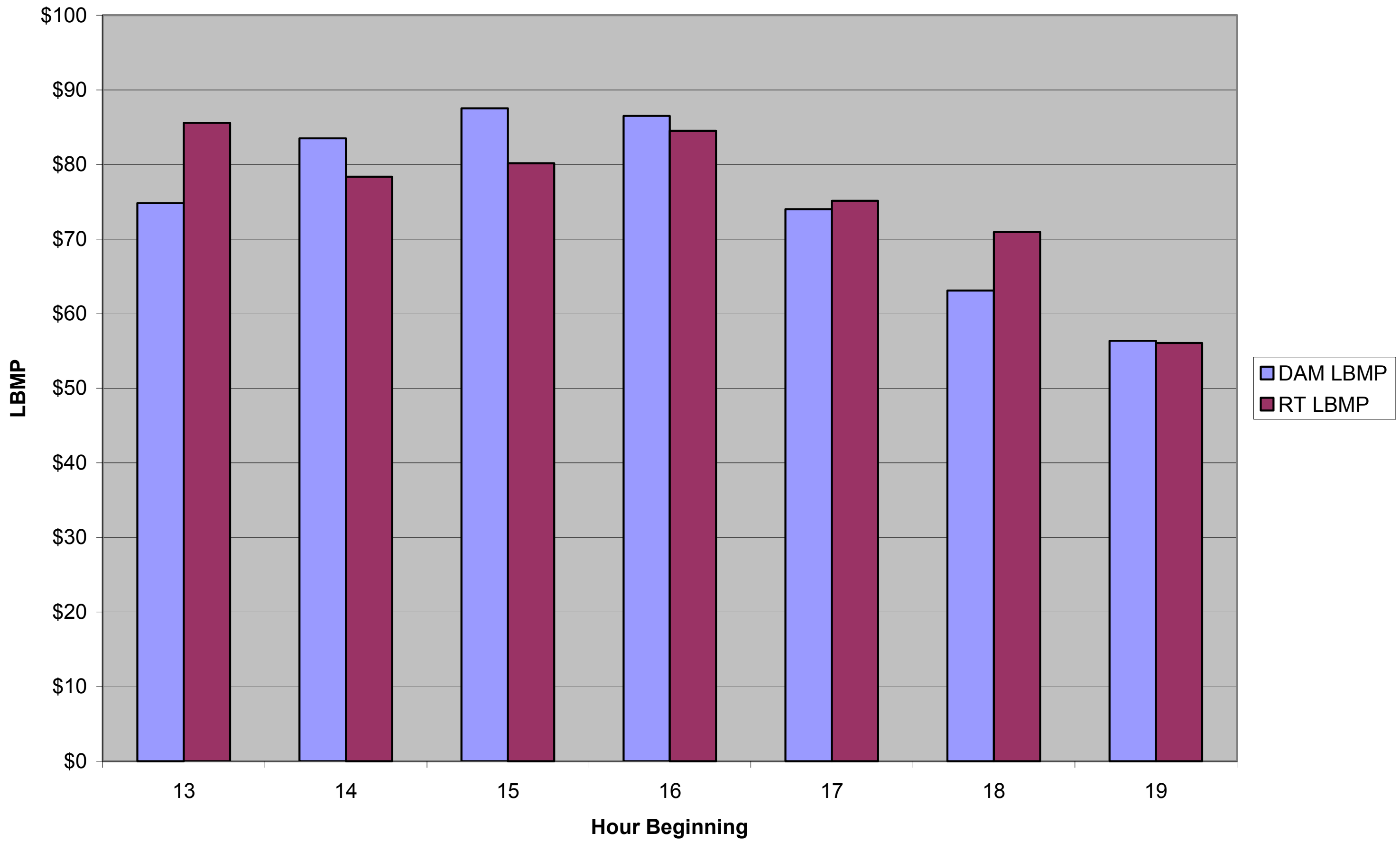


Chart 1.11A. New York State Average DAM vs. Real-Time LBMP (Summer 2001)



Appendix 1B
Variable Definitions and Formulas for Supply Price Flexibilities

The tables in this appendix define the variables used in the short-run electricity supply models reported in Tables 2 through 11, and also report the formulas for calculating the supply flexibilities in those models where there are shifter variables.

Table 1.1B Definition of Variables Used in the Electricity Supply Function Regressions*

Variable Name	Variable Definition
DAM-LBMP	Price in the Day-Ahead Market ($/MW)
RT-LBMP	Price in the Real-Time Market ($/MW)
FB-LOAD	Fixed Bid Load in the DAM, including Bilaterials (MW)
RT-LOAD	Actual Load Served in the RTM (MW)
Avail. Gen./ICAP	Proportion of ICAP bid in the DAM (system wide)
RT-Load-2L	Actual Load Served in Real Time, lagged 2 hours (MW)
Adj. Load	Load Served (RTM) or Fixed Bid Load (DAM) in Zones Adjacent to the One Being Modeled
Forecast Load	SCUC Forecast Load in the DAM (MW)
Forecast Load-2L	SCUC Forecast Load in the DAM, lagged two hours (MW)
Trans Const.-L	Number of Minutes in the Hour (lagged one hour) in which there is Congestion on Major Transmission Constraints affecting the Modeled Zone (weighted by line capacity relative to the total capacity of all relevant lines)
DADRP Sch.	MW of Load Scheduled for that Hour in DADRP

* All variables are defined for each hour of the day by zone, except where noted differently. Data for the regression analysis and the summary tables and charts were obtained from the NYISO website and with the help of the NYISO personnel. We are indebted to Tim Duffy for supply load data and to Dave Lawrence for the data on transmission constraints.

Table 1.2B Formulas for Calculating Price Flexibilities of Supply for the DAM*		
Zone or Region	Lower Load Limit to Which Flexibility Applies	Formula for Supply Flexibility
Capital	1602 MW	- 15.25 – 0.03 ln (FB-Load-2L) – 305.92 ln (Avail. Gen./ICAP) + 0.11 (DADRP Sch.)
New York City	78% Max. Load	-1206.18 – 97.20 ln (Avail. Gen./ICAP) + 140.54 ln (Adj. Load)
Long Island	80% Max. Load	4.27 – 0.20 ln (Avail. Gen./ICAP) + 0.08 ln (Adj. Load)
Western New York	7651 MW	7.82 + 1.14 (DADRP Sch.)
Hudson River	3417 MW	-30.30 ln (Avail. Gen./ICAP) + 17.22 ln (Adj. Load) - 20.17 ln (RT-Load-2L)
*Calculated as ∂ ln (RT-LBMP)/∂ ln (FB-LOAD) according to equations (31-33) in the text. Variables are defined in Table B1 above. Interaction variables except for Trans Const.-L and DADRP Sch. Coefficients are from the estimated supply equations from Tables 2-6 in the text.		

Table 1.3B Formulas for Calculating Price Flexibilities of Supply for the RTM*		
Zone or Region	Lower Load Limit to Which Flexibility Applies	Formula for Supply Flexibility
Capital	1848 MW	1.11 ln (RT-Load-2L)
New York City	65% Max. Load	277.24 – 31.95 ln (Adj. Load) + 0.68 (Trans. Const.-L) - 101.83 ln (Avail. Gen./ICAP)
Long Island	78% Max. Load	2 (0.62) ln (RT-Load)
Western New York	8675 MW	6.66 + 0.10 ln (Forecast Load) - 0.12 ln (Avail. Gen./ICAP)
Hudson River	3655	8.62
*Calculated as ∂ ln (RT-LBMP)/∂ ln (RT-LOAD) according to equations (31-33) in the text. Variables are defined in Table B1 above. Interaction variables except for Trans Const.-L and DADRP Sch. Coefficients are from the estimated supply equations from Tables 7-11 in the text.		

Table 1.1C. Daily Effect of EDRP Events in the Capital Zone, August, 2001

		Fixed Bid	With EDRP			Simulated		% Change in Due to EDRP		Arc	
Date	Hour	Load in the DAM	Real-Time Load (MW)	Real-Time LBMP ($/MW)	EDRP Load (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**
8/7	15	1,791	2,063	91	61	2,124	116	3.0%	28.0%	9.5	52,528
8/7	16	1,790	2,073	337	61	2,134	430	2.9%	27.6%	9.5	193,016
8/7	17	1,769	2,057	128	63	2,120	165	3.1%	29.2%	9.5	76,737
8/7	18	1,729	2,018	687	63	2,081	891	3.1%	29.7%	9.5	411,480
8/8	13	1,831	2,078	130	54	2,132	162	2.6%	24.3%	9.3	65,669
8/8	14	1,847	2,091	414	57	2,148	519	2.7%	25.5%	9.4	220,171
8/8	15	1,837	2,076	132	61	2,137	168	2.9%	27.7%	9.5	75,717
8/8	16	1,828	2,080	138	59	2,139	175	2.8%	26.8%	9.4	77,160
8/8	17	1,814	2,062	318	68	2,130	418	3.3%	31.5%	9.6	206,292
8/8	18	1,768	2,017	441	67	2,084	581	3.3%	31.8%	9.6	282,920
8/9	11	1,771	1,976	243	69	2,045	324	3.5%	33.2%	9.5	159,430
8/9	12	1,809	1,997	146	70	2,067	194	3.5%	33.4%	9.6	97,098
8/9	13	1,853	2,047	962	72	2,119	1,286	3.5%	33.6%	9.6	662,298
8/9	14	1,878	2,068	86	73	2,141	115	3.5%	34.1%	9.6	60,358
8/9	15	1,882	2,056	89	70	2,126	118	3.4%	32.6%	9.6	59,743
8/9	16	1,887	2,057	117	68	2,125	154	3.3%	31.6%	9.6	76,258
8/9	17	1,878	2,051	115	66	2,117	150	3.2%	30.8%	9.6	72,512
8/9	18	1,851	2,025	115	61	2,086	148	3.0%	28.8%	9.5	67,061
8/10	13	1,779	1,858	93	48	1,906	115	2.6%	23.7%	9.2	40,886
8/10	14	1,792	1,852	41	60	1,912	54	3.3%	30.9%	9.5	23,656
8/10	15	1,783	1,863	46	59	1,922	59	3.1%	29.5%	9.4	25,208
8/10	16	1,770	1,871	39	58	1,929	51	3.1%	29.2%	9.4	21,482
8/10	17	1,736	1,831	49	60	1,891	54	3.3%	9.5%	2.9	8,531
Hourly Avg.		1,812	2,007	215	63	2,070	280	3.1%	28.8%	9.20	132,009
Total		41,673	46,167		1,446	47,613					3,036,211

*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 variation in the price flexibility by hour. Thus, these 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.

Table 1.2C. Daily Effect of EDRP Events in the New York City Zone, August, 2001

		Fixed Bid	With EDRP			Simulated		% Change in Due to EDRP		Arc	
Date	Hour	Load in the DAM	Real-Time Load (MW)	Real-Time LBMP ($/MW)	EDRP Load (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	Load	LBMP	Price Flexibility	Collateral Benefits ($)**
8/7	15	-	-	87	36	-	90	0.36%	3.00%	8.2	25,591
8/7	16	-	-	373	35	-	381	0.36%	2.28%	6.3	83,777
8/7	17	-	-	142	33	-	146	0.34%	2.45%	7.1	33,847
8/7	18	-	-	756	28	-	786	0.30%	3.92%	13.0	276,747
8/8	13	-	-	141	39	-	148	0.39%	4.83%	12.2	67,974
8/8	14	-	-	350	41	-	368	0.40%	4.93%	12.2	173,524
8/8	15	-	-	146	39	-	150	0.38%	2.72%	7.2	41,557
8/8	16	-	-	152	38	-	158	0.36%	4.08%	11.2	64,795
8/8	17	-	-	350	35	-	358	0.34%	2.13%	6.3	77,074
8/8	18	-	-	350	29	-	364	0.29%	3.93%	13.3	136,536
8/9	11	-	-	200	35	-	210	0.34%	4.72%	13.9	97,812
8/9	12	-	-	131	38	-	138	0.36%	4.96%	13.6	68,111
8/9	13	-	-	1,071	40	-	1,099	0.38%	2.61%	6.9	294,886
8/9	14	-	-	131	43	-	135	0.41%	2.79%	6.8	38,790
8/9	15	-	-	123	46	-	127	0.44%	2.90%	6.6	37,743
8/9	16	-	-	131	46	-	135	0.44%	3.01%	6.8	40,830
8/9	17	-	-	126	45	-	130	0.44%	3.32%	7.5	42,617
8/9	18	-	-	125	38	-	129	0.39%	3.29%	8.5	40,619
8/10	13	-	-	351	22	-	357	0.21%	1.80%	8.5	66,227
8/10	14	-	-	351	37	-	374	0.37%	6.31%	17.2	224,391
8/10	15	-	-	451	39	-	480	0.41%	6.53%	16.1	283,321
8/10	16	-	-	126	38	-	136	0.40%	8.55%	21.3	102,734
8/10	17	-	-	124	37	-	137	0.40%	10.25%	25.9	119,502
Hourly Avg.		-	-	273	37	-	284	0.37%	4.14%	11.2	106,044
Total		-	-		860	-					2,439,005

*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 variation in the price flexibility by hour. Thus, these 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.

Table 1.3C. Daily Effect of EDRP Events in the Long Island Zone, August, 2001

		Fixed Bid	With EDRP			Simulated		% Change in		Arc	
		Load in	Real-Time	Real-Time	EDRP	Real-Time	Real-Time	Due to EDRP		Price	Collateral
Date	Hour	the DAM	Load (MW)	LBMP ($/MW)	Load (MW)	Load (MW)	LBMP ($/MW)	Load	LBMP	Flexibility*	Benefits ($)**
8/7	15	-	-	199	6	-	201	0.13%	0.69%	5.23	6,497
8/7	16	-	-	366	6	-	368	0.13%	0.67%	5.24	11,757
8/7	17	-	-	200	6	-	201	0.13%	0.66%	5.24	6,343
8/7	18	-	-	741	6	-	746	0.13%	0.68%	5.22	23,299
8/8	13	-	-	203	6	-	205	0.13%	0.67%	5.24	6,562
8/8	14	-	-	349	7	-	352	0.14%	0.72%	5.24	12,135
8/8	15	-	-	203	6	-	204	0.13%	0.69%	5.25	6,842
8/8	16	-	-	202	6	-	204	0.13%	0.68%	5.25	6,753
8/8	17	-	-	347	6	-	349	0.13%	0.67%	5.25	11,275
8/8	18	-	-	426	6	-	429	0.13%	0.66%	5.23	13,296
8/9	11	-	-	200	6	-	201	0.14%	0.73%	5.22	6,705
8/9	12	-	-	202	7	-	203	0.14%	0.74%	5.24	7,084
8/9	13	-	-	1,060	7	-	1,068	0.14%	0.72%	5.25	37,042
8/9	14	-	-	191	7	-	193	0.13%	0.70%	5.25	6,601
8/9	15	-	-	196	7	-	197	0.14%	0.72%	5.25	6,883
8/9	16	-	-	196	7	-	198	0.14%	0.73%	5.25	6,999
8/9	17	-	-	196	7	-	198	0.14%	0.73%	5.24	6,923
8/9	18	-	-	196	6	-	198	0.14%	0.72%	5.23	6,669
8/10	13	-	-	350	6	-	352	0.13%	0.69%	5.22	11,225
8/10	14	-	-	351	7	-	354	0.15%	0.76%	5.21	12,233
8/10	15	-	-	450	7	-	450	0.16%	0.00%	0.02	57
8/10	16	-	-	125	7	-	125	0.18%	0.01%	0.04	36
8/10	17	-	-	202	6	-	202	0.16%	0.01%	0.06	76
Hourly Avg.		-	-	311	6	-	313	0.14%	0.61%	4.56	9,274
Total		-	-		148	-					213,294

*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 variation in the price flexibility by hour. Thus, these 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.

Table 1.4C. Daily Effect of EDRP Events in the Western New York "super" Zone, August, 2001

Date	Hour	Fixed Bid Load in the DAM	With EDRP Real-Time Load (MW)	With EDRP Real-Time LBMP ($/MW)	EDRP Load (MW)	Simulated Real-Time Load (MW)	Simulated Real-Time LBMP ($/MW)	% Change in Due to EDRP Load	% Change in Due to EDRP LBMP	Arc Price Flexibility*	Collateral Benefits ($)**
8/7	15	7,893	9,115	52	258	9,373	62	2.8%	19.7%	7.0	92,908
8/7	16	7,940	9,051	329	266	9,317	397	2.9%	20.5%	7.0	611,936
8/7	17	7,790	8,884	124	266	9,150	150	3.0%	21.0%	7.0	231,071
8/7	18	7,625	8,648	671	270	8,918	727	3.1%	8.4%	2.7	488,073
8/8	13	7,989	9,153	125	283	9,436	152	3.1%	21.6%	7.0	247,408
8/8	14	8,140	9,152	114	303	9,455	141	3.3%	23.4%	7.1	244,635
8/8	15	8,094	9,087	128	322	9,409	160	3.5%	25.2%	7.1	292,188
8/8	16	7,923	9,005	133	332	9,337	167	3.7%	26.3%	7.1	313,472
8/8	17	7,875	8,897	306	318	9,215	384	3.6%	25.4%	7.1	692,239
8/8	18	7,670	8,676	59	308	8,984	73	3.6%	25.3%	7.1	128,435
8/9	11	8,230	9,045	53	277	9,322	65	3.1%	21.4%	7.0	103,039
8/9	12	8,475	9,172	62	285	9,457	76	3.1%	21.8%	7.0	124,598
8/9	13	8,610	9,236	937	287	9,523	1,141	3.1%	21.7%	7.0	1,880,197
8/9	14	8,637	9,167	76	305	9,472	94	3.3%	23.4%	7.0	164,206
8/9	15	8,512	8,976	82	304	9,280	101	3.4%	23.9%	7.1	175,167
8/9	16	8,467	8,955	116	298	9,253	143	3.3%	23.5%	7.1	243,739
8/9	17	8,444	8,729	111	304	9,033	139	3.5%	24.7%	7.1	239,797
8/9	18	8,105	8,493	111	290	8,783	121	3.4%	9.2%	2.7	86,403
Hourly Avg.		8,134	8,969	199	293	9,262	239	3.3%	21.5%	6.6	353,306
Total		146,419	161,441		5,276	166,717					6,359,512

*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 variation in the price flexibility by hour. Thus, these 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.

Table 1.5C. Daily Effect of EDRP Events in the Hudson "super" Zone, August, 2001

		Fixed Bid	With EDRP			Simulated		% Change in Due to EDRP		Arc	
Date	Hour	Load in the DAM	Real-Time Load (MW)	Real-Time LBMP ($/MW)	EDRP Load (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**
8/7	15	3,707	4,240	85	15	4,255	88	0.4%	3.1%	8.7	11,411
8/7	16	3,702	4,244	363	19	4,263	377	0.4%	3.8%	8.8	59,151
8/7	17	3,679	4,203	138	17	4,220	143	0.4%	3.6%	8.8	21,057
8/7	18	3,573	4,070	737	17	4,087	765	0.4%	3.7%	8.8	110,627
8/8	13	3,588	4,139	138	14	4,153	142	0.3%	2.9%	8.7	16,245
8/8	14	3,634	4,159	345	20	4,179	360	0.5%	4.2%	8.8	60,453
8/8	15	3,740	4,205	142	19	4,224	147	0.5%	4.1%	8.8	24,200
8/8	16	3,737	4,242	147	19	4,261	153	0.5%	4.0%	8.8	25,035
8/8	17	3,709	4,164	340	18	4,182	353	0.4%	3.8%	8.8	54,322
8/8	18	3,601	4,033	348	13	4,046	358	0.3%	2.9%	8.7	41,005
8/9	11	3,457	3,865	199	17	3,882	207	0.5%	4.0%	8.8	30,430
8/9	12	3,576	4,012	129	19	4,031	135	0.5%	4.2%	8.8	21,880
8/9	13	3,686	4,176	1,039	20	4,196	1,083	0.5%	4.2%	8.8	183,336
8/9	14	3,748	4,245	128	21	4,266	133	0.5%	4.3%	8.8	23,393
8/9	15	3,784	4,290	119	20	4,310	124	0.5%	4.1%	8.8	21,002
8/9	16	3,784	4,292	127	21	4,313	133	0.5%	4.2%	8.8	23,187
8/9	17	3,752	4,248	123	20	4,268	128	0.5%	4.1%	8.8	21,373
8/9	18	3,631	4,167	122	18	4,185	126	0.4%	3.7%	8.8	18,992
8/10	13	3,626	4,062	337	10	4,072	344	0.3%	2.2%	8.7	30,587
8/10	14	3,652	3,883	233	22	3,905	245	0.6%	5.0%	8.8	45,396
8/10	15	3,638	3,723	223	23	3,746	235	0.6%	5.5%	8.8	45,298
8/10	16	3,624	3,661	78	23	3,684	82	0.6%	5.5%	8.8	15,637
8/10	17	3,542	3,581	116	23	3,604	116	0.6%	0.6%	1.0	2,542
Hourly Avg.		3,660	4,083	250	19	4,101	260	0	0	8	39,416
Total		84,170	93,904		430	94,334					906,559

*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 variation in the price flexibility by hour. Thus, these 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.

Table 1.6C. Zonal EDRP Program Payments for EDRP Events, August, 2001

		Program Payments ($)				
Date	Hour	Capital	NYC	Long Island	Western NY	Hudson River
8/7	15	30,510	17,548	3,430	129,425	8,896
8/7	16	32,677	20,697	3,675	134,544	10,366
8/7	17	42,625	18,951	3,495	134,658	9,685
8/7	18	31,453	14,077	3,014	135,739	8,327
8/8	13	26,959	18,475	4,303	141,855	8,229
8/8	14	38,734	27,640	6,510	178,131	14,573
8/8	15	30,391	18,498	4,405	162,005	9,708
8/8	16	29,563	17,831	4,349	166,874	9,536
8/8	17	33,839	16,263	4,255	160,104	7,899
8/8	18	33,405	13,492	6,116	154,617	6,476
8/9	11	34,388	16,320	4,431	138,883	8,671
8/9	12	34,790	17,820	4,568	142,992	9,491
8/9	13	35,868	18,615	4,533	143,532	10,009
8/9	14	36,620	20,493	4,484	153,215	10,399
8/9	15	34,927	21,867	4,592	152,001	10,279
8/9	16	33,920	21,596	4,647	149,063	10,550
8/9	17	33,086	21,398	4,594	151,772	9,661
8/9	18	30,731	17,952	4,429	144,823	8,916
8/10	13	23,863	10,411	3,766		6,183
8/10	14	30,227	17,350	4,590		11,075
8/10	15	29,323	18,292	4,631		11,441
8/10	16	29,174	17,940	4,619		11,585
8/10	17	29,824	17,368	4,216		11,445
Hourly Avg.		32,474	18,300	4,420	148,569	9,713
Total		746,896	420,895	101,653	2,674,234	223,401

Table 1.1D. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2001

			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 ($)**
7/21	10	1,457	1,274	57.8	1	1,275	57.8	0.1%	0.1%	1.6	94
7/21	11	1,493	1,363	61.8	1	1,364	61.8	0.1%	0.1%	1.6	100
7/21	12	1,507	1,377	60.1	1	1,378	60.2	0.1%	0.1%	1.6	98
7/21	13	1,481	1,383	59.9	1	1,384	60.0	0.1%	0.1%	1.6	97
7/21	14	1,486	1,387	59.8	1	1,388	59.9	0.1%	0.1%	1.6	97
7/21	15	1,502	1,393	52.8	1	1,394	52.9	0.1%	0.1%	1.6	86
7/21	16	1,519	1,390	54.9	1	1,391	55.0	0.1%	0.1%	1.6	89
7/21	17	1,537	1,389	54.8	1	1,390	54.9	0.1%	0.1%	1.6	89
7/21	18	1,531	1,350	53.3	1	1,351	53.3	0.1%	0.1%	1.6	87
7/21	19	1,490	1,276	49.7	1	1,277	49.8	0.1%	0.1%	1.6	81
7/21	20	1,486	1,281	50.0	1	1,282	50.0	0.1%	0.1%	1.6	81
7/21	21	1,477	1,285	49.3	1	1,286	49.3	0.1%	0.1%	1.6	80
7/21	22	1,374	1,343	44.8	1	1,344	44.8	0.1%	0.1%	1.6	73
7/21	23	1,246	1,230	41.3	1	1,231	41.4	0.1%	0.1%	1.6	67
7/22	0	1,143	1,165	40.0	1	1,166	40.0	0.1%	0.1%	1.6	65
7/22	12	1,520	1,331	56.5	1	1,332	56.5	0.1%	0.1%	1.6	92
7/22	13	1,548	1,321	56.1	1	1,322	56.2	0.1%	0.1%	1.6	91
7/22	14	1,532	1,305	56.3	1	1,306	56.4	0.1%	0.1%	1.6	92
7/22	15	1,548	1,300	52.1	1	1,301	52.1	0.1%	0.1%	1.6	85
7/22	16	1,565	1,316	53.3	1	1,317	53.3	0.1%	0.1%	1.6	87
7/22	17	1,575	1,327	52.0	1	1,328	52.0	0.1%	0.1%	1.6	84
7/23	0	1,217	1,082	34.5	1	1,083	34.5	0.1%	0.2%	1.6	56
7/23	1	1,147	1,018	33.0	1	1,019	33.0	0.1%	0.2%	1.6	54
7/23	2	1,115	979	32.3	1	980	32.3	0.1%	0.2%	1.6	52
7/23	3	1,097	961	31.1	1	962	31.2	0.1%	0.2%	1.6	51
7/23	4	1,104	963	31.1	1	964	31.1	0.1%	0.2%	1.6	51
7/23	5	1,153	1,010	31.7	1	1,011	31.7	0.1%	0.2%	1.6	51
7/23	6	1,276	1,155	33.6	1	1,156	33.6	0.1%	0.1%	1.6	55
7/23	7	1,459	1,330	42.7	1	1,331	42.8	0.1%	0.1%	1.6	69
7/23	12	1,868	1,557	58.9	4	1,561	59.4	0.3%	0.9%	3.4	800
7/23	13	1,878	1,577	64.1	20	1,597	66.9	1.3%	4.4%	3.4	4,403
7/23	14	1,932	1,591	64.4	20	1,611	67.1	1.3%	4.3%	3.4	4,422
7/23	15	1,963	1,586	66.7	20	1,606	69.5	1.3%	4.3%	3.4	4,580
7/23	16	1,994	1,584	71.8	16	1,600	74.3	1.0%	3.5%	3.4	3,934
7/24	0	1,425	1,081	34.4	1	1,082	34.4	0.1%	0.2%	1.6	56
7/24	1	1,355	1,017	34.0	1	1,018	34.0	0.1%	0.2%	1.6	55
7/24	2	1,317	978	32.8	1	979	32.8	0.1%	0.2%	1.6	53
7/24	3	1,297	963	29.7	1	964	29.8	0.1%	0.2%	1.6	48
7/24	4	1,302	963	29.7	1	964	29.8	0.1%	0.2%	1.6	48
7/24	5	1,360	1,010	32.3	1	1,011	32.3	0.1%	0.2%	1.6	52
7/24	6	1,469	1,156	33.9	1	1,157	33.9	0.1%	0.1%	1.6	55
7/24	7	1,628	1,331	42.5	3	1,334	42.7	0.2%	0.4%	1.6	208
7/24	8	1,784	1,303	45.4	2	1,305	45.6	0.2%	0.2%	1.6	148
7/24	9	1,895	1,395	50.1	2	1,397	50.2	0.1%	0.2%	1.6	163
7/24	10	1,967	1,479	55.3	2	1,481	55.4	0.1%	0.2%	1.6	180
7/24	11	2,029	1,536	55.2	2	1,538	55.4	0.1%	0.4%	3.4	374
7/24	13	2,104	1,585	68.9	18	1,603	71.6	1.1%	3.9%	3.4	4,254
7/24	14	2,107	1,597	69.7	18	1,615	72.4	1.1%	3.9%	3.4	4,302
7/24	15	2,080	1,596	73.3	18	1,614	76.1	1.1%	3.9%	3.4	4,522
7/24	16	2,049	1,595	78.9	18	1,613	81.9	1.1%	3.9%	3.4	4,868
7/25	0	1,456	1,034	39.6	6	1,040	39.9	0.6%	0.9%	1.6	386
7/25	1	1,383	967	34.8	1	968	34.9	0.1%	0.2%	1.6	57
7/25	2	1,336	930	34.2	1	931	34.3	0.1%	0.2%	1.6	56
7/25	3	1,312	903	33.7	1	904	33.8	0.1%	0.2%	1.6	55
7/25	4	1,312	910	33.8	1	911	33.8	0.1%	0.2%	1.6	55
7/25	5	1,341	945	33.6	1	946	33.7	0.1%	0.2%	1.6	55
7/25	6	1,476	1,091	37.0	1	1,092	37.1	0.1%	0.1%	1.6	60
7/25	7	1,652	1,316	44.3	3	1,319	44.5	0.2%	0.4%	1.6	216
7/25	8	1,771	1,283	53.1	8	1,291	53.7	0.6%	1.0%	1.6	692
7/25	9	1,881	1,374	58.8	8	1,382	59.4	0.6%	0.9%	1.6	766
7/25	10	1,949	1,435	63.2	8	1,443	63.7	0.6%	0.9%	1.6	823
7/25	11	1,986	1,495	74.0	8	1,503	75.3	0.5%	1.8%	3.4	2,016
7/25	12	1,992	1,517	78.9	6	1,523	80.0	0.4%	1.3%	3.4	1,611
7/25	13	2,011	1,529	79.5	6	1,535	80.6	0.4%	1.3%	3.4	1,622
7/25	14	2,012	1,539	84.1	6	1,545	85.3	0.4%	1.3%	3.4	1,717
7/25	15	2,002	1,528	97.5	6	1,534	98.8	0.4%	1.3%	3.4	1,989
7/25	16	1,997	1,513	94.6	4	1,517	95.4	0.3%	0.9%	3.4	1,285
7/25	17	1,949	1,499	89.5	4	1,503	90.3	0.3%	0.9%	3.4	1,215
7/25	18	1,881	1,455	74.9	4	1,459	75.2	0.3%	0.4%	1.6	487
7/25	19	1,834	1,410	67.2	4	1,414	67.5	0.3%	0.5%	1.6	437
7/25	20	1,835	1,383	63.1	4	1,387	63.3	0.3%	0.5%	1.6	410

Table 1.1D. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2001 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 ($)**
7/25	22	1,619	1,338	48.0	4	1,342	48.2	0.3%	0.5%	1.6	312
7/25	23	1,447	1,181	39.9	4	1,185	40.1	0.3%	0.6%	1.6	260
7/26	0	1,326	973	37.7	2	975	37.8	0.2%	0.3%	1.6	122
7/26	1	1,258	905	34.2	6	911	34.5	0.7%	1.1%	1.6	334
7/26	2	1,218	871	31.9	6	877	32.3	0.7%	1.1%	1.6	312
7/26	3	1,183	843	30.8	6	849	31.2	0.7%	1.2%	1.6	301
7/26	4	1,183	851	30.4	6	857	30.8	0.7%	1.1%	1.6	297
7/26	5	1,233	887	32.0	6	893	32.3	0.7%	1.1%	1.6	312
7/26	6	1,332	1,032	33.0	6	1,038	33.3	0.6%	0.9%	1.6	322
7/26	7	1,443	1,210	39.4	9	1,219	39.9	0.7%	1.2%	1.6	577
7/26	8	1,492	1,175	40.7	9	1,184	41.2	0.8%	1.2%	1.6	597
7/26	9	1,520	1,257	43.0	9	1,266	43.5	0.7%	1.2%	1.6	631
7/26	10	1,551	1,327	43.9	9	1,336	44.4	0.7%	1.1%	1.6	644
7/26	11	1,557	1,380	48.0	9	1,389	48.6	0.7%	1.1%	1.6	704
7/26	12	1,543	1,391	51.0	5	1,396	51.3	0.4%	0.6%	1.6	415
7/26	13	1,532	1,403	51.2	5	1,408	51.5	0.4%	0.6%	1.6	416
7/26	14	1,517	1,407	51.2	5	1,412	51.5	0.4%	0.6%	1.6	416
7/26	15	1,523	1,394	50.7	2	1,396	50.9	0.1%	0.2%	1.6	165
7/26	16	1,528	1,382	51.5	2	1,384	51.6	0.1%	0.2%	1.6	167
7/26	17	1,518	1,363	50.2	2	1,365	50.3	0.1%	0.2%	1.6	163
7/26	18	1,496	1,323	44.8	2	1,325	44.9	0.2%	0.2%	1.6	146
7/26	19	1,451	1,273	42.6	2	1,275	42.7	0.2%	0.3%	1.6	139
7/26	20	1,441	1,252	42.6	1	1,253	42.7	0.1%	0.1%	1.6	69
7/26	21	1,427	1,238	42.8	1	1,239	42.8	0.1%	0.1%	1.6	70
7/26	22	1,306	1,260	41.1	1	1,261	41.1	0.1%	0.1%	1.6	67
7/26	23	1,174	1,110	39.1	1	1,111	39.2	0.1%	0.1%	1.6	64
7/27	0	1,082	1,080	31.4	2	1,082	31.5	0.2%	0.3%	1.6	102
7/27	1	1,022	1,031	30.5	2	1,033	30.6	0.2%	0.3%	1.6	99
7/27	2	997	1,003	26.5	2	1,005	26.6	0.2%	0.3%	1.6	86
7/27	3	985	986	27.2	2	988	27.3	0.2%	0.3%	1.6	89
7/27	4	998	995	26.9	2	997	27.0	0.2%	0.3%	1.6	88
7/27	5	1,036	1,040	28.6	2	1,042	28.7	0.2%	0.3%	1.6	93
7/27	6	1,155	1,169	32.5	2	1,171	32.6	0.2%	0.3%	1.6	106
7/27	7	1,295	1,327	36.5	2	1,329	36.6	0.2%	0.2%	1.6	119
7/27	8	1,381	1,246	40.6	2	1,248	40.7	0.2%	0.3%	1.6	132
7/27	9	1,437	1,301	43.5	2	1,303	43.6	0.2%	0.2%	1.6	141
7/27	10	1,475	1,343	44.5	2	1,345	44.6	0.1%	0.2%	1.6	145
7/27	11	1,483	1,376	45.5	2	1,378	45.6	0.1%	0.2%	1.6	148
7/27	12	1,456	1,375	49.6	2	1,377	49.7	0.1%	0.2%	1.6	161
7/27	13	1,460	1,381	49.4	2	1,383	49.5	0.1%	0.2%	1.6	161
7/27	14	1,456	1,373	51.6	2	1,375	51.7	0.1%	0.2%	1.6	168
7/27	15	1,452	1,358	49.4	2	1,360	49.5	0.1%	0.2%	1.6	161
7/27	16	1,449	1,349	47.0	2	1,351	47.1	0.1%	0.2%	1.6	153
7/27	17	1,423	1,316	48.1	2	1,318	48.2	0.2%	0.2%	1.6	156
7/27	18	1,391	1,270	45.2	2	1,272	45.3	0.2%	0.3%	1.6	147
7/27	19	1,358	1,217	41.3	2	1,219	41.4	0.2%	0.3%	1.6	134
7/27	20	1,367	1,217	40.3	2	1,219	40.4	0.2%	0.3%	1.6	131
7/27	21	1,361	1,206	40.0	2	1,208	40.1	0.2%	0.3%	1.6	130
7/27	22	1,255	1,253	38.4	2	1,255	38.5	0.2%	0.3%	1.6	125
7/27	23	1,141	1,132	36.2	2	1,134	36.3	0.2%	0.3%	1.6	118
7/28	0	1,046	839	38.7	2	841	38.9	0.2%	0.4%	1.6	126
7/28	1	995	783	33.5	2	785	33.6	0.3%	0.4%	1.6	109
7/28	2	961	753	32.4	2	755	32.6	0.3%	0.4%	1.6	105
7/28	3	940	738	31.2	2	740	31.4	0.3%	0.4%	1.6	102
7/28	4	940	735	31.2	2	737	31.3	0.3%	0.4%	1.6	101
7/28	5	946	740	28.6	2	742	28.8	0.3%	0.4%	1.6	93
7/28	6	980	795	28.9	2	797	29.0	0.3%	0.4%	1.6	94
7/28	7	1,070	914	33.1	2	916	33.2	0.2%	0.4%	1.6	108
7/28	8	1,188	935	38.1	2	937	38.3	0.2%	0.3%	1.6	124
7/28	9	1,279	1,013	40.5	2	1,015	40.6	0.2%	0.3%	1.6	132
7/28	10	1,323	1,057	43.7	2	1,059	43.8	0.2%	0.3%	1.6	142
7/28	11	1,328	1,069	44.2	2	1,071	44.3	0.2%	0.3%	1.6	144
7/28	12	1,313	1,074	46.3	2	1,076	46.4	0.2%	0.3%	1.6	150
7/28	13	1,283	1,073	46.1	2	1,075	46.3	0.2%	0.3%	1.6	150
7/28	14	1,271	1,053	47.2	2	1,055	47.3	0.2%	0.3%	1.6	153
7/28	15	1,266	1,057	47.1	2	1,059	47.3	0.2%	0.3%	1.6	153
7/28	16	1,281	1,063	47.2	2	1,065	47.3	0.2%	0.3%	1.6	153
7/28	17	1,285	1,067	47.3	2	1,069	47.5	0.2%	0.3%	1.6	154
7/28	18	1,289	1,054	46.1	2	1,056	46.2	0.2%	0.3%	1.6	150
7/28	19	1,282	1,034	41.6	2	1,036	41.7	0.2%	0.3%	1.6	135
7/28	20	1,307	1,041	43.8	2	1,043	43.9	0.2%	0.3%	1.6	142
7/28	21	1,299	1,045	45.8	2	1,047	45.9	0.2%	0.3%	1.6	149
7/28	22	1,213	1,060	40.1	2	1,062	40.2	0.2%	0.3%	1.6	130
7/28	23	1,124	948	36.4	2	950	36.5	0.2%	0.3%	1.6	118
7/29	1	984	914	32.3	2	916	32.4	0.2%	0.4%	1.6	105

Table 1.1D. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2001 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 ($)**
7/29	4	944	833	24.8	2	835	24.8	0.2%	0.4%	1.6	80
7/29	5	943	831	24.7	2	833	24.8	0.2%	0.4%	1.6	80
7/29	6	954	848	23.7	2	850	23.8	0.2%	0.4%	1.6	77
7/29	7	1,021	876	28.5	2	878	28.6	0.2%	0.4%	1.6	93
7/29	8	1,130	802	34.2	2	804	34.3	0.2%	0.4%	1.6	111
7/29	9	1,235	897	36.5	2	899	36.6	0.2%	0.4%	1.6	119
7/29	10	1,300	922	40.1	2	924	40.3	0.2%	0.4%	1.6	130
7/29	11	1,319	1,044	42.8	2	1,046	43.0	0.2%	0.3%	1.6	139
7/29	12	1,321	1,060	44.1	2	1,062	44.2	0.2%	0.3%	1.6	143
7/29	13	1,333	1,048	43.7	2	1,050	43.8	0.2%	0.3%	1.6	142
7/29	14	1,323	1,034	43.7	2	1,036	43.8	0.2%	0.3%	1.6	142
7/29	15	1,330	1,028	43.7	2	1,030	43.8	0.2%	0.3%	1.6	142
7/29	16	1,360	1,040	44.7	2	1,042	44.8	0.2%	0.3%	1.6	145
7/29	17	1,368	1,050	47.1	2	1,052	47.2	0.2%	0.3%	1.6	153
7/29	18	1,365	1,052	44.3	2	1,054	44.5	0.2%	0.3%	1.6	144
7/29	19	1,356	1,044	44.1	2	1,046	44.3	0.2%	0.3%	1.6	143
7/29	20	1,389	1,065	47.5	2	1,067	47.7	0.2%	0.3%	1.6	155
7/29	21	1,397	1,093	48.2	2	1,095	48.3	0.2%	0.3%	1.6	157
7/29	22	1,295	1,144	43.5	2	1,146	43.6	0.2%	0.3%	1.6	141
7/29	23	1,169	1,023	36.2	2	1,025	36.3	0.2%	0.3%	1.6	118
8/2	11	1,824	1,570	127.1	4	1,574	128.2	0.3%	0.9%	3.4	1,725
8/2	12	1,866	1,591	126.4	4	1,595	127.5	0.3%	0.9%	3.4	1,716
8/2	13	1,926	1,617	120.1	4	1,621	125.5	0.2%	4.5%	18.1	8,679
8/2	14	1,955	1,626	121.2	4	1,630	126.6	0.2%	4.4%	18.1	8,754
8/2	15	1,978	1,612	121.2	4	1,616	126.6	0.2%	4.5%	18.1	8,754
8/2	16	1,989	1,607	121.4	4	1,611	127.0	0.2%	4.6%	18.5	8,998
8/3	10	1,807	1,507	126.6	4	1,511	127.8	0.3%	0.9%	3.4	1,718
8/3	11	1,844	1,553	146.8	4	1,557	148.1	0.3%	0.9%	3.4	1,992
8/3	12	1,868	1,577	137.4	4	1,581	138.6	0.3%	0.9%	3.4	1,865
8/3	13	1,900	1,596	150.5	4	1,600	151.7	0.3%	0.9%	3.4	2,041
8/3	14	1,924	1,591	150.7	4	1,595	152.0	0.3%	0.9%	3.4	2,045
8/3	15	1,900	1,597	150.7	4	1,601	151.9	0.3%	0.8%	3.4	2,044
8/3	16	1,860	1,581	150.7	4	1,585	152.0	0.3%	0.9%	3.4	2,045
8/3	17	1,792	1,576	146.1	4	1,580	147.4	0.3%	0.9%	3.4	1,983
8/5	0	1,172	1,009	36.0	2	1,011	36.1	0.2%	0.3%	1.6	117
8/6	0	1,276	1,031	43.1	2	1,033	43.2	0.2%	0.3%	1.6	140
8/6	1	1,209	982	37.8	2	984	37.9	0.2%	0.3%	1.6	123
8/6	2	1,176	943	34.4	2	945	34.5	0.2%	0.3%	1.6	112
8/6	3	1,153	928	34.0	2	930	34.1	0.2%	0.4%	1.6	111
8/6	4	1,154	928	34.2	2	930	34.3	0.2%	0.4%	1.6	111
8/6	5	1,213	957	39.1	2	959	39.2	0.2%	0.3%	1.6	127
8/6	6	1,331	1,086	41.3	2	1,088	41.4	0.2%	0.3%	1.6	134
8/6	7	1,517	1,289	46.1	2	1,291	46.2	0.2%	0.3%	1.6	150
8/6	8	1,655	1,324	54.8	2	1,326	54.9	0.2%	0.2%	1.6	178
8/6	9	1,766	1,424	58.1	2	1,426	58.2	0.1%	0.2%	1.6	189
8/6	10	1,850	1,518	70.3	2	1,520	70.6	0.1%	0.4%	3.4	475
8/6	11	1,908	1,570	82.0	2	1,572	82.4	0.1%	0.4%	3.4	555
8/6	12	1,938	1,594	80.3	2	1,596	80.6	0.1%	0.4%	3.4	543
8/6	13	1,982	1,621	85.9	2	1,623	86.7	0.1%	0.9%	7.6	1,306
8/6	14	2,004	1,648	86.2	2	1,650	87.0	0.1%	0.9%	7.6	1,313
8/6	15	2,015	1,673	98.0	2	1,675	98.8	0.1%	0.9%	7.6	1,489
8/6	16	2,026	1,695	98.0	2	1,697	98.9	0.1%	0.9%	7.9	1,544
8/6	17	2,022	1,690	86.4	2	1,692	87.3	0.1%	1.0%	8.3	1,441
8/6	18	1,995	1,663	82.7	2	1,665	83.7	0.1%	1.2%	9.6	1,590
8/6	19	1,942	1,631	77.8	2	1,633	78.7	0.1%	1.2%	9.7	1,513
8/6	20	1,940	1,623	72.7	2	1,625	73.6	0.1%	1.2%	9.7	1,414
8/6	21	1,881	1,591	62.3	2	1,593	62.6	0.1%	0.4%	3.4	421
8/6	22	1,718	1,534	50.4	2	1,536	50.6	0.1%	0.4%	3.4	341
8/6	23	1,533	1,354	43.3	2	1,356	43.4	0.1%	0.2%	1.6	141
8/7	0	1,407	1,224	44.0	6	1,230	44.3	0.5%	0.8%	1.6	429
8/7	1	1,326	1,157	36.2	2	1,159	36.3	0.2%	0.3%	1.6	118
8/7	2	1,277	1,119	36.7	2	1,121	36.8	0.2%	0.3%	1.6	119
8/7	3	1,251	1,098	36.3	2	1,100	36.4	0.2%	0.3%	1.6	118
8/7	4	1,253	1,100	36.6	2	1,102	36.7	0.2%	0.3%	1.6	119
8/7	5	1,317	1,154	37.7	2	1,156	37.8	0.2%	0.3%	1.6	123
8/7	6	1,444	1,270	41.1	2	1,272	41.2	0.2%	0.3%	1.6	133
8/7	7	1,606	1,436	50.9	2	1,438	51.0	0.1%	0.2%	1.6	165
8/7	8	1,717	1,466	61.7	2	1,468	61.8	0.1%	0.2%	1.6	201
8/7	9	1,815	1,583	85.2	6	1,589	86.3	0.4%	1.3%	3.4	1,733
8/7	10	1,904	1,651	99.4	6	1,657	101.8	0.4%	2.4%	6.6	3,947
8/7	11	1,958	1,696	114.6	6	1,702	117.3	0.4%	2.3%	6.6	4,524
8/7	12	2,009	1,732	112.6	6	1,738	115.2	0.3%	2.3%	6.7	4,532
8/7	13	2,069	1,783	124.9	6	1,789	127.6	0.3%	2.2%	6.4	4,789
8/7	14	2,073	1,811	124.9	6	1,817	127.5	0.3%	2.1%	6.3	4,721
8/7	15	2,063	1,791	124.7	6	1,797	127.3	0.3%	2.1%	6.2	4,673

Table 1.1D. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2001 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 ($)**
8/7	17	2,057	1,769	122.7	6	1,775	125.6	0.3%	2.4%	7.0	5,156
8/7	18	2,018	1,729	110.8	2	1,731	111.8	0.1%	0.9%	7.7	1,697
8/7	19	1,978	1,676	97.1	2	1,678	98.0	0.1%	1.0%	8.1	1,566
8/7	20	2,006	1,640	93.6	2	1,642	94.5	0.1%	1.0%	8.1	1,507
8/7	21	1,958	1,615	84.6	2	1,617	85.4	0.1%	1.0%	8.0	1,357
8/7	22	1,804	1,557	57.6	2	1,559	57.8	0.1%	0.4%	3.4	389
8/7	23	1,633	1,376	43.2	2	1,378	43.3	0.1%	0.2%	1.6	140
8/8	0	1,515	1,269	41.1	2	1,271	41.2	0.2%	0.3%	1.6	134
8/8	1	1,447	1,191	37.6	6	1,197	37.9	0.5%	0.8%	1.6	367
8/8	2	1,392	1,154	36.5	6	1,160	36.8	0.5%	0.8%	1.6	356
8/8	3	1,369	1,131	36.4	6	1,137	36.7	0.5%	0.9%	1.6	355
8/8	4	1,374	1,134	36.2	6	1,140	36.5	0.5%	0.9%	1.6	353
8/8	5	1,427	1,175	38.7	6	1,181	39.0	0.5%	0.8%	1.6	378
8/8	6	1,544	1,298	40.5	6	1,304	40.8	0.5%	0.8%	1.6	395
8/8	7	1,737	1,477	58.7	10	1,487	59.3	0.7%	1.1%	1.6	956
8/8	8	1,874	1,509	102.5	10	1,519	104.8	0.7%	2.3%	3.4	3,486
8/8	9	1,984	1,626	142.1	10	1,636	149.4	0.6%	5.2%	8.4	11,959
8/8	10	2,057	1,707	134.1	10	1,717	140.7	0.6%	4.9%	8.4	11,304
8/8	11	2,088	1,764	149.0	10	1,774	156.2	0.6%	4.8%	8.5	12,663
8/8	12	2,084	1,802	171.0	10	1,812	178.7	0.6%	4.5%	8.0	13,750
8/8	13	2,078	1,831	204.0	18	1,849	222.2	1.0%	8.9%	9.1	33,328
8/8	14	2,091	1,847	204.7	18	1,865	222.3	1.0%	8.6%	8.8	32,455
8/8	15	2,076	1,837	289.3	14	1,851	307.6	0.8%	6.3%	8.3	33,492
8/8	16	2,080	1,828	272.5	14	1,842	291.2	0.8%	6.9%	9.0	34,275
8/8	17	2,062	1,814	245.9	6	1,820	252.9	0.3%	2.8%	8.5	12,592
8/8	18	2,017	1,768	173.3	6	1,774	178.9	0.3%	3.2%	9.5	9,874
8/8	19	1,996	1,722	124.1	6	1,728	128.2	0.3%	3.3%	9.5	7,060
8/8	20	2,014	1,711	126.2	6	1,717	130.4	0.4%	3.3%	9.5	7,166
8/8	21	1,942	1,672	135.6	2	1,674	137.1	0.1%	1.1%	8.9	2,420
8/8	22	1,770	1,609	115.9	2	1,611	117.2	0.1%	1.2%	9.4	2,180
8/8	23	1,612	1,426	51.6	2	1,428	51.7	0.1%	0.2%	1.6	168
8/9	0	1,482	1,282	49.1	2	1,284	49.2	0.2%	0.3%	1.6	160
8/9	1	1,408	1,201	45.9	2	1,203	46.0	0.2%	0.3%	1.6	149
8/9	2	1,355	1,162	43.9	2	1,164	44.0	0.2%	0.3%	1.6	143
8/9	3	1,331	1,140	42.7	2	1,142	42.8	0.2%	0.3%	1.6	139
8/9	4	1,338	1,143	42.7	2	1,145	42.8	0.2%	0.3%	1.6	139
8/9	5	1,397	1,191	45.9	2	1,193	46.0	0.2%	0.3%	1.6	149
8/9	6	1,512	1,320	44.4	2	1,322	44.5	0.2%	0.2%	1.6	144
8/9	7	1,668	1,508	75.2	2	1,510	75.6	0.1%	0.4%	3.4	509
8/9	8	1,792	1,537	148.9	2	1,539	149.6	0.1%	0.4%	3.4	1,008
8/9	9	1,906	1,650	186.1	2	1,652	188.7	0.1%	1.4%	11.4	4,255
8/9	10	1,978	1,726	201.6	2	1,728	204.3	0.1%	1.3%	11.4	4,613
8/9	11	1,976	1,771	331.4	2	1,773	335.6	0.1%	1.3%	11.4	7,556
8/9	12	1,997	1,809	516.1	6	1,815	535.7	0.3%	3.8%	11.4	35,414
8/9	13	2,047	1,853	529.1	6	1,859	548.4	0.3%	3.6%	11.3	35,749
8/9	14	2,068	1,878	976.2	6	1,884	1,011.3	0.3%	3.6%	11.3	65,945
8/9	15	2,056	1,882	975.4	10	1,892	1,036.7	0.5%	6.3%	11.8	115,305
8/9	16	2,057	1,887	887.1	10	1,897	943.8	0.5%	6.4%	12.1	107,042
8/9	17	2,051	1,878	531.4	10	1,888	567.9	0.5%	6.9%	12.9	68,619
8/9	18	2,025	1,851	350.7	6	1,857	365.6	0.3%	4.3%	13.1	27,637
8/9	19	1,979	1,796	236.4	2	1,798	239.7	0.1%	1.4%	12.7	5,988
8/9	20	1,870	1,783	193.4	2	1,785	196.1	0.1%	1.4%	12.8	4,953
8/9	21	1,793	1,727	178.2	2	1,729	180.8	0.1%	1.5%	12.8	4,558
8/9	22	1,662	1,664	149.6	2	1,666	152.0	0.1%	1.6%	13.1	3,929
8/9	23	1,504	1,468	97.7	2	1,470	97.9	0.1%	0.2%	1.6	318
8/10	0	1,409	1,312	48.2	2	1,314	48.3	0.2%	0.2%	1.6	157
8/10	1	1,350	1,232	41.5	2	1,234	41.6	0.2%	0.3%	1.6	135
8/10	2	1,314	1,185	40.3	2	1,187	40.4	0.2%	0.3%	1.6	131
8/10	3	1,293	1,163	39.9	2	1,165	40.1	0.2%	0.3%	1.6	130
8/10	4	1,299	1,166	39.8	2	1,168	39.9	0.2%	0.3%	1.6	130
8/10	5	1,362	1,227	41.5	2	1,229	41.6	0.2%	0.3%	1.6	135
8/10	6	1,470	1,344	41.6	2	1,346	41.7	0.1%	0.2%	1.6	135
8/10	7	1,634	1,514	57.5	5	1,519	58.2	0.3%	1.1%	3.4	976
8/10	8	1,773	1,525	109.9	5	1,530	111.1	0.3%	1.1%	3.4	1,864
8/10	9	1,877	1,612	150.8	5	1,617	157.3	0.3%	4.4%	14.1	10,593
8/10	10	1,918	1,689	160.7	5	1,694	167.3	0.3%	4.2%	14.0	11,270
8/10	11	1,928	1,727	185.2	5	1,732	192.7	0.3%	4.1%	14.1	13,021
8/10	12	1,910	1,753	203.9	5	1,758	211.7	0.3%	3.9%	13.5	13,790
8/10	13	1,858	1,779	265.9	2	1,781	269.8	0.1%	1.5%	13.1	6,979
8/10	14	1,852	1,792	275.7	2	1,794	279.8	0.1%	1.5%	13.2	7,290
8/10	15	1,863	1,783	296.4	2	1,785	300.7	0.1%	1.5%	13.2	7,813
8/10	16	1,871	1,770	262.4	2	1,772	266.4	0.1%	1.5%	13.5	7,102
8/10	17	1,831	1,736	211.7	2	1,738	215.2	0.1%	1.7%	14.4	6,090
8/10	18	1,789	1,696	182.8	2	1,698	186.1	0.1%	1.8%	15.2	5,548
8/10	19	1,733	1,651	152.8	2	1,653	155.6	0.1%	1.8%	15.2	4,636

Table 1.1D. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2001 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 ($)**
8/10	22	1,487	1,545	77.1	2	1,547	77.4	0.1%	0.4%	3.4	522
8/10	23	1,342	1,390	50.5	2	1,392	50.6	0.1%	0.2%	1.6	164
8/11	0	1,217	1,089	40.7	2	1,091	40.8	0.2%	0.3%	1.6	132
8/11	1	1,140	1,010	37.5	2	1,012	37.6	0.2%	0.3%	1.6	122
8/11	2	1,093	967	35.1	2	969	35.2	0.2%	0.3%	1.6	114
8/11	3	1,069	935	34.3	2	937	34.4	0.2%	0.3%	1.6	112
8/11	4	1,063	916	34.3	2	918	34.4	0.2%	0.4%	1.6	112
8/11	5	1,067	932	34.6	2	934	34.8	0.2%	0.3%	1.6	113
8/11	6	1,093	979	34.2	2	981	34.3	0.2%	0.3%	1.6	111
8/11	7	1,192	1,075	39.0	2	1,077	39.1	0.2%	0.3%	1.6	127
8/11	8	1,327	1,099	42.7	2	1,101	42.8	0.2%	0.3%	1.6	139
8/11	9	1,420	1,192	44.4	2	1,194	44.5	0.2%	0.3%	1.6	144
8/11	10	1,486	1,250	47.5	2	1,252	47.6	0.2%	0.3%	1.6	154
8/11	11	1,492	1,252	49.0	2	1,254	49.2	0.2%	0.3%	1.6	159
8/11	12	1,500	1,254	50.5	2	1,256	50.7	0.2%	0.3%	1.6	164
8/11	13	1,499	1,253	50.5	2	1,255	50.7	0.2%	0.3%	1.6	164
8/11	14	1,499	1,245	49.5	2	1,247	49.6	0.2%	0.3%	1.6	161
8/11	15	1,508	1,239	49.9	2	1,241	50.1	0.2%	0.3%	1.6	162
8/11	16	1,526	1,246	48.8	2	1,248	48.9	0.2%	0.3%	1.6	159
8/11	17	1,538	1,248	48.4	2	1,250	48.6	0.2%	0.3%	1.6	158
8/11	18	1,549	1,218	46.2	2	1,220	46.3	0.2%	0.3%	1.6	150
8/11	19	1,538	1,208	45.5	2	1,210	45.6	0.2%	0.3%	1.6	148
8/11	20	1,575	1,206	45.5	2	1,208	45.6	0.2%	0.3%	1.6	148
8/11	21	1,542	1,187	44.6	2	1,189	44.7	0.2%	0.3%	1.6	145
8/11	22	1,447	1,184	41.2	2	1,186	41.3	0.2%	0.3%	1.6	134
8/11	23	1,338	1,057	39.5	2	1,059	39.6	0.2%	0.3%	1.6	128
8/12	1	1,184	816	29.2	2	818	29.3	0.2%	0.4%	1.6	95
8/12	2	1,150	786	24.7	2	788	24.8	0.3%	0.4%	1.6	80
8/12	3	1,122	766	23.7	2	768	23.8	0.3%	0.4%	1.6	77
8/12	4	1,115	760	23.4	2	762	23.5	0.3%	0.4%	1.6	76
8/12	5	1,118	760	24.0	2	762	24.1	0.3%	0.4%	1.6	78
8/12	6	1,137	772	23.4	2	774	23.5	0.3%	0.4%	1.6	76
8/12	7	1,188	842	32.3	2	844	32.5	0.2%	0.4%	1.6	105
8/12	8	1,288	849	37.0	2	851	37.1	0.2%	0.4%	1.6	120
8/12	9	1,369	949	38.8	2	951	38.9	0.2%	0.3%	1.6	126
8/12	10	1,424	1,012	39.9	2	1,014	40.0	0.2%	0.3%	1.6	130
8/12	11	1,448	1,040	42.6	2	1,042	42.8	0.2%	0.3%	1.6	139
8/12	12	1,434	1,053	43.0	2	1,055	43.1	0.2%	0.3%	1.6	140
8/12	13	1,429	1,056	43.2	2	1,058	43.3	0.2%	0.3%	1.6	141
8/12	14	1,413	1,053	43.3	2	1,055	43.5	0.2%	0.3%	1.6	141
8/12	15	1,392	1,054	43.2	2	1,056	43.3	0.2%	0.3%	1.6	140
8/12	16	1,408	1,078	43.5	2	1,080	43.7	0.2%	0.3%	1.6	142
8/12	17	1,413	1,082	43.9	2	1,084	44.0	0.2%	0.3%	1.6	143
8/12	18	1,429	1,072	43.5	2	1,074	43.7	0.2%	0.3%	1.6	142
8/12	19	1,457	1,054	43.9	2	1,056	44.0	0.2%	0.3%	1.6	143
8/12	20	1,511	1,088	45.7	2	1,090	45.9	0.2%	0.3%	1.6	149
8/12	21	1,476	1,095	45.4	2	1,097	45.5	0.2%	0.3%	1.6	148
8/12	22	1,382	1,095	42.5	2	1,097	42.6	0.2%	0.3%	1.6	138
8/12	23	1,269	960	39.2	2	962	39.3	0.2%	0.3%	1.6	127
8/17	6	1,346	1,051	34.0	3	1,054	34.2	0.3%	0.5%	1.6	166
8/17	7	1,476	1,204	39.0	3	1,207	39.2	0.2%	0.4%	1.6	190

Table 1.1D. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2001 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 ($)**
8/17	8	1,572	1,219	41.9	3	1,222	42.1	0.2%	0.4%	1.6	204
8/17	9	1,645	1,305	42.8	3	1,308	43.0	0.2%	0.4%	1.6	209
8/17	10	1,677	1,379	51.1	3	1,382	51.2	0.2%	0.4%	1.6	249
8/17	11	1,677	1,408	64.7	3	1,411	64.9	0.2%	0.3%	1.6	315
8/17	12	1,669	1,430	64.5	3	1,433	64.8	0.2%	0.3%	1.6	315
8/21	6	1,316	1,047	35.5	3	1,050	35.6	0.3%	0.5%	1.6	173
8/21	7	1,466	1,183	38.7	3	1,186	38.8	0.3%	0.4%	1.6	189
8/21	8	1,575	1,174	40.5	3	1,177	40.7	0.3%	0.4%	1.6	198
8/21	9	1,653	1,264	42.4	3	1,267	42.5	0.2%	0.4%	1.6	207
8/22	12	1,711	1,376	44.5	1	1,377	44.5	0.1%	0.1%	1.6	72
8/22	13	1,730	1,398	49.9	1	1,399	50.0	0.1%	0.1%	1.6	81
8/22	14	1,737	1,407	52.2	1	1,408	52.3	0.1%	0.1%	1.6	85
8/22	15	1,740	1,424	52.5	1	1,425	52.6	0.1%	0.1%	1.6	85
8/23	12	1,650	1,477	44.5	1	1,478	44.5	0.1%	0.1%	1.6	72
8/23	13	1,640	1,503	53.1	1	1,504	53.3	0.1%	0.2%	3.4	180
8/23	14	1,655	1,509	52.4	1	1,510	52.5	0.1%	0.2%	3.4	177
8/23	15	1,632	1,514	52.4	1	1,515	52.5	0.1%	0.2%	3.4	177
Hourly Avg.		1,536	1,293	78	3	1,296	80	0.2%	0.9%	3.4	2,781
Total		568,244	478,351		1,231	479,582					1,029,049

*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 bilatera

Thus, this net amount is the savings to customers buying load in the DAM.

Table 1.2D. Daily Effect of DADRP Scheduled Bids in the Western Zone, Summer, 2001

			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 ($)**
8/7	0	1,904	1,585	42	10	1,595	42	0.6%	0.6%	2.1	862
8/8	0	2,043	1,626	39	10	1,636	39	0.6%	0.6%	2.1	802
8/8	1	1,967	1,549	35	13	1,562	36	0.8%	0.8%	2.1	950
8/8	2	1,907	1,499	34	9	1,508	35	0.6%	0.6%	2.1	638
8/8	3	1,864	1,480	34	12	1,492	35	0.8%	0.8%	2.1	849
8/8	4	1,862	1,484	34	12	1,496	34	0.8%	0.8%	2.1	843
8/8	5	1,929	1,565	37	12	1,577	37	0.8%	0.8%	2.1	911
8/8	6	2,054	1,665	38	12	1,677	39	0.7%	0.7%	2.1	956
8/8	7	2,246	1,814	53	4	1,818	54	0.2%	0.2%	3.0	646
8/8	8	2,402	1,942	58	4	1,946	58	0.2%	0.2%	3.0	696
8/8	9	2,527	2,034	70	4	2,038	72	0.2%	0.2%	12.5	3,508
8/8	10	2,611	2,135	122	4	2,139	125	0.2%	0.2%	12.5	6,124
8/8	11	2,698	2,182	136	4	2,186	139	0.2%	0.2%	12.5	6,806
8/8	12	2,708	2,209	151	5	2,214	155	0.2%	0.2%	13.7	10,321
8/8	13	2,725	2,251	161	5	2,256	166	0.2%	0.2%	13.7	11,032
8/8	14	2,727	2,285	160	5	2,290	165	0.2%	0.2%	13.7	10,998
8/8	15	2,710	2,264	198	4	2,268	202	0.2%	0.2%	12.5	9,904
8/8	16	2,687	2,238	182	4	2,242	186	0.2%	0.2%	12.5	9,105
8/8	17	2,648	2,202	157	4	2,206	161	0.2%	0.2%	12.5	7,871
8/8	18	2,592	2,140	137	4	2,144	141	0.2%	0.2%	12.5	6,875
8/8	19	2,541	2,062	112	4	2,066	115	0.2%	0.2%	12.5	5,627
8/8	20	2,557	2,057	96	4	2,061	98	0.2%	0.2%	12.5	4,802
8/8	21	2,538	2,043	73	4	2,047	75	0.2%	0.2%	12.5	3,642
8/8	22	2,355	1,886	59	9	1,895	60	0.5%	0.5%	3.0	1,615
8/8	23	2,153	1,738	49	9	1,747	49	0.5%	0.5%	3.0	1,323
8/9	0	2,004	1,617	47	10	1,627	47	0.6%	0.6%	2.1	968
8/9	1	1,921	1,549	44	12	1,561	45	0.8%	0.8%	2.1	1,094
8/9	2	1,854	1,505	42	11	1,516	42	0.7%	0.7%	2.1	956
8/9	3	1,820	1,481	41	11	1,492	41	0.7%	0.7%	2.1	929
8/9	4	1,831	1,491	41	11	1,502	41	0.7%	0.7%	2.1	929
8/9	5	1,913	1,557	44	11	1,568	45	0.7%	0.7%	2.1	1,003
8/9	6	2,061	1,647	42	10	1,657	43	0.6%	0.6%	2.1	879
8/9	7	2,212	1,835	70	4	1,839	70	0.2%	0.2%	3.0	841
8/9	8	2,340	1,963	139	4	1,967	140	0.2%	0.2%	3.0	1,681
8/9	9	2,462	2,076	172	4	2,080	176	0.2%	0.2%	12.5	8,599
8/9	10	2,588	2,207	187	4	2,211	192	0.2%	0.2%	12.5	9,377
8/9	11	2,653	2,247	304	4	2,251	310	0.2%	0.2%	12.5	15,184
8/9	12	2,698	2,304	474	2	2,306	479	0.1%	0.1%	10.1	9,618
8/9	13	2,740	2,360	492	2	2,362	497	0.1%	0.1%	10.1	9,982
8/9	14	2,719	2,371	907	2	2,373	915	0.1%	0.1%	10.1	18,391
8/9	15	2,575	2,360	904	2	2,362	912	0.1%	0.1%	10.1	18,332
8/9	16	2,633	2,349	822	4	2,353	839	0.2%	0.2%	12.5	41,079
8/9	17	2,529	2,323	488	4	2,327	498	0.2%	0.2%	12.5	24,392
8/9	18	2,465	2,245	318	4	2,249	325	0.2%	0.2%	12.5	15,906
8/9	19	2,395	2,195	214	4	2,199	219	0.2%	0.2%	12.5	10,707
8/9	20	2,434	2,163	176	4	2,167	180	0.2%	0.2%	12.5	8,808
8/9	21	2,405	2,147	162	4	2,151	166	0.2%	0.2%	12.5	8,132
8/9	22	2,211	1,963	138	9	1,972	140	0.5%	0.5%	3.0	3,769
8/9	23	2,062	1,776	92	9	1,785	93	0.5%	0.5%	3.0	2,513
8/10	0	1,941	1,695	45	1	1,696	45	0.1%	0.1%	3.0	137
8/10	1	1,836	1,601	39	12	1,613	40	0.7%	0.7%	2.1	977
8/10	2	1,799	1,540	38	9	1,549	38	0.6%	0.6%	2.1	709
8/10	3	1,781	1,512	38	11	1,523	38	0.7%	0.7%	2.1	860
8/10	4	1,788	1,508	37	11	1,519	38	0.7%	0.7%	2.1	856
8/10	5	1,847	1,595	39	11	1,606	40	0.7%	0.7%	2.1	894
8/10	6	2,019	1,680	39	11	1,691	40	0.7%	0.7%	2.1	894
8/10	7	2,224	1,833	53	4	1,837	53	0.2%	0.2%	3.0	637
8/10	8	2,294	1,926	100	4	1,930	101	0.2%	0.2%	3.0	1,213
8/10	9	2,372	2,015	138	4	2,019	139	0.2%	0.2%	3.0	1,670
8/10	10	2,434	2,080	146	4	2,084	149	0.2%	0.2%	12.5	7,301
8/10	11	2,483	2,136	162	4	2,140	166	0.2%	0.2%	12.5	8,114
8/10	18	2,257	2,030	130	3	2,033	130	0.1%	0.1%	3.0	1,177
8/10	19	2,154	1,946	117	3	1,949	118	0.2%	0.2%	3.0	1,063
8/10	20	2,130	1,952	111	3	1,955	112	0.2%	0.2%	3.0	1,011
8/10	21	2,089	1,926	104	6	1,932	105	0.3%	0.3%	3.0	1,884
8/10	22	1,932	1,778	70	9	1,787	71	0.5%	0.5%	3.0	1,919
8/10	23	1,756	1,628	47	9	1,637	48	0.6%	0.6%	2.1	880
8/11	1	1,551	1,238	35	1	1,239	35	0.1%	0.1%	2.1	73
8/11	2	1,517	1,185	33	1	1,186	33	0.1%	0.1%	2.1	68
8/11	3	1,482	1,166	32	1	1,167	32	0.1%	0.1%	2.1	67
8/11	4	1,471	1,155	32	1	1,156	32	0.1%	0.1%	2.1	66

Table 1.2D. Daily Effect of DADRP Scheduled Bids in the Western Zone, Summer, 2001 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 ($)**
8/11	14	1,993	1,418	45	1	1,419	45	0.1%	0.1%	2.1	93
8/11	15	2,005	1,414	44	1	1,415	44	0.1%	0.1%	2.1	92
8/11	16	2,027	1,413	44	1	1,414	44	0.1%	0.1%	2.1	92
8/11	17	2,040	1,405	44	1	1,406	44	0.1%	0.1%	2.1	90
8/11	18	2,015	1,383	42	1	1,384	42	0.1%	0.1%	2.1	86
8/11	19	1,954	1,355	41	1	1,356	41	0.1%	0.1%	2.1	85
8/11	20	1,986	1,372	41	1	1,373	41	0.1%	0.1%	2.1	85
8/11	21	1,980	1,347	40	1	1,348	41	0.1%	0.1%	2.1	84
8/11	22	1,862	1,257	38	1	1,258	38	0.1%	0.1%	2.1	78
8/11	23	1,716	1,167	37	1	1,168	37	0.1%	0.1%	2.1	76
8/12	0	1,611	1,242	31	9	1,251	31	0.7%	0.7%	2.1	578
8/12	7	1,542	1,123	30	1	1,124	30	0.1%	0.1%	2.1	62
8/12	8	1,661	1,222	34	1	1,223	34	0.1%	0.1%	2.1	70
8/12	9	1,769	1,326	36	1	1,327	36	0.1%	0.1%	2.1	74
8/12	10	1,859	1,384	36	1	1,385	36	0.1%	0.1%	2.1	75
8/12	11	1,920	1,449	39	1	1,450	39	0.1%	0.1%	2.1	80
8/12	12	1,955	1,471	39	1	1,472	39	0.1%	0.1%	2.1	81
8/12	13	1,963	1,480	39	1	1,481	40	0.1%	0.1%	2.1	82
8/12	14	1,977	1,475	40	1	1,476	40	0.1%	0.1%	2.1	82
8/12	15	1,977	1,476	39	1	1,477	39	0.1%	0.1%	2.1	82
8/12	16	1,985	1,491	40	1	1,492	40	0.1%	0.1%	2.1	82
8/12	17	1,987	1,502	40	1	1,503	40	0.1%	0.1%	2.1	82
8/12	18	1,975	1,485	39	1	1,486	40	0.1%	0.1%	2.1	82
8/12	19	1,953	1,468	40	1	1,469	40	0.1%	0.1%	2.1	83
8/12	20	2,003	1,478	41	1	1,479	41	0.1%	0.1%	2.1	86
8/12	21	2,008	1,519	41	1	1,520	41	0.1%	0.1%	2.1	85
8/12	22	1,886	1,427	39	1	1,428	39	0.1%	0.1%	2.1	81
8/12	23	1,747	1,300	37	1	1,301	37	0.1%	0.1%	2.1	76
8/13	22	1,963	1,460	38	9	1,469	38	0.6%	0.6%	2.1	707
8/13	23	1,794	1,319	37	9	1,328	37	0.7%	0.7%	2.1	684
8/14	0	1,679	1,166	26	10	1,176	26	0.9%	0.9%	2.1	534
8/15	0	1,583	1,240	28	10	1,250	29	0.8%	0.8%	2.1	583
8/15	1	1,527	1,163	23	10	1,173	23	0.9%	0.9%	2.1	469
8/15	2	1,482	1,115	22	8	1,123	22	0.7%	0.7%	2.1	360
8/15	3	1,452	1,101	21	10	1,111	22	0.9%	0.9%	2.1	440
8/15	4	1,468	1,108	21	10	1,118	22	0.9%	0.9%	2.1	441
8/15	5	1,554	1,186	22	10	1,196	23	0.8%	0.8%	2.1	461
8/15	6	1,662	1,294	29	10	1,304	30	0.8%	0.8%	2.1	612
8/15	7	1,806	1,461	37	4	1,465	37	0.3%	0.3%	2.1	303
8/15	8	1,922	1,574	39	4	1,578	39	0.3%	0.3%	2.1	322
8/15	9	2,009	1,672	40	4	1,676	40	0.2%	0.2%	2.1	332
8/15	10	2,095	1,735	44	4	1,739	44	0.2%	0.2%	3.0	534
8/15	11	2,137	1,772	47	4	1,776	47	0.2%	0.2%	3.0	566
8/15	12	2,167	1,785	47	4	1,789	47	0.2%	0.2%	3.0	570
8/15	13	2,206	1,798	49	4	1,802	49	0.2%	0.2%	3.0	588
8/15	14	2,230	1,832	51	4	1,836	52	0.2%	0.2%	3.0	622
8/15	15	2,242	1,863	54	3	1,866	55	0.2%	0.2%	3.0	495
8/15	16	2,257	1,840	51	3	1,843	51	0.2%	0.2%	3.0	460
8/15	17	2,228	1,844	50	3	1,847	50	0.2%	0.2%	3.0	453
8/15	18	2,181	1,807	45	3	1,810	45	0.2%	0.2%	3.0	404
8/15	19	2,118	1,762	41	3	1,765	41	0.2%	0.2%	3.0	370
8/15	20	2,141	1,736	40	3	1,739	40	0.2%	0.2%	3.0	365
8/15	21	2,104	1,746	41	6	1,752	41	0.3%	0.3%	3.0	742
8/15	22	1,937	1,612	38	10	1,622	38	0.6%	0.6%	2.1	778
8/15	23	1,767	1,382	36	8	1,390	36	0.6%	0.6%	2.1	595
8/16	0	1,651	1,347	32	10	1,357	33	0.7%	0.7%	2.1	674
8/16	1	1,586	1,277	31	10	1,287	31	0.8%	0.8%	2.1	638
8/16	2	1,541	1,238	29	8	1,246	30	0.6%	0.6%	2.1	488
8/16	3	1,522	1,215	26	10	1,225	27	0.8%	0.8%	2.1	542
8/16	4	1,533	1,213	26	10	1,223	27	0.8%	0.8%	2.1	542
8/16	5	1,622	1,290	31	10	1,300	31	0.8%	0.8%	2.1	639
8/16	6	1,763	1,426	32	10	1,436	33	0.7%	0.7%	2.1	670
8/16	7	1,934	1,536	37	4	1,540	38	0.3%	0.3%	2.1	311
8/16	8	2,059	1,640	39	4	1,644	39	0.2%	0.2%	2.1	325
8/16	9	2,141	1,738	40	4	1,742	40	0.2%	0.2%	3.0	481
8/16	10	2,217	1,826	44	4	1,830	44	0.2%	0.2%	3.0	530
8/16	11	2,260	1,867	46	4	1,871	47	0.2%	0.2%	3.0	561
8/16	12	2,286	1,893	50	4	1,897	50	0.2%	0.2%	3.0	605
8/16	13	2,337	1,942	56	4	1,946	56	0.2%	0.2%	3.0	673
8/16	14	2,336	1,959	58	4	1,963	58	0.2%	0.2%	3.0	696
8/16	15	2,311	1,942	59	3	1,945	60	0.2%	0.2%	3.0	540
8/16	16	2,307	1,922	60	3	1,925	60	0.2%	0.2%	3.0	541
8/16	17	2,478	1,905	58	3	1,908	58	0.2%	0.2%	3.0	524
8/16	18	2,240	1,845	46	3	1,848	46	0.2%	0.2%	3.0	417
8/16	19	2,205	1,830	43	3	1,833	43	0.2%	0.2%	3.0	386

Table 1.2D. Daily Effect of DADRP Scheduled Bids in the Western Zone, Summer, 2001 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 ($)**
8/17	5	1,697	1,295	31	10	1,305	31	0.8%	0.8%	2.1	638
8/17	6	1,853	1,405	32	10	1,415	33	0.7%	0.7%	2.1	667
8/17	7	1,997	1,545	37	5	1,550	37	0.3%	0.3%	2.1	379
8/17	8	2,109	1,635	39	5	1,640	39	0.3%	0.3%	2.1	401
8/17	9	2,211	1,714	40	5	1,719	40	0.3%	0.3%	3.0	599
8/17	10	2,281	1,747	47	5	1,752	47	0.3%	0.3%	3.0	710
8/17	11	2,292	1,792	47	4	1,796	48	0.2%	0.2%	3.0	572
8/17	12	2,298	1,801	49	5	1,806	50	0.3%	0.3%	3.0	750
8/17	13	2,287	1,810	55	5	1,815	56	0.3%	0.3%	3.0	835
8/17	14	2,265	1,827	56	5	1,832	56	0.3%	0.3%	3.0	846
8/17	15	2,231	1,822	57	3	1,825	58	0.2%	0.2%	3.0	521
8/17	16	2,183	1,789	57	3	1,792	57	0.2%	0.2%	3.0	518
8/17	17	2,122	1,736	49	3	1,739	49	0.2%	0.2%	3.0	445
8/17	18	2,056	1,684	46	3	1,687	46	0.2%	0.2%	2.1	287
8/17	19	1,993	1,631	42	3	1,634	42	0.2%	0.2%	2.1	258
8/17	20	2,030	1,652	41	3	1,655	41	0.2%	0.2%	2.1	257
8/17	21	1,964	1,635	41	5	1,640	41	0.3%	0.3%	2.1	427
8/17	22	1,844	1,498	36	9	1,507	37	0.6%	0.6%	2.1	675
8/17	23	1,694	1,340	37	7	1,347	38	0.5%	0.5%	2.1	541
8/18	0	1,603	1,207	35	8	1,215	36	0.7%	0.7%	2.1	587
8/18	1	1,541	1,150	31	1	1,151	31	0.1%	0.1%	2.1	64
8/18	2	1,492	1,091	28	1	1,092	28	0.1%	0.1%	2.1	58
8/18	3	1,464	1,064	25	1	1,065	25	0.1%	0.1%	2.1	51
8/18	4	1,460	1,068	24	1	1,069	24	0.1%	0.1%	2.1	49
8/18	5	1,474	1,098	24	1	1,099	24	0.1%	0.1%	2.1	49
8/18	6	1,516	1,113	24	1	1,114	24	0.1%	0.1%	2.1	49
8/18	7	1,602	1,197	31	1	1,198	31	0.1%	0.1%	2.1	64
8/18	8	1,746	1,324	34	1	1,325	34	0.1%	0.1%	2.1	70
8/18	9	1,844	1,454	37	1	1,455	37	0.1%	0.1%	2.1	77
8/18	10	1,913	1,527	41	1	1,528	41	0.1%	0.1%	2.1	84
8/18	11	1,934	1,566	48	1	1,567	48	0.1%	0.1%	2.1	99
8/18	12	1,925	1,581	47	1	1,582	47	0.1%	0.1%	2.1	97
8/18	13	1,917	1,580	47	1	1,581	47	0.1%	0.1%	2.1	97
8/18	14	1,904	1,578	46	1	1,579	46	0.1%	0.1%	2.1	96
8/18	15	1,901	1,595	42	1	1,596	42	0.1%	0.1%	2.1	87
8/18	16	1,918	1,598	44	1	1,599	45	0.1%	0.1%	2.1	92
8/18	17	1,919	1,610	44	1	1,611	44	0.1%	0.1%	2.1	91
8/18	18	1,895	1,584	42	1	1,585	42	0.1%	0.1%	2.1	87
8/18	19	1,866	1,555	40	1	1,556	41	0.1%	0.1%	2.1	84
8/18	20	1,925	1,592	41	1	1,593	41	0.1%	0.1%	2.1	85
8/18	21	1,893	1,594	40	1	1,595	40	0.1%	0.1%	2.1	84
8/18	22	1,780	1,463	39	1	1,464	39	0.1%	0.1%	2.1	80
8/18	23	1,653	1,350	34	1	1,351	34	0.1%	0.1%	2.1	70
8/19	0	1,559	1,309	30	7	1,316	30	0.5%	0.5%	2.1	432
8/19	1	1,505	1,273	25	8	1,281	26	0.6%	0.6%	2.1	423
8/19	2	1,452	1,231	23	8	1,239	24	0.6%	0.6%	2.1	386
8/19	3	1,421	1,212	23	8	1,220	23	0.7%	0.7%	2.1	382
8/19	4	1,410	1,203	23	8	1,211	23	0.7%	0.7%	2.1	379
8/19	5	1,411	1,214	23	8	1,222	23	0.7%	0.7%	2.1	374
8/19	6	1,397	1,200	22	8	1,208	23	0.7%	0.7%	2.1	371
8/19	18	1,873	1,568	40	3	1,571	41	0.2%	0.2%	2.1	251
8/19	19	1,874	1,553	40	3	1,556	40	0.2%	0.2%	2.1	246
8/19	20	1,932	1,603	40	3	1,606	41	0.2%	0.2%	2.1	251
8/19	21	1,874	1,602	40	3	1,605	41	0.2%	0.2%	2.1	251
8/19	22	1,748	1,491	38	7	1,498	38	0.5%	0.5%	2.1	547
8/19	23	1,630	1,375	34	7	1,382	34	0.5%	0.5%	2.1	491
8/20	1	1,520	1,286	32	7	1,293	32	0.5%	0.5%	2.1	461
8/20	2	1,491	1,252	30	7	1,259	31	0.6%	0.6%	2.1	441
8/20	3	1,480	1,230	26	7	1,237	26	0.6%	0.6%	2.1	372
8/20	4	1,511	1,254	26	7	1,261	26	0.6%	0.6%	2.1	374
8/20	5	1,613	1,299	32	7	1,306	32	0.5%	0.5%	2.1	461
8/20	6	1,760	1,425	34	7	1,432	35	0.5%	0.5%	2.1	497
8/20	7	1,913	1,543	38	3	1,546	38	0.2%	0.2%	2.1	236
8/20	8	2,032	1,655	40	3	1,658	40	0.2%	0.2%	2.1	250
8/20	9	2,116	1,731	42	3	1,734	43	0.2%	0.2%	3.0	384
8/20	10	2,192	1,805	47	3	1,808	47	0.2%	0.2%	3.0	423
8/20	11	2,233	1,864	53	3	1,867	53	0.2%	0.2%	3.0	477
8/20	12	2,265	1,889	51	3	1,892	51	0.2%	0.2%	3.0	462
8/20	13	2,295	1,947	57	3	1,950	57	0.2%	0.2%	3.0	515
8/20	14	2,297	1,961	56	3	1,964	57	0.2%	0.2%	3.0	510
8/20	15	2,277	1,962	55	3	1,965	55	0.2%	0.2%	3.0	497
8/20	16	2,266	1,966	53	3	1,969	53	0.2%	0.2%	3.0	482
8/20	17	2,231	1,951	49	3	1,954	50	0.2%	0.2%	3.0	447
8/20	18	2,171	1,898	44	3	1,901	44	0.2%	0.2%	3.0	401
8/20	19	2,104	1,863	42	3	1,866	42	0.2%	0.2%	3.0	379

Table 1.2D. Daily Effect of DADRP Scheduled Bids in the Western Zone, Summer, 2001 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 ($)**
8/22	5	1,581	1,308	28	4	1,312	29	0.3%	0.3%	2.1	235
8/22	6	1,714	1,418	32	4	1,422	33	0.3%	0.3%	2.1	269
8/22	7	1,845	1,517	35	3	1,520	35	0.2%	0.2%	2.1	219
8/22	8	1,981	1,607	36	3	1,610	36	0.2%	0.2%	2.1	221
8/22	9	2,075	1,702	37	3	1,705	38	0.2%	0.2%	3.0	338
8/22	10	2,145	1,744	40	3	1,747	40	0.2%	0.2%	3.0	365
8/22	11	2,195	1,797	42	3	1,800	42	0.2%	0.2%	3.0	377
8/22	12	2,206	1,804	42	3	1,807	42	0.2%	0.2%	3.0	376
8/22	13	2,222	1,842	47	3	1,845	47	0.2%	0.2%	3.0	424
8/22	14	2,230	1,829	49	3	1,832	49	0.2%	0.2%	3.0	443
8/22	15	2,249	1,844	49	2	1,846	49	0.1%	0.1%	3.0	297
8/22	16	2,229	1,845	49	2	1,847	49	0.1%	0.1%	3.0	295
8/22	17	2,192	1,850	48	2	1,852	48	0.1%	0.1%	3.0	291
8/22	18	2,136	1,813	41	2	1,815	41	0.1%	0.1%	3.0	245
8/22	19	2,071	1,772	38	2	1,774	38	0.1%	0.1%	3.0	230
8/22	20	2,136	1,780	38	2	1,782	38	0.1%	0.1%	3.0	230
8/22	21	2,071	1,753	39	2	1,755	39	0.1%	0.1%	3.0	237
8/22	22	1,902	1,606	36	4	1,610	36	0.2%	0.2%	2.1	294
8/22	23	1,728	1,500	37	4	1,504	37	0.3%	0.3%	2.1	304
8/27	8	2,086	1,663	39	20	1,683	40	1.2%	1.2%	2.1	1,622
8/27	9	2,170	1,727	42	20	1,747	43	1.2%	1.2%	3.1	2,548
8/27	10	2,220	1,791	46	20	1,811	47	1.1%	1.1%	3.1	2,789
8/27	11	2,246	1,834	56	20	1,854	58	1.1%	1.1%	3.1	3,423
8/27	12	2,249	1,849	62	20	1,869	64	1.1%	1.1%	3.1	3,804
8/27	13	2,255	1,889	66	20	1,909	68	1.1%	1.1%	3.1	4,025
8/27	14	2,260	1,905	53	20	1,925	54	1.0%	1.0%	3.1	3,231
8/27	15	2,248	1,904	53	20	1,924	54	1.1%	1.1%	3.1	3,232
8/27	16	2,244	1,895	52	20	1,915	54	1.1%	1.1%	3.1	3,183
8/27	17	2,216	1,864	53	20	1,884	55	1.1%	1.1%	3.1	3,275
8/27	18	2,163	1,808	44	20	1,828	46	1.1%	1.1%	3.1	2,702
8/27	19	2,114	1,771	41	20	1,791	42	1.1%	1.1%	3.1	2,511
Hourly Avg.		1,995	1,624	66	5	1,629	67	0.3%	0.3%	3.7	1,641
Total		556,577	453,025		1,463	454,488					457,851

*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.

Table 1.3D. Hourly DADRP Payments for Scheduled DADRP Bids, Summer, 2001

Date	Hr.	Capital Program Payments ($)#	Date	Hr.	Western NY Program Payments ($)#
7/21	10	58	8/7	0	415
7/21	11	62	8/8	0	386
7/21	12	60	8/8	1	457
7/21	13	60	8/8	2	308
7/21	14	60	8/8	3	408
7/21	15	53	8/8	4	406
7/21	16	55	8/8	5	439
7/21	17	55	8/8	6	460
7/21	18	53	8/8	7	214
7/21	19	50	8/8	8	231
7/21	20	50	8/8	9	280
7/21	21	49	8/8	10	489
7/21	22	45	8/8	11	544
7/21	23	41	8/8	12	753
7/22	0	40	8/8	13	805
7/22	12	56	8/8	14	802
7/22	13	56	8/8	15	792
7/22	14	56	8/8	16	728
7/22	15	52	8/8	17	629
7/22	16	53	8/8	18	549
7/22	17	52	8/8	19	450
7/23	0	34	8/8	20	384
7/23	1	33	8/8	21	291
7/23	2	32	8/8	22	534
7/23	3	31	8/8	23	437
7/23	4	31	8/9	0	466
7/23	5	32	8/9	1	527
7/23	6	34	8/9	2	460
7/23	7	43	8/9	3	447
7/23	12	236	8/9	4	447
7/23	13	1,281	8/9	5	483
7/23	14	1,287	8/9	6	424
7/23	15	1,333	8/9	7	278
7/23	16	1,148	8/9	8	557
7/24	0	34	8/9	9	687
7/24	1	34	8/9	10	750
7/24	2	33	8/9	11	1,214
7/24	3	30	8/9	12	949
7/24	4	30	8/9	13	985
7/24	5	32	8/9	14	1,814
7/24	6	34	8/9	15	1,808
7/24	7	128	8/9	16	3,286
7/24	8	91	8/9	17	1,951
7/24	9	100	8/9	18	1,272
7/24	10	111	8/9	19	856
7/24	11	110	8/9	20	704
7/24	13	1,241	8/9	21	650
7/24	14	1,255	8/9	22	1,244
7/24	15	1,319	8/9	23	829
7/24	16	1,420	8/10	0	45
7/25	0	237	8/10	1	471
7/25	1	35	8/10	2	342
7/25	2	34	8/10	3	414
7/25	3	34	8/10	4	412
7/25	4	34	8/10	5	431
7/25	5	34	8/10	6	431
7/25	6	37	8/10	7	211
7/25	7	133	8/10	8	401
7/25	8	425	8/10	9	553
7/25	9	470	8/10	10	583
7/25	10	505	8/10	11	649
7/25	11	592	8/10	18	389
7/25	12	474	8/10	19	352
7/25	13	477	8/10	20	334
7/25	14	505	8/10	21	622
7/25	15	585	8/10	22	633
7/25	16	378	8/10	23	424
7/25	17	358	8/11	1	35
7/25	18	300	8/11	2	33
7/25	19	269	8/11	3	32

Table 1.3D. Hourly DADRP Payments for Scheduled DADRP Bids, Summer, 2001

Date	Hr.	Capital Program Payments ($)#	Date	Hr.	Western NY Program Payments ($)#
7/26	5	192	8/11	13	46
7/26	6	198	8/11	14	45
7/26	7	355	8/11	15	44
7/26	8	367	8/11	16	44
7/26	9	387	8/11	17	44
7/26	10	395	8/11	18	42
7/26	11	432	8/11	19	41
7/26	12	255	8/11	20	41
7/26	13	256	8/11	21	40
7/26	14	256	8/11	22	38
7/26	15	101	8/11	23	37
7/26	16	103	8/12	0	278
7/26	17	100	8/12	7	30
7/26	18	90	8/12	8	34
7/26	19	85	8/12	9	36
7/26	20	43	8/12	10	36
7/26	21	43	8/12	11	39
7/26	22	41	8/12	12	39
7/26	23	39	8/12	13	39
7/27	0	63	8/12	14	40
7/27	1	61	8/12	15	39
7/27	2	53	8/12	16	40
7/27	3	54	8/12	17	40
7/27	4	54	8/12	18	39
7/27	5	57	8/12	19	40
7/27	6	65	8/12	20	41
7/27	7	73	8/12	21	41
7/27	8	81	8/12	22	39
7/27	9	87	8/12	23	37
7/27	10	89	8/13	22	341
7/27	11	91	8/13	23	330
7/27	12	99	8/14	0	257
7/27	13	99	8/15	0	281
7/27	14	103	8/15	1	226
7/27	15	99	8/15	2	173
7/27	16	94	8/15	3	212
7/27	17	96	8/15	4	212
7/27	18	90	8/15	5	222
7/27	19	83	8/15	6	295
7/27	20	81	8/15	7	146
7/27	21	80	8/15	8	155
7/27	22	77	8/15	9	161
7/27	23	72	8/15	10	176
7/28	0	77	8/15	11	187
7/28	1	67	8/15	12	188
7/28	2	65	8/15	13	194
7/28	3	62	8/15	14	205
7/28	4	62	8/15	15	163
7/28	5	57	8/15	16	152
7/28	6	58	8/15	17	150
7/28	7	66	8/15	18	134
7/28	8	76	8/15	19	122
7/28	9	81	8/15	20	120
7/28	10	87	8/15	21	245
7/28	11	88	8/15	22	375
7/28	12	93	8/15	23	287
7/28	13	92	8/16	0	324
7/28	14	94	8/16	1	307
7/28	15	94	8/16	2	235
7/28	16	94	8/16	3	261
7/28	17	95	8/16	4	261
7/28	18	92	8/16	5	308
7/28	19	83	8/16	6	323
7/28	20	88	8/16	7	150
7/28	21	92	8/16	8	157
7/28	22	80	8/16	9	159
7/28	23	73	8/16	10	175
7/29	1	65	8/16	11	185
7/29	2	60	8/16	12	200
7/29	3	54	8/16	13	222
7/29	4	50	8/16	14	230
7/29	5	49	8/16	15	178
7/29	6	47	8/16	16	179
7/29	7	57	8/16	17	173
7/29	8	68	8/16	18	138

Table 1.3D. Hourly DADRP Payments for Scheduled DADRP Bids, Summer, 2001

Date	Hr.	Capital Program Payments ($)#	Date	Hr.	Western NY Program Payments ($)#
7/29	9	73	8/16	19	128
7/29	10	80	8/16	20	125
7/29	11	86	8/16	21	269
7/29	12	88	8/16	22	372
7/29	13	87	8/16	23	303
7/29	14	87	8/17	0	32
7/29	15	87	8/17	1	376
7/29	16	89	8/17	2	236
7/29	17	94	8/17	3	262
7/29	18	89	8/17	4	262
7/29	19	88	8/17	5	307
7/29	20	95	8/17	6	321
7/29	21	96	8/17	7	183
7/29	22	87	8/17	8	194
7/29	23	72	8/17	9	198
8/2	11	508	8/17	10	235
8/2	12	506	8/17	11	189
8/2	13	480	8/17	12	247
8/2	14	485	8/17	13	276
8/2	15	485	8/17	14	279
8/2	16	486	8/17	15	172
8/3	10	507	8/17	16	171
8/3	11	587	8/17	17	147
8/3	12	550	8/17	18	139
8/3	13	602	8/17	19	125
8/3	14	603	8/17	20	124
8/3	15	603	8/17	21	206
8/3	16	603	8/17	22	325
8/3	17	584	8/17	23	261
8/5	0	72	8/18	0	283
8/6	0	86	8/18	1	31
8/6	1	76	8/18	2	28
8/6	2	69	8/18	3	25
8/6	3	68	8/18	4	24
8/6	4	68	8/18	5	24
8/6	5	78	8/18	6	24
8/6	6	83	8/18	7	31
8/6	7	92	8/18	8	34
8/6	8	110	8/18	9	37
8/6	9	116	8/18	10	41
8/6	10	141	8/18	11	48
8/6	11	164	8/18	12	47
8/6	12	161	8/18	13	47
8/6	13	172	8/18	14	46
8/6	14	172	8/18	15	42
8/6	15	196	8/18	16	44
8/6	16	196	8/18	17	44
8/6	17	173	8/18	18	42
8/6	18	165	8/18	19	40
8/6	19	156	8/18	20	41
8/6	20	145	8/18	21	40
8/6	21	125	8/18	22	39
8/6	22	101	8/18	23	34
8/6	23	87	8/19	0	208
8/7	0	264	8/19	1	204
8/7	1	72	8/19	2	186
8/7	2	73	8/19	3	184
8/7	3	73	8/19	4	182
8/7	4	73	8/19	5	180
8/7	5	75	8/19	6	179
8/7	6	82	8/19	18	121
8/7	7	102	8/19	19	119
8/7	8	123	8/19	20	121
8/7	9	511	8/19	21	121
8/7	10	596	8/19	22	264
8/7	11	688	8/19	23	237
8/7	12	676	8/20	1	222
8/7	13	749	8/20	2	212
8/7	14	750	8/20	3	179
8/7	15	748	8/20	4	180
8/7	16	748	8/20	5	222
8/7	17	736	8/20	6	240
8/7	18	222	8/20	7	114
8/7	19	194	8/20	8	121
8/7	20	187	8/20	9	127

Table 1.3D. Hourly DADRP Payments for Scheduled DADRP Bids, Summer, 2001

Date	Hr.	Capital Program Payments ($)#
8/8	11	1,490
8/8	12	1,710
8/8	13	3,671
8/8	14	3,684
8/8	15	4,051
8/8	16	3,814
8/8	17	1,476
8/8	18	1,040
8/8	19	745
8/8	20	757
8/8	21	271
8/8	22	232
8/8	23	103
8/9	0	98
8/9	1	92
8/9	2	88
8/9	3	85
8/9	4	85
8/9	5	92
8/9	6	89
8/9	7	150
8/9	8	298
8/9	9	372
8/9	10	403
8/9	11	663
8/9	12	3,097
8/9	13	3,174
8/9	14	5,857
8/9	15	9,754
8/9	16	8,871
8/9	17	5,314
8/9	18	2,104
8/9	19	473
8/9	20	387
8/9	21	356
8/9	22	299
8/9	23	195
8/10	0	96
8/10	1	83
8/10	2	81
8/10	3	80
8/10	4	80
8/10	5	83
8/10	6	83
8/10	7	288
8/10	8	549
8/10	9	754
8/10	10	803
8/10	11	926
8/10	12	1,019
8/10	13	532
8/10	14	551
8/10	15	593
8/10	16	525
8/10	17	423
8/10	18	366
8/10	19	306
8/10	20	246
8/10	21	241
8/10	22	154
8/10	23	101
8/11	0	81
8/11	1	75
8/11	2	70
8/11	3	69
8/11	4	69
8/11	5	69
8/11	6	68
8/11	7	78
8/11	8	85
8/11	9	89
8/11	10	95
8/11	11	98
8/11	12	101
8/11	13	101

Date	Hr.	Western NY Program Payments ($)#
8/21	0	127
8/22	1	121
8/22	2	94
8/22	3	93
8/22	4	93
8/22	5	114
8/22	6	130
8/22	7	106
8/22	8	107
8/22	9	112
8/22	10	121
8/22	11	125
8/22	12	125
8/22	13	140
8/22	14	147
8/22	15	99
8/22	16	98
8/22	17	96
8/22	18	81
8/22	19	76
8/22	20	76
8/22	21	79
8/22	22	142
8/22	23	147
8/27	8	779
8/27	9	831
8/27	10	910
8/27	11	1,117
8/27	12	1,242
8/27	13	1,315
8/27	14	1,055
8/27	15	1,056
8/27	16	1,040
8/27	17	1,069
8/27	18	882
8/27	19	819

Table 1.3D. Hourly DADRP Payments for Scheduled DADRP Bids, Summer, 2001

Date	Hr.	Capital Program Payments ($)#	Date	Hr.	Western NY Program Payments ($)#
8/11	23	79			
8/12	1	58			
8/12	2	49			
8/12	3	47			
8/12	4	47			
8/12	5	48			
8/12	6	47			
8/12	7	65			
8/12	8	74			
8/12	9	78			
8/12	10	80			
8/12	11	85			
8/12	12	86			
8/12	13	86			
8/12	14	87			
8/12	15	86			
8/12	16	87			
8/12	17	88			
8/12	18	87			
8/12	19	88			
8/12	20	91			
8/12	21	91			
8/12	22	85			
8/12	23	78			
8/17	6	102			
8/17	7	117			
8/17	8	126			
8/17	9	129			
8/17	10	153			
8/17	11	194			
8/17	12	194			
8/21	6	106			
8/21	7	116			
8/21	8	122			
8/21	9	127			
8/22	12	44			
8/22	13	50			
8/22	14	52			
8/22	15	53			
8/23	12	44			
8/23	13	53			
8/23	14	52			
8/23	15	52			
Hourly Avg.		363	Hourly Avg.		298
Total		134,232	Total		83,255

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 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%