# Chapter 2 – Electricity Demand and Prices in New York

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

### *Characteristics of the Short-Run Electricity Supply Curves*

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

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

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

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

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

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

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

## Price Flexibilities in the DAM

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

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

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

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

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

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

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

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

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

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

## Price Flexibilities in the RTM

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

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

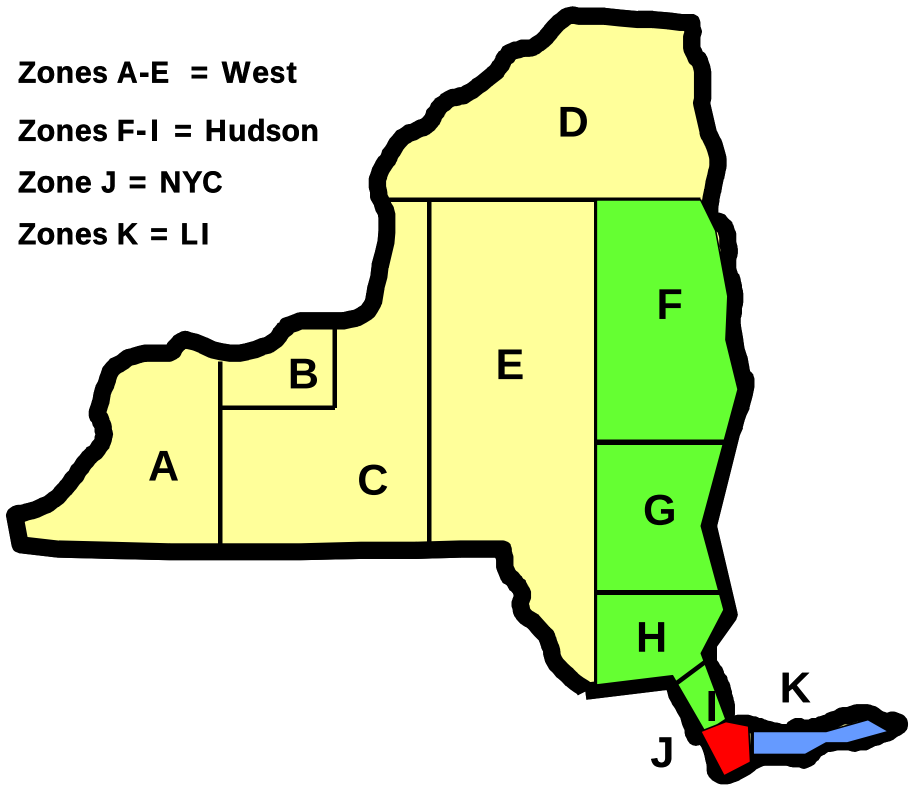
Consistent with these results, the average price flexibility in the new Capital-Hudson Region averaged 2.54 in 2003 (Chart 2.8 and Table 2-5A, Zones A, B, C, D, and E, Average column). This is half of the average value for the average of the two separate estimates for the Capital and Hudson River Regions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

## Some Conclusions

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

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

# Figure 2.1: Estimated Price Flexibility Zones



# Figure 2.2: Scatter Diagram of LBMP vs. Load

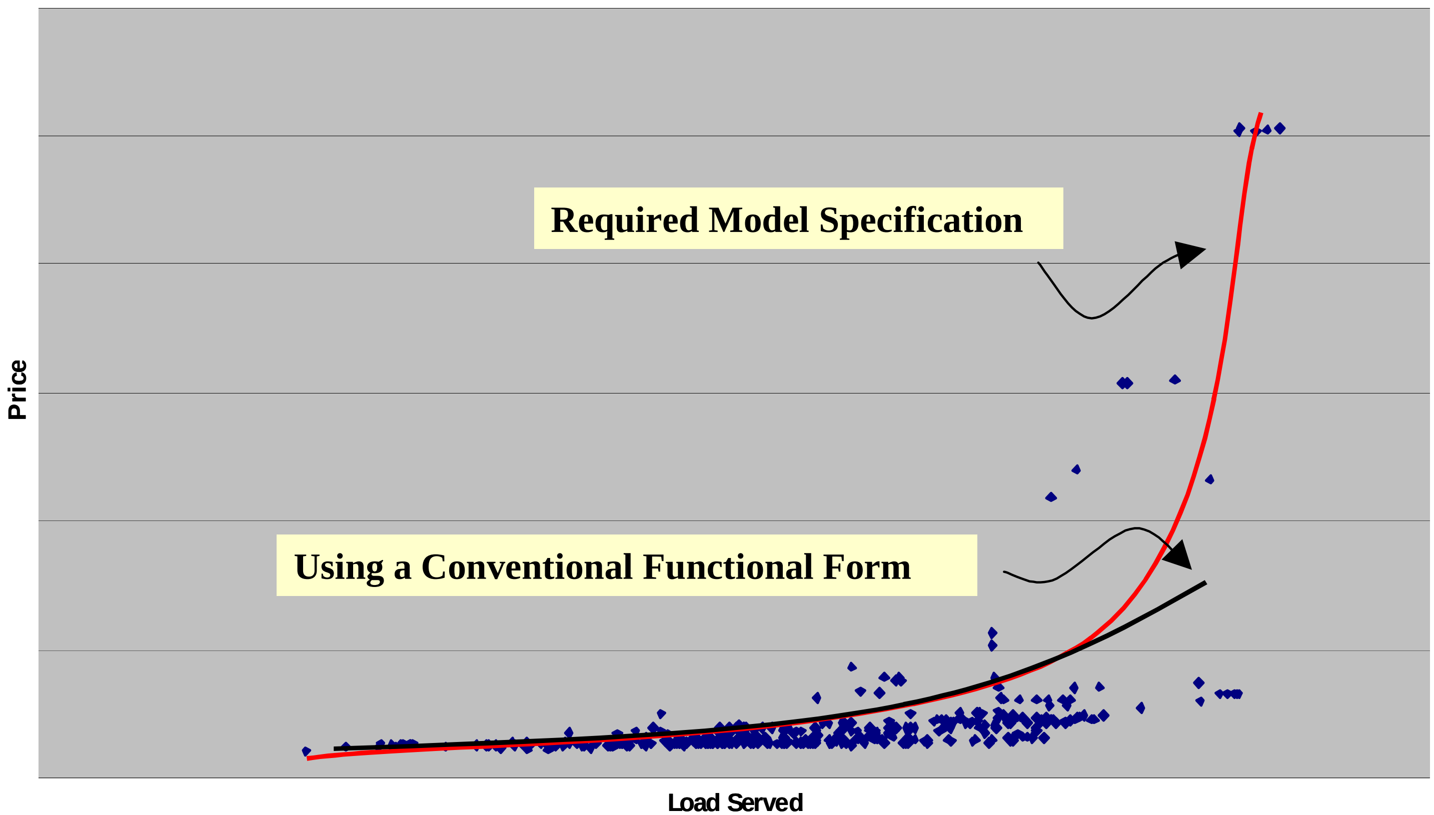
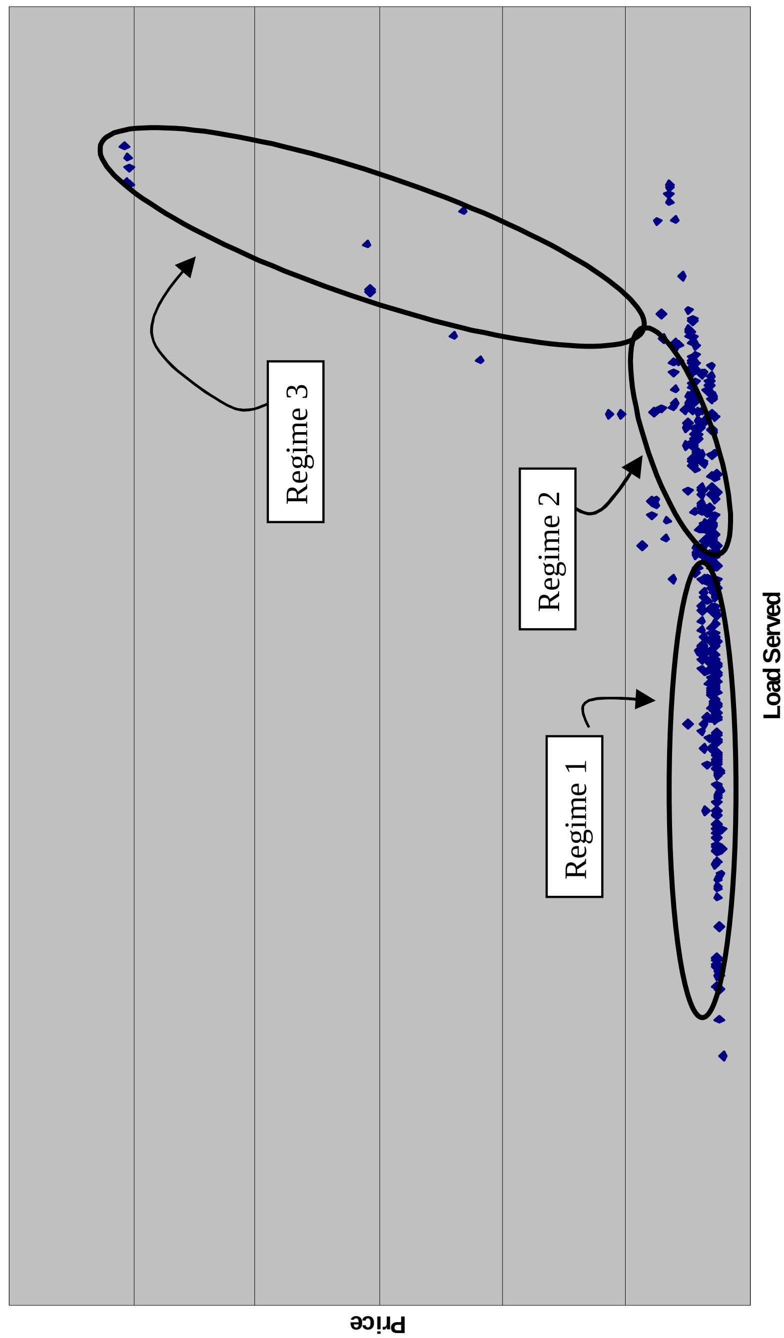


**Figure 2.3: Different Supply Regimes**



# Figure 2.4: “Spline” Model Specification

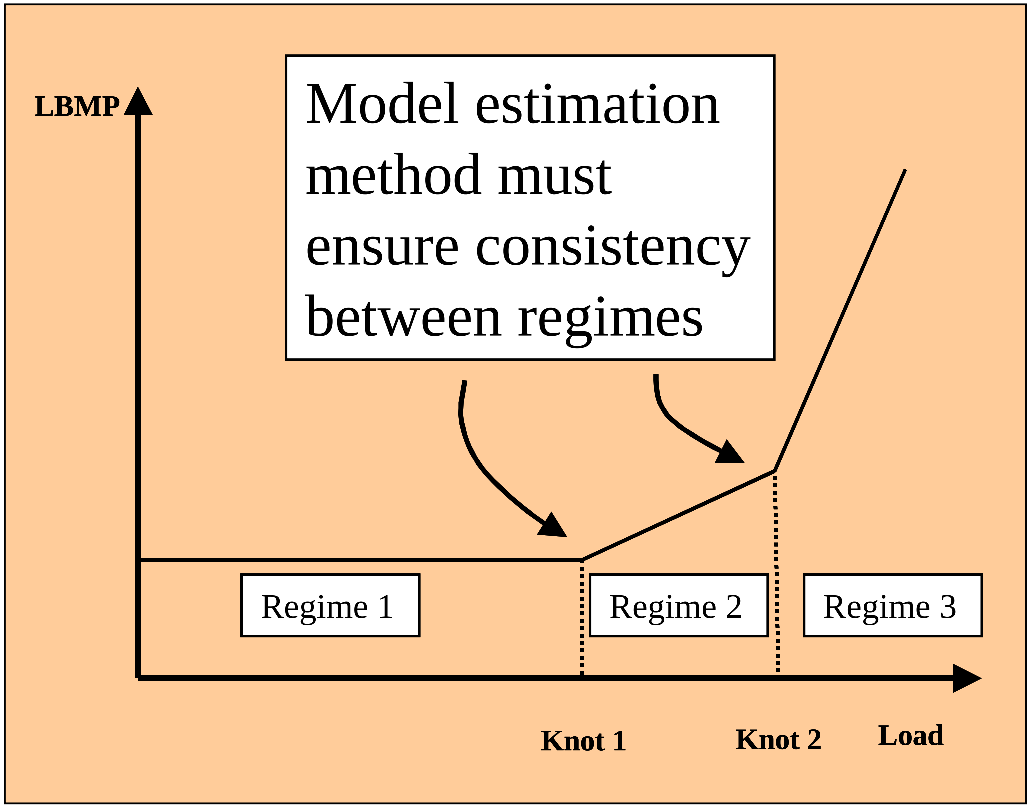
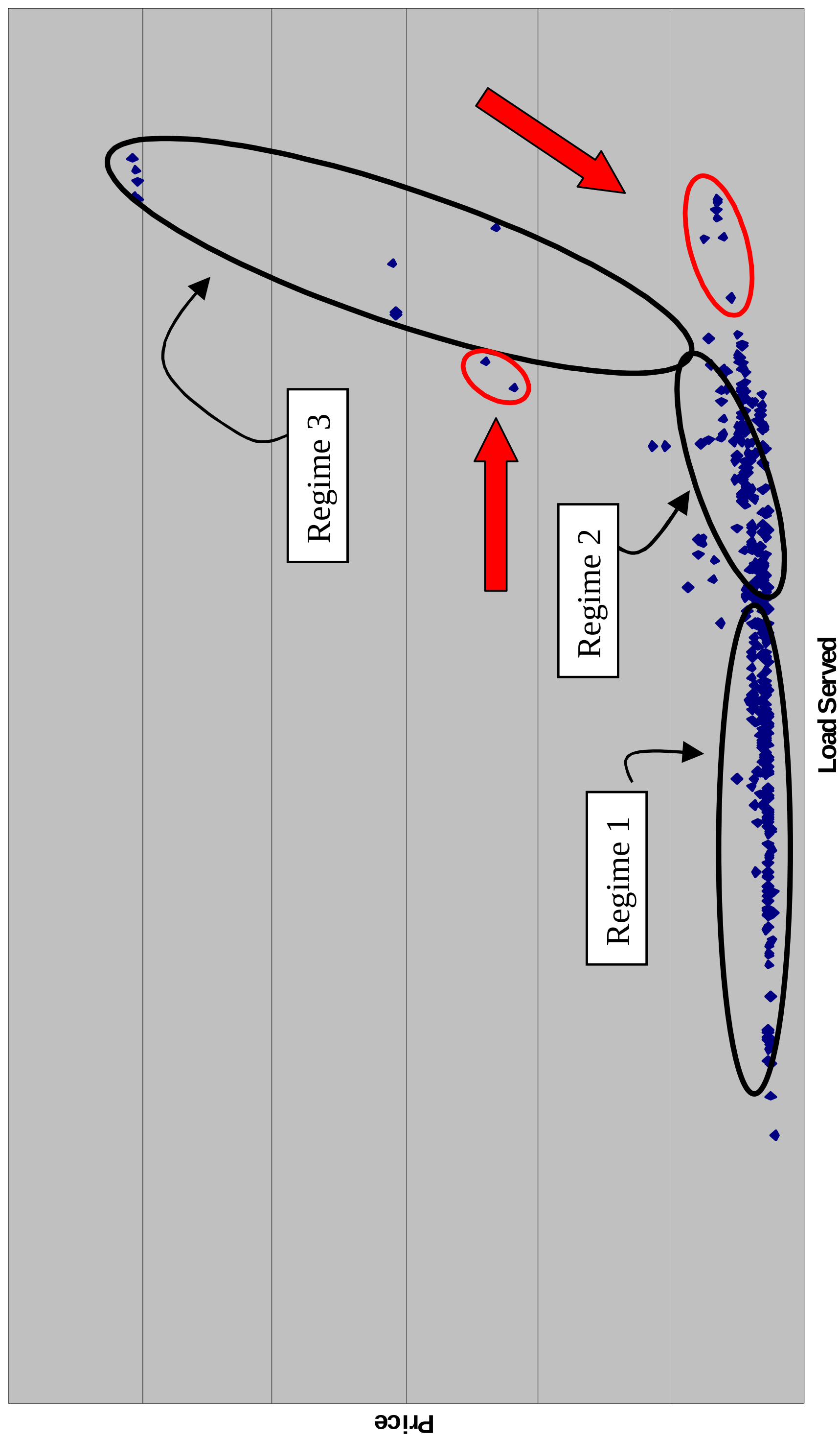
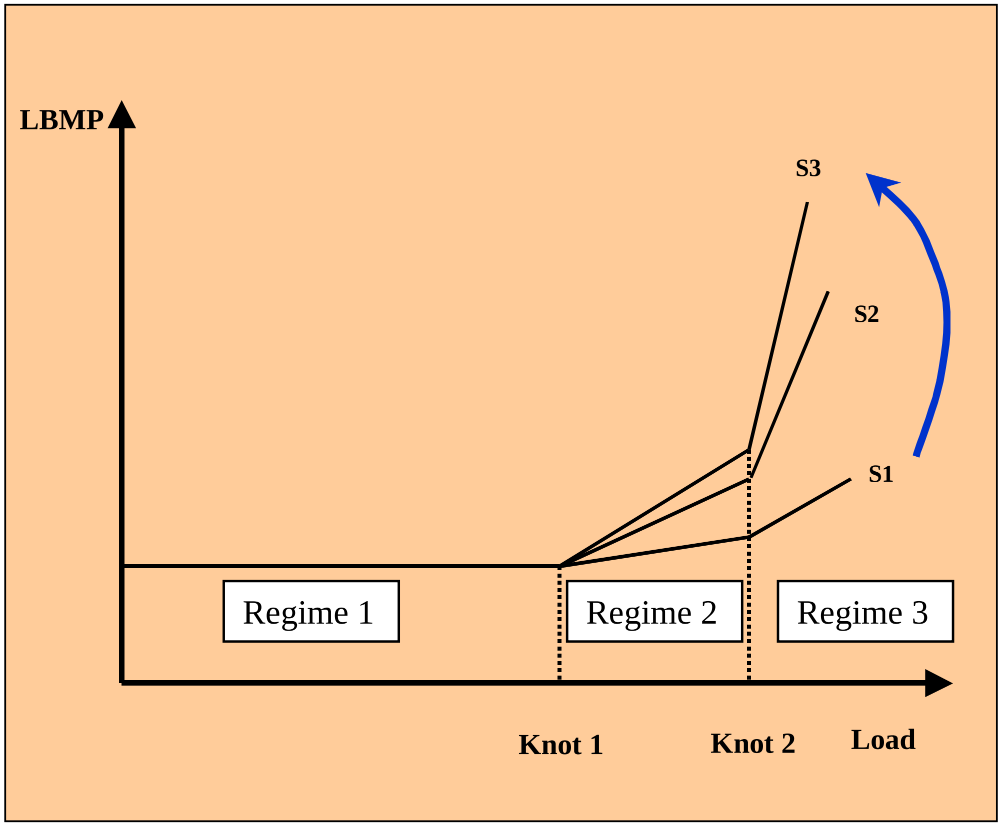


**Figure 2.5: Modeling Apparent Outliers**



# Figure 2.6: Final Model Specification




Supply Shift due to:

•Transmission Constraints,

•Generator Availability,

•Demand in Adjacent Zones,

•Others

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

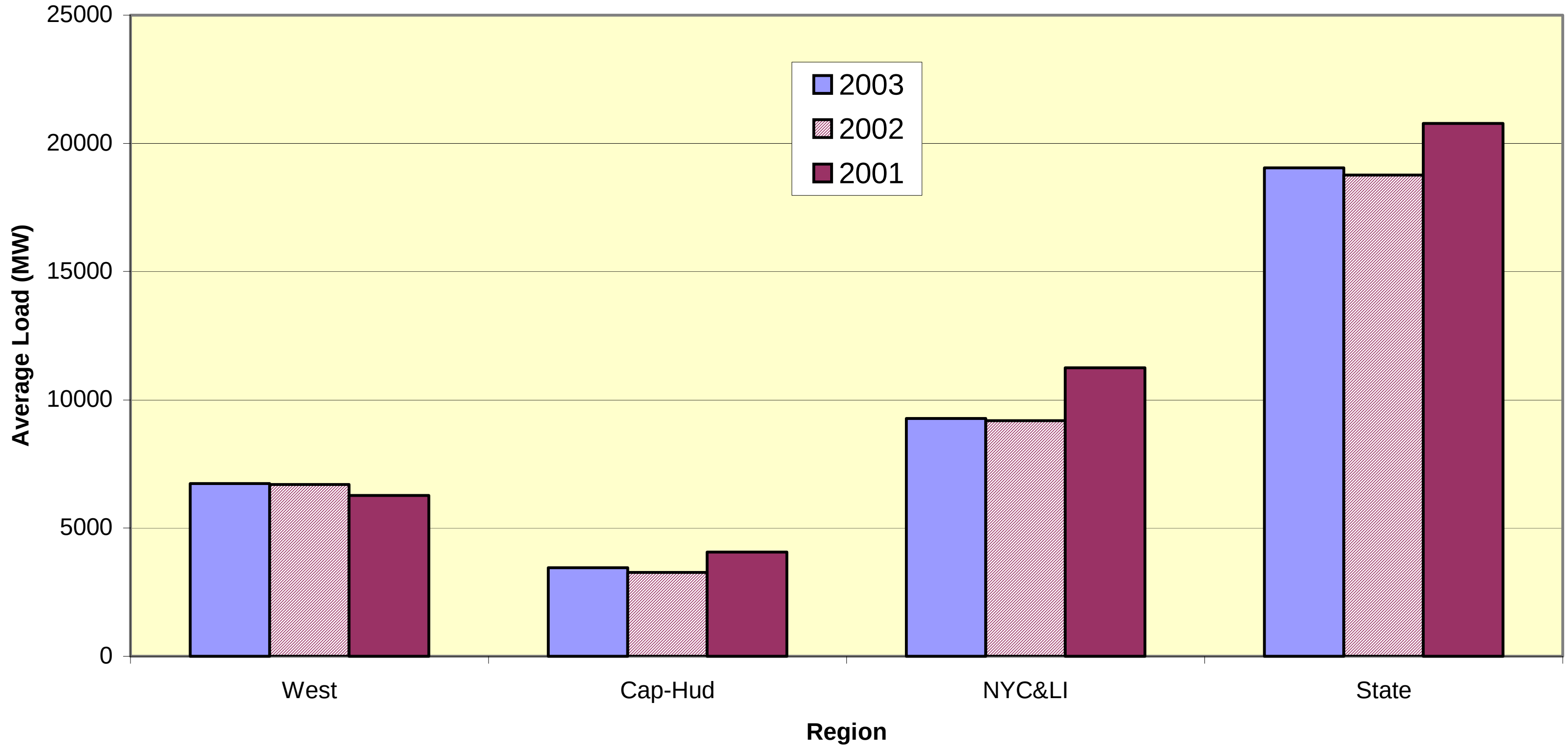


**Chart 2.2: Average Load in New York's Real Time Electricity Market, by Region and Year (Summer Months, noon through 7:00pm)**

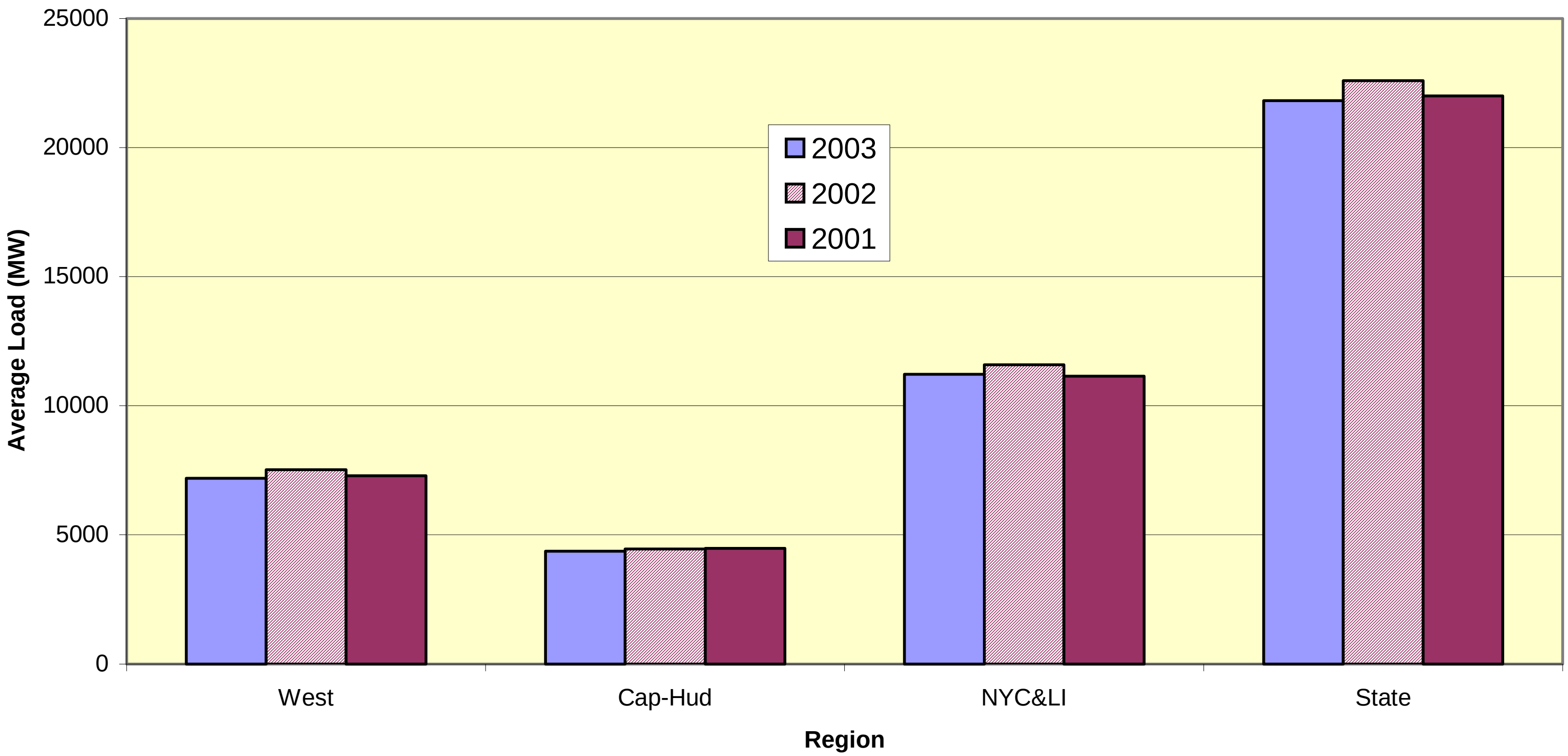


**Chart 2.3: Average LBMPs in New York's Day-Ahead Electricity Market, by Region and Year**
**(Summer Months, noon through 7:00pm)**

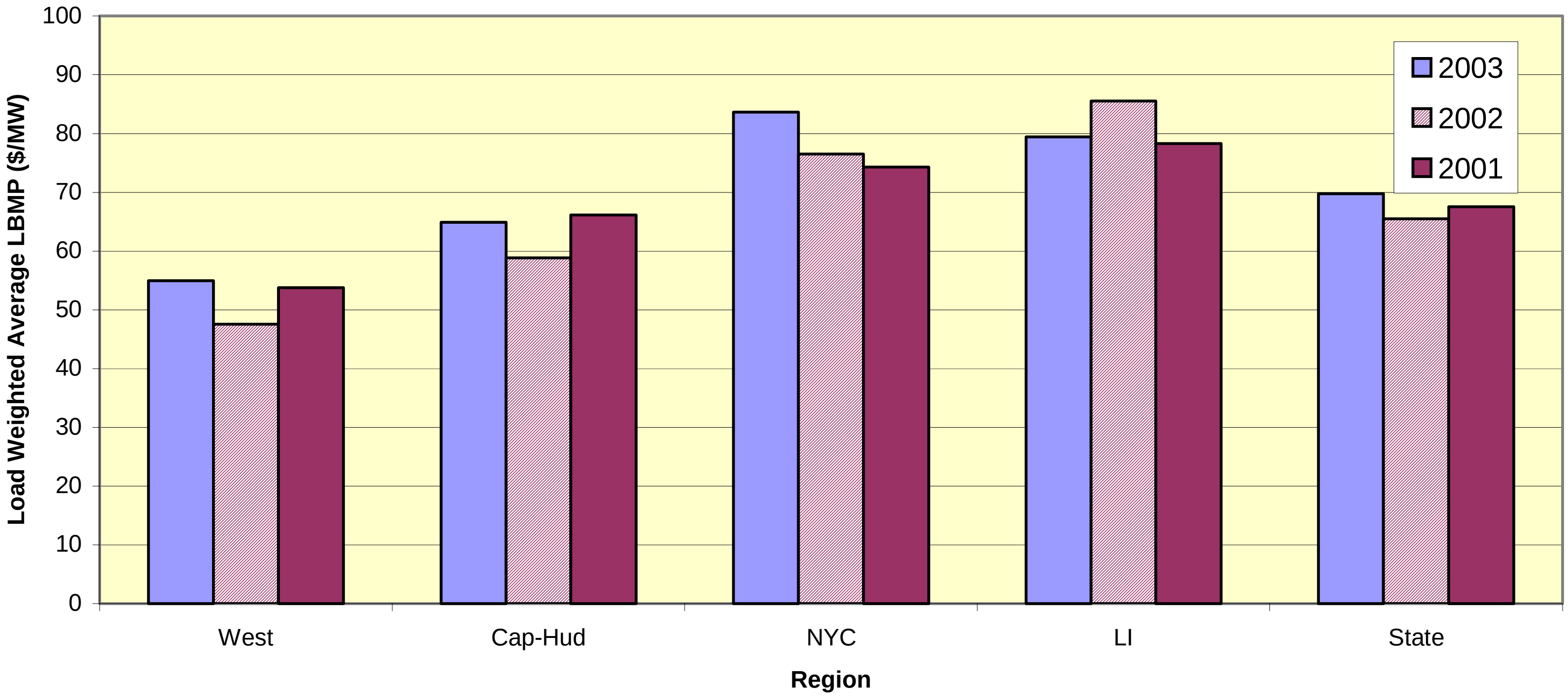


**Chart 2.4: Average LBMPs in New York's Real Time Electricity Market, by Region and Year (Summer Months, noon through 7:00pm)**

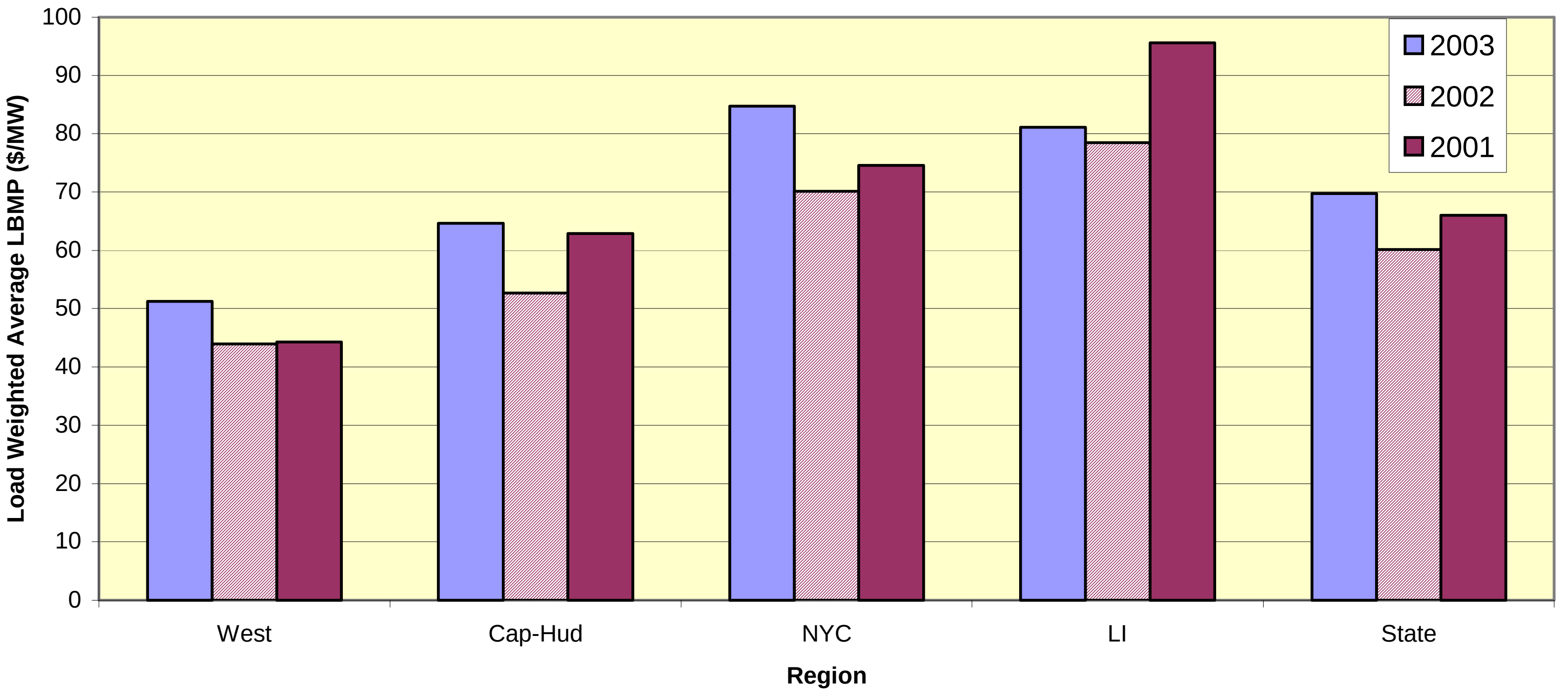


**Chart 2.5: Relative Variability in LBMPs in New York's Day-Ahead Electricity Market, by Region and Year (Summer Months, noon through 7:00pm)**

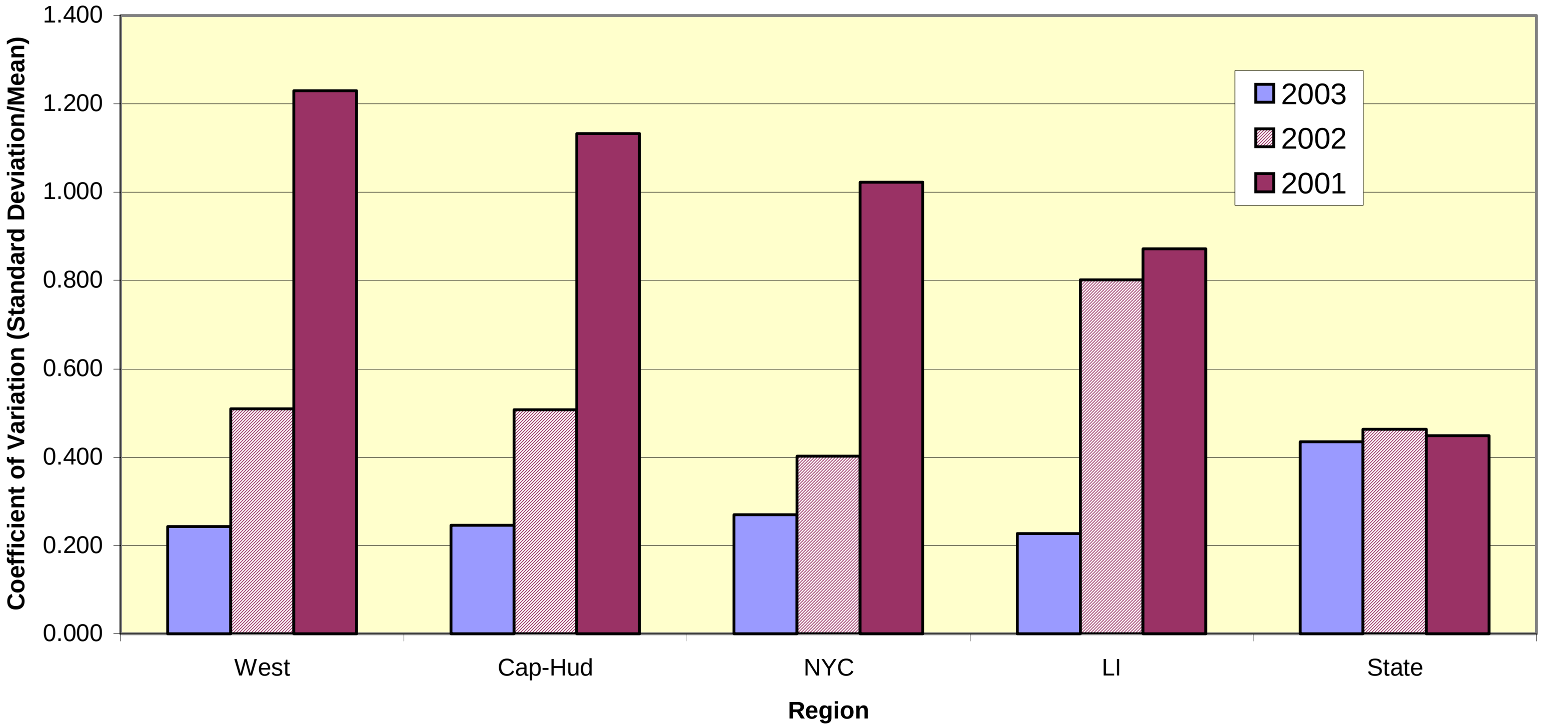


**Chart 2.6: Relative Variability in LBMPs in New York's Real Time Electricity Market, by Region and Year (Summer Months, noon through 7:00pm)**

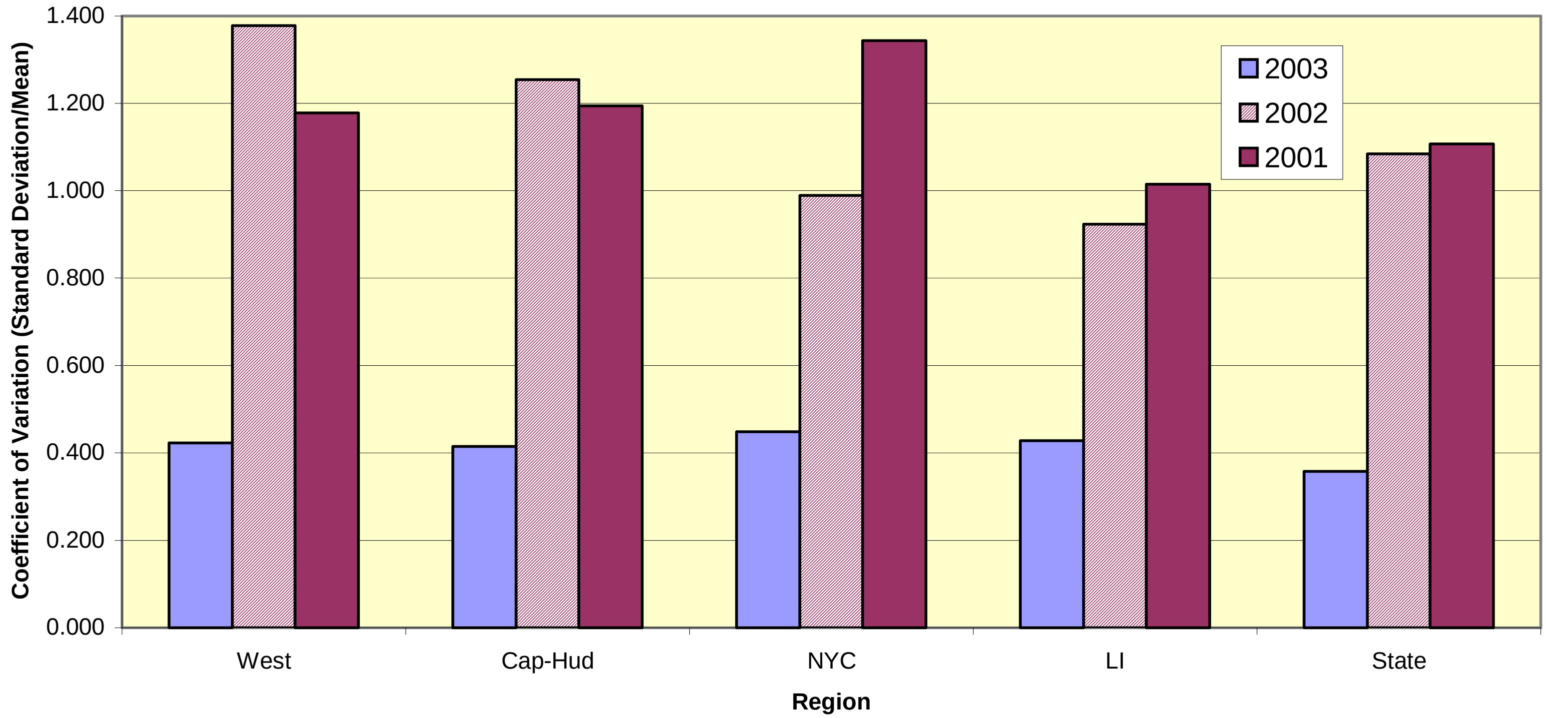
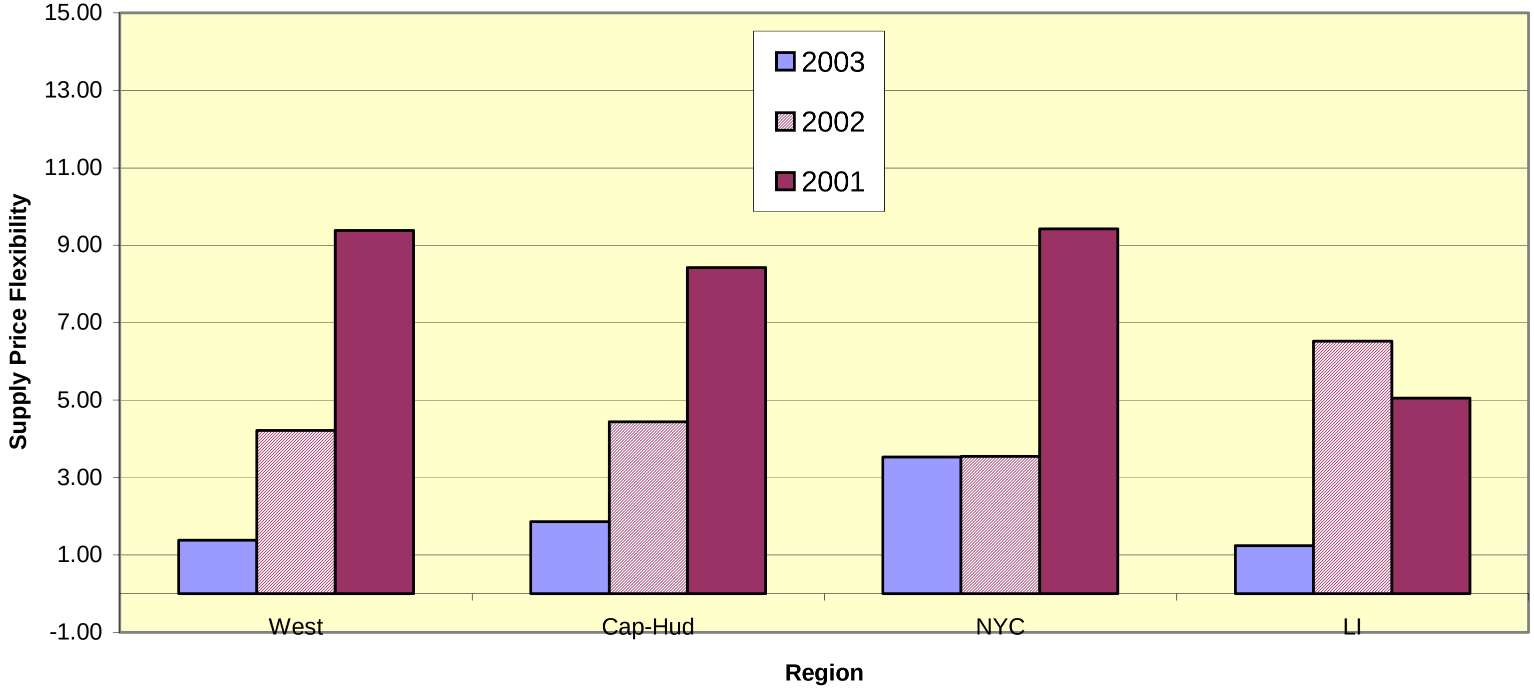


**Chart 2.7: Supply Price Flexibilities in the New York Day-Ahead Market for Electricity, by Region and Year**



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

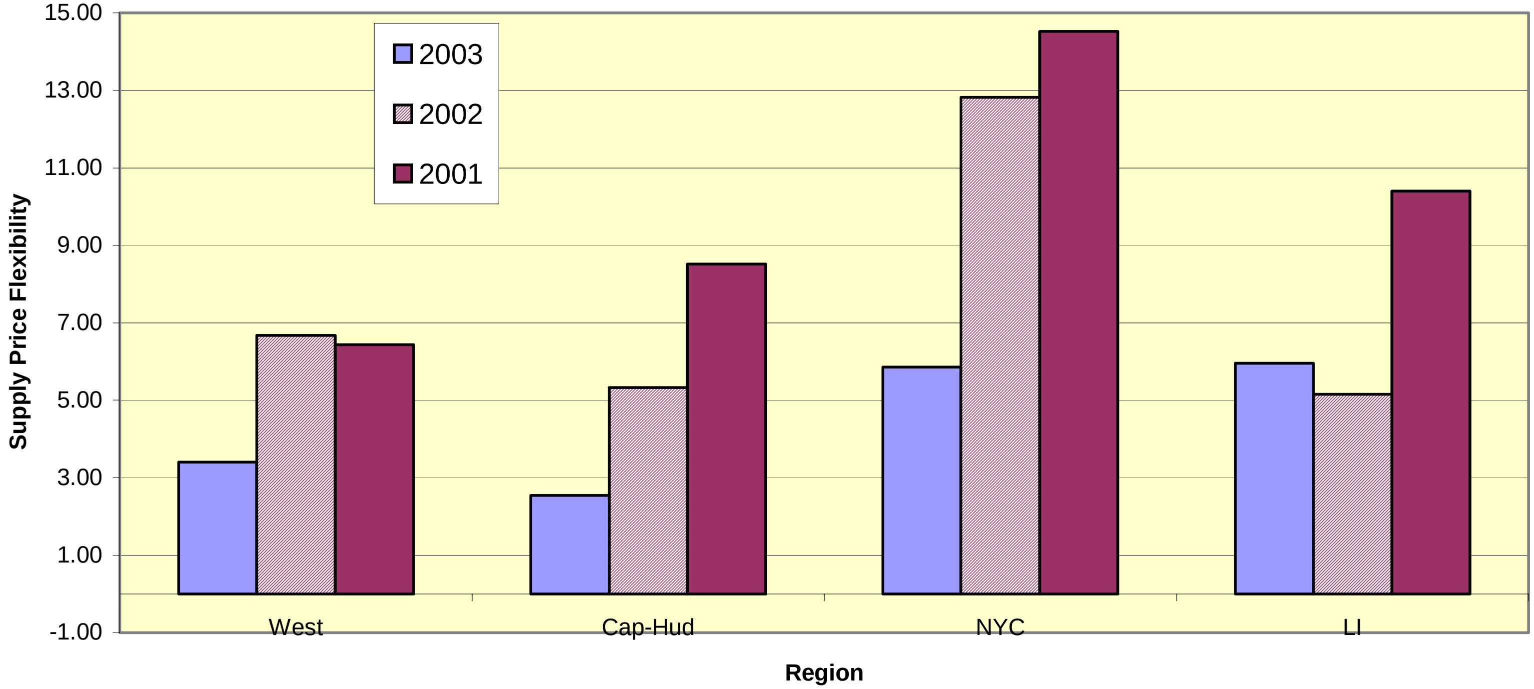


**Table 2-1A. Summary Data for Hourly LBMP and Load by Zonal Aggregates for Which Separate Supply Functions are Estimated (Summer 2003, Afternoon Hours) ***

| | | West of Total East (Zones A, B, C, D & E) | | |
|---|---|---|---|---|
| Statistic | DAM Bid Load (MW) | DAM LBMP ($/MW) | RT Load (MW) | RT LBMP ($/MW) |
| Maximum | 8,436 | $127 | 8,943 | $242 |
| Mean | 6,735 | $55 | 7,185 | $51 |
| Minimum | 5,071 | $35 | 4,041 | $0 |
| Standard Deviation | 780 | $13 | 829 | $22 |
| Coefficient of Variation | 0.12 | 0.24 | 0.12 | 0.42 |

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

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

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

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

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

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

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

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

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

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

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

**New York City (Zones J)**

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

**Long Island (Zone K)**

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

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

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

**New York State (Zones A - K)**

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

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

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

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

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

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

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

**New York City (Zone J)**

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

**Long Island (Zone K)**

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

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

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

**New York State (Zones A - K)**

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

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

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

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

* In both 2001 and 2002, a supply curve for the Capital Zone was estimated. separately. In 2003, it was combined with the Hudson Super Zone.

+ There is only one knot in these supply models.

Note: Supply flexibilities for 2001 and 2002 are from Neenan Associates (2002, 2003).

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

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

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

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

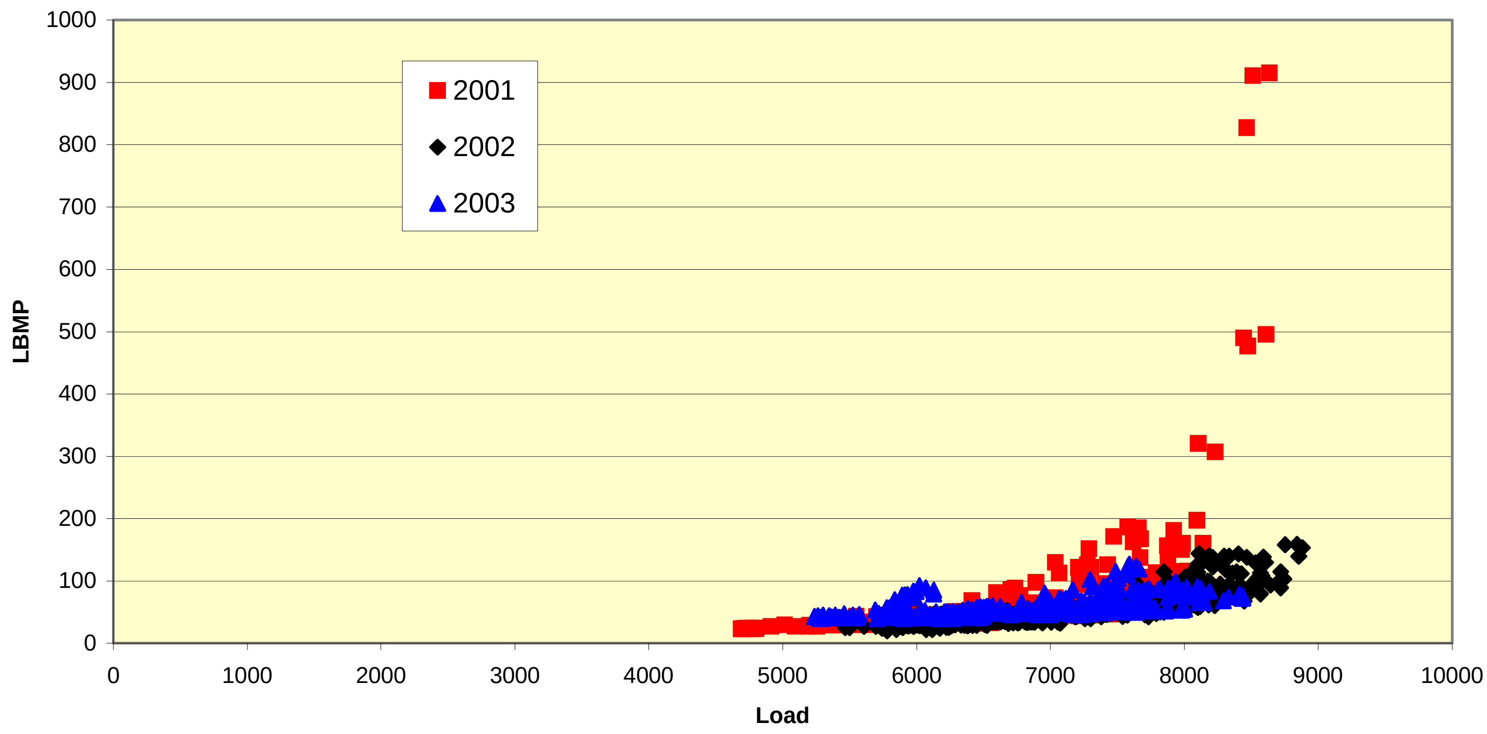


Figure 2-2B. Load vs. LBMP in the DAM, by Year, Capital and Hudson Region

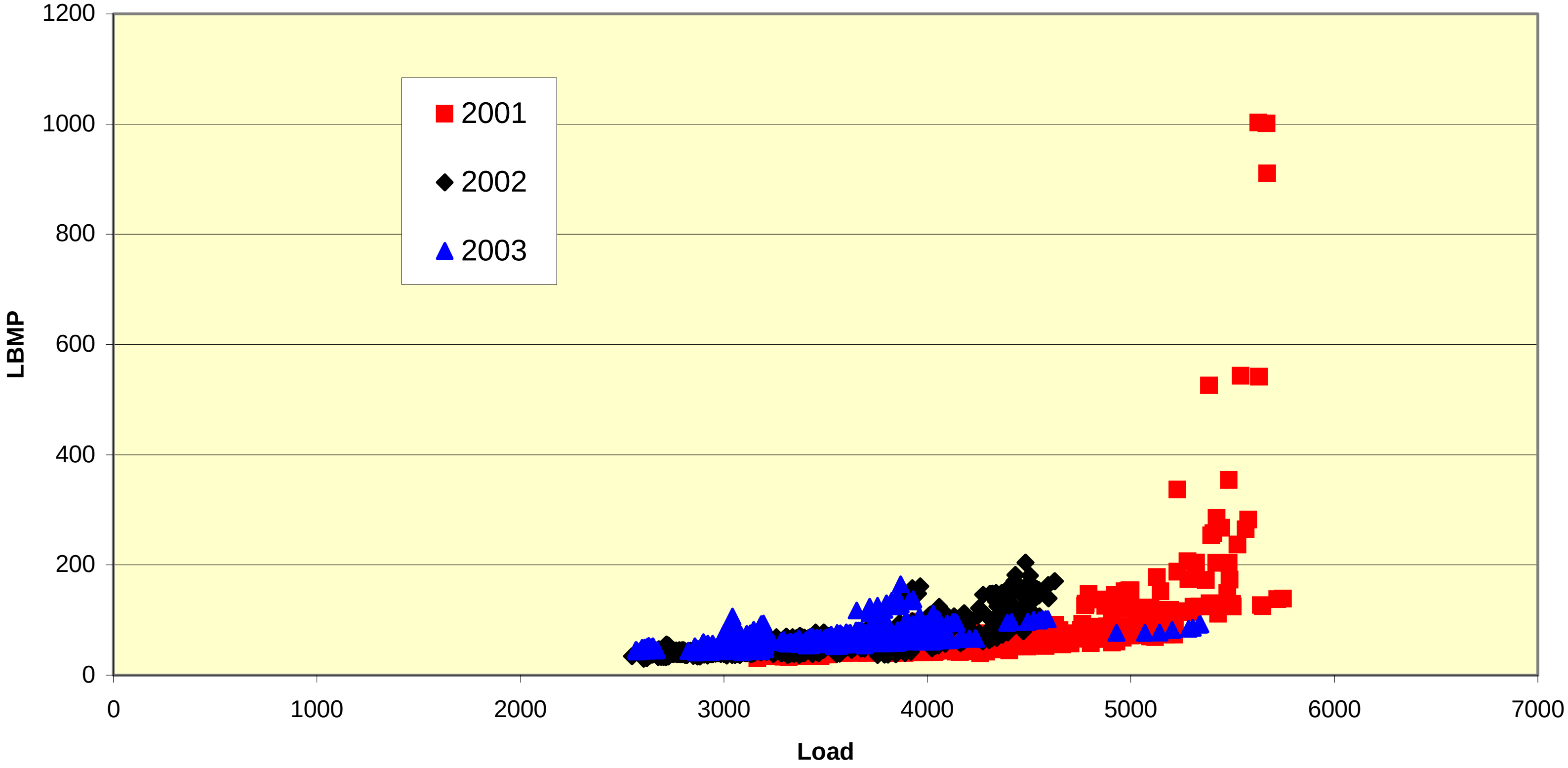


**Figure 2-3B. Load vs. LBMP in the DAM, by Year, New York City**

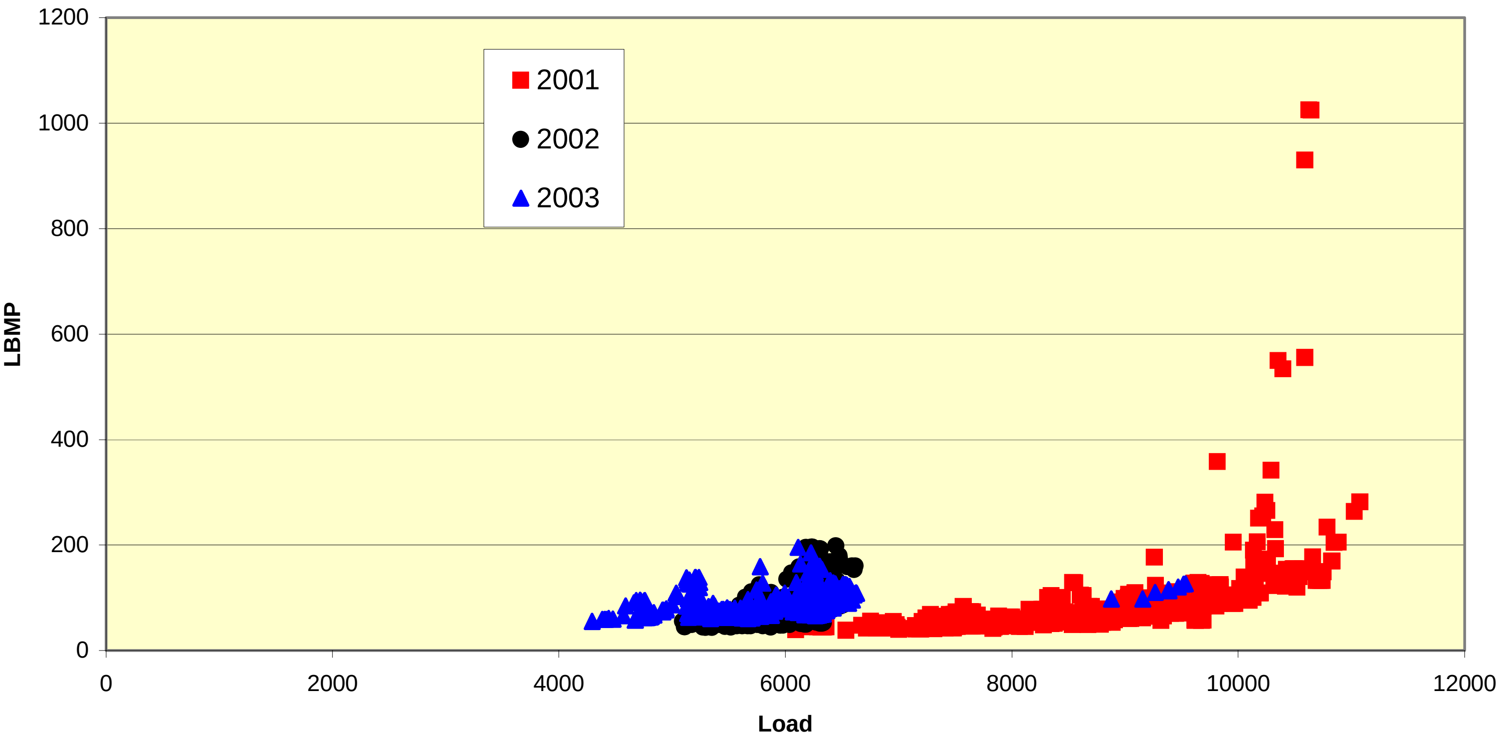


**Figure 2-4B. Load vs. LBMP in the DAM, by Year, Long Island**

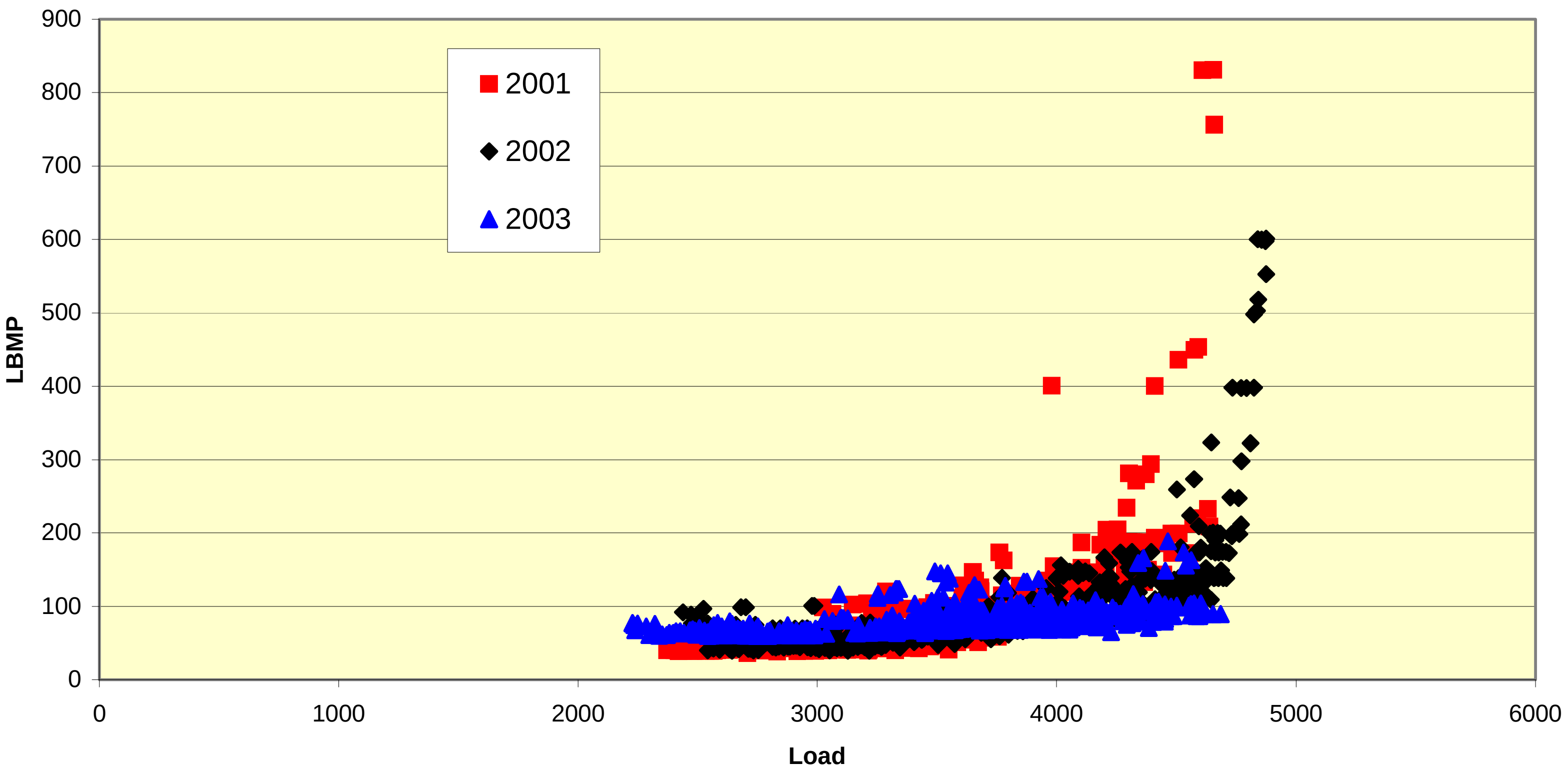


**Figure 2-5B. Load vs. LBMP in the RTM, by Year, Western New York**

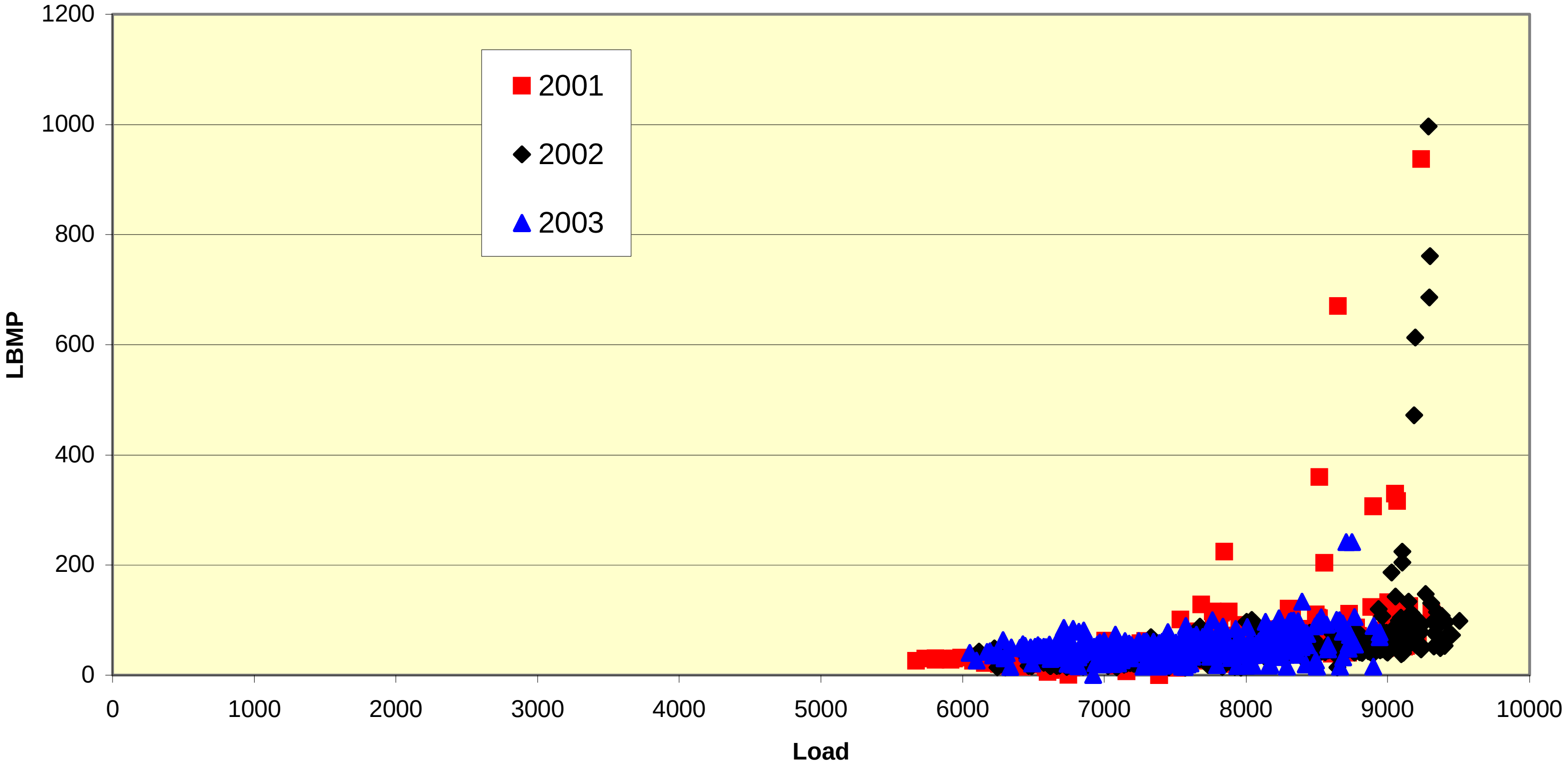


**Figure 2-6B. Load vs. LBMP in the RTM, by Year, Capital and Hudson Region**

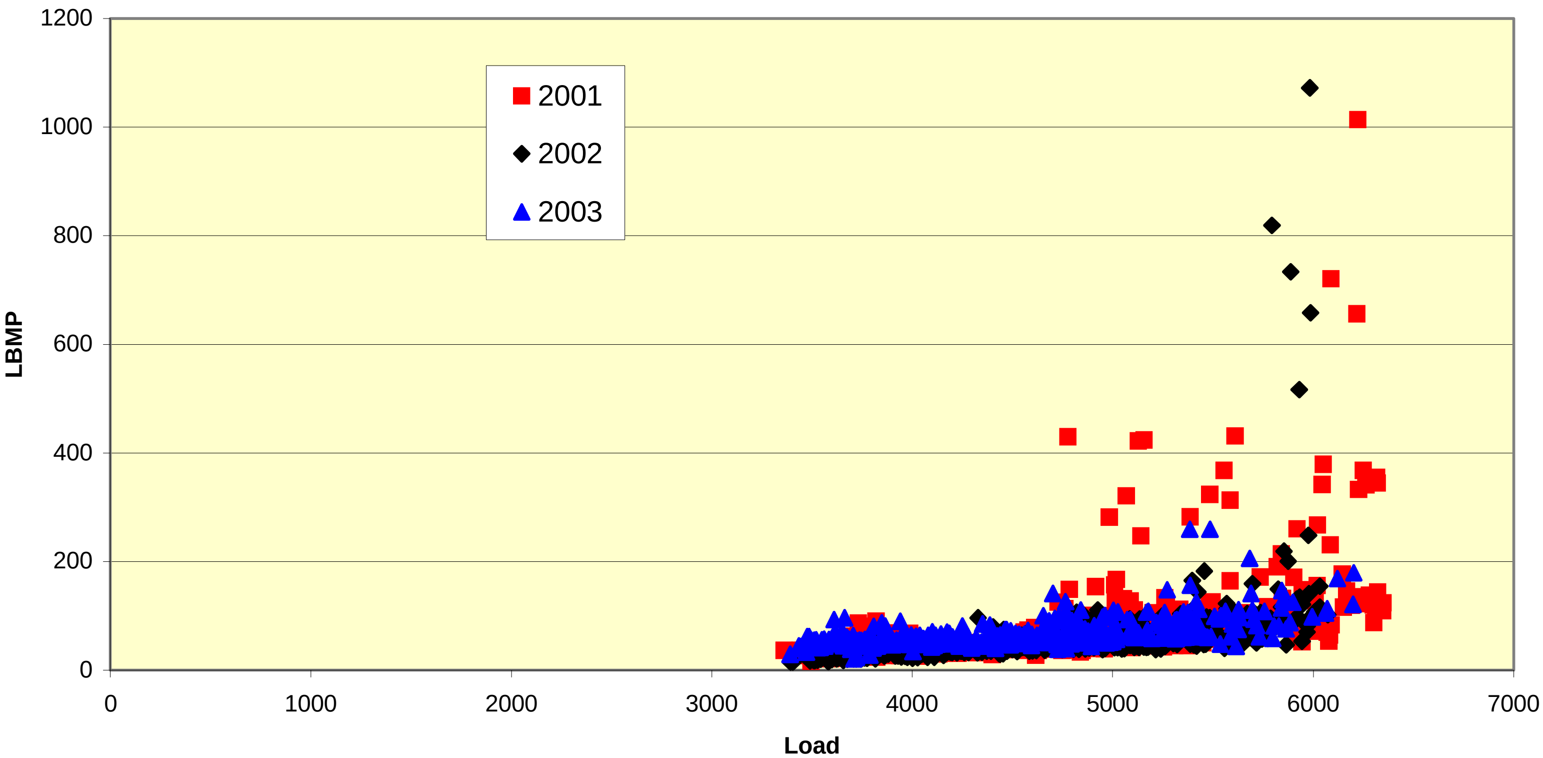


**Figure 2-7B. Load vs. LBMP in the RTM, by Year, New York City**

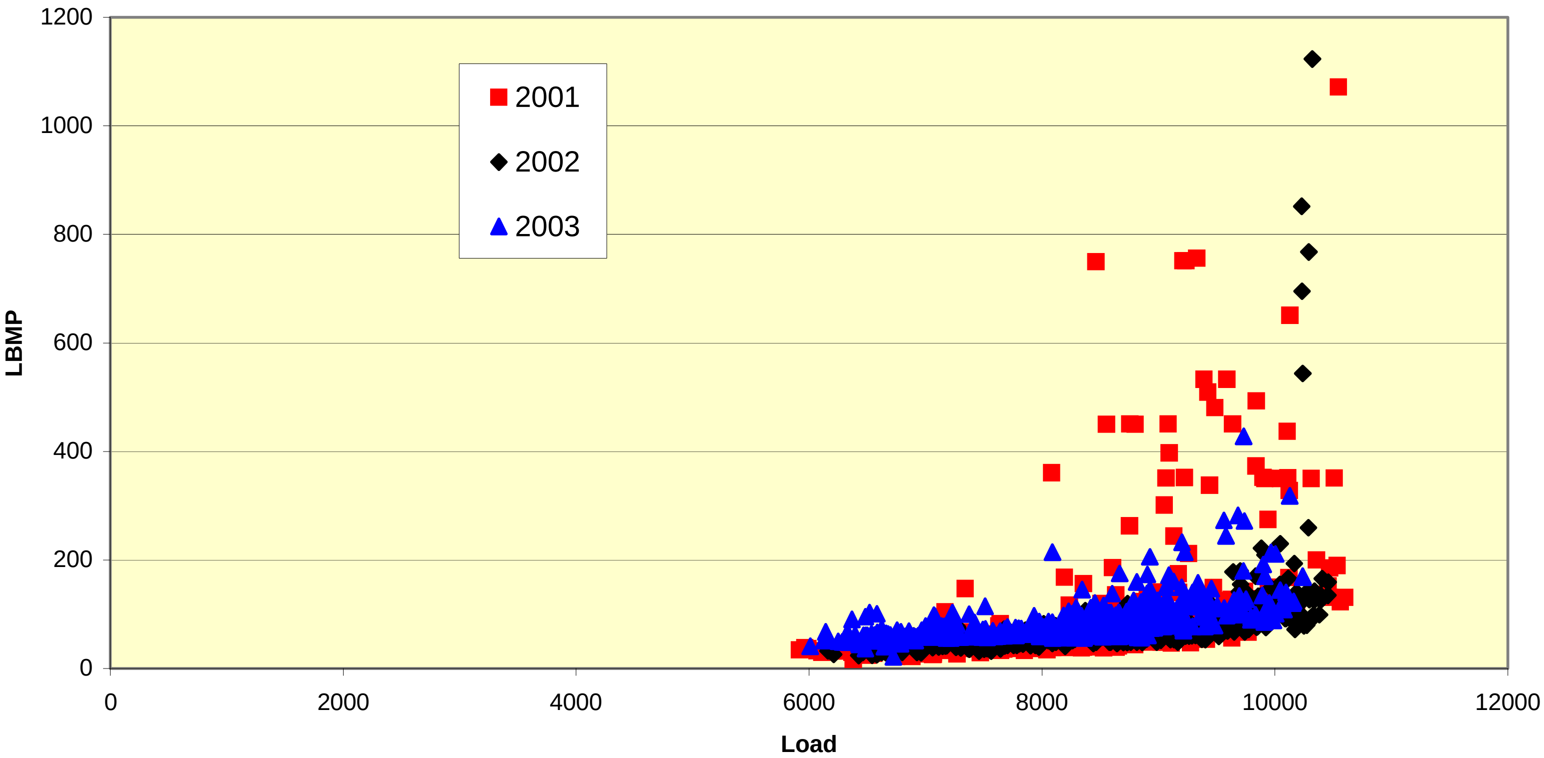
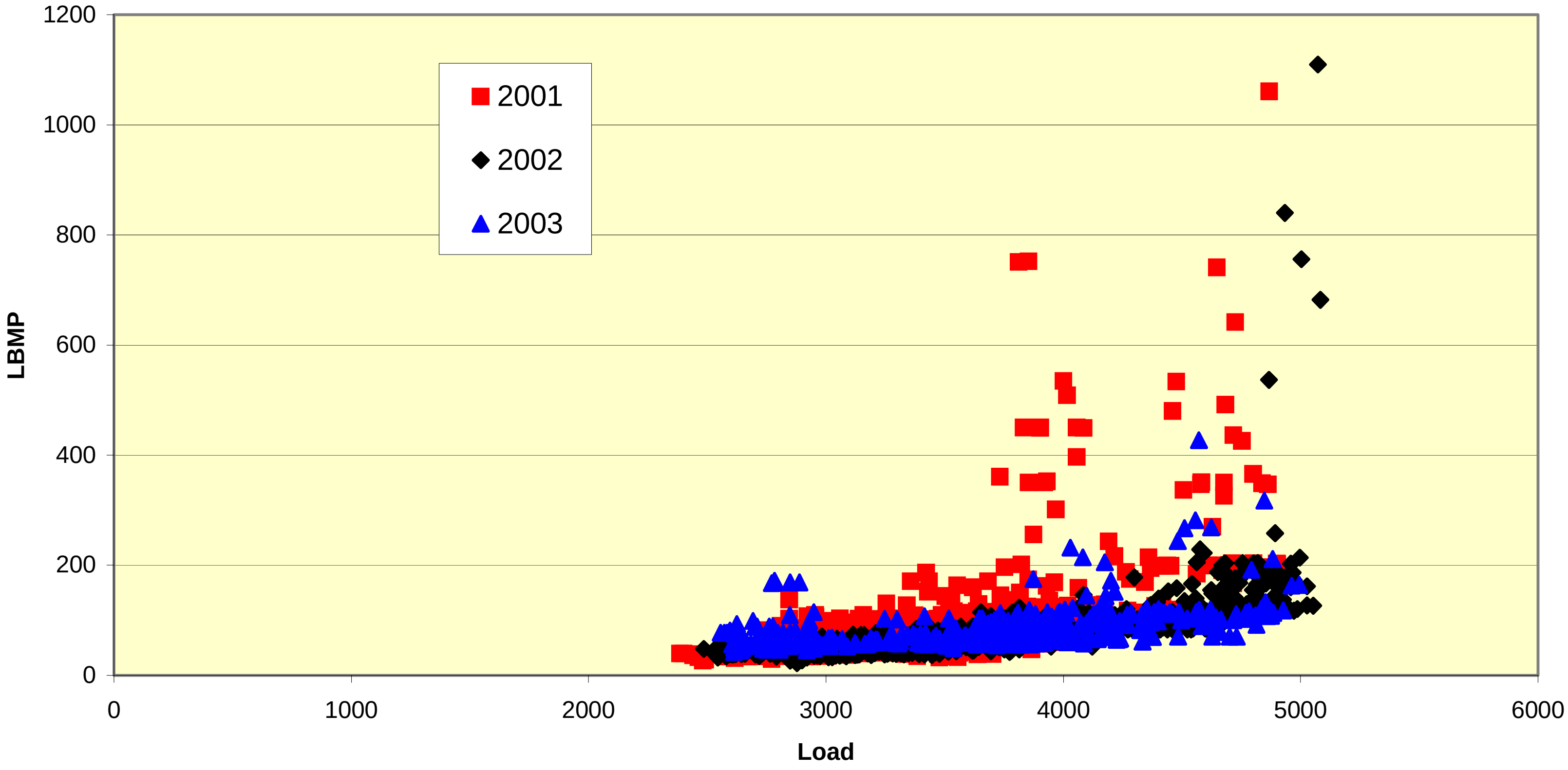


**Figure 2-8B. Load vs. LBMP in the RTM, by Year, Long Island**



# Appendix 2C – The Econometric Model of Supply

## *Introduction*

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

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

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

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

### *Equilibrium Price Determination*

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

### *The Econometric Model Specification for Short-Run Electricity Supply Relationships*

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

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

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

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

confidential load data available.

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

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

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

## Some Modeling Issues

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

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

### *The "Spline" Formulation of the Supply Curve*

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

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

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

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

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

## The Linear "Spline" Function

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

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

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

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

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

The resulting constrained regression (equation (C-4) subject to equations (C-5) and (C-6)) can be estimated by ordinary least squares (OLS), through simple variable transformations made possible by solving equations (C-5) and (C-6) for $\alpha_1$ and $\alpha_3$, and then substituting the results into equation (C-4). In this way, we eliminate all of the intercept terms except $\alpha_2$, and we are left with the following specification:

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

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

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

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

In the data, the three zero-one variables add to a vector of ones. Thus, the first term in equation (C-7) reduces to a standard intercept term in OLS. All parameters of the original model are identified from this regression, except for $\alpha_1$ and $\alpha_3$. These parameters are identified after the fact by using equations (C-5) and (C-6).

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

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

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

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

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

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

## A More Complex "Spline" Formulation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

## Introduction

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

## Estimates of the Short-Run Electricity Supply Curves

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

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

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

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

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

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

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

It is advisable to test for the existence of heteroscedasticity (the error terms are correlated with load), but this was problematic given the need to transform the variables for the "spline" formulation. General tests of heteroscedasticity, such as the White test which regresses the estimated squared error on a quadratic expression in all the explanatory variables, led to estimates of the variance-covariance matrix that were not of full rank. This was most likely due to the transformation of the variables needed to estimate the "spline" function. Thus, these tests were of little use.

Since load varies systematically over the afternoon hours, we also tested for auto-correlation in the error terms. If autocorrelation in present, then the error in the current hour is related to those in one or more previous hours, and again the OLS estimators remain unbiased, but are inconsistent. The test for autocorrelation is to regress the estimated squared error from the OLS regression in time t on the estimated errors in times t-1, ..., (t-k). To conduct these tests, it was necessary to assume that the same auto-regressive error structure exists from the evening of one day to the afternoon of the next as it does from hour to hour. There is no good way to test the validity of this assumption, but a similar assumption is often implicitly necessary in other electricity demand and supply studies when weekends are treated differently from weekdays. If the tests suggest autocorrelation is present, the model is essentially re-estimated using maximum likelihood (ML) methods. This procedure generates the appropriately estimated variance-covariance matrix from which to calculate the standard errors of the coefficients and the t-ratios. The tests for autocorrelation and the corrected estimates of the models were performed using PROC AUTOREG in SAS.

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

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

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

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

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

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

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

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

### *Supply Price Flexibilities*

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

## Supply Price Flexibilities in the DAM, Summer 2003

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

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

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

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

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

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

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

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

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

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

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

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

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

**Supply Price Flexibilities in the DAM, Winter/Spring 2003**

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

**Supply Price Flexibilities in the DAM, Summer 2003**

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

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

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

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

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

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

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

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

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

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

**Supply Price Flexibilities in the RTM, Winter/Spring 2003**

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

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

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

| | The Segments of the "Spline" Supply Function | | | | | |
|---|---|---|---|---|---|---|
| | Segment 1 | | Segment 2 | | Segment 3 | |
| **Model Coefficients** | Coefficient | T-Ratio | Coefficient | T-Ratio | Coefficient | T-Ratio |
| Constant | | | -8.2167 | -1.1171 | | |
| Load | 0.5977 | 18.7443 | 1.2773 | 1.5631 | | |
| Wgt Constraints | | | | | | |
| Weather Index | | | 0.0006 | 11.3749 | | |
| Gas Price Index*** | | | | | | |
| Proportion of Gen Offered | | | -0.2414 | -27.8787 | | |
| Lagged Wgt. Constraints | | | | | | |
| Adjacent Zonal Load | | | | | | |
| Arch (0) | 0.0015 | 7.43 | | | | |
| Arch (1) | 0.7141 | 4.77 | | | | |
| Arch (2) | 0.0940 | 2.81 | | | | |
| $R^2$ = | 0.7190 | | | | | |
| | **Knots ( % of Maximum Load )** | | | | | |
| **Price Flexibilities**** | 90.0% | | 100.0% | | | |
| Minimum | 0.60 | | 1.38 | | | |
| Maximum | 0.60 | | 1.39 | | | |
| Mean | 0.60 | | 1.38 | | | |

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

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

| | The Segments of the "Spline" Supply Function | | | | | |
|---|---|---|---|---|---|---|
| | Segment 1 | | Segment 2 | | Segment 3 | |
| **Model Coefficients** | Coefficient | T-Ratio | Coefficient | T-Ratio | Coefficient | T-Ratio |
| Constant | | | -11.1713 | -3.8679 | | |
| Load | 0.5820 | 26.0754 | 1.7456 | 5.0340 | | |
| Wgt Constraints | | | | | | |
| Weather Index | | | 0.0007 | 15.5478 | | |
| Gas Price Index*** | | | | | | |
| Proportion of Gen Offered | | | -0.2723 | -30.7760 | | |
| Lagged Wgt. Constraints | | | | | | |
| Adjacent Zonal Load | | | | | | |
| Arch (0) | 0.0013 | 8.98 | | | | |
| Arch (1) | 1.0440 | 6.63 | | | | |
| Arch (2) | | | | | | |
| $R^2$ = | 0.6701 | | | | | |
| | **Knots ( % of Maximum Load )** | | | | | |
| **Price Flexibilities**** | 85.0% | | 100.0% | | | |
| Minimum | 0.58 | | 1.86 | | | |
| Maximum | 0.58 | | 1.86 | | | |
| Mean | 0.58 | | 1.86 | | | |

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

| | The Segments of the "Spline" Supply Function | | | | | |
|---|---|---|---|---|---|---|
| | Segment 1 | | Segment 2 | | Segment 3 | |
| **Model Coefficients** | Coefficient | T-Ratio | Coefficient | T-Ratio | Coefficient | T-Ratio |
| Constant | | | -49.7111 | -10.5199 | | |
| Load | -1.3049 | -2.5129 | 5.8292 | 11.1620 | | |
| Wgt Constraints | | | 0.0008 | 12.9813 | | |
| Weather Index | 0.0146 | 2.6373 | | | | |
| Gas Price Index*** | | | | | | |
| Proportion of Gen Offered | -8.6440 | -3.6378 | -0.1471 | -4.0902 | | |
| Lagged Wgt. Constraints | | | | | | |
| Adjacent Zonal Load | | | | | | |
| Arch (0) | 0.0137 | 5.81 | | | | |
| Arch (1) | 0.5960 | 4.52 | | | | |
| Arch (2) | 0.5379 | 6.71 | | | | |
| $R^2$ = | 0.4798 | | | | | |
| | **Knots ( % of Maximum Load )** | | | | | |
| **Price Flexibilities**** | 85.0% | | 100.0% | | | |
| Minimum | 0.68 | | 5.85 | | | |
| Maximum | 3.09 | | 5.90 | | | |
| Mean | 1.22 | | 5.86 | | | |

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

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

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

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

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

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

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

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

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

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