Chapter 2

Implicit Price Elasticities of Demand for Electricity of Participants in NYISO's Emergency Demand Response Program

As stated in the introduction, a comprehensive evaluation of NYISO's PRL programs must, to the extent possible, provide estimates of the amount of load reduction customers' will bid into DADRP or contribute to EDRP when an emergency is called, once they have subscribed to either program.

It would be difficult to provide definitive answers to this question based on only one years' program experience. However, some important, first estimates of customers' responsiveness can be developed from the performance data. From these estimates, one can also gain initial insights into how the amount of load reduction is likely to be affected by changes in the payment guarantee. It is to this purpose that this chapter is directed.

This report proceeds in the following way. First, we outline some simple economic principles of factor demand by firms and demonstrate how the amount of load reduction in response to a change in the price guarantee can be characterized by the concept of the price elasticity of demand. Next, we summarize the load response of customers in EDRP relative to their event Customer Baseline Load (CBL), and examine the impact of the $500/MW guaranteed minimum payment level relative to customers' background electricity rates. Based on these data, we also provide estimates of the implicit price elasticities of demand for electricity by event day and zone. These elasticities are, in turn, used to forecast changes in load reduction in EDRP if the payment levels were changed from $500/MW to either $250/MW or $750/MW. Finally, some conclusions and recommendations are drawn.

The Theory of Factor Demand

The neoclassical theory of the firm is based on the assumption that firms allocate factors of production in such a way as to achieve the profit maximizing output for the firm, given a prevailing set of input and output prices. Implicit in this theory is also the fact that for a given set of input prices, factors are allocated in such a way as to produce the appropriate profit maximizing level of output at minimum cost (Ferguson, 1969).

Accordingly, it can be shown that the demand curve for any input or factor of production in the short run is the value of the marginal product (VMP) schedule for that factor. Each value on the VMP schedule represents the marginal product of the input (the additional output that can be produced with an additional unit of an input, all else constant) *multiplied* by the price of the output. This places a dollar value on the additional output produced by the extra unit of input. The VMP schedule therefore indicates the value to the firm of marginal input levels.

It can further be shown that the marginal product schedule is downward sloping. By applying the law of diminishing marginal productivity, the marginal product of any factor eventually begins to decrease as the use of the factor continues to increase. Therefore, the relevant portion of the VMP schedule is downward sloping.

By using an input up to the point that its value in production (e.g., the value of the marginal product) is equal to the price of the input, the firm's profit is maximized. Because of the law of diminishing marginal productivity, if the firm uses fewer than the profit maximizing level of input units, some profit is forgone because the value of the additional output from using the additional unit of input is above the cost of the input. On the other hand, if inputs in excess of the profit-maximizing level are used, the value of the additional output forthcoming from the last unit of the input is below the price of the factor, and profit falls. Profit would be higher by not using this last unit of input. To summarize, knowing the demand curve for the firm's inputs provided the means for ascertaining the optimal level of input use. The demand curve also provides the means for ascertaining how input levels would change as input prices change.

Simple representations of two separate demand curves (VMP_E) for electricity are shown in Exhibit 2.1. It is assumed that one of these curves characterizes the demand for electricity as viewed by a firm participating in NYISO's DADRP. This curve is labeled $VMP_{E|DADRP}$, and it represents the amounts of electricity that will be demanded at various prices in real time as long as the price the firm is charged (or is paid to curtail load) is known a day in advance. The other demand curve (labeled $VMP_{E|EDRP}$) is assumed to be the demand curve for electricity by the same firm in real time for prices that are not known until real time. This second demand curve reflects the situation of a firm participating in EDRP. In both cases, as the price of electricity rises, the demand for electricity will fall.[1]

The significant difference in the two curves is that the one corresponding to the demand in real time under EDRP is steeper than the one for the day-ahead market. The reason for the difference is that if a firm is participating in DADRP, it has 24 hours to make necessary adjustments to minimize the effect of a reduction in electricity usage. In the case of EDRP, the customer is informed only two or so hours before it must reduce electricity usage; the firm has less time to make adjustments that can minimize the effect on the firm's production, and generally is less capable of altering its economic activity.

[1] In this analysis, we assume that customers face a predetermined price schedule or rate and that on occasion that rate is supplemented with DADRP or EDRP curtailment prices that are several times higher.

In the customer representation of electricity demand depicted in Exhibit 2.1, before either a bid in the DAM for DADRP is scheduled or an EDRP event is called, we assume that the firm plans to consume at the CBL and pay a background rate of P_B. Given the argument above, if the firm is going to provide load reduction, indicated in Exhibit 2.1 as the shift in usage from the CBL down to a load of L_R, the firm would respond differently depending on the program in which it participates. It would require a price increase up to only P_D to induce this load reduction from the firm's participation in DADRP, moving along the $VMP_{E|DADRP}$ curve from the point where CBL intersects it to the point where L_R intersects the same curve, and then extending that point to the vertical axis, point P_D. Alternatively, if the firm was called for an EDRP event, the firm would respond along the steeper curve $VMP_{E|EDRP}$, and this same load reduction, from the CBL down to a load of L_R, would only be forthcoming at a payment level of P_E, which, as illustrated in Figure 2.1, is substantially higher than P_D.

In more precise economic terms, the situation depicted in Exhibit 2.1 is one in which the elasticity of demand for electricity (as an input) when participating in the day-ahead market is larger than it is for participation in EDRP. The elasticity of factor demand is defined formally as the percentage change in demand for a factor when the price of the factor is changed by one percent. In practical terms, the elasticity of demand is calculated as the percentage change in demand for a factor divided by the percentage change in the price of that factor.

These elasticities of demand can be calculated from program participant data corresponding to EDRP and DADRP events.[2] First, we define some terms:

[2] In the discussion that follows, elasticity and factor elasticity are used interchangeably.

CBL = the customer baseline load (the level of load the participant would otherwise consume under its standard rate or supply contract);
P_B = the participant's background rate;
P_E = the payment rate the participant receives for load curtailment in EDRP;
P_D = the payment rate the participant receives for a DADRP bid; and
L_R = load served during the load reduction EDRP event;
CBL - L_R.= load reduction provided in response to EDRP or DADRP payment.

The firm's two elasticities of demand for electricity corresponding to the factor demands illustrated in Exhibit 2.1 are now defined as:

(1) $E_{(EDRP)} = \{[(L_R - CBL) / CBL] \div [(P_E - P_B) / P_B]\}$

(2) $E_{(DADRP)} = \{[(L_R - CBL) / CBL] \div [(P_D - P_B) / P_B]\}$.

In equations (1) and (2), the numerators are equal because we have assumed that the load reduction is the same in both programs, CBL - L_R in Exhibit 2.1. Since ($P_E - P_B$) > ($P_D - P_B$), the denominator of (1) is larger than the denominator of (2), the absolute value of $E_{(DADRP)}$ is greater than the absolute value of $E_{(EDRP)}$. Thus, as we indicated, the demand elasticity for participation in DADRP is higher than for participation in EDRP because the slope of the input demand curve is higher. [3]

Using the same logic as above, one would expect that for the same price incentive for curtailing load, the firm would offer greater load reduction in DADRP than if it would participate in EDRP, because the former is more price elastic. This situation is depicted in Exhibit 2.2, where the same price change results in different changes in load, depending on the slope of the factor demand schedule.

This situation can be defined algebraically as well. First, we define some terms again:

CBL = the customer baseline load;

[3] Demand elasticities for normal inputs are negative. By comparing elasticities in absolute value terms, we can facilitate the understanding of the relative differences.

P_B = the customer's background rate;
P_R = the same payment rate for participation in either EDRP or DADRP;
L_D = load served after the DADRP load reduction of CBL – L_D; and
L_E = load served after the EDRP load reduction of CBL – L_E.

Now, the firm's two elasticities of demand for electricity for the relationships depicted in Exhibit 2.2 are defined as:

(3) $E_{(EDRP)} = \{[(L_E - CBL) / CBL] \div [(P_R - P_B) / P_B]\}$

(4) $E_{(DADRP)} = \{[(L_D - CBL) / CBL] \div [(P_R - P_B) / P_B]\}$.

In equations (3) and (4), the denominators are now equal because we have assumed that the same payment applies to the DADRP bid and the EDRP load reduction. Since the load curtailment induced by the price difference under DADRP (L_D –CBL) is greater in absolute value than the absolute value of (L_E – CBL), the absolute value of the numerator in (4) is larger than the absolute value of the numerator in (3). As was demonstrated previously, the demand elasticity for participation in DADRP is higher than for participation in the EDRP if input demands are as we have illustrated them.

Although the argument for the case that demand elasticities for firms in DADRP are larger than for their participation in EDRP is unequivocal in this stylized theoretical model, the validity of the argument in practice is an empirical question.[4] The situation will differ according to each firm's production schedule and a host of other factors that influence factor demands such as weather and economic conditions. It is clear that the larger the elasticity of demand for electricity, the greater the load relief forthcoming for the same DADRP bid price or EDRP payment. Therefore, it is important to have estimates of these price elasticities of demand for program participants.

[4]If this were to be universally true, then greater real- time price responsiveness is realized from DADRP participation than from EDRP participation.

Some Empirical Results from the PRL Programs for 2001

As is evident from the algebraic form of equations (1) through (4), "implicit" demand elasticities can be derived for participants using the NYISO EDRP program data that include the CBL, the load reduction, and the price paid for curtailments.[5] The only data that are missing are customers' background electricity rates. These background rates were derived from published rate schedules so that implicit electricity input demand elasticities could be estimated.[6] We present below some empirical estimates of these implicit demand elasticities for EDRP customers for the four-day event. To protect the confidentiality of the customers, we do not report elasticities for individual PRL participants. Instead, we provide the range in firm-level elasticities as well as the average elasticity across firms by pricing zone.[7]

Calculated Implicit Demand Elasticities for Electricity

The average estimated implicit factor demand elasticities for 214 EDRP participants by NYISO pricing zone are given in Table 2.1, along with the load, CBL and load reduction data that went into their calculation.[8] The elasticity estimates are based on the minimum price guarantee of $500/MW for the EDRP program for the summer of

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[5] In this analysis, we assumed participants were paid the full amount that the NYISO paid out. Most likely they received less than this amount as a result of sharing arrangements with their LSE/CSP broker. There was no way to ascertain what these arrangements might have been.

[6] Background rates were derived for each LSE and were assigned to all PRL participants located in that LSE's territory. Such rates were derived assuming a 500 kW demand and 60% load factor usage profile for a summer month.

[7] DADRP participants were not included in this analysis. The small number of participants in this program would have limited the applicability of any generalizations of the results to the larger population of retail customers. In addition, with so few participants in DADRP, any data reporting could have jeopardized their confidentiality.

[8] The data used in this analysis are only for EDRP participants that registered to provide only load reduction. It was not possible to disentangle the price-responsiveness of load relief and generation from those participants offering both load reduction and on-site generation. In addition, there were also a number of the total 292 EDRP subscribers (Table 1.12, Chapter 1) for which there were no CBL and performance data in the files provided by the NYISO.

2001, and they are calculated according to equation (3).[9] The average zonal elasticities in Tables 2.1 and the zonal elasticity ranges and standard deviation in Table 2.2 are based on the percentage reductions in load that are calculated as the difference between total load over all hours of all event days and the total CBL over all event hours of all event days. This strategy assumes that for event days that are quite close together, customers would respond in a similar fashion. This seemed a reasonable assumption after examining the data.[10]

During the EDRP event hours, these EDRP participants consumed a total of 10,975 MWH of electricity, and the associated combined CBL was 17,868 MWH (Table 2.1). Thus, the total load relief for these customers was nearly 6,893 MWH over the four event days, which amounts to a 38.5% reduction in typical (CBL) usage in response to the EDRP curtailment call. Participant load for which elasticities were developed represent about 84% of the 8,159 MWH of total EDRP performance during the four event days (Table 1.13, Chapter 1); the total EDRP curtailment performance includes those customers offering on-site generation or a combination of load reduction and generation.

Relative to the customers' base electricity rates, the *average* calculated price elasticities of demand by customers in the various NYISO pricing zones ranged from a

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[9] Even though customers in some event hours were paid LBMPs above the $500 price guarantee, these prices were not known at the time of curtailment. Therefore, as in done in much economic analysis, we assumed that the price on which these load reductions were based is the minimum price guarantee.

[10] Although these elasticities are consistent with the performance data, we have labeled them "implicit" elasticities because they are based on simple algebraic differences that are put in percentage terms by dividing by the beginning CBLs and baseline rates. The estimates are not based on a systematic econometric modeling of repetitive behavior due to price differences for programs in which customers have participated for some extended period of time. These results are consistent with more formal analyses conducted elsewhere, and on this basis, the results are very encouraging. See for example, Herriges, *et al*., 1993; Caves and Christensen, 1980 a,b; Long, *et al*., 2000; Braithwait, 2000; and Patrick, 1990).

low of - 0.01 in zone D and H, to a high (in absolute value) of - 0.14 in zone I (Table 2.1). As noted above, these elasticities are consistent with response elasiticites found in more formal price response studies of customers participating in real-time and TOU pricing programs.

Moreover, there is substantial variation in these elasticities about the mean (Table 2.2). Some individual participants' implied response elasticities are as large as - 0.47, while several are in the neighborhood of - 0.22. Some of this firm-level variation reflects differences in the ability of customers to respond on certain days, and it also reflects differences in the CBLs against which performance is measured.[11] For the 11% of customers registering small positive price elasticities on average (Chart 2.1, first bar), the implication is that usage was on average above the CBL during the events. These customers either found it impossible to curtail load, or in attempting to comply they misjudged their CBL, and usage inadvertently remained above the CBL in the aggregate, even though they may have actually curtailed some electricity usage in response to the call.

These implicit elasticities of response varied considerably by the size of a firm's average electricity usage (Chart 2.2). The majority of the participants in EDRP had loads between 1,000 kWH to 4,000 kWH and exhibited low (elasticities greater in algebraic value than - 0.05) to modest (elasticities between – 0.05 and – 0.20) implied response. Participants with low elasticities were, in general, equally distributed amongst the other firm sizes. However, as firm size increased, so did the percentage of participants in that size category with high elasticities of response (elasticities less than - 0.20). This

[11] Some program providers assert that the CBL is biased against weather sensitive participants, and therefore their curtailment response is under-estimated.

observation is consistent with the belief by some that larger customers have better knowledge of their load shapes, and are thus better able to respond during curtailment opportunities. The results also show that firms with an average hourly load under a megawatt generally did not appear to be as responsive as their larger counterparts. These smaller customers may be inherently less capable of curtailing usage under EDRP terms, or they may simply need more education concerning their load shape and assistance on load management strategies to become more effective in reducing load during EDRP events.

Conventional wisdom would also suggest that the performance of EDRP load reduction resources would drop off substantially toward the end of emergency events, especially if the events last for several hours each day and are called over a number of consecutive days as well. Conversely, for those participants with on-site generation, one might also expect that this “fatigue factor” would be minimal, or perhaps non-existent, given these customers’ abilities to simply turn on a generator at the event start time and leave it on for the event’s entire duration. In contrast to this conventional wisdom, however, it appears that most EDRP participants without on-site generation remained steadfast in their load curtailment contribution once they committed to the EDRP event (Chart 2.3). Measured in percentage terms over the first three EDRP event days, the range in performance of their counterparts’ with on-site generation was almost 1.8 times higher (calculated from data displayed in Chart 2.3). Although there is a small decrease in the overall curtailment level of load reduction resources as each event day progressed (Chart 2.3), for the most part, load-curtailing participants were able to sustain their load reduction efforts through events that lasted up to eight hours.

NYSERDA's EDRP Participants

Before moving to another topic, it is important to emphasize that a little over half of the EDRP participants received funding from either NYSERDA's PON 577 or PON 585, NYSERDA's Peak Load Reduction and Enabling Technology programs, respectively (Table 1.12 in Chapter 1), to help them respond. These programs offered financial assistance to firms for the purchase of load reduction or load shifting technology, and/or metering and communications equipment that could well have affected customers' decisions to participate in EDRP and increased the amount of load reduction offered during curtailment events. As a sponsor of this research, NYSERDA is interested in the performance of this subset of customers relative to the population of participants. To provide this comparison, we have prepared tables that break out elasticity estimates for two subgroups of customers: those participants in a NYSERDA program (Tables 2.3 and 2.4), and those customers not participating in a NYSERDA program (Tables 2.5 and 2.6).

As is seen in Table 2.3, there were a total of 60 NYSERDA participants who pledged to participate in EDRP events through load reduction efforts only and for which EDRP performance data were available. This constitutes 28% of the 214 customers whose performance data are included in this analysis, and they contributed 33% of these customers' total load reduction by load curtailing participants over the four event days.

From Tables 2.3 and 2.5, we see that the average price elasticity of demand for the customers in the NYSERDA subgroup are slightly higher (-0.09) compared to the other participants (- 0.08). The distributions of these implicit elasticities for each subgroup are displayed in Charts 2.4 and 2.5, respectively. Chapters 3 and 4 provide insight into how NYSERDA program funding influences EDRP participation and response.

Actual vs. Subscribed Performance

At the time they enrolled in EDRP, customers were asked to provide an indication of the amount of load reduction they anticipated being able to supply during an EDRP event. In Charts 2.6 (Daily) and 2.7 (Zonal), we have provided comparisons of these initial "subscribed load reduction capacities" with customers' actual average performance. For the entire customer group, the ratio of average actual and subscribed performance ranged from between 47% and 61% during the four event days. What is striking about these results on all days, and in all but a few of the pricing zones, is the performance of the NYSERDA customers relative to their initial subscription levels. Over the four event days, NYSERDA's customers delivered an average of 63% of their initial indicated subscription amount. This performance was well above that of the non-NYSERDA subgroup. One explanation for this result is that NYSERDA funding provided for greater attention to curtailment capacity auditing, so these customers better understood what they could deliver when they registered for EDRP.

Simulating the Effect of a Change in EDRP Payment Levels

The range in the estimates of elasticities is quite large, and this range has implications for the EDRP program. An elasticity of - 0.01 (the low end of the range) implies that a 100% difference between the background rate and the EDRP payment would yield only a 1% reduction in load. On the other hand, if the elasticity is - 0.47 (the high end of the range for individual firm elasticites) , the same difference between the background rate and EDRP payment would yield a 47% load reduction. This wide range in demand elasticities serves to underscore the fact that the EDRP program has a very different value to customers, and this value may differ by month or even time of day. These are factors that the existing program data can not reveal. Further, the program's value to these firms may change if the program features are changed as well.

To begin to shed light on how the diversity of response affects program performance, we simulated the load reduction that would have been forthcoming, based on these estimated elasticities, assuming that the minimum guaranteed EDRP curtailment payment were increased to $750/MW and, alternatively, if it were lowered to $250/MW. These simulated results for all customers are in Table 2.1, and for the NYSERDA and other participant subgroups are in Tables 2.3 and 2.5, respectively.

At a higher price for curtailment, our analysis suggests that the load reduction would have totaled 11,037 MWH over the four days, or a 60% increase (Table 2.1). Alternatively, if there were a 50% reduction in the guaranteed payment, the load reduction would have fallen to about 2,483 MWH, only 36% of what was delivered this summer. As seen in Table 2.1, the implications of these two payment levels vary by zone because the price elasticity of demand for electricity differs substantially from zone to zone.

The implications of these payment levels also are a bit different still for the NYSERDA customers (Table 2.3). At the higher of the payment levels, the contribution to additional load relief by the NYSERDA would rise by about 58%. Whereas, these customers would likely reduce their performance to 36% of the level offered during the August, 2001, events if the payment level were to be cut in half.

Some Conclusions

Being based on only four event days during one summer, these results, though very encouraging and consistent with price response estimates in previous studies of customers who have been on rates that differ by time of day, must be interpreted with some degree of caution. What is clear, however, is that for EDRP to be of greatest benefit to the system as a whole, the differential ability and willingness of firms to reduce load when EDRP events are called must be taken into account explicitly. It is important to know which types of customers are likely to be the most responsive.

Finally, it is important to emphasize two things about these results. First, while extremely encouraging, these "implicit" elasticities are based on observed performance during only four days; they and are not based on the results of a comprehensive, integrated study of electricity demand of these customers. Such a study would produce more precise estimates of price elasticities, the results of which could be used to project response over a wide range of prices and program features.

Second, the simulated changes in the load reduction due to changes in the guaranteed payments are based on the assumption that any change in the guaranteed payment would have no effect on the number of firms participating in EDRP. This is clearly an over simplification of reality. From this perspective, the reduction in EDRP performance at the $250/MW price is clearly an upper bound on the amount of load relief associated with a payment reduction. Further, for the guaranteed price increase, the simulated performance would be a lower bound. In Chapter 3, the analysis of the data collected in the customer acceptance survey, sheds light on the effects of program features on customer participation in PRL programs.

There is clearly a need for further research into both of these issues in order to understand more completely those factors and program characteristics most important for participation of firms by zone and, once having enrolled in the program, the amount of load reduction likely to be offered when events are called.

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Table 2.1. Average Zonal EDRP Event Performance by EDRP Customers in the August, 2001, All Event Hours

	Participants*		Load (MWH)		CBL (MWH)		At $500/MW Load Reduction (MWH)		Implicit Price Elasticity**		At $250/MW# Load Reduction (MWH)		At $750/MW# Load Reduction (MWH)	
Zone	Number	%	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.
A	26	12%	110.9	181	226.6	347	115.74	220	-0.09	0.08	56.9	93	241.4	393
B	8	4%	39.0	88	42.8	93	3.85	5	-0.05	0.02	0.7	0	2.8	1
C	24	11%	32.0	56	69.0	123	36.98	102	-0.09	0.09	15.2	41	64.0	171
D	4	2%	16.6	8	20.1	11	3.47	3	-0.01	0.02	0.5	1	1.9	3
E	19	9%	28.8	26	41.3	34	12.47	13	-0.08	0.06	4.5	5	19.2	21
F	23	11%	55.0	85	121.9	185	66.96	122	-0.10	0.08	25.6	47	108.4	198
G	15	7%	73.3	157	87.8	170	14.49	16	-0.12	0.13	4.8	6	24.2	26
H	5	2%	62.6	89	64.9	88	2.37	4	-0.01	0.03	1.0	2	3.8	7
I	15	7%	22.3	22	28.0	23	5.65	8	-0.14	0.18	1.5	2	9.8	14
J	62	29%	54.1	70	65.7	74	11.59	22	-0.09	0.11	3.1	6	20.5	39
K	13	6%	2.5	5	13.4	18	10.95	19	-0.12	0.10	4.2	7	17.7	30
Avg.##			**49.2**		**80.8**		**31.11**		**-0.09**		**13.0**		**57.8**	
Totals	**214**		**10,975**		**17,868**		**6,893**				**2,483**		**11,037**	

*These EDRP participants offered only load reduction. Those that supplied on-site generation, or both generation and load reduction are not included.

**These implicit price elasticities are calculated according to equation (3) above. See the text for more details of the calculations.

These load reductions are calculated by substituting the estimated price elasticities into equation (3) and solving for the reduction in load when P_E is set either at $250 or $750/MW.

##These are weighted averages, weighted by the proportion of firms in each zone.

Table 2.2. Implicit Price Elasticities by EDRP Customers, August, 2001

		Implicit Price Elasticity of Demand			
Zone	Participants	Minimum	Maximum	Average	Standard Deviation
A	26	-0.22	0.01	-0.09	0.08
B	8	-0.07	-0.02	-0.05	0.02
C	24	-0.22	0.00	-0.09	0.09
D	4	-0.02	0.00	-0.01	0.02
E	19	-0.18	0.02	-0.08	0.06
F	23	-0.23	0.01	-0.10	0.08
G	15	-0.44	0.01	-0.12	0.13
H	5	-0.06	0.02	-0.01	0.03
I	15	-0.47	0.03	-0.14	0.18
J	62	-0.46	0.04	-0.09	0.11
K	13	-0.23	0.00	-0.12	0.10

*These EDRP participants offered only load reduction. Those supplying on-site generation, or generation and load reduction are not included.

Note: See the footnotes to Table 2.1 for more details about the calculations.

Table 2.3. Average Zonal Performance by NYSERDA's EDRP Customers in the August, 2001, All Event Hours

	Participants*		Load (MWH)		CBL (MWH)		At $500/MW Load Reduction (MWH)		Implicit Price Elasticity**		At $250/MW# Load Reduction (MWH)		At $750/MW# Load Reduction (MWH)	
Zone	Number	%	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.
A	8	13%	25.4	32	62.4	63	36.96	46	-0.14	0.08	21.3	19	90.2	80
B	7	12%	43.6	94	47.7	100	4.04	6	-0.05	0.02	0.6	0	2.5	1
C	16	27%	40.3	66	84.9	145	44.62	122	-0.10	0.09	19.2	50	80.4	211
D	3	5%	13.7	6	15.7	7	1.97	2	-0.01	0.02	0.5	1	1.9	3
E	2	3%	13.9	1	24.0	10	10.02	9	-0.09	0.05	3.9	3	16.2	15
F	5	8%	102.3	125	289.4	320	187.09	195	-0.15	0.06	71.4	74	302.8	316
G	1	2%	624.8	0	683.1	0	58.23	0	-0.02	0.00	21.9	0	94.5	0
H	4	7%	25.4	38	28.9	42	3.52	4	-0.02	0.03	1.4	2	5.7	7
I	3	5%	16.3	27	30.6	33	14.38	13	-0.19	0.26	3.8	3	25.0	22
J	11	18%	44.9	24	56.8	33	11.88	18	-0.09	0.09	3.5	5	22.7	31
K	0	0%	0.0	0	0.0	0	0.00	0	0.00	0.00	0.0	0	0.0	0
Avg.##			**49.2**		**86.5**		**37.02**		**-0.09**		**15.2**		**66.4**	
Totals	**60**		**3,003**		**5,248**		**2,245**				**816**		**3,556**	

*These EDRP participants offered only load reduction. Those that supplied on-site generation, or both generation and load reduction are not included.

**These implicit price elasticities are calculated according to equation (3) above. See the text for more details of the calculations.

These load reductions are calculated by substituting the estimated price elasticities into equation (3) and solving for the reduction in load when P_E is set either at $250 or $750/MW.

##These are weighted averages, weighted by the proportion of firms in each zone.

Table 2.4. Zonal Implicit Price Elasticities for NYSERDA's EDRP Customers, August 2001

		Implicit Price Elasticity of Demand			
Zone	Participants	Minimum	Maximum	Average	Standard Deviation
A	8	-0.22	-0.02	-0.14	0.08
B	7	-0.07	-0.02	-0.05	0.02
C	16	-0.22	0.00	-0.10	0.09
D	3	-0.02	0.00	-0.01	0.02
E	2	-0.12	-0.05	-0.09	0.05
F	5	-0.20	-0.05	-0.15	0.06
G	1	-0.02	-0.02	-0.02	0.00
H	4	-0.06	0.02	-0.02	0.03
I	3	-0.47	0.03	-0.19	0.26
J	11	-0.21	0.01	-0.09	0.09
K	0	0.00	0.00	0.00	0.00

*These EDRP participants offered only load reduction. Those supplying on-site generation, or generation and load reduction are not included.

Note: See the footnotes to Table 2.3 for more details about the calculations.

Table 2.5. Average Zonal EDRP Event Performance by Non-NYSERDA EDRP Customers in the August, 2001, All Event Hours

	Participants*		Load (MWH)		CBL (MWH)		At $500/MW Load Reduction (MWH)		Implicit Price Elasticity**		At $250/MW# Load Reduction (MWH)		At $750/MW# Load Reduction (MWH)	
Zone	Number	%	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.
A	18	12%	148.9	207	299.6	397	150.75	258	-0.07	0.08	68.8	105	291.8	443
B	1	1%	6.4	0	8.9	0	2.49	0	-0.06	0.00	1.0	0	4.0	0
C	8	5%	15.6	21	37.3	56	21.72	38	-0.05	0.07	8.3	15	35.1	62
D	1	1%	25.5	0	33.5	0	7.97	0	0.00	0.00	0.0	0	0.0	0
E	17	11%	30.5	27	43.3	36	12.76	14	-0.08	0.06	4.6	5	19.6	22
F	18	12%	41.8	69	75.4	99	33.60	71	-0.09	0.08	12.8	27	54.4	114
G	14	9%	33.9	39	45.3	44	11.37	11	-0.13	0.13	3.6	3	19.2	18
H	1	1%	211.1	0	208.9	0	-2.25	0	0.01	0.00	-0.6	0	-3.9	0
I	12	8%	23.8	22	27.3	22	3.46	5	-0.12	0.17	0.9	1	6.0	9
J	51	33%	56.1	76	67.6	80	11.53	23	-0.09	0.12	3.1	6	20.0	41
K	13	8%	2.5	5	13.4	18	10.95	19	-0.12	0.10	4.2	7	17.7	30
Avg.##			**48.8**		**78.0**		**28.79**		**-0.08**		**11.7**		**52.6**	
Totals	**154**		**7,972**		**12,620**		**4,648**				**1,667**		**7,481**	

*These EDRP participants offered only load reduction. Those that supplied on-site generation, or both generation and load reduction are not included.

**These implicit price elasticities are calculated according to equation (3) above. See the text for more details of the calculations.

These load reductions are calculated by substituting the estimated price elasticities into equation (3) and solving for the reduction in load when P_E is set either at $250 or $750/MW.

##These are weighted averages, weighted by the proportion of firms in each zone.

Table 2.6. Zonal Implicit Price Elasticities by Non-NYSERDA EDRP Customers, August 2001

		Implicit Price Elasticity of Demand			
Zone	Participants	Minimum	Maximum	Average	Standard Deviation
A	18	-0.21	0.01	-0.07	0.08
B	1	-0.06	-0.06	-0.06	0.00
C	8	-0.18	0.00	-0.05	0.07
D	1	0.00	0.00	0.00	0.00
E	17	-0.18	0.02	-0.08	0.06
F	18	-0.23	0.01	-0.09	0.08
G	14	-0.44	0.01	-0.13	0.13
H	1	0.01	0.01	0.01	0.00
I	12	-0.47	0.02	-0.12	0.17
J	51	-0.46	0.04	-0.09	0.12
K	13	-0.23	0.00	-0.12	0.10

*These EDRP participants offered only load reduction. Those supplying on-site generation, or generation and load reduction are not included.

Note: See the footnotes to Table 2.5 for more details about the calculations.

Chart 2.1. Distribution of EDRP Customers by Elasticity of Demand for Electricity During August EDRP Events

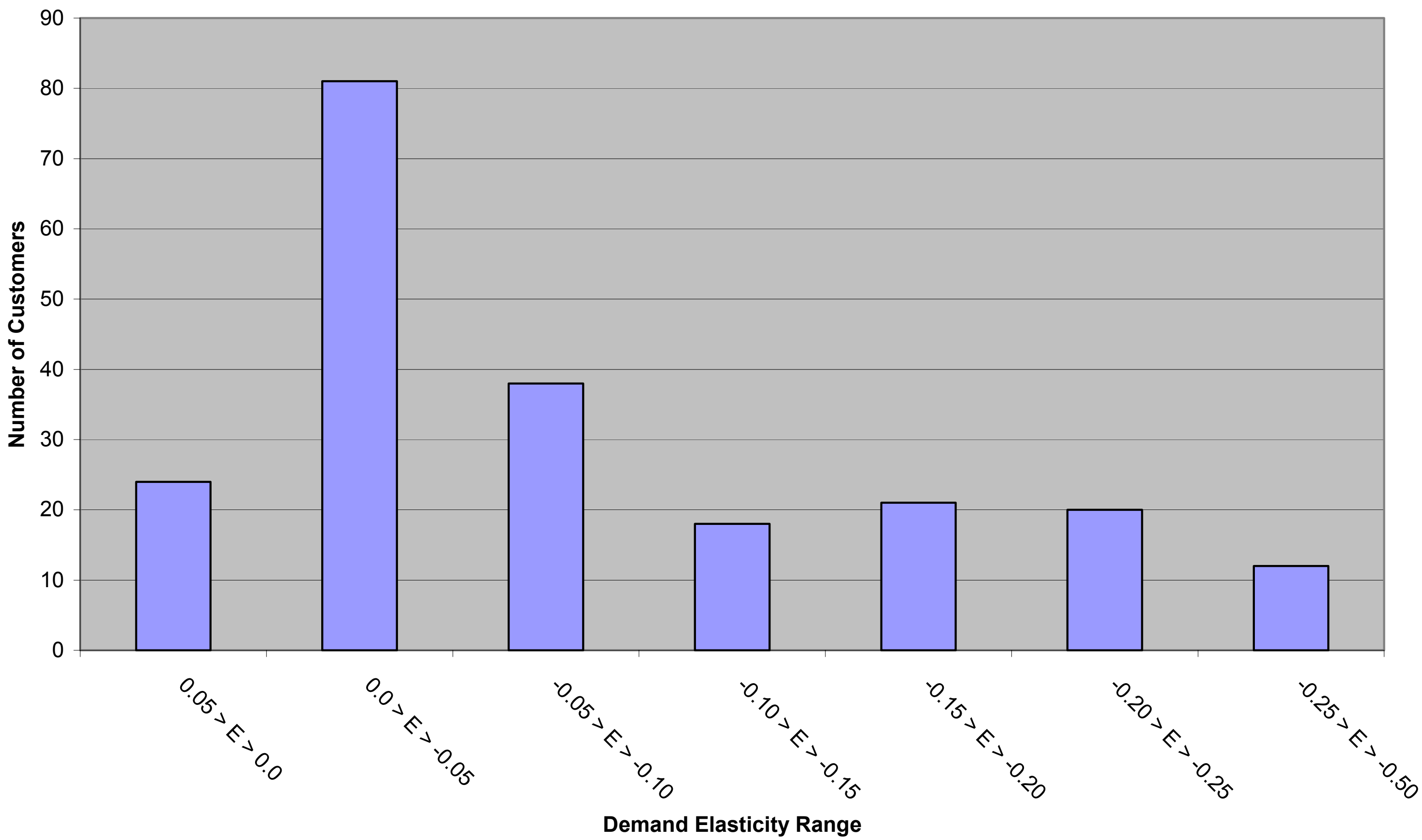

Chart 2.2. Distribution of Elasticities by EDRP Participant's Electricity Consumption Level

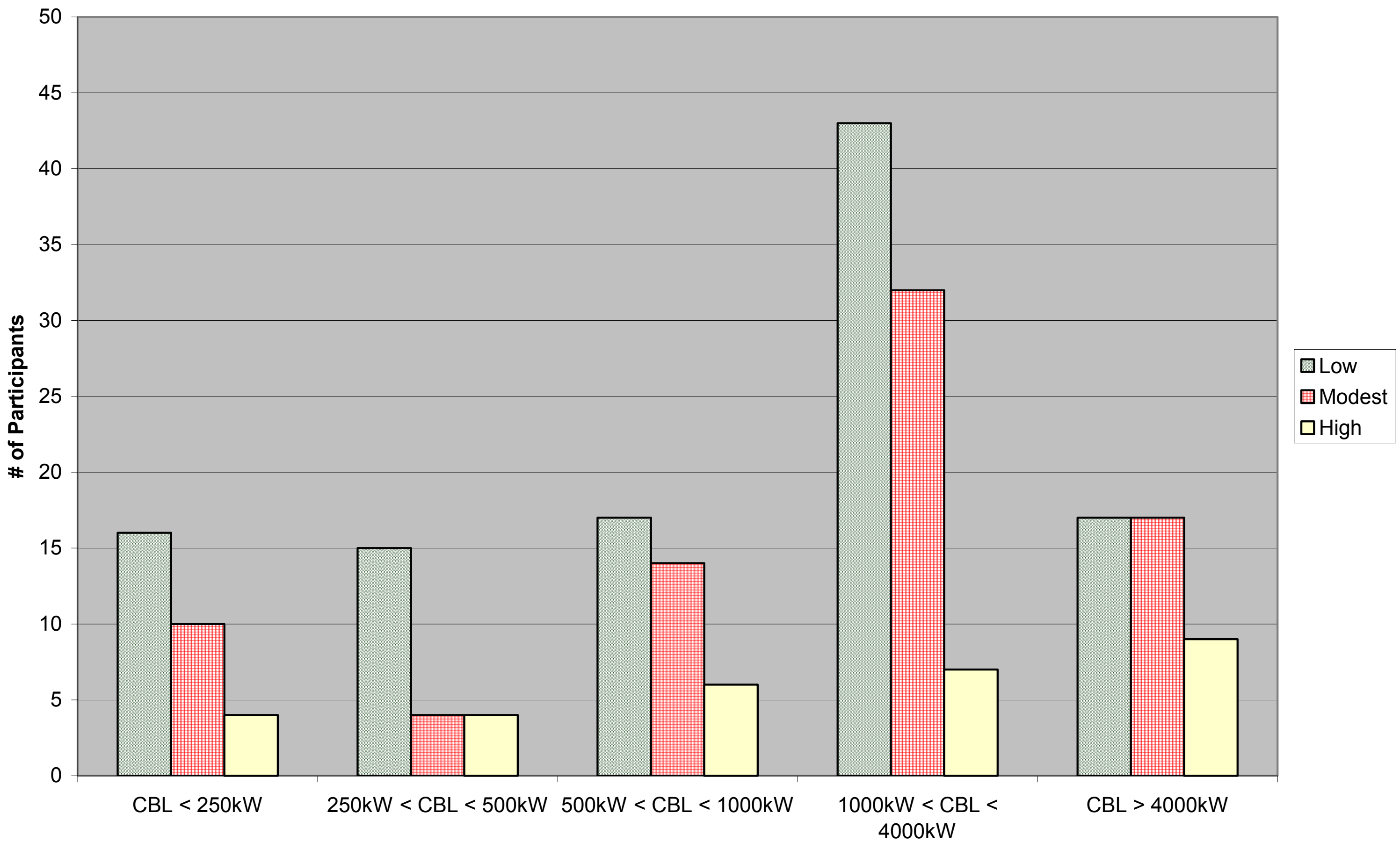

Chart 2.3. NYISO-Wide 2001 EDRP Event Performance

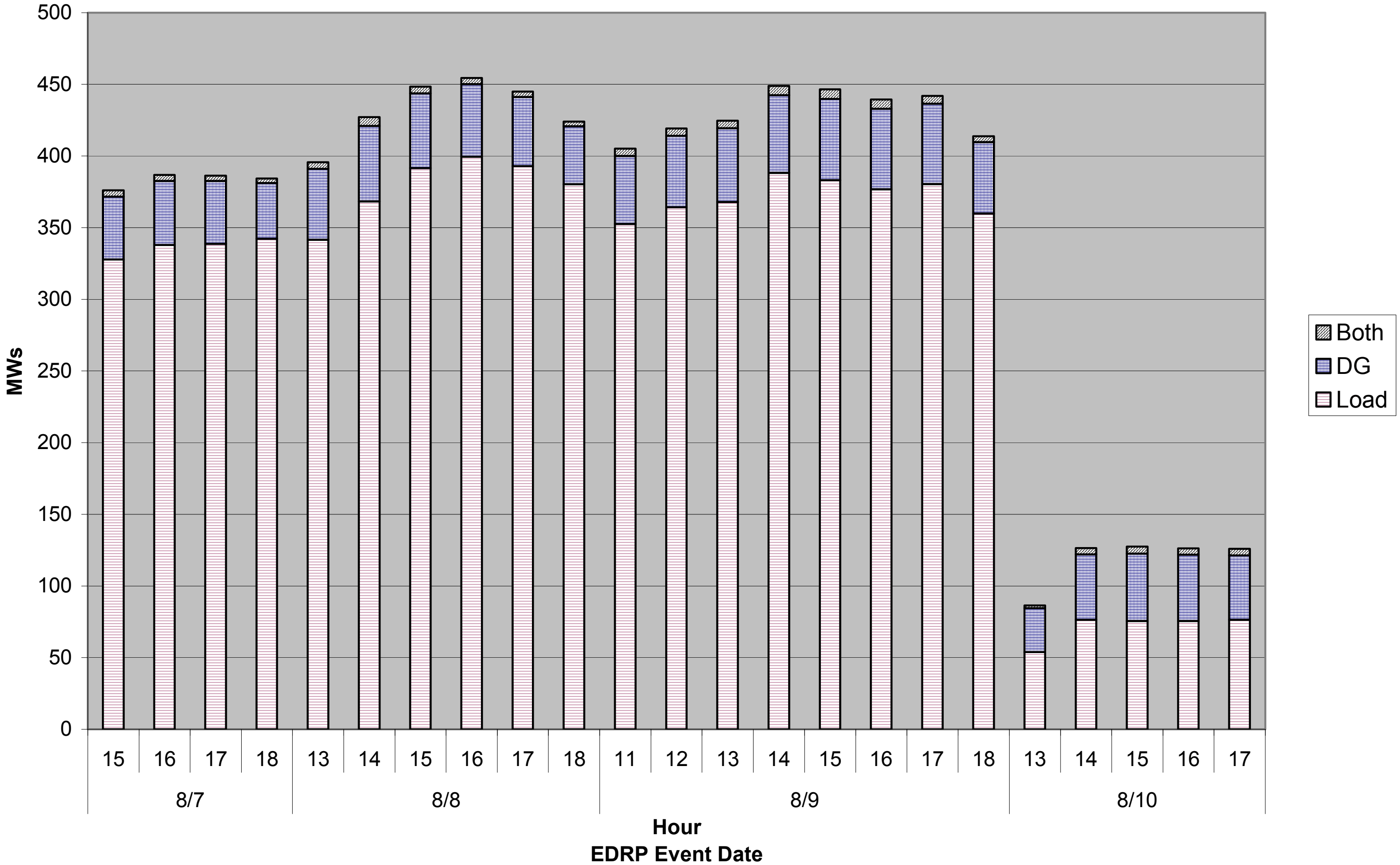

Chart 2.4. Distribution of NYSERDA'S EDRP Customers by Elasticity of Demand for Electricity During August EDRP Events

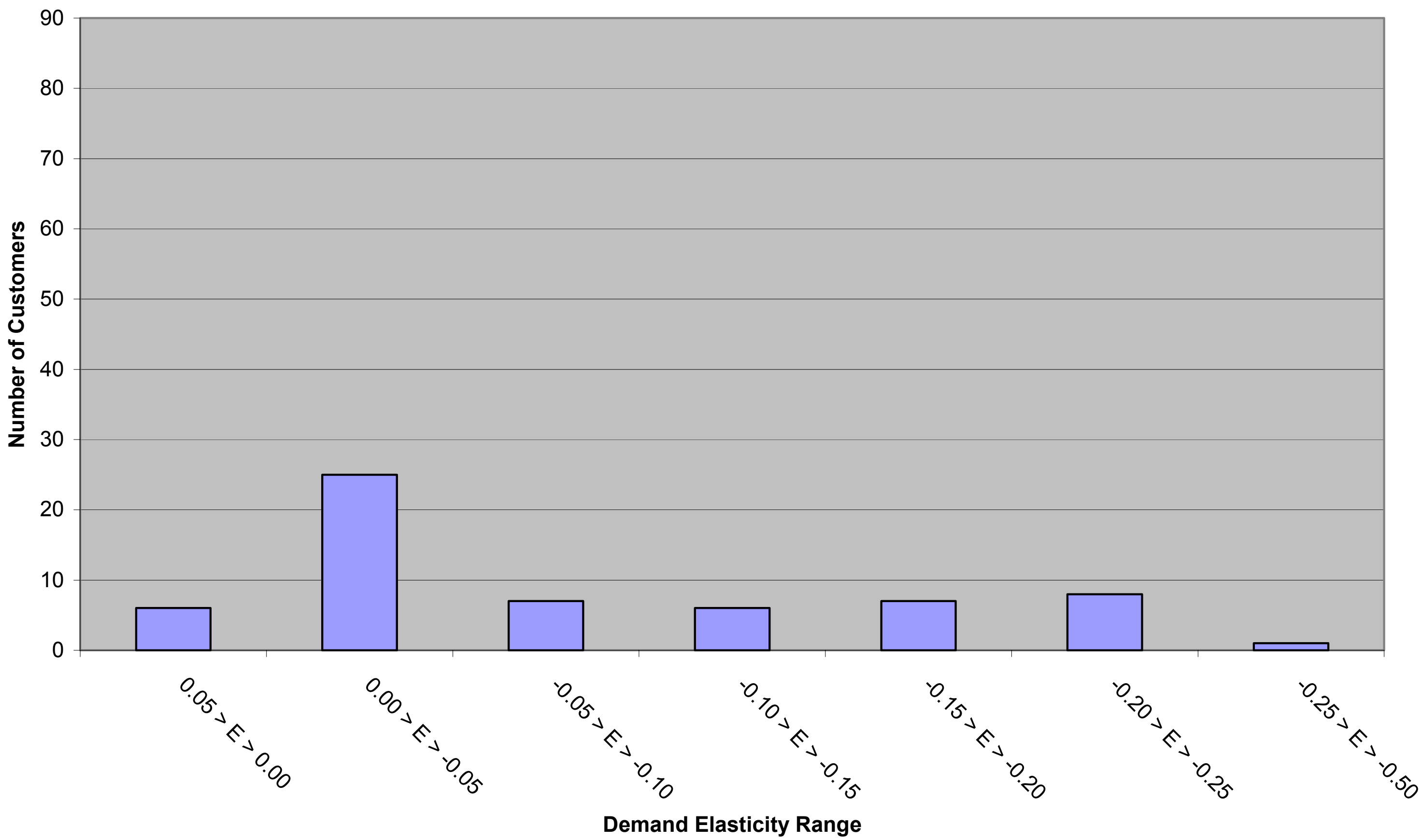

Chart 2.5. Distribution of Non-NYSERDA EDRP Customers by Elasticity of Demand for Electricity During August EDRP Events

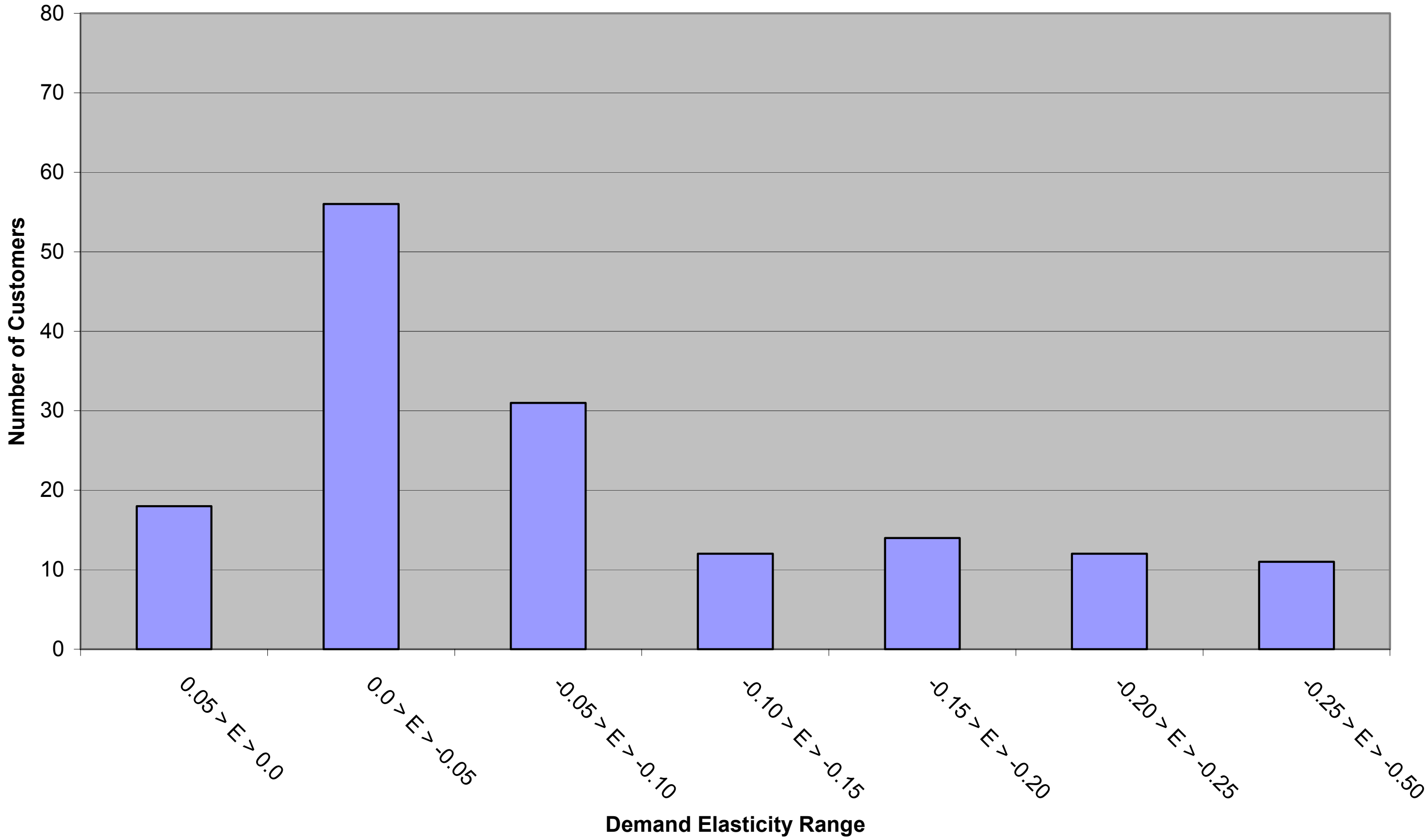

Chart 2.6. Ratio of Average Hourly EDRP Performance to Initial Subscribed Load Reduction Capability by EDRP Event Day

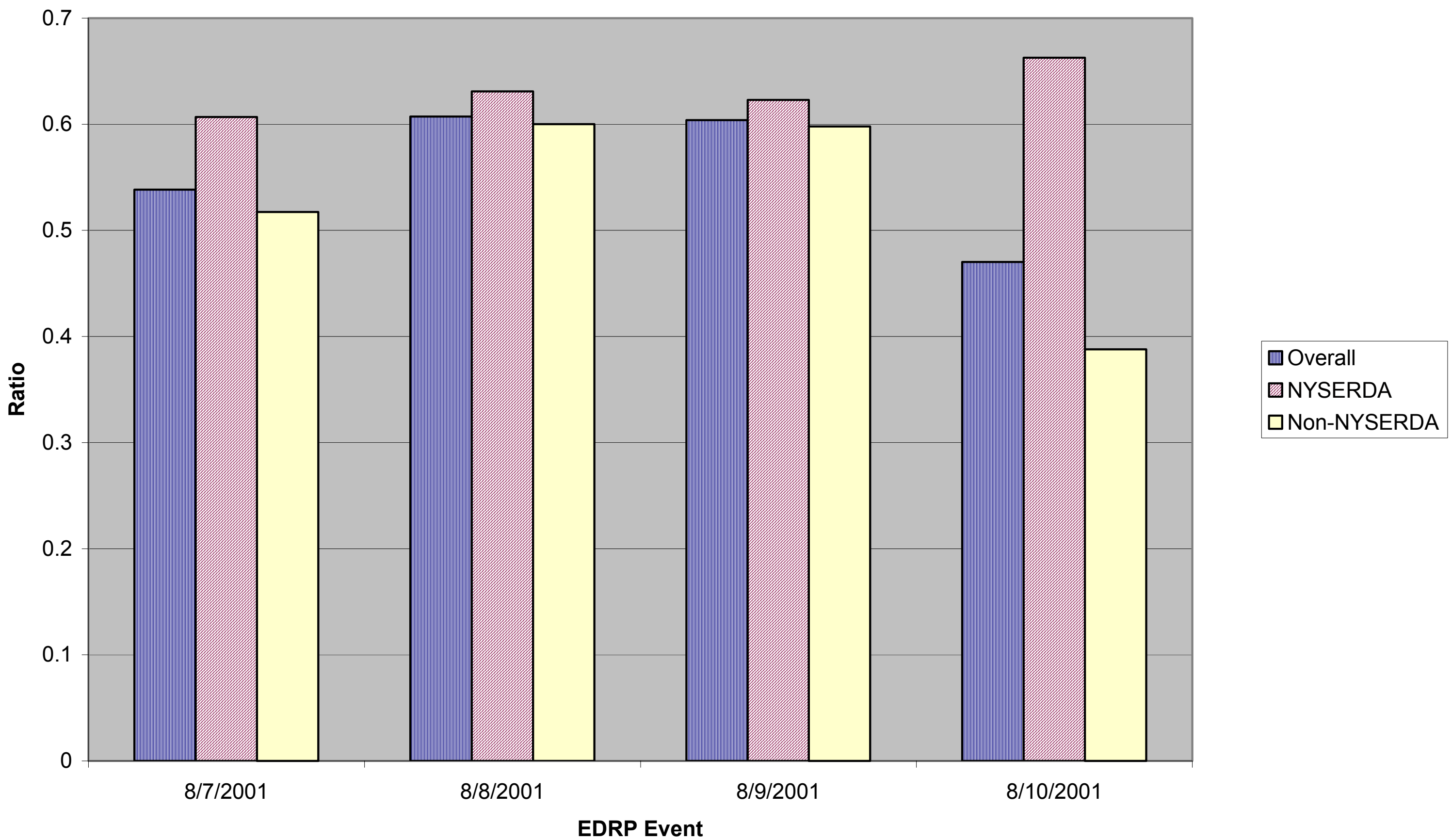

Chart 2.7. Ratio of Average Hourly EDRP Load Curtailment Performance to Initial Subscribed Load Reduction Capability by Zone

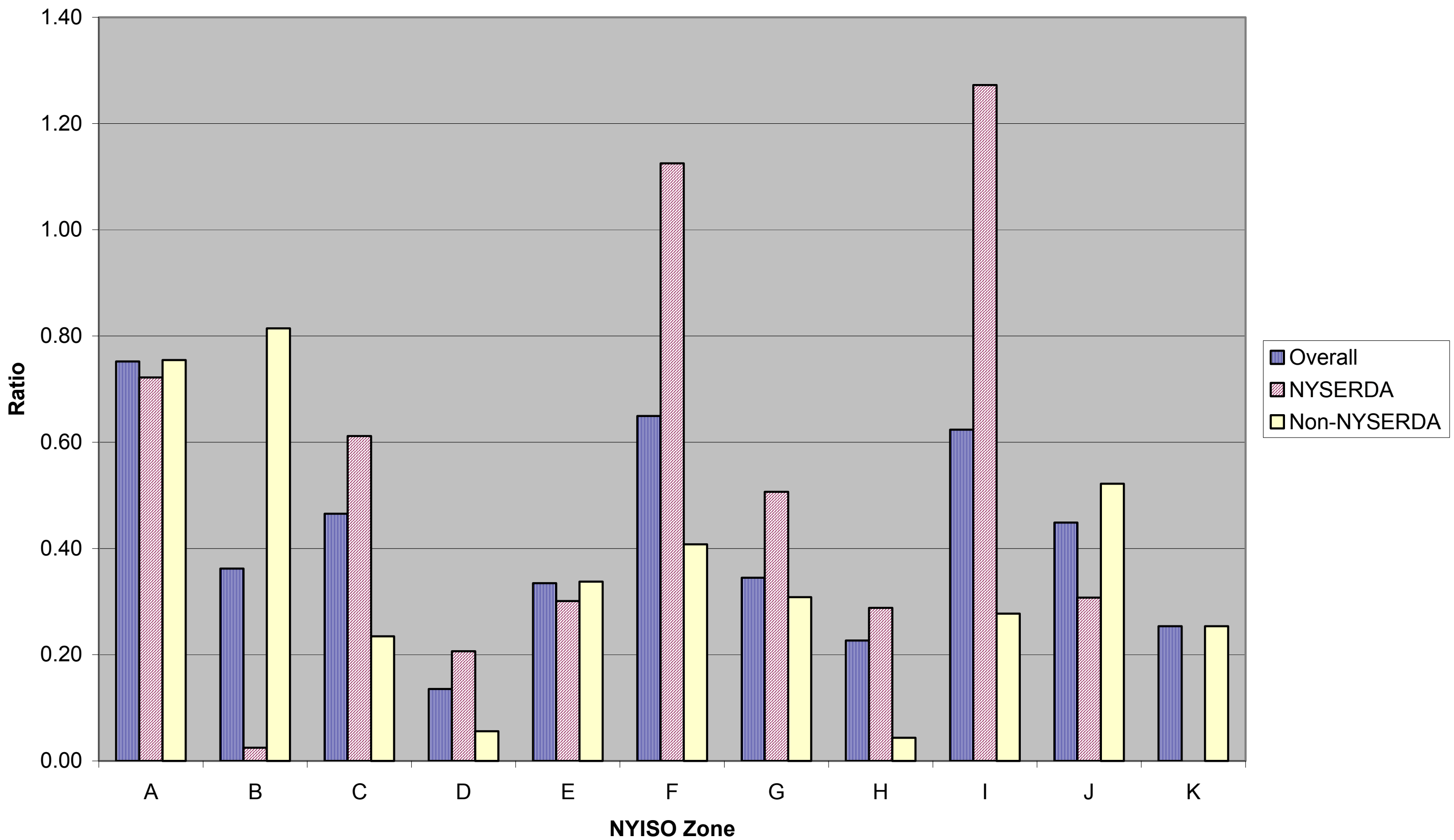

Exhibit 2.1. Price Elasticities of Demand for Electricity: Equal Load Reduction

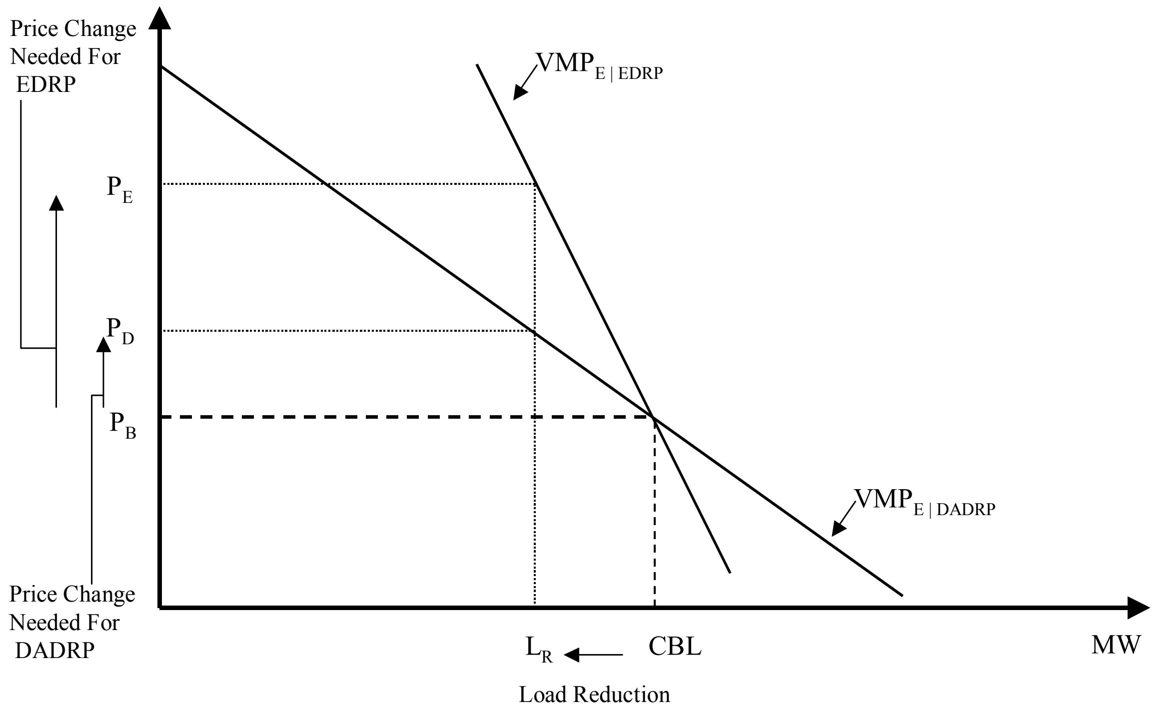

Exhibit 2.2. Price Elasticities of Demand for Electricity: Equal Price Change