NYISO Response to FERC Questions on Demand Response

1. Do you believe that, in order to promote and maintain fully competitive markets, demand side solutions should provide for long-term incentives (e.g., subsidies on an on-going basis)?

To ensure that demand side solutions contribute to the promotion and maintenance of fully competitive energy markets in New York State, the NYISO and its Market Participants have jointly developed and implemented an Emergency Demand Response Program (EDRP) and a Day-Ahead Demand Response Program (DADRP). Incentive structures in each encourage participation so as to achieve each program's stated purpose, given the market circumstances under which each was designed.

The EDRP Program is designed to provide NYISO system operators with an additional tool for responding to system emergency conditions in the New York Control Area (NYCA). It provides financial incentives to program participants willing to voluntarily curtail their energy consumption when directed to do so by the NYISO. Because the EDRP serves an important reliability function, financial incentives to encourage and maintain participation may be required over the long term. The need for long-term financial incentives, however, will be reviewed and reconsidered in the future as the NYISO evaluates the performance of the program.

The DADRP program is designed to provide an economic and market-based tool for encouraging demand side response to market signals in the Day-Ahead Market. The program currently includes an incentive payment in recognition of the fact that demand response is in its infancy in the New York energy markets. As has been the case with most nascent products, markets, or industries, customers need incentivized economic benefits to become participants in such new programs. Accordingly, the DADRP includes a financial incentive to encourage the development of this new energy market product.

As DADRP continues (it has been approved until Oct. 31, 2004), the NYISO and its Market Participants will evaluate the costs and benefits of the program to determine if the level of participation and payments, and the costs to other Market Participants, are appropriate and provide the right market signals. When and if retail energy customers begin to receive price signals in their retail rates that more effectively convey the continuously changing dynamic of wholesale energy prices, demand side solutions may be able to thrive entirely on market-based financial support and incentives may be phased out.

2. Please briefly describe each load response program of the transmission owners that are located in NYISO.

Attachment A summarizes the load response programs offered by New York Transmission Owners. In addition to the eight Transmission Owner (TO) programs described, a total of nineteen other Curtailment Service Providers (CSP) offer programs that deliver the NYISO's demand response programs to the retail customer:

- *Four unregulated load serving entities*
- *Seven aggregators*
- *Eight EDRP direct customers*

Non-TO providers currently sponsor 34 percent of the total EDRP registered megawatts.

3. What is the mix of customer participation (e.g., residential, small commercial, large commercial, industrial) by type of program within NYISO?

As of 9/12/2002, the NYISO's EDRP had the following approximate breakdown by customer class (the NYISO's registration process does not require end-use customers to identify class):

Customer Class	***MW Registered***	***# of Customers***
Industrial	*929*	*88*
Large Commercial (=1 MW)	*293*	*148*
Small Commercial (<1 MW)	*238*	*1466*
Residential	*20*	*Not recorded*
Totals	***1480***	***1702***

3. (continued) For each customer for each instance of demand response triggered during the summer of 2002, provide (a) the expected MWs to be reduced, (b) the actual
MWs reduced, (c) the respective hours (or fraction thereof) of reduction, (d) the payment for reduction and whether it was the locational marginal price or the stated price for demand response, (e) the market price when demand response was triggered and (f) whether this curtailable load or demand reduction was counted toward an installed capacity obligation.

Also indicate for each triggering of demand response, whether there was an emergency alert (Stage 1 or higher), whether customers were interrupted, or whether other active load management was called upon before demand response was triggered, and the level of operating reserves. This information should be provided separately for each instance.

Attachment B summarizes the system conditions, activation sequence and EDRP and ICAP Special Case Resource performance on the four days in 2002 when the programs were activated.

4. What are the respective triggers (e.g., operating reserve levels, price) in the NYISO tariff for calling on demand response? How may times have you reached that point this past Summer? Have you called on demand response each time there was an opportunity to do so? Are there selection criteria for calling on demand response (e.g., certain customers/types of demand response over others), and if so what are they? If you have not called on demand response each time you reached the trigger provided in the tariff or as part of the program, what was the basis/reasoning for not calling on demand response and what were the market price and system conditions at the time?

The procedures described in the following NYISO manual sections are used for activating EDRP:

- *Emergency Operations manual section 3.3 Major Emergency*
- *Emergency Operations manual section 4.4 Operating Reserve Deficiency*
- *NYISO EDRP manual.*

Notification of possible EDRP activation was given for the following dates in 2002:

- *4/16, 4/17, 4/18, 7/30, 7/31, 8/1, 8/2, 8/14, 8/15*
- *EDRP was, in fact, activated on 4/17, 4/18, 7/30, 8/14.*

The NYISO's decisions, whether to issue notifications of potential EDRP activation or to actually activate EDRP, were based on its assessments of in-dayreal time system conditions.

5. How are the costs of the load response programs recovered, e.g., are they based on all participants in the day-ahead or real-time markets?

The monthly charge for EDRP payments are recovered from all Transmission Customers, and are calculated as the product of (A) payments made to CSPs by month and (B) the ratio of (i) the customer's billing units for the month to (ii) the sum of all billing units during that month.

Billing units are based on the Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA, and hourly Energy schedules for all Wheels Through and Exports. To the extent that the ISO activates the EDRP in response to an Emergency or a real-time locational Operating Reserves shortage or a peak forecast of an Operating Reserves shortage in a particular zone or zones, including relief to meet a Local Reliability Rule within a zone as requested by a Transmission Owner, the billing units for such charges are based on the Actual

Energy Withdrawals in the affected zone(s) during the hours in which the Emergency Demand Response Program was activated.

DADRP costs are also recovered from Transmission Customers.

A static method is used to allocate costs associated with the under-collection of revenue according to those who benefit from the DADRP:

a) *Each Zone (or set of Zones)is allocated the cost of the DADRP based upon its load ratio share on a daily basis using real-time metered daily load data and the static probability: (i) that no constraints existed, (ii) that this Zone(s) was upstream of a constraint and curtailment occurred upstream, and (iii) that this Zone(s) was downstream of a constraint and curtailment occurred downstream.*

b) *The three most often limiting NYCA interfaces are used, with the total probabilities (for the historical period June 12-September 30, 2001) of them being limiting or having no constraints normalized to 100%. Based upon current data, the three most limiting interfaces historically have been Central-East, Sprainbrook-Dunwoodie, and Con Ed - Long Island. For the purposes of DADRP cost allocation, four composite zones are used: West of Central-East (Zones A,B,C,D,E,), East Upstate Excluding NYC and LI (Zones F,G,H,I), New York City (Zone J), and Long Island (Zone K). For the period June 12 –September 30, 2001, the percentages of time when the specific interfaces were constrained are:*
   - *No constraints: 36.%*
   - *Central-East: 4.9%*
   - *Con Ed – Long Island: 55.1%*
   - *Sprainbrook – Dunwoodie: 3.6%*

The equations used to allocate costs to individual LSEs are as follows:

For LSE m in Zones A-E:

$\boldsymbol{a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +}$ **'no constraints**

$\boldsymbol{a_2 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E) +}$ **'above Central-East const**

$\boldsymbol{a_3 * (cost_A+\ldots+cost_I+cost_k) * load_m / (load_A+\ldots+load_I+load_k) +}$ **'above S-D constraint**

$\boldsymbol{a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)}$ **'above CE-LI constraint**

For LSE m in Zones F-I:

$\boldsymbol{a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +}$ **'no constraints**

$\boldsymbol{a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +}$ **'below Central-East const**

$\boldsymbol{a_3 * (cost_A+\ldots+cost_I+cost_k) * load_m / (load_A+\ldots+load_I+load_k) +}$ **'above S-D constraint**

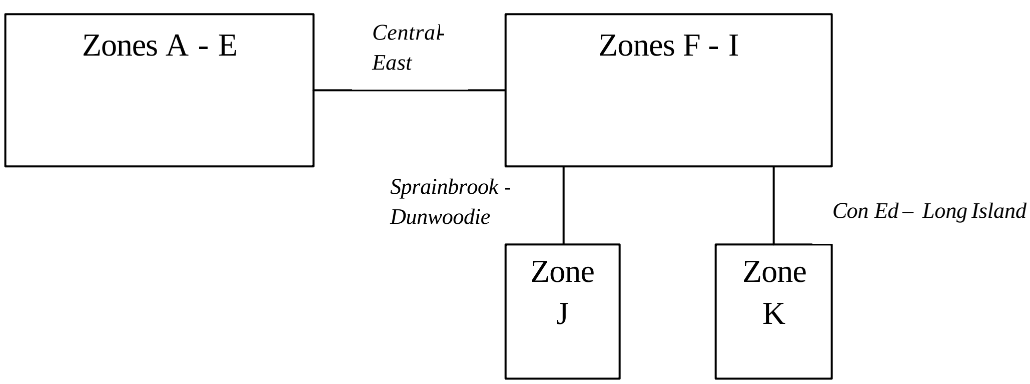
$\boldsymbol{a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)}$ **'above CE-LI constraint**

For LSE m in Zone J:
$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ **‘no constraints**
$a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +$ **‘below Central-East const**
$a_3 * cost_J * load_m / load_J +$ **‘below S-D constraint**
$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)$ **‘above CE-LI constraint**

For LSE m in Zone K:
$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ **‘no constraints**
$a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +$ **‘below Central-East const**
$a_3 * (cost_A+\ldots+cost_I+cost_k) * load_m / (load_A+\ldots+load_I+load_k) +$ **‘above S-D constraint**
$a_4 * cost_K * load_m / load_K$ **‘below CE-LI constraint**

In all cases, the variables are:
a_1 = fraction of time when no constraints exist (0.364)
a_2 = fraction of time when Central-East interface is constraining (0.049)
a_3 = fraction of time when Sprainbrook-Dunwoodie interface is constraining (0.036)
a_4 = fraction of time when Con Ed-Long Island interface is constraining (0.551)
$cost_{A\ldots K}$ = revenue deficiencies due to DADRP load reductions in zones A…K, calculated on a daily basis
$load_m$ = real-time load for LSE m, calculated on a daily basis
$load_{A\ldots K}$ = real-time loads for all LSEs in each zone A…K, calculated on a daily basis

The specific values for $a_1 \ldots a_4$ will be used for 2002. The specified values and the overall methodology will be reviewed by the Price-Responsive Load Working Group prior to 2003.



Relationship Between Interface Constraints and Zones

6. Is there any evidence of gaming by market participants in the demand response programs? If so, please identify each specific instance. How do DR gaming opportunities (if any) compare to supply-side gaming opportunities?

In the eight instances where the NYISO has called upon EDRP and SCR resources over the past two years, there has been no evidence of gaming by market participants. The NYISO follows a detailed set of procedures for verifying EDRP load reductions so as to minimize the possibility of gaming.

Participants in the DADRP have, on a few occasions, submitted zero price load reduction offers for one- to two-week periods over holidays, effectively acting as a price-taker during long-duration scheduled outages. While this behavior was not specifically prohibited in the initial program design, it does not represent a true reduction in consumption based upon price and, therefore, has no overall market benefit. In response to this behavior, the NYISO is proposing a minimum floor of $50/MWHr; participants' average offer price must be at least at this level to be considered for scheduling in the day-ahead energy market.

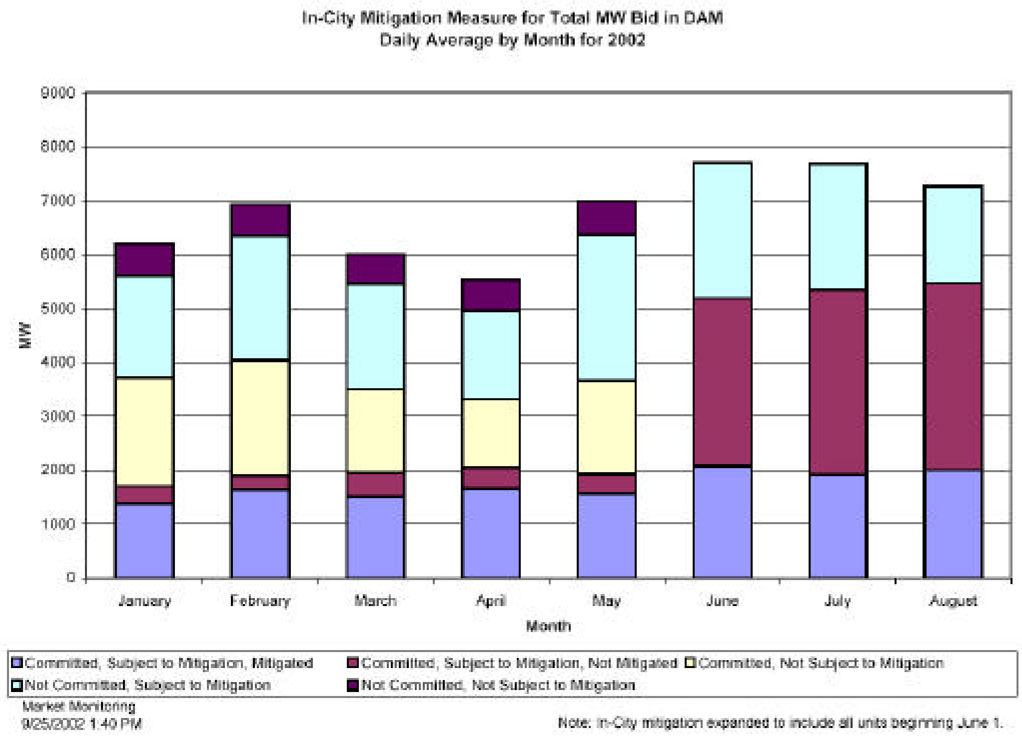
7. Has the NYISO encountered any resistance from electric distribution companies during the registration and/or verification process of the ISO's DR programs?

No. In fact, distribution companies have worked with the NYISO and the New York Department of Public Service (NYDPS) to implement programs that are consistent with the NYISO's demand response programs.

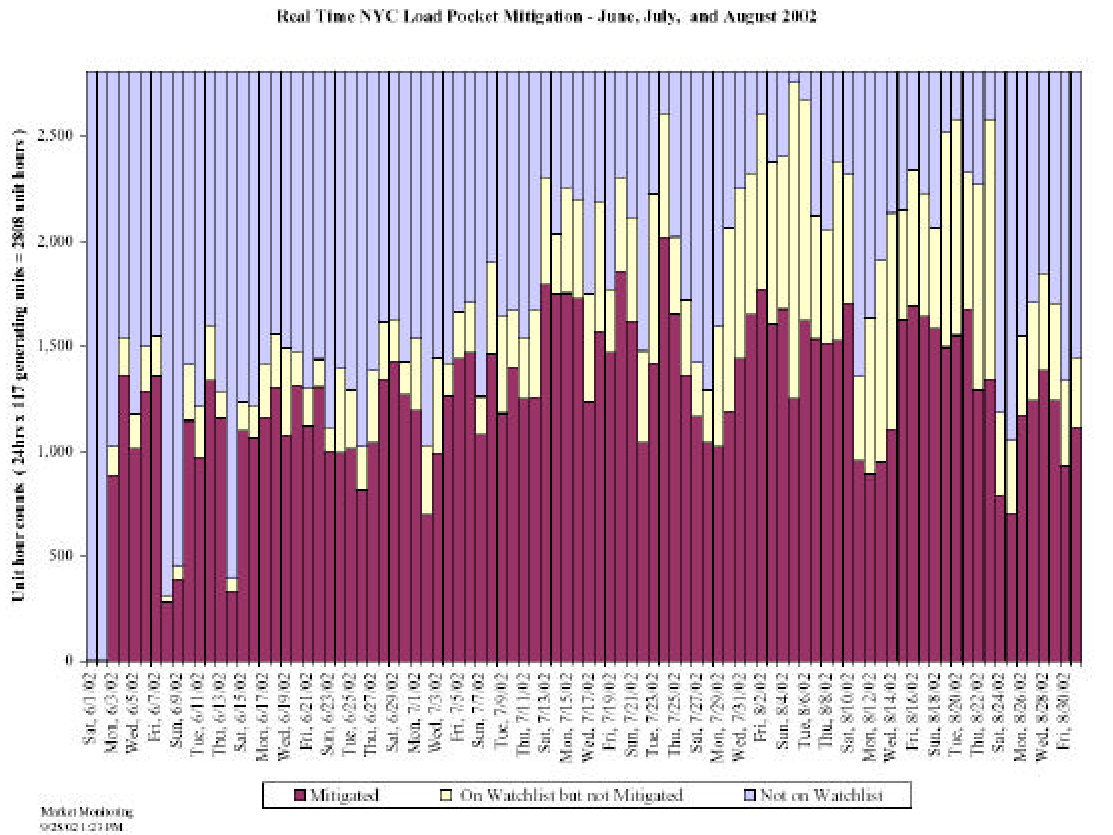
Verification of EDRP performance is subject to the normal meter read cycle, which can introduce delays in the normal 45-day data submission process for those companies acting as Meter Data Service Providers (MDSPs). To date, the NYISO has not had any significant (more than two week) delays beyond the 45-day window, and we have worked with program participants, CSPs and MDSPs to resolve any outstanding metering issues.

8. How often have prices in NYISO been mitigated during the past year? What were the prices pre- and post-mitigation? How is the decision made to mitigate as opposed to triggering a demand side response?

For the day-ahead market, mitigation actions have been limited to load zones in New York City, which occurs almost daily. The attached chart illustrates the daily average number of megawatts bid in NYC (by month) and how much of that was mitigated and committed.



For the real time market, mitigation also occurred in New York City. The attached chart for real time shows mitigation on a unit hour basis, with categories for mitigated units, units on watchlist but not mitigated, and units not on the watchlist. Real-time in-city mitigation began in early June.



The NYISO plans to report later this year on the effect of the in-City measures, both Day-Ahead and Real-Time. That report will include an assessment of price impacts. However, those impacts are not accessible yet in a timely manner.

9. What was the impact on price when demand response was invoked ($ per MWH impact, MW reduction, duration of load response)?

Attachment C describes the estimated benefits of the NYISO demand response programs based upon 2001 experience; Attachment F contains a discussion of the impact of demand response on scarcity pricing, and estimated improvements as a result of proposed changes to the EDRP and SCR programs.

10. To what extent did NEPOOL's Southwest Connecticut Reliability Relief Program affect prices in that area this past Summer? Do PJM and NYISO currently have, or are they developing, targeted demand side programs for congested sub-regions? If not, please indicate whether there would be benefits to such a program and, if so, how it could best be designed.

The NYISO has no plans to design such a Reliability Relief Program. Reflecting congestion in the day-ahead market prices and locational ICAP requirements, in the NYISO's view, provides sufficient signals for demand response in New York.

11. What type of program evaluation does NYISO perform for the demand response programs? Do they evaluate the cost-effectiveness of the program, participation, and impact on wholesale prices? If so, please provide a copy of such studies to the Commission.

Attachment D is the executive summary taken from the 2001 NYISO demand response program evaluation report prepared by Neenan and Associates. The full report (roughly 600 pages) can be made available in electronic form upon request.

The NYISO is undertaking an evaluation of the performance of the price-responsive load programs it has made available to customers for the summer 2002. The objective of the PRL program evaluation is three-fold:

1. *Quantify the level and distribution of benefits arising from curtailments undertaken by NYISO PRL program participants in 2002, and compare them to the 2001 program results,*
2. *Characterize the key drivers to customer participation in existing PRL programs and develop a more comprehensive understanding of how changes in program features affect participation and response, with special focus on DADRP, and*
3. *Characterize the key drivers to customer participation in the ancillary services price-taker markets now under development as part of the RTS.*

The NYISO intends to use the results to evaluate the benefits of changes in the design of its existing PRL program , to support the design of new PRL offerings, and to contribute to the general understanding of how customers value participation in programs that expose customers to market prices. LSEs, CSPs, and TOs use the results to design derivative or complementary programs and to devise marketing strategies for recruiting participation. The NYDPS employs the results to ascertain what role the incumbent utilities should play in promoting customers participation in competitive electricity markets. The state's system benefit fund administrator – the New York State Energy Research and Development Authority - (NYSERDA) uses the evaluation results to design programs that enable greater customer participation in price responsive load programs. A *copy of the draft 2002 report will be included as part of the NYISO's December demand response filing with the FERC.*

12. Is NYISO taking an active role in promoting greater participation in the DR programs in the ISO? If so, how?

For the past two years, the NYISO, together with the NYDPS and NYSERDA, have assembled and presented programs to potential CSPs and end-use customers. In the spring of 2002, a series of six workshops were scheduled across the state, providing the opportunity to discuss program mechanics directly with interested parties. In addition to the workshops, the NYISO participated in two meetings with specific TOs, their account representatives, and interested end-use customers.

The NYISO has also participated in several conference panel sessions directed at demand response, including presentations for the Midwest ISO, INDIEC, New York Multiple Intervenors, and the IEEE PES Winter Power Meeting.

13. What plans does the NYISO have in place to support competitive metering? Please provide a copy of any studies you have done on this subject.

The NYISO believes the issue of competitive metering falls under the purview of the NYDPS, and supports the evolution of such programs to the extent required at the wholesale level. As a separate issue, regardless of the status of competitive metering in New York, the NYISO supports the introduction of real-time metering technology as programs such as the NYISO's Real-Time Scheduling software proceed.

For emergency demand response programs, the NYISO program rules allow for the use of real-time metering and energy management data collection systems in addition to revenue meters.

Specific Questions Pertaining to NYISO

26. NYISO recently amended its Emergency Demand Response Program to allow up to 25 MW of participation by aggregations of small customers that would not otherwise be able to participate due to existing requirements for performance measurement. Has NYISO relaxed these requirements or installed new devices to allow for measurement? If the latter, please identify the new devices, their cost and the derived benefit (expressed in $ per MWh) from the participating customers.

The NYISO has incorporated the small customer aggregation requirements into EDRP. To date, two TO direct load control programs (Long Island Power Authority and Consolidated Edison) have enrolled and participated in the August 14 event. Information on the costs and benefits of these programs can be obtained by contacting the program sponsors.

27. In NYISO, load under a DR program is paid the zonal price. What would be the impact (if any) of paying a nodal price.

The NYISO'sDADRP pays on a nodal price basis. EDRP, however, pays zonally, but real-time prices have been low, resulting in uniform $500/MWHr payments.

28. Under NYISO's day-ahead demand response program (where retail customers can participate through LSEs), what has been the level of participation and has demand-side set the clearing price?

Attachment E provides statistics on the offers and accepted offers received from DADRP participants in 2002.

29. How many MW of demand response does NYISO have under its programs in New York City and how often has it been called upon in the past year?

Attachment B delineates the EDRP registration by geographic zone; New York City is represented as Zone J.

DADRP has no active NYC participation.

30. In NYISO's Emergency Demand Response program, payment is based on the higher of $500 per MWh or the zonal real time locational price per MWh of demand reduced. What is the support/basis for the $500 per MWh payment, i.e., how was it arrived at and how does it compare to alternatives other than DR at the margin?

When EDRP was initially developed in the Spring of 2001, it was believed that the $500/MWh payment was a reasonable proxy reflecting expected real-time conditions. Real-time prices during the four events in 2002, however, were not consistent with this assumption. In August the NYISO and market participants began working on revisions to the EDRP and SCR programs that would allow for scarcity pricing conditions when these resources are needed but, at the same time, would not present a barrier to participation. Attachment F describes the resulting program changes as approved by the NYISO Business Issues Committee on Sept. 25, 2002.

If EDRP resources are called upon only to resolve reserve shortfalls, which arise because there is no generation available to supply these reserves at any price, then the correct valuation is the cost customers would incur if the situation resulted in an outage. The convention for measuring outage costs is to weight customer damage and inconvenience costs by the marginal probability of an *outage. In the case of EDRP, that marginal improvement on the probability of an outage times the accepted customer outage costs would be relevant.*

A relative small body of research into outage cost suggests that they are subject to a large range of values, from near zero to over $100/kWh. Values between $2.50 and $5.00 have been used in the industry for planning purposes, and the English PoolCo pricing mechanism utilized a value near $2.50/kWh to price congestion. Clearly in the context to EDRP, the valuation would be situation-specific, depending on the reliability improvement that resulted. In a specific instance investigated as part of the NYISO program evaluation, when EDRP resources were invoked, reserves were at 25% of design level, and EDRP resources contributed to abating that shortfall improving the marginal LOLP by .25. Using an outage cost of $2.50/kWh, that translates into an equivalent value of the EDRP reprocess of over $.63/kWh, which would rationalize the EDRP floor payment of $.50/kWh. The actual hourly valuation would depend on the prevailing circumstances, and lower assumed outage cost values lower the value of the curtailed loads, but higher values raise the valuation.