UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Programs — Docket No. AD02-23-000

NOTICE OF PRESENTATION ON DEMAND RESPONSE ISSUES
AND REQUEST FOR PUBLIC COMMENT

(September 20, 2002)

Take notice that at the Commission's public meeting on October 9, 2002, presentations will be given on demand response (DR) programs in the Northeastern United States. These presentations will include panels that will generally address how the DR programs in PJM Interconnetion, L.L.C. (PJM), the New York ISO (NYISO) and ISO-New England (ISO-NE) are designed to operate, how they performed during this past Summer and how they may be improved upon. In preparation of those presentations, PJM, NYISO and ISO-NE are explicitly requested to respond to the following questions as they apply to their ISO, and the public is invited to also comment on these questions.

<u>Questions Pertaining to All Three Northeast ISOs</u>:

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

2. Please briefly describe each load response program of the transmission owners that are located in [PJM / NYISO / ISO-NE].

3. What is the mix of customer participation (<u>e.g.</u>, residential, small commercial, large commercial, industrial) by type of program within [PJM / NYISO / ISO-NE]? 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.

4. What are the respective triggers (e.g., operating reserve levels, price) in the [PJM / NYISO / ISO-NE] 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

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?

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?

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

8. How often have prices in [PJM / NYISO / ISO-NE] 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?

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

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.

11. What type of program evaluation does [PJM / NYISO / ISO-NE] 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.

12. Is [PJM / NYISO / ISO-NE] taking an active role in promoting greater participation in the DR programs in the ISO? If so, how?

13. What plans do [PJM / NYISO / ISO-NE] have in place to support competitive metering? Please provide a copy of any studies you have done on this subject.

<u>Specific Questions Pertaining to PJM</u>:

14. Did PJM reach its estimated demand side load reduction of 2700 MW this past Summer?

15. PJM's Emergency Load Response program relies on the higher of the $500 per MWh or the appropriate zonal locational price for payment for demand reduction. What is the basis for the stated $500 per Mwh? How was this figure computed?

16. Is the $500/MWH minimum payment in the PJM Emergency Load Response Program an inhibiting factor in the frequency of calling that program? If so, what is a more appropriate level for the minimum payment?

17. How often did PJM's Economic Load Response program participants reduce load when the LMP was below $75/MWh? How often when the LMP was equal to or greater than $75/Mwh?

18. How many times did PJM declare a Maximum Generation Emergency this Summer? Did PJM implement load reductions prior to the Active Load Management (ALM) program?

19. When clearing prices are at or below $75 per MWH, is a transmission and distribution off-set used to reduce the payments that are made to customers who participate in the PJM Economic Load Response Program? If so, what is the justification for this?

20. Should retail customers whose contracts are based upon Locational Marginal Pricing (LMP) be included in PJM's Economic Load Response Program?

21. Please explain why on certain days this past Summer (<u>e.g.</u>, July 29, 2002), PJM's Emergency Load Response Program was not called prior to the calling of an Active Load Management event?

22. How effective has PJM's customer baseline calculation methodology proven to be as a surrogate for past history?

23. How many customers in PJM are actually participating in the day-ahead and real time bidding markets as opposed to participating as price takers? If the number of

bidding participants is low in comparison to the number of price takers, what is the reason for this?

24. Is PJM planning to make any changes in the interface for load response customers in order to facilitate their participation as real-time market bidders?

25. Has PJM conducted a comparison of the benefit of the Load Response Programs to the Active Load Management Programs? If not, does PJM plan to do so?

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.

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?

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?

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?

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?

This notice is available for review at the Commission or may be viewed on the Commission's web site at http://www.ferc.gov using the "RIMS" link, select "Docket #" and follow the instructions (call 202-208-2222 for assistance). Comments may be filed electronically via the Internet in lieu of paper; see 18 C.F.R. 385.2001(a)(1)(iii) and the instructions of the Commission's web site under the "e-Filing" link. Comments should be filed no later than October 4, 2002. The Commission strongly encourages electronic filings.

Magalie R. Salas
Secretary