Market Monitoring Unit

COMPLIANCE REPORT
TO
THE FEDERAL ENERGY REGULATORY COMMISSION

Docket No. ER02-1326-006

ASSESSMENT OF PJM LOAD RESPONSE PROGRAMS (REVISED)

PJM Market Monitoring Unit

October 31, 2004

In an order issued August 8, 2003,[1] the Federal Energy Regulatory Commission (FERC) ordered PJM Interconnection, L.L.C., to make two compliance filings (on December 31, 2003 and October 31, 2004) based on the FERC evaluation of PJM's report filed on June 2, 2003 ("Report to the Federal Energy Regulatory Commission: PJM 2002 Load Response Program"). PJM submitted the first compliance report "Assessment of PJM Load Response Programs" on December 31, 2003. The Market Monitoring Unit of PJM Interconnection, L.L.C. (PJM) submits this second report assessing the effectiveness of PJM's load response programs in response to the August 8 Order.

The Economic Program[2]

Data on Economic Program

The Economic Program has grown significantly in the three years since 2001, as measured by total MW enrolled in the program and actual MWh response under the program. Table 3 shows the increase in registration in the Economic Program over the past three years.[3] In 2004, there were a total of 1,109 MW registered in the Economic Program, an increase of 53 percent from the 724 MW registered in 2003, which was an increase of 115 percent from the 337 MW in 2002 which was, in turn an increase of about 400 percent from the 65 MW enrolled in 2001. Table 4 shows the actual load reductions and associated payments under the Economic Program from 2001 to 2004. The level of load reductions increased from 50 MWh in 2001 to 6,462 MWh in 2002 to 19,290 MWh in 2003 to 31,719 MWh in 2004.[4] Consistent with lower system LMPs, payments per MWh decreased 58 percent from 2001 to 2002, decreased 64 percent from 2002 to 2003, and decreased 19 percent from 2003 to 2004.[5] The MWh of actual load reductions per MW enrolled in the Economic Program increased significantly in 2002, increased about 40 percent in 2003 and increased about 10 percent in 2004.

The detailed data requested by the Commission is included in the attached Tables and Figures. Table 1 includes data on the Pilot Program. Table 2 presents data on the price impact of DSR programs. Tables 3, 4 and 5 include summary data on the Economic Program. Table 6 presents data on total payments under the Economic and Emergency Programs from 2001 through 2004, while Table 7 shows MW enrolled in each program from 1999 through 2004. Table 8 includes daily data on the Economic Program. Table 9 shows MWh reductions both when the LMP is greater than and less than $75/MWh. Table 10 provides zonal detail for the Economic Program. Figure 1 shows the relationship between total reductions under the Economic Program and credits paid under

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1 PJM Interconnection, L.L.C., 104 FERC 61,188 (2003) (August Order).

2 There was no 2004 activity in the Emergency Program. As a result there is no separate section of this Report addressing the Emergency Program. Enrollment data is included in the summary tables.

3 Table and Figures for 2003 include a full 12 months of data. Only 9 months of data was available when the prior report was filed. Attachment A contains updated tables and figures for the complete year of 2003. Tables and Figures for 2004 include the seven months of available, verified data.

4 Load reductions are measured by multiplying hourly MW reductions by the hours in which they occurred. Thus a 1 MW reduction for one hour is 1 MWh. A 1 MW reduction in one hour and a 3 MW reduction in a second hour equals 4 MWh.

5 About 81 percent of load reductions in 2004 took place when prices were less then $75/MWh. About 70 percent of load reductions in 2003 took place when prices were less than $75/MWh and about 34 percent of load reductions in 2002 took place when prices were less than $75/MWh.

the Program while Figure 2 shows the relationship between total reductions under the Economic Program and LMP and Figure 3 shows the relationship between total reductions under the Economic Program and coincident system load. Figure 4 shows aggregate supply and demand curves for 2002, 2003 and 2004. Figure 5 illustrates the relationship between average hourly reductions and LMP. Figure 6 shows the frequency of reductions occurring when the LMP was less than $75 and Figure 7 shows the frequency of reductions when the LMP was greater than or equal to $75/MWh. Figure 8 shows the frequency distribution of real-time reductions under the Economic Program by hour of the day for hours when LMP was less than $75. Figure 9 shows the frequency distribution of real-time reductions under the Economic Program by hour of the day for hours when LMP was greater than or equal to $75.

Overall, there was limited participation in Day-ahead option of the program. For the 15 end users that were participating, reductions in only 10 hours were cleared in June.

There were 22 total end users that registered as LMP based customers, of which 8 also were registered as ALM customers. Overall there were 60 customers that selected the ALM option. During the period of interest there were no instances when LMP based customers curtailed. Likewise, there were not any end users with a standing bid dispatched in real time.

Results of the Economic Program:
Table 9 shows that 94 percent of MWh reductions, 85 percent of credits and 91 percent of hours resulted from the Real-Time Option under the Economic Program. Table 9 shows that 1 percent of the MWh reductions, 1 percent of the credits and 1 percent of the hours resulted from the Day-Ahead Option. Finally, Table 9 shows that 5 percent of the MWh reductions, 14 percent of the credits and 8 percent of the hours resulted from the Pilot Program.

There is a significant difference among zones in activity under the Economic Program. For example, 87 percent of MWh, 82 percent of credits and 54 percent of hours under the Real-time Option were accounted for by a single zone. Overall, 82 percent of MWh, 71 percent of credits and 51 percent of hours under the Economic Program were accounted for by a single zone. (See Table 10.) By contrast there were four zones where no activity occurred in either of the DSR programs.

Table 9 shows that 81 percent of all MWh reductions, 48 percent of all credits and 61 percent of all curtailed hours under the Economic Program occurred when the LMP was less than $75/MWh.

Figure 8 shows that activity under the Economic Program when LMP was less than $75 was dispersed over all hours of the day with maximum activity spread fairly evenly over hours ended 0900 to 2200. Figure 9 shows that activity under the Economic Program when LMP was greater than $75 was concentrated more narrowly in hours ended 0700 to 2200 with maximum activity concentrated in hours ended 1400 to 1800.

After Commonwealth Edison (ComEd) Company was integrated into PJM's markets, (May 1, 2004), ComEd participants were provided with an option of participating in PJM's DSR program. Between June and July of 2004, 4,121 end users enrolled in the program of which 4,119 selected the emergency option and two chose to participate in the economic program. Of these, 217 end users entered the program as an ALM/MIL (Mandatory Interruptible Load) customer. None of these participants registered as LMP based customers. No reductions were performed by either of the participants. MIL is a month-by-month, year-round program in ComEd.

Costs and Benefits of Economic Program

The quantifiable costs of the Economic Program include the direct administrative costs of operating the programs for PJM and LSEs as well as the cost of subsidies paid to market participants.[6] The directly quantifiable benefits are based on the price impact of the load reductions that result from the Economic Program. Note that the costs and benefits are calculated from the perspective of the wholesale market. No attempt is made to assess the costs or benefits of individual participants.

The direct administrative costs of the Economic Program are difficult to calculate precisely but are estimated to be approximately $20,000 per year. When divided by the total 31,719 MWh of load reductions that result from the programs in 2004, the cost is less than $1/MWh of load reductions. The administrative cost was also about $1/MWh for 2003 and 2002.

The costs of the Economic Program associated with payments by LSEs are the payments for the generation component of retail rates. The data show that of the $1,096,573 total payments to loads by LSEs under the Economic Program in 2004, $854,816 were payments made by the LSEs directly serving load and $243,249 were payments made by zonal LSEs and recoverable from zonal load. The $854,816 represents payments based on LMP less the generation and transmission components of retail rates. The $243,249 represents payments for both the generation and transmission components of retail rates. Under the assumption that these are approximately equal, the cost of the program is $121,625. When divided by the total 31,719 MWh of load reductions that resulted from the programs in 2004, the cost is about $4 per MWh of load reductions in 2004. In 2003, given the lower level of actual load reductions, the cost per MWh of load reductions was about $6 per MWh of load reductions in 2003, and about $13 per MWh of load reductions in 2002.[7] [8]

The payments of the LMP savings transferred by the LSEs are a direct benefit to curtailing customers ($1,096,573). In addition, curtailing customers save in the amount of

6 The programs are described in detail in the December 31, 2003 Report.

7 See the prior Report for a full explanation of the logic underlying these calculations.

8 If the total amount of recoverable charges reflecting the generation and transmission charges for the entire program exceeds $17.5 million in a year, participants will receive LMP less an amount equal to the applicable generation and transmission charges regardless of the level of LMP. This threshold has not been approached in any year to date. In 2004, the total charges reflecting the generation and transmission charges for the Economic Program were only $243,249.

the retail rates that they do not pay as a result of curtailing. As noted above, these customer-specific benefits are not the focus of this analysis, but serve to offset any customer-specific costs and provide an incentive for participation.

The Economic Program provides a benefit to all wholesale market customers when it results in a decrease in energy market prices. When load is reduced in response to price increases, the overall level of prices is less than it would have been in the absence of that load reduction, all else equal. Table 2 shows the price impact of all demand response programs which was estimated based on demand reductions and real-time supply curves. The maximum price impact of the Economic Program, on a stand-alone basis, was estimated to be about $50 per MWh on July 3, 2002.

During the summers of 2004 and 2003, the combination of milder weather and changes in supply and demand conditions resulted in lower prices. Again using actual demand reductions and real-time supply curves, the maximum price impact of the Economic Program was approximately $1 in 2004.

The reduction in market clearing price affects the entire energy market. Thus the dollar value of the benefit is the change in market price multiplied by total load at the time. Thus, in 2004, even using an average $.50 per MWh of overall price reduction multiplied by the average hourly load during the load reductions of about 48,000 MW equals $24,000 per hour, or about $54,000,000 for the 2,248 hours of load reductions.[9] Even if adjusted for the share of the spot market in total activity (about 40 percent) the market price benefits are about $22,000,000, still much larger than the direct costs of the program.

The maximum hourly load reduction attributable to the Economic Program was about 168 MWh in 2004. Based on the real-time supply curves for a representative day during the summer of 2004 and the summer peak load, a reduction of 1,000 MW would have resulted in a $10 reduction in LMP and a reduction of 2,000 MW would have resulted in a $15 reduction in LMP. LMPs were lower during the summer of 2004 based on supply-demand fundamentals and the potential price impacts of load reductions was also attenuated by supply-demand fundamentals. This is demonstrated by the aggregate supply curve for the summer of 2004. (See Figure 4.)

In summary, direct administrative costs for the PJM Economic Program were about $1 per MWh of actual load reductions in 2004, 2003, and 2002. The subsidy costs were about $13 per MWh of load reductions in 2002, about $6 per MWh of load reductions in 2003, and about $4 per MWh of load reductions in 2004. Thus, total program costs were approximately $14 per MWh of load reductions in 2002, about $7 per MWh of load reductions in 2003, and about $5 per MWh of load reductions in 2004. The benefits of the Economic Program when measured as the impact on overall market prices were much larger than the costs. These benefits are a direct function of prevailing market price levels and will thus increase if prices rise compared to 2004 levels or decrease if prices decrease

[9] The 2,248 represents unique hours in which load reductions of any type under the Economic Program occurred.

compared to 2004 levels. The evaluation of the benefits associated with overall market price reductions must consider that these benefits do not necessarily represent an increase in market efficiency but represent a transfer from generation to load, in the short term. Whether this results in a lower overall market cost in the long run remains to be seen. Regardless, the potential benefits of increasing demand side responsiveness in improved efficiency of the market are extremely large and certainly exceed the relatively small program costs by a wide margin. These benefit calculations do not include any calculation of reliability benefits of the demand side programs. It was not necessary to make such a calculation to demonstrate that there are substantial net benefits to the Economic Program.

Economic Program and the Demand Side of Markets: Strategy for the Future

As stated in the prior Report, the Economic Program should be understood as a transition mechanism to a fully functional demand side of the energy market. Thus in order to understand how PJM can "best elicit the maximum possible amount of demand response"[10] and whether the current programs are the best means of doing that, a complete transitional strategy must be more fully developed and implemented. PJM has begun taking steps toward a complete transitional strategy that must continue to be more fully developed.[11] The Economic Program is an essential part of the portfolio of PJM demand side programs. The goal is to ensure that customers have the capabilities required to make informed decisions about energy consumption and that they face incentives based on market fundamentals.

In order to achieve these goals and to integrate a functional demand side into the wholesale energy market, PJM and its stakeholders must add new elements to the demand side portfolio that now includes primarily specific targeted DSR programs like the Economic Program and ensure that all PJM markets are designed so as to make demand side participation fully and seamlessly integrated into each PJM market. The specific targeted programs serve a critical function and should not be abandoned but at the same time these programs should be understood as a transition mechanism and not as the goal.

PJM and its members have begun the process of integrating DSR programs into market design. While there are many difficult issues to resolve, these represent significant steps. The members, voting at the April 15, 2004 Electricity Market Committee (EMC) meeting to extend the Emergency and Economic Load Response Programs through December 31, 2007, premised their unanimous endorsement on a commitment by PJM staff and the stakeholders to integrate demand response into PJM's markets.

More specifically, the EMC required PJM to present market initiatives for Demand Response to the Market Implementation Committee (MIC) together with timetables. A number of market initiatives were presented to the MIC at the May 26, 2004 meeting, including forward energy products, enhancement of the Emergency Load Response Program, development of a Demand Response product for the Economic Planning

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10 August Order at P 15.

11 This section is an abbreviated and updated version of the corresponding section in the prior Report. Please see the prior Report for a fuller exposition.

process and other congestion relief service, and development of Demand Response as reserve (10 minute spinning and other). In addition, PJM presented a proposed DSR Sub Model for the RPM to the DSR Working Group at a special meeting on August 13th.

Demand side resources are an essential part of the interface between wholesale and retail markets. Integrating and developing the demand side of wholesale power markets must rely to a significant extent on cooperation and coordination among the Commission, RTOs and state public utility commissions. In order for demand side resources to fully participate in the energy markets, the widespread installation of meters that permit the monitoring of real-time usage is essential. That is unlikely to occur without the referenced cooperation and coordination. The role of state public utility commissions is critical. The appropriate role for competition in the provision of meters and metering services must be considered and resultant changes implemented.

U.S. Department of Energy (DOE) and PJM representatives began discussions early in 2004 that led to a joint effort to reduce market barriers to distributed resources including demand response. This effort culminated in the two-day interactive workshop “Enabling Demand Response and Distributed Generation in the Mid-Atlantic” in June of 2004. The public utility commissions of Delaware, District of Columbia, Maryland, New Jersey and Pennsylvania, along with PJM Interconnection, the U.S. Department of Energy and the U.S. Environmental Protection Agency, announced the establishment of the Mid-Atlantic Distributed Resource Initiative (MADRI) to develop regional policies and market-enabling activities to support distributed generation and demand response in the Mid-Atlantic region. The working group will be headed by a steering committee comprised of utility commissioners from the five Mid-Atlantic States and representatives from PJM, DOE and EPA. The initial focus areas for the working group are interconnection standards, advanced metering, and regional DR benefits assessments.

While PJM is engaged in the effort to fully integrate demand response into its markets, PJM should continue its efforts to educate market participants about current programs and opportunities, and to recruit and train Curtailment Service Providers for the existing programs. The current programs are an essential part of the transition strategy and together with efforts to integrate demand side resources into all PJM markets and to remove institutional barriers to demand side resources, constitute a portfolio approach to develop the demand side of the power markets.

Costs and Benefits of Economic Program: Survey Results

In evaluating the level of DSR activity, it is important to include not just the activity that occurs in direct response to PJM programs but also other types of DSR activity. Both state public utility commission policies on retail competition and the programs of individual LSEs have had a significant impact on DSR activity. It has been difficult to acquire meaningful data on either of these phenomena. To address this issue, in July 2003 and September 2004, PJM conducted surveys of LSEs to obtain information about price responsive tariffs, as well as load response programs offered by either electric distribution companies or competitive electric suppliers at the retail level.

The July 2003 PJM survey results were discussed in the prior Report. The 2004 survey continued the format of the 2003 survey for EDCs serving as LSEs but added a new format for competitive LSEs designed to identify and quantify the load subject to curtailment, priced dynamically, or responsive to price by means of some other contractual mechanism as well as load served at a fixed price. The new format for competitive LSEs was designed to enhance the survey as a tool for identifying and measuring the amount of price responsive load in the PJM marketplace. PJM plans to issue the survey annually. The 2004 survey was issued at the September 2nd meeting of the DSR Working Group after prior review. The results of the survey were not available for this report.

Non Hourly-Metered Pilot Program
While it is essential to the full integration of the demand side of wholesale markets that appropriate metering technology be widely installed, the current lack of such meters should not be a barrier to participation in PJM's demand side programs, if adequate measurement and verification protocols are in place.

In 2004 one customer (with about 45,000 end users) participated in the non hourly-metered pilot program for about 134 separate hourly reductions totaling about 1,620 MWh and averaging about 12 MW per hour. Table 1 displays the non hourly-metered response by day. The expansion of the aggregate MW limit allowed for a maximum hourly reduction of 49 MW in the pilot program.

PJM developed and implemented a plan to attempt to validate the engineering methodology for estimating load reductions under the Pilot Program accomplished by direct load controls (DLCs) installed on the water heaters of large numbers of residential customers using the proposed measurement and verification methodology. The plan included analysis of a combination of customer usage data and sub-station data obtained during field tests in October and November of 2003. The results of the field studies were inconclusive largely because the participating customers were unable to follow the protocols precisely enough. The conclusion did not support continued inclusion of these customers in the Pilot Program.

Key results from the pilot project were a recognition that PJM pilot customers were using demand side resources to respond directly to market prices and that there remains a need to develop less expensive Measurement and Verification (M & V) methodologies for DLC resources.

The creation and extension of the non hourly-metered pilot program is an essential part of PJM's demand side resource efforts. Given the current absence of appropriate metering, especially for smaller customers, this program is the only way that such customers are likely to be able to participate in the demand side of the markets. This program should be continued and the MW threshold expanded further, with PJM continuing and strengthening its efforts to ensure that measurement and verification are accurate. In order to ensure that the program serves as a transition to a fully effective demand side of the wholesale market that can benefit all market participants, the Commission, PJM and state public utility commissions should continue efforts designed to encourage the installation of appropriate metering technology.