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December 31, 2003

Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, D.C. 20426

Re: PJM Interconnection, L.L.C., Docket No. ER02-1326-006
Report on PJM Load Response Programs

Dear Ms. Salas:

In accordance with the Commission's directive in PJM Interconnection, L.L.C., 104 FERC ¶ 61,188 (2003), the Market Monitoring Unit of PJM Interconnection, L.L.C. ("PJM") hereby submits the attached compliance report assessing the status of PJM's load response programs.

This report has been served upon each person designated on the official service list compiled by the Secretary in this proceeding.

If you have any questions regarding this matter, please do not hesitate to contact the undersigned.

Sincerely yours,

Carrie L. Bumgarner
Counsel for
PJM Interconnection, L.L.C.

cc: Service List

Attachment

Market Monitoring Unit

COMPLIANCE REPORT
TO
THE FEDERAL ENERGY REGULATORY COMMISSION

Docket No. ER02-1326-006

ASSESSMENT OF PJM LOAD RESPONSE PROGRAMS

PJM Market Monitoring Unit

December 31, 2003

In an order issued August 8, 2003,[1] the Federal Energy Regulatory Commission (FERC) ordered PJM Interconnection, L.L.C., to make a compliance filing 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"). Prior to this report, PJM submitted the "Report on the 2001-2002 PJM Customer Load Reduction Pilot Program" on December 28, 2001.

The Market Monitoring Unit of PJM Interconnection, L.L.C. (PJM) submits this report assessing the effectiveness of PJM's load response programs. PJM has prepared this report in response to the August 8 Order. This report on the PJM load response programs responds to a series of specific questions posed by the Commission regarding the Economic Load Response Program (Economic Program). This report also evaluates the non hourly-metered pilot program and the Emergency Load Response Program (Emergency Program).

The Economic Program

Data on Economic Program

The Economic Program has grown significantly in the two 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 two years. In 2003, there were a total of 724 MW registered in the Economic Program, an increase of 115% from 337 MW in 2002 which was, in turn an increase of about 400% over the 65 MW enrolled in 2001. Table 4 shows the actual load reductions and associated payments in the Economic Program from 2001 to 2003. The level of load reductions increased from 50 MWh in 2001 to 6,462 MWh in 2002 to 14,678 MWh in 2003.[2] Consistent with lower LMPs, payments per MWh have decreased 58% from 2001 to 2002, and decreased 61% from 2002 to 2003.[3] The MWh of actual load reductions per MW enrolled in the Economic Program increased from 2001 to 2002 and was relatively constant between 2002 and 2003.

The detailed data requested by the Commission is included in the attached Tables and Figures. Tables 3, 4 and 5 include summary data on the Economic Program. Table 8 includes daily data on the Economic Program. Figure 1 shows the relationship between total reductions under the Economic Program and credits paid under 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.

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

2 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 a second hour is 4 MWh.

3 About 80 percent of load reductions in 2003 took place when prices were less than $75 while 34 percent of load reductions in 2002 took place when prices were less than $75.

Analysis of Economic Program: Long Term Goal

The Commission requested "a full estimate of the costs and benefits of the Economic Program."[4] As is typically the case for efforts to calculate the costs and benefits of programs, costs and benefits that can be quantified must be distinguished from those that cannot be quantified in a meaningful way. Quantifiable costs and benefits of the Economic Program are discussed below. The costs and benefits that are not quantifiable are more difficult to assess and probably more important. It has been frequently and accurately pointed out that markets require both a supply and a demand side to operate efficiently. It has also been pointed out that the demand side of wholesale electric power markets is significantly underdeveloped. The Economic Program should be understood as a transition mechanism to a fully functional demand side of the energy market.

The reason that the Economic Program is required in order to elicit what are, with minor exceptions, rational responses to existing market price signals is based on the complex interaction between wholesale and retail market structures and incentives and the barriers to rational economic behavior that result.

A functional demand side of the energy market does not mean that all customers will curtail usage at specified levels of price. A fully functional demand side of the energy market does mean that all or most customers, or their designated proxies, will have the ability to see real time prices, will have the ability to react to real time prices, in real time, and will have the ability to receive the direct benefits or costs of changes in real time energy usage. If these conditions are met, customers can decide for themselves the relationship between the value and price of power for particular activities from operating a production plant to running a commercial building to smaller scale retail and residential applications. The real goal of demand side programs is to ensure that customers have the capabilities required to make informed decisions about energy consumption. Customers can and will make investments in demand side management technologies based on their own evaluations of those tradeoffs.

A functional demand side of the wholesale energy market does not necessarily mean that prices will be lower than they otherwise would be. A functional demand side of the market does mean that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and the actual cost of the power.

A functional demand side of the wholesale energy market will also tend to induce more competitive behavior among suppliers and will tend to limit the ability to exercise market power. If customers have the essential tools to respond to prices then suppliers will have the incentive to deliver power on a cost-effective basis, consistent with customers' evaluations.

The cost-benefit evaluation reduces to an evaluation of the effectiveness of the Economic Program in effectuating, or helping to effectuate, that transition. A narrow focus on the quantifiable, short-term costs and benefits may be significantly misleading. However an

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4 August Order at P 17.

analysis of the quantifiable costs and benefits is necessary as part of an evaluation of the Economic Program to determine if the Economic Program is as effective as possible in assisting the transition to a fully functional demand side of the market.

Analysis of Economic Program: Detailed Structure of Incentives

Incentives associated with the Economic Program are based upon the actual load reduction provided in excess of committed day-ahead load reductions plus the adjustment for losses. The actual payment depends on the level of zonal LMP.[5] If zonal LMP exceeds $75 per MWh, customers are paid the full LMP. If zonal LMP is less than $75 per MWh, customers are paid the LMP less the generation and transmission components of the applicable retail rate. The rationale for this difference is based on an assessment of the actual costs and benefits associated with customer load reductions. If the load response is dispatched by PJM, payment will not be less than the total value of the load response bid, including any submitted shut-down cost. 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 2003, the total charges reflecting the generation and transmission charges for the Economic Program were only $165,095.

From the perspective of an individual customer on a standard fixed retail rate, the savings that result from a load reduction equal that applicable retail rate. If the customer pays a total retail rate of $150 per MWh, the customer saves exactly $150 when consumption is reduced by 1 MWh. Standard retail rates include payments for generation, transmission and distribution. If the customer paid the LMP for each MWh used, rather than the generation component of retail rates, the savings to the customer associated with the reduction of usage by 1 MWh would equal the LMP plus the transmission and distribution component of retail rates. The situation is somewhat different if the LSE pays the LMP to purchase the energy required to serve the customer at a flat retail rate. In this case, the savings to the LSE from a reduction of 1 MWh by the customer equal the difference between the avoided cost to the LSE, or the LMP, and the lost revenue to the LSE, or the full retail rate. Thus, if the LSE pays the LMP to purchase energy to serve the customer, the savings received by the customer, paying a flat retail rate, will be less than the benefits, to the LSE, of reducing usage by 1 MWh when the LMP is greater than the full retail rate.[6] The difference between the savings to the LSE and the benefits to the customer equal the difference between the LMP and the generation component of retail rates.

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5 Relevant aggregate LMPs may also be used in some cases.

6 Depending on the structure of the transaction, this would also be the case if the LSE paid a flat rate to a generator and charged the retail customer a flat rate plus a mark up. In this case, the generator would incur the incremental cost equal to the LMP less the flat rate charged to the LSE whenever the real time LMP exceeds that flat rate. The incremental cost to the generator is the LMP because the output could be sold at the LMP rather than to the LSE, if the customer reduced load.

The design of the Economic Program reflects a compromise between the benefits that would be received by a customer paying LMP plus a fixed retail rate covering transmission and distribution charges and the benefits received by an LSE serving a retail customer under a fixed retail rate covering generation, transmission and distribution. When the LMP is less than $75 per MWh, customers that reduce load under the Economic Program receive a payment from the program equal to the LMP less the generation and transmission components of the retail rate. This is in addition to the direct savings that the customer achieves by reducing consumption and avoiding paying the retail rate. Thus, when the LMP is less than $75 per MWh, for a customer paying a fixed retail rate, the actual savings associated with reducing load equal the LMP plus the distribution component of retail rates. This is the case because the customer receives a payment under the Economic Program equal to the LMP less the generation and transmission components of the retail rate and the customer also avoids paying the generation, transmission and distribution components of the retail rate.[7]

When the LMP is greater than $75 per MWh, customers that reduce load under the Economic Program receive a payment from the program equal to the LMP. This is in addition to the direct savings that the customer achieves by reducing consumption and avoiding paying the retail rate. Thus, when the LMP is greater than $75 per MWH, for a customer paying a fixed, flat retail rate, the actual savings associated with reducing load equal the LMP plus the generation, transmission and distribution components of the retail rate. This is the case because the customer receives a payment under the Economic Program equal to the LMP and the customer also avoids paying the full retail rate.

The optimal payment under the Economic Program when LMP is in excess of $75 per MWh would be the LMP less the generation component of retail rates because the generation component of retail rates is paying for the cost of purchasing energy and is a substitute for the LMP. If a customer is paying $40 per MWh for energy (generation component) in retail rates but by reducing load eliminates the need to purchase a MWh at $900 per MWh, the benefit is $900 per MWh. The customer receives $40 per MWh of that benefit by not paying the generation component of the retail rate and should receive the balance, $860 in this example, from the LSE payment.

The $75 per MWh cutoff serves several purposes in the Economic Program design. It reduces the chances that customers will be paid based on differences between actual non-curtailed usage and the estimate of baseline load when in fact customers take no action to reduce load. The measurement of load reductions is based on the difference between actual load and baseline load. In addition, the $75 cutoff is a measure of the threshold for a system benefit. The probability of a system benefit related to load reductions is higher, the higher is the LMP. As explained below, a load reduction is more likely to have a significant impact on system price when demand and the corresponding LMP are high due to the shape of the supply curve. While customers should curtail whenever it is in their economic interests to do so, it is reasonable to have a threshold for the payment of a

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7 It is frequently the case that a Curtailment Service Provider is the intermediary between the customer and the LSE.

subsidy to customers in order to minimize overpayments for measured load reductions against an arbitrary baseline load.

The result of the payment structure in the Economic Program is that the LSE serving the curtailing load pays that load the LMP less the generation and transmission component of retail rates. This is a reasonable measure of the actual savings received by the LSE when it is not required to serve a load by purchasing energy at a price in excess of the generation component of retail rates. Even if the LSE is not literally purchasing the energy to serve the load, the LMP is the market value of that energy which could be sold by the LSE in the wholesale market at that price if it were not being provided to the retail customer. The LSEs in the zone where the curtailing load resides pay the generation and transmission component of rates to the curtailing load when the LMP is greater than $75 per MWh. Given that the optimal payment to curtailing loads would be the LMP, adjusted only for the generation component of retail rates, the payments by zonal LSEs represent a subsidy to curtailing loads to the extent that they cover the generation component of retail rates, but do not represent a subsidy to the extent that they cover the transmission component of retail rates. This assumes that the transmission and generation components of retail rates can be unbundled, which is a reasonable assumption.

As an example, assume that the LMP is $100 per MWh, the generation component of retail rates is $25 per MWh and the transmission component of retail rates is $20 per MWh. A customer that reduces consumption by 1 MWh would pay $45 less if only the retail rates were avoided. If the full LMP value of the energy were avoided, the customer would avoid $120 per MWh where the total is the sum of the $100 LMP and the $20 transmission component of retail rates. It would be double counting the generation/energy component of rates to reduce the customer's bill by the LMP plus the generation component of retail rates plus the transmission component of retail rates. The current program pays the customer the $100 LMP and the customer avoids the $25 retail generation component and the $20 retail transmission component for a total savings of $145. This represents a subsidy in the amount of the $25 generation component of retail rates.

Revisions were made to the business rules for the Economic Program effective April 1, 2003. These revisions were based on the FERC order issued on December 19, 2002 concerning LMP-based contracts.[8] Under an LMP-based contract an end-use customer agrees to pay its LSE for the delivery of energy based on the hourly LMP as calculated by PJM. Under the previous business rules, if an end-use customer were on an LMP-based contract, registration to the Economic Program would be denied. FERC ruled that customers on LMP-based contracts should be included in an appropriate manner in the Economic Program. The revised business rules allow for LMP-based customers to participate in the Economic Program in the real-time market only and based on specific rules specified in the tariff and business rules.

The goal of the basic Economic Program incentives is to ensure that customers on retail rates with an embedded generation component that is not linked to the market LMP see

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8 PJM Interconnection, L.L.C., 101 FERC 61,308 (2002).

the appropriate price signal. The goal of the incentive program is to encourage customers to move to a pricing structure where they can avoid the market LMP when appropriate. In effect the program provides an accounting mechanism under which the LSE provides the wholesale energy market savings, or a share of them under a contract, to the end use customer. The Economic Program provides an accounting mechanism, managed by PJM, that requires the payment of the real savings that result from load reductions to the load reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the incentive and regulatory structures faced by LSEs and customers. The broader goal of the Economic Program is to transition to a structure where customers do not require mandated payments but where customers see and react to market signals or enter into contracts with intermediaries to provide that service. Even as currently structured, the Economic Program represents a minimal and relatively efficient intervention into the markets.

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. 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. The direct administrative costs attributable to the Economic Program are approximately $20,000 per year. When divided by the total 14,678 MWh of load reductions that result from the programs in 2003, the cost is about $1/MWh of load reductions. The administrative cost number is comparable for 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 total payments to loads by LSEs under the Economic Program in 2003 of $678,220, $513,125 were payments made by the LSEs serving the load and $165,095 were payments made by zonal LSEs. The $165,095 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 $82,548. When divided by the total 14,678 MWh of load reductions that result from the programs in 2003, the cost is about $6 per MWh of load reductions in 2003. In 2002, given the lower level of actual load reductions, the cost per MWh of load reductions was about twice as high, or about $13 per MWh of load reductions in 2002.

The payments of the LMP savings transferred by the LSEs are a direct benefit to curtailing customers ($678,220). In addition, curtailing customers save in the amount of 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. In the June 2, 2003 Report,[9] the price impact of all demand response programs was estimated based on demand reductions and real time supply curves for July 3, 2002 (see Table 2). 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 summer of 2003 load levels were somewhat lower than during the summer of 2002 and 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 2003.

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 2003, even using an average \$.50 per MWh of overall price reduction multiplied by the average hourly load during the load reductions of about 46,000 MW equals \$23,000 per hour, or about \$25,000,000 for the 1,100 hours of load reductions. Even if adjusted for the share of the spot market in total activity (about 35%) the market price benefits are about \$9,000,000, still much larger than the direct costs of the program, about \$100,000.

The maximum hourly load reduction attributable to the Economic Program was about 82 MW in 2003. Based on the real time supply curves for a representative day during the summer of 2003 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 2003 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 2003 (see Figure 4.)

In summary, direct administrative costs for the PJM Economic Program were about \$1 per MWh of actual load reductions in both 2002 and 2003. The subsidy costs were about \$13 per MWh of load reductions in 2002 and about \$6 per MWh of load reductions in 2003. Thus, total program costs were approximately \$19 per MWh of load reductions in 2002 and about \$13 per MWh of load reductions in 2003. 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 2003 levels or decrease if prices decrease compared to 2003 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.

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9 "Report to the Federal Energy Regulatory Commission PJM 2002 Load Response Program," Docket No. ER02-1326-006 (filed June 2, 2003).

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.

Costs and Benefits of Economic Program: Three Scenarios for Incentives

Given these costs and benefits associated with the Economic Program as implemented, the Commission requested that PJM estimate the costs and benefits of the Economic Program for three scenarios: elimination of incentives; maintaining current incentives; and increasing current incentives.

The costs and benefits of the current package of incentives for the Economic Program are discussed above. It is clear from our review of the history of the Economic Program that the incentives have provided an essential motivation for customers and Curtailment Service Providers to provide load reduction services. The observed load reduction activity would not have occurred in the absence of the Economic Program. The direct costs of the incentives are relatively small and the actual and potential benefits of the incentives are quite large. Thus, the elimination of the Economic Program would result in a small reduction in costs and a large decrease in benefits and would not pass the basic cost-benefit test. In addition, the Economic Program design is based on providing market signals directly to customers and introduces minimal market distortions. For these reasons, it would be a mistake to eliminate the incentives at this point in the development of the Economic Program.

The costs and benefits of the current package of incentives are described above. The benefits of load reductions under the Economic Program are a direct function of the market price levels. Thus, with exactly the same costs but higher market prices, the benefits of the current package of incentives would increase. As a more general matter, the current incentive structure is well designed and minimizes direct subsidies. Subsidies could be eliminated by removing the payment to curtailing customers of the generation component of retail rates when the price is greater than $75 per MWh.

The costs and benefits of increasing incentives depend on the assumed structure of such incentives. Incentives in the Economic Program could be increased by reducing the $75 per MWh cutoff for payment of the full avoided LMP. Such a reduction would be appropriate only if significantly improved rules for preventing payments for essentially inadvertent reductions below the baseline load levels and if combined with the elimination of a payment for the generation component of retail rates. If implemented in this way, there would be no increase in costs and a potentially significant increase in benefits, thus passing the basic cost-benefit threshold.

It would not be appropriate to increase payments for load reductions to a level greater than LMP. The current level of payments appropriately reflects the real market-based value of the savings associated with load reductions. Any increase would be an artificial subsidy that is likely to make the transition to fully market based mechanisms more rather than less difficult.

As a general matter, the appropriateness of decreasing or increasing incentives does not depend on the results of a cost-benefit study. Cost benefit studies suffer from an inability to capture significant, long term market structure impacts as well as the potential to confuse wealth transfers with benefits. While they provide a useful context, cost benefit studies should be used carefully. Even if such a study could show that an increase in net benefits would accrue from a subsidy that is not based on market fundamentals, it would not be appropriate to implement such a subsidy. It is important to design demand side programs such that they provide incentives consistent with the underlying market fundamentals and limit the distortions they introduce into the markets. PJM's current Economic Program meets these criteria.

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

As stated earlier, 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. The Economic Program is an essential part of the portfolio of demand side programs that are or will soon be implemented by PJM. These include, as detailed below, both programs that provide direct financial incentives as well as programs that address institutional and market design barriers to participation.

As stated earlier, 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. Customers can and will make investments in demand side management technologies based on their own evaluations of those tradeoffs. A functional demand side of the market does mean that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and the actual cost of the power.

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 seamless 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.

The success of demand response in the PJM market requires PJM to ensure that market designs provide an opportunity for demand side resources to participate fully in each PJM market. Such market design does not mean that demand side resources will necessarily be

10 August Order at P 15.

treated as if they are identical to supply side resources but that demand side resources will be able to respond to market signals that are appropriate for and consistent with the specific characteristics of such resources. While this is relatively straightforward to state, it is more difficult to implement, given the complexities of market design and given the relatively limited role of demand side response in wholesale power markets to date. Part of the maturation of demand side participation must be recognition that while demand side resources need to be integrated into markets more fully, this should not come at the expense of reliability or efficiency.

PJM has begun the process of evaluating its market designs to ensure that markets are designed consistently and designed on an integrated basis. As an example, PJM ancillary services markets are integrated into the PJM energy market using opportunity cost as a key mechanism to ensure that incentives are consistent across markets and recognizing the integrated nature of markets. Nonetheless, there are opportunities to more fully integrate demand response into each of the PJM markets.

While the capacity market has relied on demand side resources via the Active Load Management (ALM) program, the current capacity market design initiative must ensure that there is a range of ways for demand side resources to participate appropriately in capacity markets. Clearly, demand side resources can serve as capacity resources but the capacity market design must include opportunities for demand side resources to provide reliability services and be compensated for those services while ensuring that reliability is supported.

The PJM Regional Transmission Expansion Planning process has historically included all resources, but it has focused primarily on generation and transmission resources. This has continued to be the case with the recent economic planning initiatives. While this approach made sense, PJM should and is considering various approaches for incorporating demand side resources in the process.

The PJM approach to local market power mitigation has historically focused on generation resources and on transmission resources. The approach to local market power is explicitly addressing integration with the PJM planning process. This needs to include demand side resources both on the planning side and on the local market power mitigation design side. The current local market power mitigation auction proposal explicitly incorporates demand side resources and the detailed auction design should attempt to integrate demand side resources as one element of the solution to local market power.

There is a potential role for demand side resources in the provision of ancillary services like spinning reserves. PJM should consider ways in which demand side resources can be integrated into ancillary services markets so that demand side resources are another alternative source of ancillary services with appropriate incentives for participation and for the provision of this service.

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.

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, PJM conducted a survey 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 revealed that there is substantial load in PJM that is exposed to real time prices as the result of actions by state public utility commissions. In addition, LSEs in the PJM footprint operate DSR programs that are completely independent of the PJM programs.

The survey results identified 3,122 MW of load that pays real time prices. These customers pay real time prices as the result of tariffs approved by state public utility commissions in New Jersey and Maryland. Of the 3,122 MW of load, 1,978 MW, or about 63% of the total, currently purchases electricity directly at an hourly LMP rate plus an adder. This load has chosen to pay the LMP rates rather than enter into a contract with a competitive supplier. The remaining 1,144 MW, or 37%, represents customers who have shifted the risk of managing real time price volatility to a competitive supplier.

The survey also identified a total of about 500 MW enrolled in independent DSR programs. Of the total, 193 MW, or 39%, were included in price responsive load programs or pilot programs, 73 MW, or 15%, participated in interruptible load programs and 235 MW, or 47%, of load is currently participating in emergency load response programs of electric distribution companies.

The July 2003 PJM survey revealed that significant DSR activity has resulted from the actions of state public utility commissions as they implement policies governing retail competition. The primary result has been more load directly exposed to real time prices. This is a critical prerequisite to an effective demand side of the wholesale energy markets. In addition, individual LSEs have implemented independent DSR programs that parallel the PJM programs in basic design and that have resulted in additional DSR activity.

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. The Commission, PJM and state public utility commissions should continue efforts designed to encourage the installation of appropriate metering technology.

PJM created the non hourly-metered pilot program as part of the effort to extend the ability to participate in the demand side of the market to smaller customers that generally do not have hourly meters in place. PJM's non hourly-metered pilot program serves as a pilot program for customers without hourly metering, provided these customers or their representatives propose an alternate method for measuring load reduction. Such measurement methods are approved by PJM on a case by case basis, and participants are otherwise subject to the rules and procedures governing the load response program in which the customer has enrolled.

As stated in the June 2, 2003 Report, there was no participation in the non hourly-metered pilot program during the summer of 2002. At that time, the aggregate MW limit over the PJM region, including both the Economic and the Emergency Load Response Programs, for non-hourly metered customers was 25 MW. At its April 16, 2003 meeting, the Energy Market Committee supported an increase in the aggregate MW limit, expanding this limit to 100 MW. PJM's Members Committee approved this change at its May 1, 2003 meeting, endorsing the revisions to the PJM Open Access Transmission Tariff. These changes were accepted by the FERC in a June 2003 order.[11]

In 2003,[12] one customer (with about 45,000 end users) participated in the non hourly-metered pilot program for about 131 separate hourly reductions totaling about 1,816 MWh and averaging about 14 MW per hour. Table 1 displays the non hourly-metered response by hour. The expansion of the aggregate MW limit allowed for a maximum hourly reduction of 43 MW in the pilot program.

Small customers, like large customers, must be given the opportunity to participate in the demand side of wholesale energy markets. As for large customers, small customers, or

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11 PJM Interconnection, L.L.C., 103 FERC 61,365 (2003).

12 2003 numbers will not be final until 60 days after December 31, 2003 because rules require load reducers to submit claims for payment within 60 days of the event.

their designated proxies, must have the ability to see real time prices, must have the ability to react to real time prices, in real time, and must have the ability to receive the direct benefits or costs of changes in real time energy usage. Given the costs, in terms of time, effort and money, associated with the individual participation of small customers in energy markets, it is reasonable to expect that intermediaries will provide the most cost-effective mechanism for the participation of small customers. These intermediaries, or aggregators, can more efficiently bundle large groups of small customers and offer their demand management services, in aggregate, to the wholesale markets.

While it is not known for certain, it is likely that the nature of such aggregation efforts led to the absence of participation in the non hourly-metered pilot program in 2002. Such aggregation takes significant marketing effort on the part of the intermediary which in turn takes time. It is likely that there was insufficient time between the final approval of the program and the summer to make such participation economic. In addition, the participation of small customers via aggregators is likely to be subject to economies of scale. Larger groups of customers will provide more diversity and a higher likelihood of being able to achieve targeted load reduction goals. While at first counter intuitive, too low a MW threshold for participation apparently served as a barrier to entry for this reason. Finally, lack of knowledge by potential participants was clearly also a barrier to participation in this program. PJM continues active efforts to educate potential participants about the program.

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.

Emergency Program

Emergency Demand Response Procedures

On July 3, 2002, PJM requested a load reduction under the Emergency Load Reduction Program. Although PJM system operators forecasted that there would be a need for response from the Emergency Program participants, actual load was less than forecasted load and, based on an after the fact evaluation, the Emergency Program was not needed. PJM addressed this situation in its compliance report filed July 28, 2003, which presented the findings of the PJM Operating Committee.[13] The committee concluded that "PJM acted too conservatively by initiating a request for load reduction too far in advance of the anticipated need." [14] It was recommended that load reductions be called upon closer in time to the anticipated emergency conditions.

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13 "Compliance Filing," Docket No. ER03-807-001 (filed July 28, 2003).

14 Id. at 2.

Based on PJM's review of the July 3, 2002 events, in an emergency situation, PJM will call for Active Load Management (ALM) reductions as early as possible, and will call the Emergency Program only when a Maximum Generation Emergency is impending. This is appropriately not a formal guideline in the PJM manuals, so as to allow PJM dispatchers the flexibility to maintain system reliability in real time and in the face of real, extremely dynamic, system conditions. In addition, in order to increase the accuracy of reserve status information, an application known as the Supplemental Status Report (SSR) has been implemented by PJM. The Supplemental Status Report gives PJM an instantaneous representation of the PJM Control Area generating capacity, load management, and fuel limitations. Each Local Control Center (LCC) is required to enter information concerning each of these sections, and then totals are calculated into a PJM summary. PJM uses the SSR to perform an analysis and prepare a capacity, load and reserve projection when the potential exists for a serious PJM bulk power emergency.

Since July 3, 2002, PJM has initiated requests for load reductions under the Emergency Program only after declaring a Maximum Generation Emergency. There was only one emergency event during the summer of 2003 (August 15), and this event was a locational emergency.

Emergency Program and the Market Clearing Price

PJM has been asked to evaluate the appropriateness of the Emergency Program setting the PJM market clearing price. Currently, the Emergency Program payments, the higher of LMP or $500/MWh, do not set the market clearing price. However, Economic Program participants can set the real time market clearing price. Economic Program participants can also set the market clearing price in the Day Ahead market.

The New York Independent System Operator (NYISO) proposed that certain demand side resources comparable to PJM Emergency Program resources (NYISO Special Case Resources or SCR) should set the market clearing price when these specific resources have been called, based on the argument that the New York Control Area would experience a shortage of 30-minute reserves without these resources. The FERC agreed with NYISO in that these resources are the "marginal resources required to meet reserve shortages."[15] On June 20, 2003, the FERC approved the NYISO's request that SCR and EDRP resources should set the market clearing prices for the New York Control Area. Under this pricing method, if the EDRP is activated and the NYISO is short on reserves, then the program will set the market clearing price.

PJM concluded that this pricing method is not applicable to the PJM control area based on the differences between PJM and NYISO's markets. The Commission's decision in the NYISO case was based on specific conclusions about reserve shortages. Using the criteria specified by the NYISO, the PJM Emergency Program would not have set the market clearing price when it was implemented during the summer of 2002.

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[15] N.Y. Indep. Sys. Operator, Inc., 103 FERC ¶ 61,339 at P 24 (2003).

In the July 3, 2002 event, the system operators made a reasonable decision to call on the Emergency Program, based on the facts available to them, although PJM could have done a better job of load forecasting on that day. It was also appropriate that the system price did not reflect the $500 per MWh paid to the Emergency Program resources, as that was not the value of the resources to the system, but was the required payment under the DSR tariff. The issue raised by the July 3, 2002 use of the Emergency Program is not whether it should have set the price, but whether it should have been called at all. It is extremely unusual that prices remain low in PJM while PJM operators are required to implement the full range of available emergency measures. It must be remembered that the $500 per MWh payment to the Emergency Program resources was a somewhat arbitrary number, designed to provide what was considered a floor payment to Emergency Program resources. This floor payment was not designed based on an evaluation of the value of the resources to the system. Rather, it was designed to serve as a guarantee that any such resource that curtailed load would be paid $500 per MWh at minimum. The appropriate comparison is to an operating reserve payment made to a generator, based on its offer price, that finishes out its minimum run time but does not set the system price. The design of the Emergency Program was to ensure that Emergency Program resources were paid the system price when called upon as the system price reflects the market value of the resource. Nonetheless, as a general matter, the system price should reflect the value of demand side resources when they are the marginal resource. That has not been the case in PJM. If Emergency Program resources are to be permitted to set the price, PJM should consider whether to create a market for such resources. The $500 per MWh floor is not based on the value of the resources to the market and should not serve to set the market price in the absence of a market mechanism to acquire such resources.

Table 1: 2003 Pilot Program Reductions		
Daily Reductions		
Date	MWh	Credits
1-Apr-03	166	$3,249
7-Apr-03	197	$8,947
9-Apr-03	36	$555
10-Apr-03	114	$522
1-May-03	170	$5,895
11-Jun-03	19	$1,705
12-Jun-03	8	$985
18-Jun-03	4	$345
24-Jun-03	19	$1,625
25-Jun-03	54	$5,288
26-Jun-03	33	$3,661
27-Jun-03	7	$538
7-Jul-03	46	$5,966
8-Jul-03	204	$15,568
11-Jul-03	7	$617
21-Jul-03	77	$7,408
22-Jul-03	1	$82
4-Aug-03	19	$1,690
8-Aug-03	2	$196
12-Aug-03	30	$2,886
13-Aug-03	153	$13,171
14-Aug-03	169	$20,827
15-Aug-03	122	$9,998
20-Aug-03	15	$1,359
21-Aug-03	159	$14,791
22-Aug-03	15	$1,221
28-Aug-03	13	$1,141
8-Sep-03	4	$373
Daily Statistics		
Total	1,865	$130,608
Average	67	$4,665
Maximum	204	$20,827
Hourly Statistics		
Average	14	$967
Maximum	43	$5,362

Table 2: July 3, 2002 Price Impacts

	ALM	Economic Program	Emergency Program
Average Reduction in LMP	$70	$50	$40

Table 3: 2001 – 2003 Registered Participants in Load Response Programs

	Economic Progam		Emergency Program	
	Sites	MW	Sites	MW
2001		65		155
2002	116	337	61	548
2003	245	724	168	659

Table 4: 2001 – 2003 Performance of Economic Program Participants

	Total MWh	Total Payments	$/MWh
2001	50	$13,994	$283
2002	6,462	$761,977	$118
2003	14,678	$678,220	$46

Table 5: 2003 Emergency Program and Economic Program Comparison

	MWh	Credits	Price/MWh
Emergency	47	$26,613	$566
Economic	14,678	$678,220	$46

Table 6: 2001 - 2003 Payments Comparison			
	Emegency ($)	**Economic ($)**	**Total ($)**
2001	$287,514	$13,994	$301,508
2002	$282,756	$761,997	$1,044,753
2003	$26,613	$678,220	$704,833

Table 7: Load Response Programs and ALM History					
	1999	**2000**	**2001**	**2002**	**2003**
ALM Resources (MW)	2,005	1,693	1,962	1,292	1,207
Pilot Program Resources (MW)	NA	80	220	NA	NA
Load Response Program (MW)	NA	NA	NA	891	1,383
Load Response MW also enrolled in ALM	NA	NA	164	298	445

Table 8: 2003 Total Daily Reductions

	Economic Program				Emergency Program		Pilot Program		Totals	
Date	RT MW	RT Credits	DA MW	DA Credits	MW	Credits	MW	Credits	MW	Credits
27-Jan-03	50	$2,980	0	$0	0	$0	0	$0	50	$2,980
28-Jan-03	85	$2,787	0	$0	0	$0	0	$0	85	$2,787
29-Jan-03	24	$398	0	$0	0	$0	0	$0	24	$398
3-Mar-03	193	$24,599	0	$0	0	$0	0	$0	193	$24,599
6-Mar-03	37	$4,693	0	$0	0	$0	0	$0	37	$4,693
7-Mar-03	64	$4,446	0	$0	0	$0	0	$0	64	$4,446
10-Mar-03	68	$7,411	0	$0	0	$0	0	$0	68	$7,411
11-Mar-03	118	$7,626	0	$0	0	$0	0	$0	118	$7,626
12-Mar-03	45	$1,887	0	$0	0	$0	0	$0	45	$1,887
13-Mar-03	126	$3,161	0	$0	0	$0	0	$0	126	$3,161
21-Mar-03	4	$88	0	$0	0	$0	0	$0	4	$88
27-Mar-03	42	$1,411	0	$0	0	$0	0	$0	42	$1,411
1-Apr-03	0	$0	0	$0	0	$0	166	$3,249	166	$3,249
7-Apr-03	0	$0	0	$0	0	$0	197	$8,947	197	$8,947
9-Apr-03	2	$136	0	$0	0	$0	36	$555	38	$691
10-Apr-03	0	$0	0	$0	0	$0	114	$522	114	$522
11-Apr-03	1	$34	0	$0	0	$0	0	$0	1	$34
21-Apr-03	1	$11	0	$0	0	$0	0	$0	1	$11
23-Apr-03	1	$40	0	$0	0	$0	0	$0	1	$40
1-May-03	2	$19	0	$0	0	$0	170	$5,895	172	$5,914
2-May-03	2	$113	0	$0	0	$0	0	$0	2	$113
9-May-03	3	$129	0	$0	0	$0	0	$0	3	$129
14-May-03	2	$1	0	$0	0	$0	0	$0	2	$1
19-May-03	2	$13	0	$0	0	$0	0	$0	2	$13
22-May-03	1	$0	0	$0	0	$0	0	$0	1	$0
11-Jun-03	0	$0	0	$0	0	$0	19	$1,705	19	$1,705
12-Jun-03	0	$0	0	$0	0	$0	8	$985	8	$985
14-Jun-03	3	$219	0	$0	0	$0	0	$0	3	$219
18-Jun-03	0	$0	0	$0	0	$0	4	$345	4	$345
19-Jun-03	41	$82	0	$0	0	$0	0	$0	41	$82
23-Jun-03	75	$528	0	$0	0	$0	0	$0	75	$528
24-Jun-03	129	$5,196	0	$0	0	$0	19	$1,625	148	$6,821

Table 8: 2003 Total Daily Reductions

	Economic Program				Emergency Program		Pilot Program		Totals	
Date	RT MW	RT Credits	DA MW	DA Credits	MW	Credits	MW	Credits	MW	Credits
25-Jun-03	346	$13,963	0	$0	0	$0	54	$5,288	400	$19,251
26-Jun-03	778	$36,264	84	$9,988	0	$0	33	$3,661	895	$49,912
27-Jun-03	286	$3,740	0	$0	0	$0	7	$538	293	$4,277
29-Jun-03	0	$24	0	$0	0	$0	0	$0	0	$24
30-Jun-03	376	$35,293	0	$0	0	$0	0	$0	376	$35,293
1-Jul-03	0	$1	0	$0	0	$0	0	$0	0	$1
2-Jul-03	290	$6,111	0	$0	0	$0	0	$0	290	$6,111
3-Jul-03	0	$2	0	$0	0	$0	0	$0	0	$2
4-Jul-03	337	$6,640	0	$0	0	$0	0	$0	337	$6,640
5-Jul-03	362	$18,047	4	$260	0	$0	0	$0	365	$18,307
6-Jul-03	39	$4,057	0	$0	0	$0	0	$0	39	$4,057
7-Jul-03	590	$26,467	0	$0	0	$0	46	$5,966	637	$32,433
8-Jul-03	270	$4,851	35	$3,101	0	$0	204	$15,568	510	$23,520
9-Jul-03	318	$5,980	0	$0	0	$0	0	$0	318	$5,980
10-Jul-03	337	$4,301	48	$1,277	0	$0	0	$0	385	$5,578
11-Jul-03	262	$5,278	0	$0	0	$0	7	$617	270	$5,896
13-Jul-03	68	$2,337	0	$0	0	$0	0	$0	68	$2,337
14-Jul-03	282	$7,101	0	$0	0	$0	0	$0	282	$7,101
15-Jul-03	285	$3,785	0	$0	0	$0	0	$0	285	$3,785
16-Jul-03	171	$8,018	0	$0	0	$0	0	$0	171	$8,018
17-Jul-03	62	$940	0	$0	0	$0	0	$0	62	$940
18-Jul-03	258	$637	0	$0	0	$0	0	$0	258	$637
19-Jul-03	60	$1,576	0	$0	0	$0	0	$0	60	$1,576
20-Jul-03	128	$11,147	0	$0	0	$0	0	$0	128	$11,147
21-Jul-03	276	$30,424	0	$0	0	$0	77	$7,408	352	$37,832
22-Jul-03	133	$5,736	0	$0	0	$0	1	$82	134	$5,817
23-Jul-03	130	$4,001	0	$0	0	$0	0	$0	130	$4,001
24-Jul-03	78	$3,374	0	$0	0	$0	0	$0	78	$3,374
25-Jul-03	126	$3,020	0	$0	0	$0	0	$0	126	$3,020
26-Jul-03	16	$295	0	$0	0	$0	0	$0	16	$295
27-Jul-03	14	$254	0	$0	0	$0	0	$0	14	$254
28-Jul-03	187	$3,680	0	$0	0	$0	0	$0	187	$3,680

Table 8: 2003 Total Daily Reductions

	Economic Program				Emergency Program		Pilot Program		Totals	
Date	RT MW	RT Credits	DA MW	DA Credits	MW	Credits	MW	Credits	MW	Credits
29-Jul-03	194	$4,892	0	$0	0	$0	0	$0	194	$4,892
30-Jul-03	89	$1,369	0	$0	0	$0	0	$0	89	$1,369
31-Jul-03	41	$1,072	0	$0	0	$0	0	$0	41	$1,072
1-Aug-03	97	$4,254	0	$0	0	$0	0	$0	97	$4,254
4-Aug-03	156	$2,378	0	$0	0	$0	19	$1,690	175	$4,068
5-Aug-03	71	$645	0	$0	0	$0	0	$0	71	$645
6-Aug-03	60	$1,050	0	$0	0	$0	0	$0	60	$1,050
7-Aug-03	47	$738	0	$0	0	$0	0	$0	47	$738
8-Aug-03	51	$1,662	0	$0	0	$0	2	$196	53	$1,858
11-Aug-03	22	$161	0	$0	0	$0	0	$0	22	$161
12-Aug-03	162	$6,941	0	$0	0	$0	30	$2,886	192	$9,827
13-Aug-03	388	$20,896	0	$0	0	$0	153	$13,171	541	$34,067
14-Aug-03	585	$38,430	0	$0	0	$0	169	$20,827	755	$59,257
15-Aug-03	397	$27,101	0	$0	47	$26,613	122	$9,998	565	$63,712
18-Aug-03	53	$1,960	0	$0	0	$0	0	$0	53	$1,960
19-Aug-03	42	$489	0	$0	0	$0	0	$0	42	$489
20-Aug-03	110	$6,291	0	$0	0	$0	15	$1,359	125	$7,649
21-Aug-03	332	$24,382	0	$0	0	$0	159	$14,791	491	$39,173
22-Aug-03	580	$29,201	0	$0	0	$0	15	$1,221	595	$30,423
23-Aug-03	158	$3,495	0	$0	0	$0	0	$0	158	$3,495
24-Aug-03	81	$529	0	$0	0	$0	0	$0	81	$529
26-Aug-03	67	$2,018	0	$0	0	$0	0	$0	67	$2,018
27-Aug-03	73	$1,319	0	$0	0	$0	0	$0	73	$1,319
28-Aug-03	39	$2,884	0	$0	0	$0	13	$1,141	52	$4,025
29-Aug-03	400	$18,741	0	$0	0	$0	0	$0	400	$18,741
1-Sep-03	61	$183	0	$0	0	$0	0	$0	61	$183
2-Sep-03	33	$489	0	$0	0	$0	0	$0	33	$489
4-Sep-03	74	$1,401	0	$0	0	$0	0	$0	74	$1,401
8-Sep-03	0	$0	0	$0	0	$0	4	$373	4	$373
10-Sep-03	11	$272	0	$0	0	$0	0	$0	11	$272
16-Sep-03	22	$528	0	$0	0	$0	0	$0	22	$528
22-Sep-03	106	$1,430	0	$0	0	$0	0	$0	106	$1,430

Table 8: 2003 Total Daily Reductions

	Economic Program				Emergency Program		Pilot Program		Totals	
	RT MW	RT Credits	DA MW	DA Credits	MW	Credits	MW	Credits	MW	Credits
23-Sep-03	52	$308	0	$0	0	$0	0	$0	52	$308
23-Oct-03	4	$124	0	$0	0	$0	0	$0	4	$124
Maximum										
	778	$38,430	84	$9,988	47	$26,613	204	$20,827	895	$63,712
Hourly Average										
	129	$5,439	2	$149	0	$272	19	$1,333	150	$7,192
Total										
	12,641	$532,987	171	$14,625	47	$26,613	1,865	$130,608	**14,724**	**$704,833**

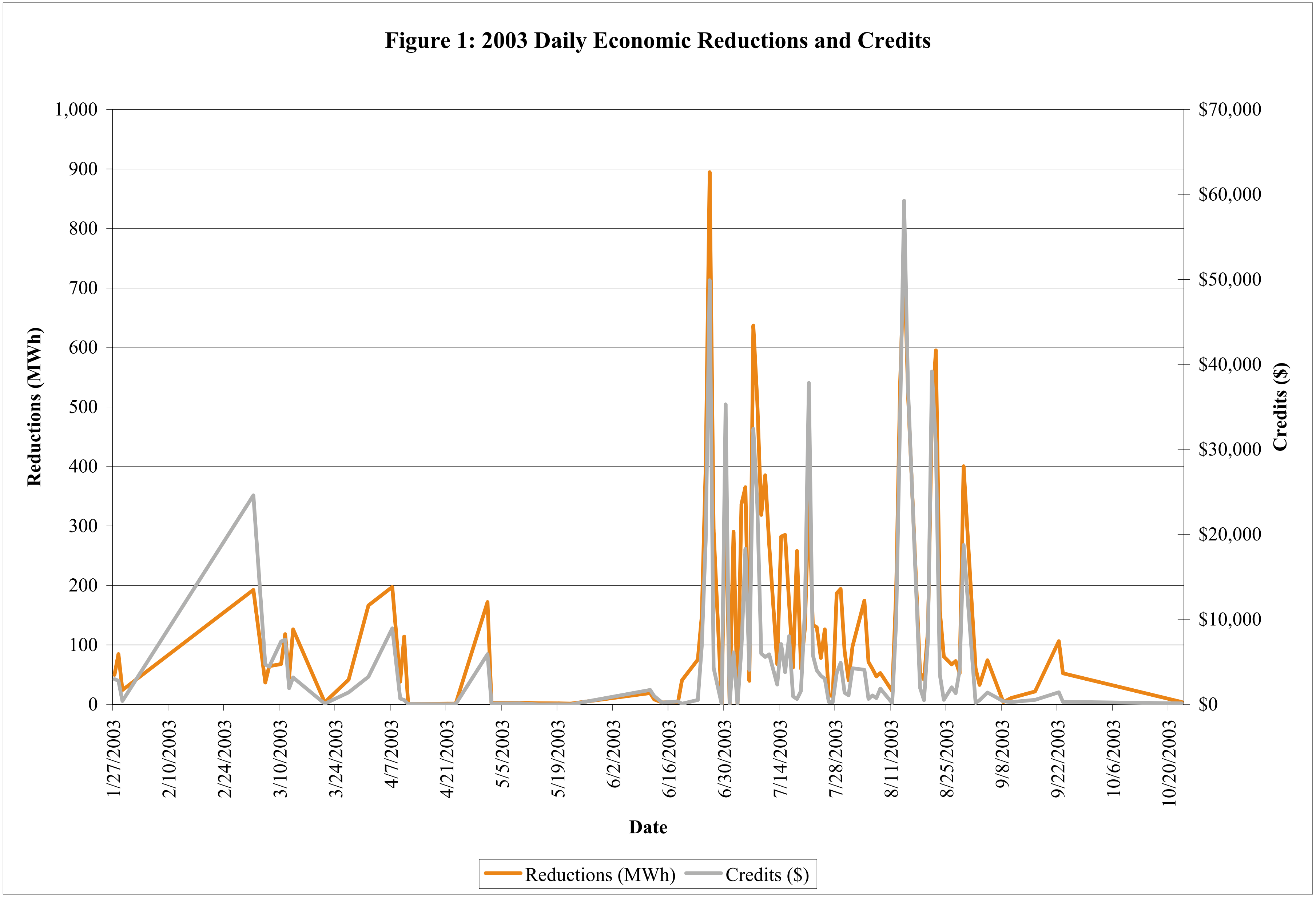

Figure 1: 2003 Daily Economic Reductions and Credits
1,000
900
800
700
600
500
400
300
200
100
0
Reductions (MWh)
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
Credits ($)
1/27/2003
2/10/2003
2/24/2003
3/10/2003
3/24/2003
4/7/2003
4/21/2003
5/5/2003
5/19/2003
6/2/2003
6/16/2003
6/30/2003
7/14/2003
7/28/2003
8/11/2003
8/25/2003
9/8/2003
9/22/2003
10/6/2003
10/20/2003
Date
Reductions (MWh)
Credits ($)

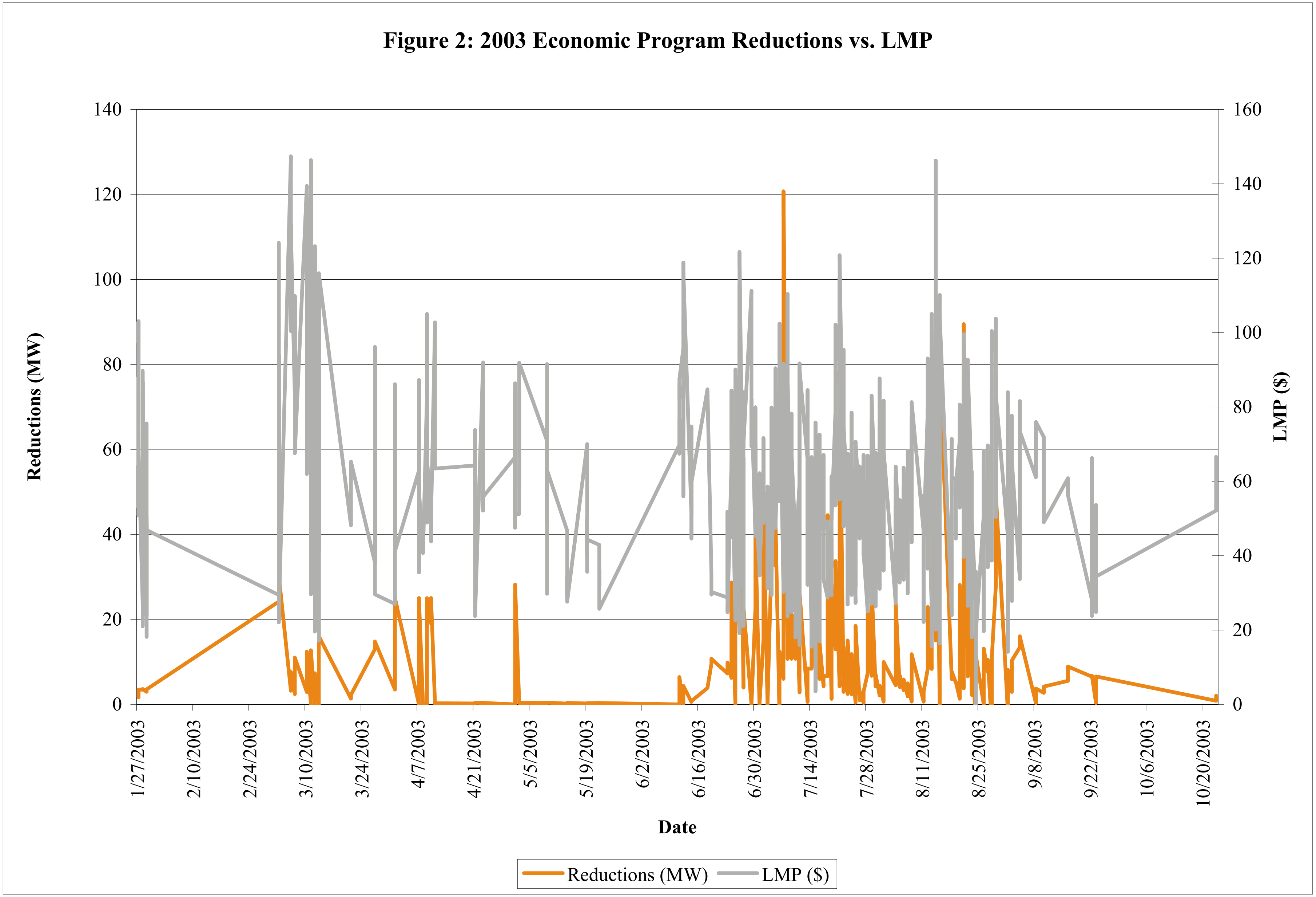

Figure 2: 2003 Economic Program Reductions vs. LMP
Reductions (MW)
LMP ($)
Date
0
20
40
60
80
100
120
140
160
1/27/2003
2/10/2003
2/24/2003
3/10/2003
3/24/2003
4/7/2003
4/21/2003
5/5/2003
5/19/2003
6/2/2003
6/16/2003
6/30/2003
7/14/2003
7/28/2003
8/11/2003
8/25/2003
9/8/2003
9/22/2003
10/6/2003
10/20/2003
Reductions (MW)
LMP ($)

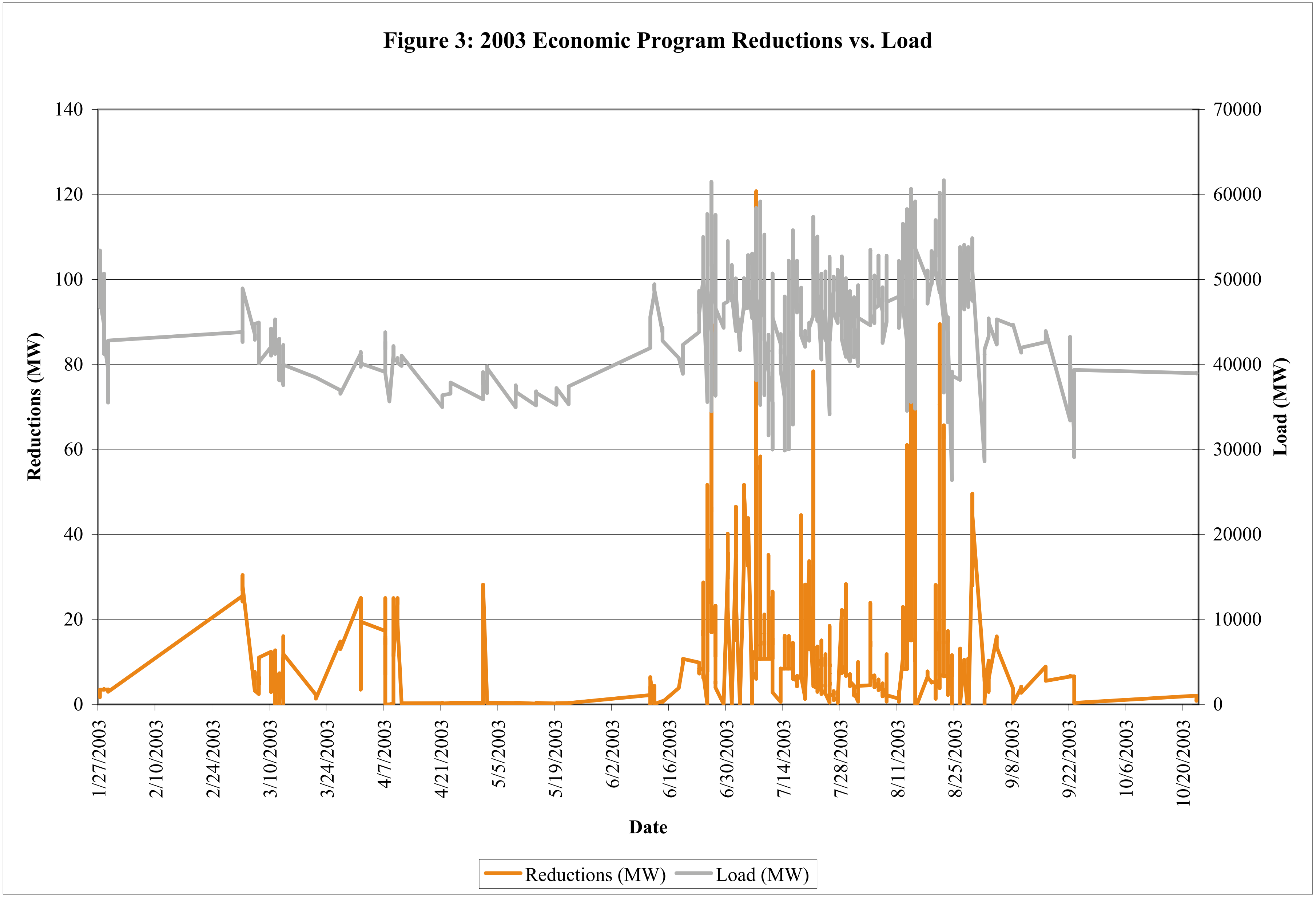
Figure 3: 2003 Economic Program Reductions vs. Load
Reductions (MW)
Load (MW)
Date
0
20
40
60
80
100
120
140
0
10000
20000
30000
40000
50000
60000
70000
1/27/2003
2/10/2003
2/24/2003
3/10/2003
3/24/2003
4/7/2003
4/21/2003
5/5/2003
5/19/2003
6/2/2003
6/16/2003
6/30/2003
7/14/2003
7/28/2003
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9/8/2003
9/22/2003
10/6/2003
10/20/2003
Reductions (MW)
Load (MW)

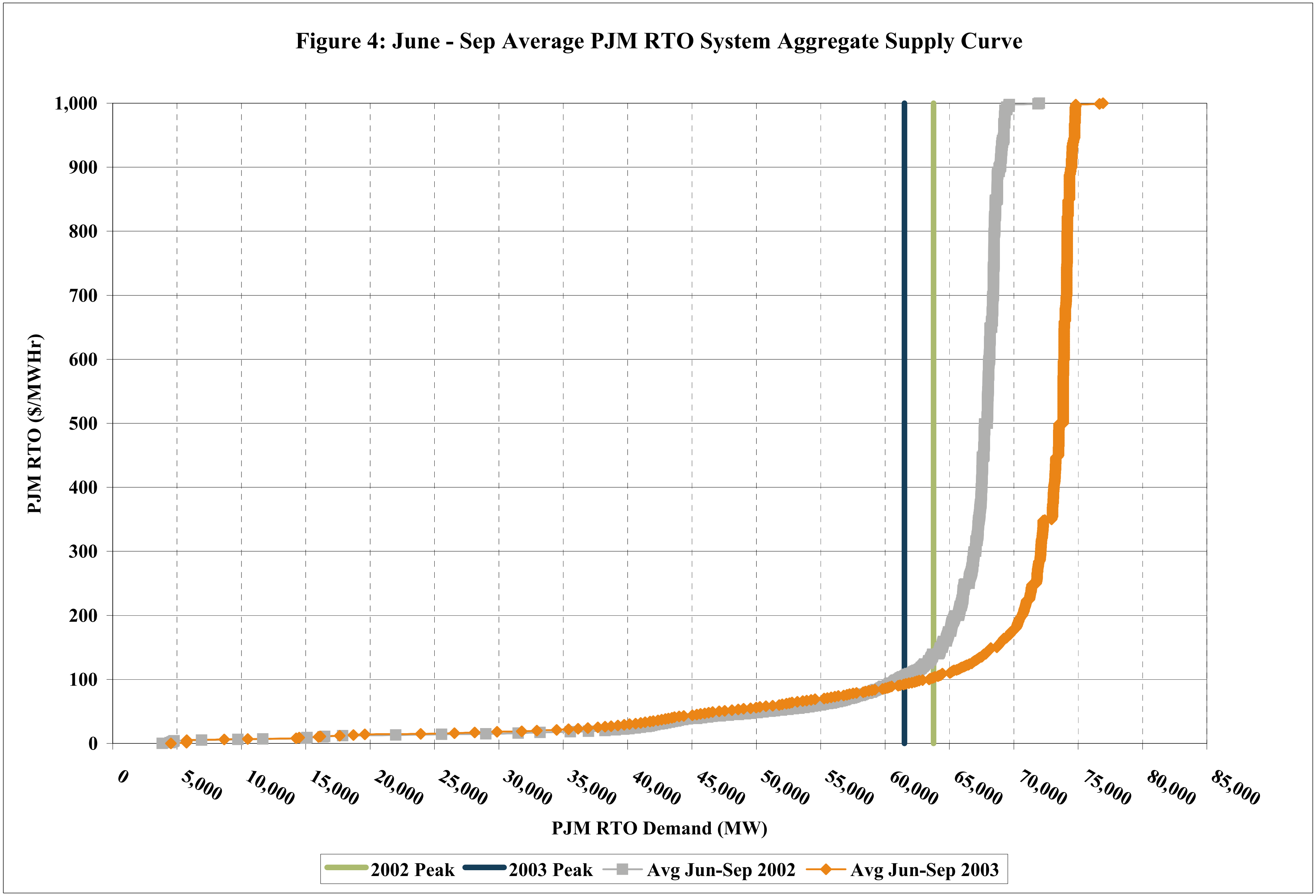
Figure 4: June - Sep Average PJM RTO System Aggregate Supply Curve
1,000
900
800
700
600
500
400
300
200
100
0
PJM RTO ($/MWHr)
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
45,000
50,000
55,000
60,000
65,000
70,000
75,000
80,000
85,000
PJM RTO Demand (MW)
2002 Peak
2003 Peak
Avg Jun-Sep 2002
Avg Jun-Sep 2003

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. ER02-1326-006

NOTICE OF FILING

Take notice that on December 31, 2003, in compliance with PJM Interconnection, L.L.C., 104 FERC ¶ 61,188 (2003), the Market Monitoring Unit of PJM Interconnection, L.L.C. ("PJM") submitted a compliance report assessing the status of PJM's load response programs.

Copies of this filing have been served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Any person desiring to be heard or to protest this filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 210, 211, and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.210, 385.211, 385.214). All such petitions or protests should be filed on or before the Comment Date. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection. This filing may also be viewed on the web at http://www.ferc.gov using the "eLibrary" link, select "General Search" and follow the instructions (call 202-208-2222 for assistance). Comments, protests and interventions may be filed electronically via the Internet in lieu of paper. See 18 C.F.R. § 385.2001(a)(1)(iii) and the instructions on the Commission's web site under the "eFiling" link.

Comment Date: