UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Wholesale Competition in Regions with Organized Electric Markets	))	Docket Nos. RM07-19-000 and AD07-7-000

COMMENTS
OF THE PJM POWER PROVIDERS GROUP, INC.

In accordance with the Advance Notice of Proposed Rulemaking ("ANOPR") issued by the Federal Energy Regulatory Commission ("Commission") on June 22, 2007[1] and the Notice of Extension of Time for filing comments issued on July 27, 2007,[2] The PJM Power Providers Group, Inc. ("P3") respectfully submits these comments in response to the Commission's request for comment on the ANOPR regarding Wholesale Competition in Regions with Organized Electric Markets.[3] P3 also sponsors the testimony of Dr. Roy J. Shanker on certain issues raised in the ANOPR.[4] Specifically Dr. Shanker's testimony responds to the Commission's request for comments on "actions to improve demand response and market pricing during a power shortage". P3's comments focus on demand response, market monitoring issues and enhanced RTO responsiveness.

---

[1] *Wholesale Competition in Regions with Organized Electric Markets*, Advance Notice of Proposed Rulemaking, 71 Fed. Reg. 36276 (Jul. 2, 2007), 119 FERC ¶ 61,306 (2007) ("ANOPR").

[2] *Wholesale Competition in Regions with Organized Electric Markets*, Notice of Extension of Time, 72 Fed. Reg. 44437 (Aug. 8, 2007).

[3] These comments represent the position of the PJM Power Providers Group (P3) as an organization, but not necessarily the views of any particular member with respect to any issue.

[4] Dr. Shanker's Affidavit is provided as Attachment A hereto ("Shanker Affidavit").

I. THE COMMISSION SHOULD AGGRESIVELY PURSUE PROPOSED ACTIONS TO IMPROVE DEMAND RESPONSE AND MARKET PRICING DURING A POWER SHORTAGE

In the ANOPR, the Commission offered four proposals to modify wholesale RTO[5] market design to ensure demand resources' direct participation in the energy and ancillary services markets on a basis comparable to supply resources: (1) requiring each RTO to purchase demand resources in its markets for energy imbalance service, spinning reserves and supplemental reserves similar to any other resources, if the resources meet the necessary technical requirements and submit bids pursuant to bidding rules at or below the market-clearing price; (2) requiring RTOs to modify their tariffs to eliminate, for load reductions during a system emergency, charges to buyers in the energy market for taking less electric energy in the real-time market than purchased in the day-ahead market; (3) requiring RTOs to amend their market rules to permit aggregated retail customers to bid a demand reduction on behalf of retail customers directly into the RTO's organized markets; and (4) modifying RTOs' market power mitigation rules and other market rules when demand nears the amount of available supply.

Several months after issuing the ANOPR, the Commission published its second annual report assessing the state of demand response resources and initiatives and advanced metering developments in satisfaction of the obligation imposed by the Energy Policy Act of 2005.[6] The Staff Report focuses on developments over the last year, and discusses demand response

---

[5] RTO will be used hereafter to refer to either an RTO or an ISO.

[6] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005). Federal Energy Regulatory Commission Assessment of Demand Response and Advanced Metering 2007 – Staff Report (September 2007) ("Staff Report").

developments in both wholesale and retail markets and trends and observations with regard to the increased incorporation of demand response into organized markets.

In the report, Commission Staff found that the use of demand response in wholesale electric markets increased over the past year. In RTO markets, demand response represented between 1.4 and 4.1 percent of system peaks on record-breaking peak days. Estimates of customer enrollment—showing the potential demand reduction that could be achieved—resulted in even higher percentages for 2007. Staff noted that while this percentage of an RTO's total load is small, small load reductions at system peaks can significantly reduce stress on electric delivery systems in times of near-shortages of operating reserves. Moreover, demand response in certain load pockets such as southwest Connecticut and Long Island was even higher, at six percent and four percent of regional peak load on record-breaking days.[7]

The Staff Report identified several trends observed in the last year with regard to demand response: (1) the bidding of demand into forward capacity markets administered by PJM Interconnection, L.L.C. ("PJM") and ISO New England, Inc. ("ISO-NE"); (2) the growing ability of demand resources to participate in ancillary services markets; (3) increased participation by demand response in the eastern RTOs, particularly in those RTOs' reliability programs, with enrollment in reliability-based demand response programs increasing from 2003-2007 by 32 percent, 257 percent and 18 percent in PJM, ISO-NE, and the New York Independent System Operator, respectively; (4) increased national and regional focus on measurement and verification of demand reductions, such as ISO-NE's measurement and verification protocol to support demand resource participation in the forward capacity market; (5) more attention paid to development of a "smart grid"; (6) increased number of multi-state

[7] Staff Report at 4-6, Figure II-1.

and state-federal groups working to coordinate retail and wholesale demand response efforts; (7) greater reliance on demand response in strategic plans and policies developed by RTOs, public power agencies, and states; and (8) increased activity by third party demand-response aggregators, whose bidding of aggregated demand reductions into the markets comprises a significant portion of the demand reductions experienced by those markets.[8]

As the Staff Report indicates, demand response program participation rates have increased dramatically over the last several years. Not only have enrollment statistics improved, but also demand response participation has shaved system peaks by up to 4.1%. As the ANOPR recognized, however, significantly greater effects can be achieved if economic considerations warrant increased participation levels in demand response programs. In support of this result, the Commission properly proposed modifying RTOs' market power mitigation rules and other market rules when demand nears the amount of available supply.

As P3 witness Dr. Shanker testifies, demand response efforts will thrive if the price is right, especially during periods of shortage. He states:

> Fundamental to effective demand response is showing consumers the prices that should exist when conditions approach physical shortage so that consumers can consider demand reduction as a cost effective response to these prices. In turn, in order to allow prices to efficiently ration power to those that value it most, there has to be a rational pricing scheme during these same periods that reflects the impending physical scarcity and the need for mandated load reductions unless consumers voluntarily reduce consumption in response to these right price signals. Thus, the issues are inseparable, effective demand response goes hand-in-hand with efficient pricing during shortages. As a result, the path to the right public policy regarding demand response has to include direct measures to improve the accuracy of energy pricing as conditions approach a supply shortage.[9]

---

[8] *Id*. at 16-21.

[9] Shanker Affidavit at P 7.

He recognizes, however, that because load generally does not experience real-time pricing and because load does not readily have the option to interrupt in lieu of paying those prices, demand response is not an automatic response but must be encouraged through market mechanisms.[10] The market mechanisms should "try to set the prices correctly to reflect the value of marginal supply when total supply exceeds demand, or the value that load places on supply when supply is less than demand (inclusive of reserves)."[11] Dr. Shanker explains that:

> Shortage pricing, or the setting of price when potential demand approaches or exceeds supply, is very important. Shortage pricing transmits the fundamental pricing message for load to reduce consumption. It also provides generation with the right short term price signals for production, and, over the long-term, allows for the recovery of fixed costs to support maintenance of needed existing facilities and new entry. Practical limitations prevent load from easily seeing and responding to increasing prices during shortage.[12]

He concurs with the Commission in recognizing that practical impediments, such as the lack of real-time load response, add complexity to the task of providing appropriate price signals. He concurs in the suggestion to "allow prices to rise above supply offers when demand reaches a level where 'normal' operating reserves can not be maintained", as this approach "allows price to approach the value that load would be willing to pay".[13] He explains that in capacity market constructs such as RPM in PJM, the more that energy payments reflect the true intersection of the demand and supply curve during peak conditions, the less revenues will be paid for capacity.[14]

---

[10] *Id.* at P 8-12.

[11] *Id.* at P 14.

[12] *Id.* at P 19.

[13] *Id.* at P 21.

[14] *Id.* at P 21-22.

Dr. Shanker next examines how to attain the right price. He recommends the development of triggers for scarcity pricing as load nears target reserve levels.[15] He indicates the shortcomings in existing systems, finding that PJM would not trigger shortage pricing when reserve levels are violated, but that shortages of operating reserves and the occurrence of local reserve violations *should* trigger such pricing.[16] He admonishes that the value of lost load should set the market price.[17]

Finally, Dr. Shanker provides extensive comments on the four specific alternatives proposed by the Commission regarding how to set prices during a supply shortage.[18] He examines each of these alternatives in terms of their relative effectiveness in achieving the goal of allowing price to approach the real value of lost load.[19] And Dr. Shanker proposes a fifth alternative to be considered along with the other four, namely reflecting in scarcity pricing the discretionary decisions of operators that otherwise depress prices.[20]

II. THE COMMISSION SHOULD PURSUE POLICIES DESIGNED TO ENSURE THAT MARKET MONITORING WILL REMAIN INDEPENDENT, EFFECTIVE AND ACCOUNTABLE, WITH A CLEARLY DEFINED ROLE

As a matter of principle, P3 agrees with FERC that market monitors must be independent, effective and accountable. In order for markets to work well, all market participants need confidence in the integrity of the market itself. Market manipulation can cause price distortions that hurt both buyers and sellers and cannot be tolerated if a market is to be successful.

---

[15] *Id.* at P 27.

[16] *Id.* at P 28-29.

[17] *Id.* at P 32.

[18] *Id*. at P 33-51.

[19] *Id*. at P 33-51.

[20] *Id*. at P 50-51.

MMUs must be Independent

P3 fully subscribes to the principle that the market monitor should be an independent watchdog over conduct that occurs in the wholesale market. Like a "cop on the beat," the MMU should have a clear understanding of what the rules are and the ability to identify and report – "blow the whistle on" – any violations of those rules. P3 shares FERC's belief that independence can be ensured regardless of whether the MMU is internal or external to the RTO. Accordingly, P3 would not support a standardized organizational structure or "one size fits all" approach to market monitoring. The Commission has set forth several proposals to create the necessary independence regardless of structure. P3 supports those proposals.

MMUs must have Clearly Defined Roles

P3 agrees with the Commission's policy statement on market monitoring that the proper role of an MMU is to "monitor organized wholesale markets to identify ineffective market rules and tariff provisions, identify potential anticompetitive behavior by market participants, and provide the comprehensive market analysis for informed policy decision making." But expanded roles for an MMU are not appropriate or consistent with the proper limitations on an entity charged with independently monitoring the markets. For example, as the Commission states in the ANOPR at P 119, the Market Monitor should not be involved in designing the market rules that he will later be called upon to monitor and about which he will make recommendations. Instead, the MMU must maintain independence from all market sectors and interests. The MMU reports after the fact, others decide. This allows the MMU to provide a completely unbiased evaluation of rules, as it did not author them. Extensive involvement in development of market rules creates potential for the MMU to be placed in the position of reviewing the effectiveness of its own recommendations and positions. Expanded roles are not appropriate for an independent market monitor.

MMUs must be Effective

It almost goes without saying that the market monitor should be given all the tools necessary to perform its job. P3 supports tariff provisions that require the RTO to provide the MMU with access to market data, resources and personnel sufficient to enable the MMU to perform its function. Of course, the Commission must be certain that MMU activities are being performed in the most cost effective manner possible since ratepayers and market participants ultimately pay the costs of market oversight. Ultimately, ensuring the cost effectiveness of market monitoring operations is an obligation shared by FERC and the RTO Board.

MMUs must be Accountable

Whether internal or external to the RTO, the market monitor should be accountable to the RTO Board (or a special committee of the Board), not the RTO management, to create both the appearance of, and, more importantly, actual autonomy to perform its market monitoring functions without interference from either RTO management or stakeholders. P3 would support the Commission imposing such a condition on RTOs as suggested by the Commission.

Some interested parties have suggested that the MMU report directly and exclusively to FERC. P3 believes such an arrangement to be extraordinarily inappropriate. RTO Boards by their nature must be independent overseers of the RTO and its operations. They have a fiduciary duty to independently make decisions that improve the health of the market. It is entirely appropriate that the RTO Board (or a special committee of the RTO Board) have some degree of oversight of market monitoring functions.

A code of ethics for MMUs along the lines suggested by the Commission would also help to create accountability for MMUs. P3 would fully support a requirement that MMUs adhere to a Code of Ethics that would govern their behavior. Such a code should give clear direction to the MMU and other stakeholders as to what activities would be in violation of such a code. Moreover, any breach of such a code of ethics should be met with severe consequences up to and including termination.

Access to Information

P3 understands that access to timely and accurate information is critical to the essence of properly designed and well-functioning wholesale markets. P3 fully supports the notion that market monitors be provided access to the RTO market data they need to fulfill their duties. Specifically, P3 supports the Commission proposal to require MMUs to make quarterly reports on RTO/ISO performance to FERC staff, staff of interested state commissions, and to the RTO/ISO management, followed by conference calls during which the appropriate MMU staff would be made available for questions. P3 also agrees with the Commission that "helpful and appropriate" information about the performance of the RTO/ISO markets should be made available to the public so long as the provision of the information it does not undermine the very integrity on which the market relies.

P3 appreciates that state commissions, by virtue of their role, have a unique interest in reviewing market data and should be able to make tailored requests for additional information regarding general market trends and performance, and general analyses of the market and aggregated price data. With respect to specific bid and offer data from individual companies, P3 believes that the RTO tariffs provide appropriate access to such data, subject to adequate confidentiality protection. Beyond what the tariffs provide, P3 agrees with the Commission that States may properly use their own enforcement agencies to obtain such information.

P3 believes that the MMU should be allowed to supply states tailored information drawn from data the MMU already collects in performing its core functions, but the MMU should not be required to collect data beyond its core function for the states or to perform additional studies based on such data. In other words, P3 does not believe that the MMU's functions should be expanded so that the MMU essentially becomes an extension of the state regulatory structure. P3 agrees whole-heartedly with the Commission's statement that "[t]he limited resources of the MMUs should be confined to providing information regarding the workings of the market itself and identifying any structural flaws which the MMUs think should be addressed."[21]

III. THE COMMISSION SHOULD CAREFULLY PURSUE POLICIES DESIGNED TO ENHANCE RTO RESPONSIVENESS

P3 agrees wholeheartedly with the goal of the Commission to increase RTO/ISO responsiveness to stakeholders and we believe that stakeholders within PJM in particular would benefit from better access to the Board and more responsiveness to stakeholder needs and concerns from the PJM organization. We also concur with the Commission's observations that there is a natural tension between the need for RTOs to maintain independence while also being adequately sensitive to the needs of their customers. The ANOPR suggests the use of advisory committees or hybrid boards as possible mechanisms for stakeholders to obtain increased access to the RTO boards and seeks comment on whether any other reforms are appropriate.

---

[21] *Id*. at P 129.

While we believe the Commission is on the right track in seeking reform, we are also concerned that both mechanisms proposed by the Commission require considerable refinement before either can be embraced and implemented. Our concerns stem in particular from the need for stakeholders to designate a subset of representatives to sit on either the advisory committee or the hybrid board. In our experience such representative governance is challenging insofar as it requires industry stakeholders to cooperate in the election of their peer representatives and to assure accountability of those representatives to their constituency. As the Commission notes, "stakeholder members must not be allowed to serve their own interests inappropriately." This challenge is present in the case of the hybrid board or a fully engaged advisory committee[22], where a stakeholder must not only be the advocate for one or more of its market competitors but will also participate in the debate and/or the decision making process. P3 believes that further work in addressing the potential for conflicting duties on the part of stakeholder representatives is fundamentally required in order for the advisory committee or the hybrid board approach to be adopted.

[22] The Commission envisions a Board Advisory Committee that would have no voting authority but that would otherwise interact with the Board directly, make recommendations to the Board, advise the Board about expected effects on customers and stakeholder groups, and present majority and minority views to the Board. *Id*. at P 153.

IV. CONCLUSION

P3 appreciates the opportunity to submit comments in this proceeding and requests that the Commission consider and adopt these suggestions in any NOPR that the Commission issues.

Respectfully submitted,

September 14, 2007

/s/ *Glen R. Thomas*

Glen R. Thomas
GT Power Group

On behalf of the PJM Power Providers Group, Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Wholesale Competition in Regions with Organized Electric Markets	))))	Dockets Nos. RM07-19-000 and AD07-7-000

AFFIDAVIT OF ROY J. SHANKER PH.D.

I. INTRODUCTION

1) My name is Roy J. Shanker. My business address is P.O. Box 60450, Potomac, MD, 20859.

2) I have attached a summary of my educational background and experience as Exhibit No. 1. I have commented frequently upon, and testified before this Commission on matters relating to overall market design issues in specific markets and with respect to generic market design issues. I have been actively involved in all aspects of the development and design of energy markets in several regions of the country, including in particular PJM and NYISO. In this capacity, I have offered my expert economic analysis of numerous issues related to markets, including market rules and procedures and evaluations of market behavior.

3) Over the last ten years, I have worked extensively in the restructuring of electricity markets. In particular, I have had continuing involvement in the development and implementation of the PJM and New York regional transmission organizations (RTOs). In each of those markets, I participate regularly in the stakeholder committee processes relating to business issues and technical market development. Much of my work has focused on the development of rules related to energy, transmission rights and the installed capacity markets.

4) Since the very beginning of both the NYISO and PJM markets, I have been an active participant on several committees and working groups on behalf of various clients. In PJM, I have been active in the Markets and Reliability Committee, the Market Implementation Committee and various working groups which have addressed issues relevant to the Commission's current inquiry. In NYISO, I have participated in the Business Issues Committee, the Market Structure Working Group and Scheduling and Pricing Working Group (now the Market Issues Working Group), Installed Capacity Working Group, and other stakeholder groups related to transmission planning and interconnection issues.

5) In parallel with this market design and development work, I maintain an active practice related to the negotiation, implementation, and when required, litigation of bilateral agreements for power sales and transmission. On behalf of my clients, I have offered expert testimony in many instances in associated regulatory and legal proceedings, and also served as an expert advisor and arbitrator. Much of this experience is identified in Exhibit No. 1.

II. SCOPE OF TESTIMONY

6) I have been asked by the PJM Power Providers Group, Inc. (P3) to offer comments with respect to the Commission's June 22, 2007 Advance Notice of Proposed Rule Making addressing Wholesale Competition in Regions with Organized Electric Markets (ANOPR). P3 asked me to review and comment on the Commission's inquiries set forth in paragraphs 57-82 which address "actions to improve demand response and market pricing during a power shortage".[1] In particular, I was asked to comment on the final area addressed in that section of the ANOPR which relates to energy and ancillary service pricing for the time period when demand is nearing the amount of total available supply, *i.e.*, pricing during shortage

---

[1] ANOPR at 57.

conditions or what is typically referred to as scarcity pricing. For purposes of this affidavit, I will use the terms "shortage pricing" and "scarcity pricing" interchangeably.

III. DISCUSSION

7) The Commission appropriately focuses its inquiry of how to best implement shortage pricing within the context of the Commission's overall consideration of demand response. The two concepts are directly linked, and both revolve around the usual priority—getting the prices right. Fundamental to effective demand response is showing consumers the prices that should exist when conditions approach physical shortage so that consumers can consider demand reduction as a cost effective response to these prices. In turn, in order to allow prices to efficiently ration power to those that value it most, there has to be a rational pricing scheme during these same periods that reflects the impending physical scarcity and the need for mandated load reductions unless consumers voluntarily reduce consumption in response to these right price signals. Thus, the issues are inseparable, effective demand response goes hand-in-hand with efficient pricing during shortages. As a result, the path to the right public policy regarding demand response has to include direct measures to improve the accuracy of energy pricing as conditions approach a supply shortage. However, as noted by the Commission, practical considerations make both of these tasks and their integration difficult.

A Simple Abstraction of Pricing In a Perfect World

8) Starting with a simple abstraction of the electricity markets helps to put both shortage pricing and demand response in context. In addition, the abstraction is useful in answering several of the Commission's inquiries.

9) The PJM market is approximately 150,000 MW. Assume that there were 150,000 independent 1 MW generators and an equal number of 1 MW loads/customers. Each generator

and load/customer can see the real time price of electricity and can continuously adjust its production and/or demand in response to changing conditions and prices, as well as freely enter and exit the market. Also assume that several of the typical operating requirements for an electric system can be suspended and that no reserves are required, there are no transmission limitations, and demand and supply do not have to instantly balance. Assume further that in such a system, due to outages or fluctuation in demand, conditions arise where total potential demand can exceed available supply. Also assume there is no mandated reliability standard; generators enter and exit the market in response to market prices.

10) In such a system, when there was sufficient supply to meet demand, one would expect the clearing price for all load to be set by the marginal supplier. As load increases above the available supply, price would no longer be set by the offers of the marginal producers, but rather by competitive bids of loads, each indicating the price it is willing to pay or alternatively the prices at which its load would decrease. In turn, the limited supply and demand would equilibrate as prices rise to a level where demand is sufficiently reduced, and reflected the offers of the load. This is the typical "efficient" outcome where power is properly priced for both producers and consumers, and used by the parties that value it the most. As usual, this result is also consistent with the general economic conditions characterized as necessary for maximizing efficiency for the economy as a whole.

11) Under this abstraction, there would be no need for either an external reliability standard or a capacity or adequacy market. The level of reliability for the system is an output that reflects load's preferences and willingness to pay for resources, equilibrating at a level that supports reliable supply. There is no need for capacity markets as scarcity payments rise to the level where net margins are sufficient to support new entry, *i.e.*, there is no missing money for

generators to "make up" in order to recover fixed costs due to suppressed prices associated with mandated reliability requirements or price caps. Inherent in such a system is both the ability of load to indicate its willingness to pay, and the ability of operators to curtail or force specific load off the system should they indicate that they will not pay.

12) In such an abstraction, the answers to most of the Commission's questions become simple. There is no need for incentives or price distortions to "encourage" demand response, it is automatic as load sees the price of power and adjusts consumption accordingly. Similarly there is no need to compensate a customer for demand response once prices are set correctly – load will buy less at higher prices. Furthermore, there is no need for complicated shortage pricing rules or procedures to raise or modify supplier offers, as suppliers also see the right price when supplies are short. The right prices are reflected in the price signals from load, as load competes for the limited supply. Thus, the long run result is a market-based level of reliability with energy prices recovering all necessary revenues.

Actual Pricing In the Real World

13) Obviously the real world doesn't work this well and it is the real complications that lead to the questions raised in the Commission's ANOPR. Load and generation are not continuously and instantly adjustable with corresponding price levels nor do load and generation instantly and continuously see the "right" price. In addition, there are (i) transmission limitations, (ii) public policy concerns over extreme price volatility, (iii) exogenous reliability standards set outside of a market mechanism including operating and reserve requirements, (iv) severe limitations on the ability to identify and drop load on a customer-by-customer basis, and (v) no assurances that operating margins are sufficient to maintain needed existing capacity or support new entry.

14) However, the guidance from the simple abstraction is still valid: try to set the prices correctly to reflect the value of marginal supply when total supply exceeds demand, or the value that load places on supply when supply is less than demand (inclusive of reserves). In almost every instance, the Commission's questions are resolved by simply trying to accomplish these two pricing principles, while at the same time attempting to deal with the practical implications and complications of the real world.

Double Compensation

15) The Commission seeks comments on how to appropriately compensate a customer for demand response.[2] As seen in the above simple abstraction, the answer is straight forward: simply set prices correctly and facilitate customers' adjustment of demand in response to the "right price". There is no need for further compensation, and all this can do is result in both a subsidy and distortion of prices to other market participants. There is no need to pay someone for something they haven't purchased, and to do so results in the double compensation referred to by the Commission. If the price is set correctly, customers will consume less, and demand will be appropriately limited.

16) The Commission is correctly concerned with double compensation; however, the Commission's reference and description of PJM's Economic Load Response Program (ELRP) is incomplete.[3] A full description of the ELRP and demand response pricing is necessary to recognize how double payment is avoided in some circumstances (and how a subsidy persists in others). As noted by the Commission, the PJM ELRP pays demand response the LMP less the generation and transmission component of each retail customer's retail rate. However, what is

---

[2] ANOPR at 74.

[3] ANOPR at 74.

not explained is that this payment comes from the LSE who serves the customer, not the PJM market as a whole.[4]

17) Seen in this context, the payment for demand response is very different from a generic notion of being paid not to consume something that hasn't been purchased. Absent the reduction in demand, the LSE would have to purchase energy at the LMP, and only receive the agreed upon retail rate. Thus, for LMPs under $75/MWh, the LSE is indifferent – its payment (LMP less retail generation and transmission) to the demand responder is the amount that the LSE would have "lost" had it purchased supplies for the load at the higher LMP rate and sold at the agreed upon lower retail rate. Unlike the implied notion of being paid not to consume, the demand responder is getting paid for something that they did possess, a call for energy at a fixed price from the LSE. PJM is simply facilitating the repurchase of the "call", or a bilateral transaction between the LSE and load.

18) While part of the overall PJM market design, recognizing that PJM's ELRP program is more similar to a private bilateral transaction that is not subsidized by the rest of the market provides important insight into how to properly compensate a customer for demand response. It supports a general solution where the role of the RTO is to get the prices right, communicate the right prices to participants, not provide subsidies, but rather facilitate private transactions that may encourage more efficient consumption and demand response. In fact,

[4] Under the PJM program, this construct exists for LMPs under $75/MWh. For prices above $75/MWh, a subsidy exists and the demand responder receives the full LMP instead of only LMP less retail generation and transmission costs. Other LSEs in the same load zone pay the additional retail generation and transmission charge. This subsidy ends this year on December 31, 2007.

PJM's own progress in this area will be greatly enhanced by the elimination of the current subsidy when LMPs are over $75/MWh.[5]

Pricing During Shortage

19) As discussed in the simple abstraction, shortage pricing, or the setting of price when potential demand approaches or exceeds supply, is very important. Shortage pricing transmits the fundamental pricing message for load to reduce consumption. It also provides generation with the right short term price signals for production, and, over the long-term, allows for the recovery of fixed costs to support maintenance of needed existing facilities and new entry. Practical limitations prevent load from easily seeing and responding to increasing prices during shortage. Real time metering and communications is limited, as well as the corresponding ability of load to instantly bid and respond to changing prices and supply/demand conditions. Further, as a practical matter, electric systems do not operate to the point at which load is continuously added or dropped due to shortage, but rather attempt to maintain an operating reserve margin as a buffer against unanticipated shifts in either supply or demand, particularly generation or transmission contingencies.

20) Because of these limitations, one means to communicate the important price information is to find a proxy or process to establish prices similar to what would be expected in the abstract example discussed above. One general approach, which is the area of Commission inquiry, is to allow prices to rise above supply offers when demand reaches a level where "normal" operating reserves can not be maintained. As the level of reserves decreases, the market price for energy increases in some "to be specified" manner.

---

[5] The very limited empirical information that has been presented in the PJM stakeholder process suggests that the current subsidy does not have a material impact on the level of demand response, e.g. levels of response are comparable below and above the $75/MWh.

21) In the real world, this approach is desirable as it allows price to approach the value that load would be willing to pay if the abstract conditions of the example were being met. Further, it is important to understand that in PJM with the associated Reliability Pricing Model (RPM) for adequacy/capacity, the result of adopting such pricing will solely be an increase in price "accuracy" and not the often suggested windfall for suppliers.

22) Indeed, on a market average basis, all the increased revenues received by suppliers when prices reflect such scarcity is offset by reductions in capacity payments. This occurs as PJM employs an empirical adjustment to its RPM demand curve process that directly subtracts net energy margins on a historic three year basis (income in excess of operating costs for the new entrant) from the targeted capacity payments. This means that higher, more accurate prices that reflect scarcity will result in a corresponding average reduction in payments for capacity.

23) This offset was recognized and directly incorporated into the current PJM scarcity pricing process.[6] Thus, in any ISO/RTO where this type of netting process exists in the development of capacity payments, the move towards more accurate, but estimated, scarcity payments can be seen as a cost neutral adjustment for load that improves energy pricing accuracy, while at the same time maintaining the level of revenues to generators needed to support new entry and maintenance of existing needed facilities. Further, more accurate energy pricing should actually complement the capacity market designs by rewarding the most efficient generators without creating a suggested windfall.[7]

---

[6] Explanatory Statement, Docket No. EL03-236-006, EL04-121-000, http://www.pjm.com/committees/mic/downloads/20060328-item6.pdf

[7] The net energy and ancillary service payment offset used in the establishment of the RPM demand curve in PJM is empirical and based on a lagging average. This means that if energy income increases due to higher payments that result from demand approaching shortage conditions, capacity prices will be reduced, with it taking a rolling three

24) With the benefits of accurate energy pricing established, the question then becomes how to identify reasonable approaches to estimating or establishing a proxy for what the theoretical price should be when conditions approach a supply shortage, taking into consideration of the realities of the electric system.

25) The first element in this process is to recognize that electric systems do not operate to a level of demand that just reflects load, but also maintain additional supply as reserves. Supply shortage can exist prior to the actual dropping of load during periods when supply is insufficient to maintain the "usual" reserve levels. Typically electric systems are operated with fixed operating reserves that are related to operating contingencies (*e.g.* loss of largest generator or transmission element) or based upon an established percentage of load. PJM follows this general practice. As stated in the synchronized reserve business rules:

> • Total PJM Synchronized Reserve Requirement for each Synchronized Reserve Zone is determined in whole MW for each hour of the operating day.
> o The RFC Synchronized Reserve Zone Requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. The requirement will be defined as the greater of the ReliabilityFirst Corporation (RFC) imposed minimum requirement or the largest contingency on the system.
> o The Southern Synchronized Reserve Zone Requirement is defined as the Dominion load ratio share of the largest system contingency within VACAR, minus the available 15 minute quick start capability within the Southern Synchronized Reserve Zone.[8]

26) However, in reality, such rules of thumb are not followed in all circumstances, and operating reserves are allowed to fall below such levels (up to some limit) when demand

---

year average for the reduction to work its way fully through into capacity payments. Similarly, when energy prices fall due to new additions of generation, it will take three years for this price impact to work its way through and result in a higher demand curve for the determination of capacity prices. On average for the market, all energy premiums are returned, with this type of lag in both directions.

[8] PJM Synchronized Reserve Business Rules, Manual 11, Section 4. http://www.pjm.com/contributions/pjm-manuals/pdf/m11.pdf

approaches the level of available supply prior to directed load shedding. Analysis of these conditions, that is where effective demand exceeds supply (as evidenced by the reduction of operating reserves), can provide information related to pricing during shortage.

27) Thus, what is needed as a starting point is a clear and unambiguous set of triggers for when the proxy pricing should start to be applied as load encroaches on target reserve levels. While it seems easy to simply state, as the Commission has suggested, that this should begin when operating reserves are diminished, again practical considerations make this difficult. For example, under the existing PJM rules, such pricing is supposed to go into effect during emergency conditions when presumably such reserve levels are violated. However, this is not always the case today and no adjustment exists for local shortage conditions.

28) PJM's scarcity pricing rules are a result of a settlement process that was established to resolve a different, but related issue – the frequency of price/offer mitigation. And there are at least two significant problems with these existing rules. First, these existing rules do not even trigger any actions to reduce price mitigation when reserve levels are violated. Under PJM's existing rules, price mitigation is not suspended until PJM physically calls on emergency generation, purchases emergency generation from outside of PJM, declares a voltage reduction or takes even more draconian actions such as load shedding. These triggers can and do occur after system reserve levels are violated. Merely violating reserve levels does not trigger suspension of price mitigation under PJM's existing rules. Second, under PJM's scarcity pricing rules, conditions must be met across large areas of the system in order to suspend bid mitigation. These triggers totally ignore local reserve violations. Such local violations can often be seen

when the only operator contingency responses are identified as load dump, *i.e.*, non-sufficient reserves.[9]

29) The need for triggers based upon shortages of operating reserves and local reserve violations is very important, because without these, accurate prices, and the associated benefits of conveying the right price to load, will not be realized. An example of this may have occurred in PJM on August 8, 2007, when there were clear indications of significant areas of reduced operating reserves, yet no adjustment in pricing occurred consistent with the current rules until well after such conditions began.[10] The issue here is not that PJM necessarily failed to implement their rules appropriately, but that the rules were too coarse to respond to true shortage conditions with appropriate prices.

30) In order for the markets to work effectively, a related issue must also be addressed; there must be a consistent application of the rules and associated pricing between the day-ahead and real-time markets. Inconsistent rules can create a bias in offers and possibly economic decision making not only by market participants but also the RTO with respect to day-ahead planning and system commitment. Inconsistent rules also promote skewed bidding behavior that can not reasonably be discerned from gaming or market manipulation, leading to implementation and market monitoring problems. A simple rule of thumb is that if a contingency or constraint related to operations and reserves is characterized in one market, *e.g.* real-time; than it must be similarly reflected in the other, *e.g.* day-ahead.

---

[9] See discussion of PJM's current scarcity pricing below at para. 40.

[10] On August 8, 2007 at 12:33 PJM declared a maximum emergency generation event in 2 zones: PEPCO and BGE; This maximum emergency event reflected shortage conditions, however, because the constraint that needed to be relieved (Conastone) was not reflected in the current definition of scarcity pricing regions, no scarcity pricing was triggered. Later in the day, at approximately 3 PM, one of the defined constraints, Bedington-Black Oak did trigger scarcity pricing. See PJM summary at http://www.pjm.com/markets/energy-market/downloads/20070808-scarcity-pricing-implementation-timeline.pdf

31) Given appropriate and consistent triggers, as well as uniform application of the shortage pricing mechanism to both markets, it should be clear that as the level of reserves decreases, the likelihood of a system contingency and associated levels of un-served load or energy increases. For example, if the typical level of reserves were 1200 MW, the likelihood of a loss of load will be less than if reserves are allowed to drop to 1000 MW. It is possible to actually measure this shift in reliability using probabilistic tools to estimate the change in loss of load probability and the expected lost load due to various potential contingencies at the 1200 MW reserve level versus the 1000 MW reserve level. If one had a measure for the displaced or lost load, typically referred to as the Value of Lost Load (VOLL), one could relate these changes in reserve levels to measurable changes in potential costs for load.

32) The VOLL is effectively the proxy for the willingness of load to pay for additional supplies in the abstract example. In turn, this suggests that the value of the power being sold increases during such times with the value of the power increasing as the likelihood of the potential loss of load rises. Accordingly, the VOLL should be the value that sets the market price. Such an approach could conceivably be applied to very small locations where there is appropriate information about locational reserve requirements, the probability of local contingencies being violated and VOLL. In general the smaller the targeted area, the more accurate the pricing.[11] This is discussed further below in the context of the third suggestion by the Commission regarding pricing during shortage.

---

[11] A discussion of this general type of approach and related issues to applying the results to pricing during shortage can be seen in a paper presented by William Hogan at http://ksghome.harvard.edu/-whogan/hogan_hepg_030206.pdf.

The Commission's Four Alternatives

33) One reasoned alternative approach to setting prices during a supply shortage is to tie the VOLL proxy value with the operational reality of the electric system during these conditions. The question is how to get this information into prices. The Commission's four alternatives presented in paragraphs 75-82 of the ANOPR address this problem. Each of these alternatives can be considered in terms of their relative effectiveness in accomplishing both the exact result of the abstraction as well as the more practical proxy just discussed. In addition, I offer a fifth option, that should be considered for inclusion with any of the other four, and is an important overall improvement to pricing in any conditions, but particularly those related to conditions of scarcity.

Increase Energy Bid Caps

34) The first alternative suggested by the Commission is to "require that RTOs and ISOs increase the energy bid caps and price caps above the current levels only during an emergency."[12] The Commission acknowledges a generic definition of emergency in the same context as discussed above, a reduction of operating reserves below the specified requirements. This could help improve pricing during scarcity if the definition of "emergency" were consistent with the discussion above, *i.e.*, any reduction (local or otherwise) of operating reserves from "target" levels where the only operating alternatives in the event of a contingency event would be a load dump. To further improve the accuracy of the pricing, the target levels should be defined on a locational basis. Triggering mechanisms of this type are required to define shortage consistent with local area constraints and the reduction of overall reliability as operating reserves decline. Such mechanisms also must be clear and not subjective.

---

[12] ANOPR at 76.

35) However, this approach puts generation in the position of having to "guess" at the value of power to convey the right price signals to load. If the intent is to induce the proper load response to scarcity price signals, some other offer mechanism for generators in this situation would be needed than simply allowing higher bids, *i.e.*, encouraging the generators to provide offers consistent with expected VOLL. As the Commission has implied, not only would any mitigated offer caps need to be lifted, but the overall market caps would have to be raised during emergencies to get into the range of prices typically needed to start price-based reductions of load. Load reductions aren't necessarily bad, but given the expected levels of prices necessary to induce this behavior, such bidding is likely to prove politically controversial.

36) Another complication of this type of market design is the issue of market monitoring for the exercise of market power. There simply isn't an obvious set of criteria to determine whether a seller is attempting to exercise market power because the intent of the market design is to induce offers that are representative of the value load places on the power, rather than production costs. While market monitoring can look for behavior that may inappropriately create the shortage situation, *e.g.*, physical withholding, it is unclear what if any criteria would be applied to supply offers in this situation. In fact, the situation exists in the current PJM market design where there is no aggregate market level mitigation other than the overall offer cap (mitigation only applies to constrained on units).

37) Should the Commission seek to mitigate supply offers after "lifting" offer caps, it would seem that the standard for measuring offers should be consistent with the estimates of VOLL times the increased probability of outages. There is no reason why any specific supplier should be expected to be knowledgeable about this value. Therefore, a catch-22 situation may be created where attempts at mitigation directly undo the efforts to communicate the higher price

signal because it is difficult to differentiate a supply side bid in response to a shortage from the possible exercise of market power. This suggests that a superior approach would be the third option discussed below.

38) A mitigating factor with respect to concerns raised about high supplier offer prices is the interaction of energy prices with the RPM/capacity market design, which assures that any additional revenues derived from higher energy prices is offset by reductions in the demand curve estimation process. At the aggregate market level, this type of offset is a desirable component of mitigation with respect to the exercise of market power provided that shortage pricing in is place when there is an actual supply shortage.

39) Regardless of whatever limits are selected for changing offer prices during a supply shortage, allowing generators to increase their bids should be expected to lead to higher prices consistent with the general direction of the desired price movement. What is not clear; however, is whether any of these methods is more accurate than some direct attempt to estimate the price signals that load should see in order to make the correct decisions about curtailing load.

40) PJM currently has this type of scarcity pricing in place. However, the approach is relatively gross – the triggers are too limited and fail to include some operator actions to control for perceived scarcity, which perversely may reduce prices at just such times of shortage. The triggers also are required across very broad regions of the PJM system, and therefore PJM's procedures fail to respond to localized scarcity before it becomes a system-wide (or nearly system-wide) emergency. In addition, prices under PJM's scarcity rules are set against generator offers made in the day-ahead market and prior to potential mitigation. Prices are not set against the perceived value of power to load during scarcity situations, which is desired if the intent were to allow generators to raise their offers to approximate the scarcity value. PJM's scarcity pricing

rules limit prices during such conditions to the $1000 per MWh offer cap (and generally lower), well below typical expectations of VOLL.[13]

41) Thus, there is a fundamental mismatch between the prices used for "released" or unmitigated offers during a supply shortage in the PJM design, and the intent of the price signal that is being sought. Rationally, if asked to supply bids that are indicative of VOLL, suppliers would be expected to provide estimated prices much higher than those they would provide absent mitigation for local transmission constraints. Another related issue, both in PJM and in general, is the importance of maintaining a consistent design in terms of both pricing and mitigation between the day-ahead and real-time markets. It would be totally inappropriate to use this type of shortage pricing in real time, while possibly maintaining mitigated prices for the same conditions in the day-ahead market. This approach would convey possibly very high "design" risk for suppliers who would not see the right signal day ahead due to a mismatch of mitigation with the shortage pricing design, yet would bear the outage and replacement risks in real time as they have to purchase replacement power at the higher shortage pricing levels.

42) A final comment on this alternative, and one that applies to the three other approaches suggested by the Commission, relates to the need to integrate any scarcity pricing mechanism with the overall market design. The PJM markets are a good example of why integrating scarcity pricing into the overall market design is necessary. In general, generation "chases" price in the PJM market, and generators are not given set operating points in the

[13] For a discussion of some of the PJM scarcity pricing mechanism's deficiencies, see the discussion of the PJM MMU at http://www.pjm.com/markets/market-monitor/downloads/20070521-scarcity-rules.pdf (The PJM scarcity pricing rules are triggered during emergency energy events, maximum emergency generation events, manual load dump events and voltage reduction events. They also require that these emergency actions be implemented over an area consisting of two or more contiguous zones, each with 5% or greater positive distribution factor relative to the binding 500 kV or greater transmission constraints. At such times the prices increase to the highest offer price of a generator within the zone, generators required for such constraints outside of the zone can not set price.).

dispatch (with the associated performance penalties) as is the case in the NYISO design. In this type of design, simply increasing prices during a supply shortage, particularly locally defined reserve violations, creates operating and control issues for the PJM RTO, as generators will push operating limits and take other efforts to expand supply, without providing corresponding reserves for the system operator.

43) In order for any shortage pricing to work within this type of "chase price" market design, it has to be coupled with a correspondingly new reserve product that matches the shortage definition. Such a product would have to match the locational nature of the shortage definition, provide the system operator with the ability to hold or maintain reserves consistent with the locational definition (*e.g.* turn down a local generator), and similarly price the opportunity cost of held reserves (*e.g.* the amount of energy held down for local reserves) consistent with the overall prices established under the shortage pricing rules.

Raise Bid Caps for Demand Offers Only

44) The second alternative identified by the Commission "is [during an emergency] to raise bid caps above the current level only for demand bids, … [*i.e.*] an offer by a potential purchaser to buy a certain amount of energy at a given market price. … Under this proposal, such high demand bids would not only be allowed, but also would be allowed to set the market price if they clear the market."[14]

45) It is hard to argue with the theory of this approach, as it directly places a demand curve for energy into the market pricing. It is unclear why there would be any limitations on such bids at any times, emergency or not. Basically this approach is consistent with a fundamental element of the "perfect world" abstraction presented above—load indicates its

[14] ANOPR at 78.

willingness to purchase a given quantity at a given price, and continuously adjusts their consumption in the face of changing prices. The difficulty is not with the theoretical approach, but with the current practical limitations in conveying such information between the ISO/RTO and load, load's actual willingness to make bids approaching the VOLL, assuring load compliance, and consistent implementation of the process in the pricing software. Ultimately, it also means that there has to be a mechanism to drop or control load consistent with these offers on a load by load basis. None of these conditions are met as a practical matter today. Ultimately, when and if these limitations were fully addressed, and sufficient load was responsive via these types of bids, this would be a good solution. In all events, developing the capability to incorporate such bids and responsiveness significantly improves the efficiency of the market.

Require a Demand Curve for Operating Reserves

46) The third alternative "is to require a demand curve for operating reserves in each RTO or ISO market."[15] Under this proposal, neither supply nor demand offers directly set prices during scarcity. Rather, an administratively set curve establishes prices as operating reserves decline below a specified level. This is an attractive solution for several reasons. First, as the Commission has noted, it is probably the most straight-forward in terms of concerns regarding the exercise of market power. Under this approach existing mitigation continues as per the status quo, however, as soon as there is an "incursion" into a reserve deficiency, prices are then set by the demand curve. Second, this proposal is relatively simple to implement, once a demand curve for reserves is established. The triggering conditions are monitored, and prices default to the demand curve values based on the varying level of reserve deficiency. Third, this type of

[15] NOPR at 79.

approach is amenable to being "tuned" to accomplish the underlying objective, sending price signals to encourage load to reduce consumption. Demand response can be monitored or surveyed and the reserve demand curves modified (up or down) to try and mesh with the underlying objective. This ability to "tune" also suggests that the use of reserve demand curves could constructively be coupled with the second alternative, demand bids. There is no reason that both options could not be implemented together, with the use of the reserve demand curves being adjusted to continually encourage additional demand bids. For example, if load would economically curtail at $1400 per MWh but had not developed the ability to offer and respond to this price, the initial reserve demand curve could be set for scarcity at $1500/MWh. In time, there would be an incentive for the load to develop the appropriate demand response capability and more accurately respond through both demand bid offers and taking the necessary steps to be able to curtail, *i.e.*, making the second alternative the Commission suggested feasible to implement.

47) The obvious challenges to implementing this type of demand curve for reserves is establishing the shape of the curves, as well as the granularity of the triggers or local operating reserve requirements. Conceptually, as discussed above, one approach to developing such a curve is simply to estimate the change in loss of load probability as a function of the reduction in reserves, and multiply that value times an estimate of the VOLL. This would result in a continuous increasing curve for pricing as a function of the decline of reserves. The change in loss of load as a function of the level of operating reserves is amenable to direct calculation by traditional probabilistic tools used in electric system reliability/adequacy planning. The more contentious issue would be the selection of VOLL. However, as I indicated above, one of the advantages of this approach is its "adjustability" and this in of itself should not be an

impediment. Further, given the energy price offset feature of PJM's RPM market design, the impact of errors on either the high or load side should be very small on average, with the "errors" trued up over time via the energy and ancillary service payment adjustments to the demand curve.

48) Conceptually, this type of approach can be applied to as small a locational level as desired, possibly even nodally. Thus, triggers can look at regions as small as possible consistent with actual physical operating characteristics and the associated operating reserve requirements of the underlying utility system. If this approach is adopted, as discussed above, it is necessary to maintain a coordinated new reserve product definition in the market design.[16]

Set Clearing Price Based on Demand Response Payments

49) The fourth approach identified by the Commission would be "to allow the market price to reduce demand during an emergency [by setting] the market-clearing price at the payment made to participants in an emergency demand response program."[17] Absent consideration of the double payment issue, this is a reasonable approach and emergency demand response can set price under the PJM demand response programs.[18] This approach, however, is insufficient to fully address the problem. The issue remains how to set price as operating reserves, including locational reserve requirements, decline below target levels. There is no necessary relationship between the triggering of these emergency demand response programs

---

[16] See Hogan reference from footnote 12.

[17] ANOPR at 80.

[18] PJM Load Response Business Rules at 38. Load reductions due to this program [energy only emergency] will be eligible to set real time price on the PJM system at the resource's Minimum Dispatch Price. Load reductions provided by Full Emergency Load Response Program resources are eligible to set the real time price on the PJM system so long as the load reductions were needed to meet demand on the system. Energy Only Option resources must also meet PJM's telemetry requirements to be eligible to set the real time price on the PJM system Direct Load Control must also notify PJM electronically hat the signal to the devices has been sent.

and the resolution of the problem. Thus, while allowing such programs (appropriately defined to exclude subsidies) to set price is reasonable, additional actions are necessary.

50) The fifth alternative for scarcity pricing really is a recommended action that should be combined with any of the above four alternatives, and as a general matter should apply all the time, but particularly in times of scarcity. Pricing under LMP is established based on the solution to an optimal power flow (OPF) representing the transmission system, load and generation. Prices diverge and increase as constraints on the system, both transmission and generation related limitations, bind, and cause the use of more expensive resources. Thus, it is very important for the characterization of the system in the OPF to fully represent all such constraints, or prices may be set too low. It is important that the Commission assure that any constraints caused by increased or changed operational security issues are included in all pricing determinations.

51) During periods of scarcity, the ability of operators to use their discretion in the dispatch and operation of the system can introduce new operating constraints that are not represented in the OPF, and therefore result in a systematic under pricing of electricity when these constraints occur. This is due to the fact that the system is operating to solve a more restrictive constraint than is reflected in the pricing. A typical example of this type of behavior might be for operators to "hold on" peaking units after they are no longer needed due to concerns that the peaking units might not be available later in the day to serve high demand because the unit may fail to restart. Keeping these units on when they are "unneeded" suppresses prices even though the supposed concern is maintaining reliability. Implicit in the operators' decision to hold the unit is the conclusion that a higher level of reserves are needed, but this concern is not reflected by changing the OPF constraints nor modifying the resulting pricing. The criticism

here is not that the operators' should not be allowed to make such decisions, but rather that all such decisions must be reflected in the pricing.

52) This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Wholesale Competition in Regions with Organized Electric Markets	)	**Dockets: RM07-19-000, AD07-7-000**

AFFIDAVIT OF
ROY J. SHANKER PH.D.

I, the undersigned, being duly sworn, depose and state that the contents of the foregoing Affidavit are true, correct, accurate and complete, to the best of my knowledge, information and belief.

Roy J. Shanker

Subscribed and sworn to before me,
this 12th day of September, 2007.

Bertha Villatoro
Notary Public

My Commission Expires: July 9, 2011

BERTHA G. VILLATORO
NOTARY PUBLIC
MONTGOMERY COUNTY
MARYLAND
MY COMMISSION EXPIRES JUL.9, 2011