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**The National
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of Regulatory
Utility
Commissioners**

Scarcity Pricing in PJM For Pennsylvania

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A report for the Pennsylvania PUC
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The report was authored by James Wilson. Throughout the preparation process, the members of NARUC provided the author(s) with editorial comments and suggestions. However, the views and opinions expressed herein are strictly those of the author(s) and may not necessarily agree with positions of NARUC or those of the U.S. Department of Energy.

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Please direct questions regarding this report to Miles Keogh, NARUC's Director of Grants & Research, mkeogh@naruc.org; (202) 898-2200.

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COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P.O. BOX 3265, HARRISBURG, PA 17105-3265

July 30, 2010

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***PJM Interconnection***; **Docket No. ER09-1063-004**; **Comments and Protest of the Pennsylvania Public Utility Commission**

Dear Ms. Bose and Mr. Davis:

Please accept for filing in the above-referenced matter electronically filed Comments and Protest of the Pennsylvania Public Utility Commission with regard to the above filing.

Thank you for your attention to this matter. If you have any questions in reference to this filing, please contact me at (717) 787-5978.

Sincerely,

/s/ John A. Levin
John A. Levin
Assistant Counsel

Enclosure

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

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Docket ER09-1063-004

**COMMENTS AND PROTEST OF THE PENNSYLVANIA
PUBLIC UTILITY COMMISSION AND SUPPORTING AFFIDAVIT**

The Pennsylvania Public Utility Commission (“PaPUC”) herewith files these Comments and Protest regarding the PJM June 18, 2010 filing of tariff changes proposing “Shortage Pricing” modifications to PJM Interconnection LLC’s (“PJM”) existing energy and capacity markets. Attached hereto is an affidavit by James Wilson F. Wilson, Principal – Wilson Energy Economics and Affiliate, LECG in support thereof (“Wilson Affidavit”).

SUMMARY OF COMMENTS AND PROTEST

The Commission’s 2008 issuance of *Order 719*¹ and its direction to RTOs to file tariff changes in compliance with *Order 719* that provides for “demand response and pricing during periods of operating reserve shortages”² initiated a yearlong stakeholder process directed by PJM. The result of the stakeholder process was not successful in developing a scarcity pricing proposal that attracted broad support. Nevertheless, the

¹ *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (“Order No. 719”)

² PJM Interconnection, L.L.C., *Order on Compliance Filing*, 129 FERC ¶ 61,250 (2009) (“2009 Compliance Order”).

effort was not wasted as it allowed many parties to develop a better understanding of the complexities of complying with the Commission's directive and the risks and benefits of making yet another significant modification to PJM's wholesale electricity market design.³

As this Protest and attached affidavit demonstrate, PJM's filing constitutes one approach to the introduction of scarcity pricing, but a flawed and incomplete approach. Without significant modification as explained below, PJM's filing may result in large and unjust wealth transfers from buyers of wholesale power to sellers of wholesale power, provide frequent opportunities for the exercise of unmitigated market power, undercut public support for the continued development of wholesale competition and produce excessive rates contrary to the Federal Power Act's mandate that all rates be "just and reasonable"⁴.

The Commission should clearly understand that the filing that PJM has made is not the product of a stakeholder process. In important respects Shortage Pricing is a filing that does not adequately address a number of the critical concerns and issues raised during that stakeholder process, does not comply with Order 719, is likely to lead to inefficient and excessive prices, and must be modified both to protect wholesale and retail customers and comply with fundamental requirements of the Federal Power Act.

³ The PaPUC has reviewed the Amended Proposal contained in the Protest and Compliance Proposal of the Independent Market Monitor ("IMM") for PJM and notes that, while the IMM's proposals are not identical to those in this Protest, we share the concerns of the IMM about the potential for exercise of market power and unjust wealth transfer raised by this filing.

⁴ Federal Power Act ("FPA"), Section 205, 16 USC § 824d (a).

Unless PJM's proposed Shortage Pricing tariffs are modified as discussed herein the PaPUC vigorously opposes any modification to the existing \$1,000 / MWh maximum energy price at this time and contends that PJM's proposed Shortage Pricing tariffs do not comport with the requirements of the Federal Power Act that rates be "just and reasonable".

The following major problems with PJM's filing, along with our recommended solutions are discussed below:

❖ **Problem – Vertical Operating Reserve Demand Curve And Additive Penalty Factors**

As Market Clearing Price: PJM's filing proposes a maximum price for energy and reserve of \$2,700 / megawatt hour ("MWh"), which is close to PJM's estimated value of lost load ("VOLL"). While a very high price may be justified when the system is in a very serious situation and the probability of loss of load is great, PJM's proposed mechanism can trigger the maximum price when reserve shortage is low, moderate or high, regardless of actual grid conditions and stress on the system. As PJM proposes to allow such scarcity events to set the market clearing price for all resources, the potential impact on consumers of this mismatch between Shortage Pricing and actual system conditions is greatly exacerbated. This design error presents irrational economic signals to supply and load, does not comply with the "value" requirements of Order 719 and encourages gaming and market power exercise.

Solution: A "stepped" operating reserve demand curve that leads to prices that more accurately reflect the amount of reserve available to the system and the actual probability of loss of load, so prices rise as reserves tighten.

❖ **Problem – Energy and Ancillary Services Offset:** The bulk of PJM's supply or demand response resources have committed to participate in PJM's RPM capacity construct through May 31, 2013 and will be paid capacity revenues in exchange for being available at all times during these entire delivery years and regardless of system conditions. While supply and demand response resources may be incented either through capacity payments/penalties or scarcity pricing during times of reserve shortage, having both mechanisms in place may be appropriate as long as market participants are not being double compensated for a single set of resources. PJM's filing acknowledges that a

revenue offset is needed for RPM resources that also receive scarcity revenues, but its proposed approach delays the offset by three years and would have the offset operate indirectly through RPM parameters and prices. This both requires load to wait four to six years to see an offset from shortage revenues, leads to RPM prices that vary based on conditions several years in the past, and is directly at odds with RPM's fundamental purpose of pricing capacity relative to future delivery year conditions

Solution: Immediately reflect shortage pricing revenues as a reduction to current year RPM revenues without a multi-year lag.

❖ **Problem – False Positive Triggering of Scarcity Pricing:** As experience in other RTOs has demonstrated, dynamic system conditions may trigger scarcity conditions when no actual scarcity will occur. For example, a very rapid increase in morning demand may seemingly result in a temporary shortage, as generation ramps up to meet the expected demand. Experienced operators familiar with the dispatch of generation resources know that generation ramp rates will “catch up” to demand without triggering a loss of load event. However, PJM's filing does not contain specific provisions which eliminate such “false positives” from triggering scarcity prices, nor does the filing discuss the problem of false positives or assert that PJM's proposed mechanism is not vulnerable to them.

Solution: Require PJM to address and propose remedies for false positive conditions. Require that scarcity pricing tariffs terms, operating procedures and “false positive” protection provisions be added to the proposed tariff filing.

❖ **Problem – Lack of Protection Against Circumstances Leading to Chronic Shortage Pricing :** The PJM filing assumes that the proposed Shortage Pricing tariff regime will be administered in a normal market, under foreseeable grid conditions, and PJM asserts that shortage pricing events occur “so infrequently” that there should be “no real concern” about significant transfers of wealth that could result from it. We disagree. In the event of extraordinary conditions, such as a major natural disaster or act of war or terrorism, all or portions of the PJM service territory impacted by such an event could be further harmed by being forced to pay extremely high “shortage prices” day after day to sellers who are no longer operating in a functioning competitive market environment in which “market clearing prices” have meaning.

Solution: Require the addition of emergency circuit breaker tariff language that would become operational in the event of an extraordinary event.

❖ **Problem – Missing and Inadequate Market Monitoring Screens and Mitigation**

Provisions: Order 719 made it clear that the Commission is concerned about the exercise of market power during the transition and implementation of shortage pricing rules and intends to closely monitor the progress of scarcity pricing implementation to forestall market power and gaming. The PJM Shortage Pricing filing does not contain adequate definitions, procedures and remedies for the monitoring and mitigation of market power and gaming of Shortage Pricing.

Solution: Require additional definitions, monitoring and mitigation rules.

COMMENTS AND PROTEST

The PaPUC herewith protests the PJM Shortage Pricing filing, and provides the following Comments in support of its protest. Attached hereto is the supporting affidavit of James Wilson F. Wilson, Principal – Wilson Energy Economics and Affiliate, LECG in support thereof (“Wilson Affidavit”). Mr. Wilson has 25 years of experience in dealing with the economic and policy issues related to the introduction of competition into the electric power and natural gas industries and is well versed in PJM market design issues.

With appropriate modifications to the PJM tariffs and an appropriate phase-in and review process to identify and correct problems, scarcity pricing modifications to PJM’s existing market design may yield the kinds of reliability and economic efficiency benefits sought by your Commission in issuing *Order 719*. Further development of scarcity pricing which spurs market-based changes to physical, operational, and contractual relationships could eventually supplant the need for PJM’s administrative capacity pricing construct. RPM has proven extremely expensive, controversial, and difficult to administer and has embroiled PJM in ongoing controversy over its administrative role

and control of critical parameters and inputs. A mature wholesale market design that relies less on centralized administrative intervention and more on competitive market forces and efficient pricing is the goal.

Approval by your Commission of a flawed version of scarcity pricing resulting in unjust and unreasonable wealth transfers to generation owners would be a serious mistake, and would be harmful to the furtherance of the national policy to advance competitive wholesale markets in electricity.

STATEMENT OF THE CASE

On February 22, 2008, the Commission issued a Notice of Proposed Rulemaking (“NOPR”) pursuant to sections 205 and 206 of the Federal Power Act. The NOPR identified four areas of reform proposed to foster wholesale competition in organized markets. The rule was largely adopted initially proposed by the Commission’s final rulemaking order, *Order 719*.

Order 719 directed each RTO and ISO to improve the operation of organized electric wholesale markets by enacting reforms in the areas of: 1) demand response and market pricing during periods of operating reserve shortage; 2) long-term power contracting; 3) market-monitoring policies; and 4) RTO/ISO responsiveness to their customers and stakeholders.

In the first enumerated areas of reform – demand response and market pricing during periods of operating reserve shortage – the Commission identified the need to address existing market rules governing the price formation during periods of operating

reserve shortage. To that end, the Commission required each RTO and ISO to make a compliance filing “proposing any necessary reforms to ensure that the market price for energy accurately reflects the value of such energy during an operating reserve shortage.” The Commission directed that the RTOs and ISOs adopt one of four alternative approaches to reserve shortage pricing suggested in Order 719, or implement another approach that accomplishes the same objectives. Further, the Commission listed six criteria that an RTO or ISO must meet in its proposed pricing shortage mechanism in order to ensure adequate factual support for the Commission’s ultimate determination.

On April 29, 2009, PJM filed an initial compliance filing with the Commission and requested additional time to submit a shortage pricing proposal. On January 22, 2010, the Commission granted PJM an extension of time until June 18, 2010. PJM established a Scarcity Pricing Working Group,⁵ which was subsequently renamed Shortage Pricing Working Group (SPWG) by PJM.⁶ The SPWG was tasked with developing a shortage pricing mechanism that meets the requirements of Order No. 719. The SPWG held numerous meetings and generated several shortage pricing proposals, including proposals developed by PJM, the Independent Market Monitor for PJM, and various PJM members or groups of members. The SPWG voted on each proposal at its April 30, 2010 meeting

⁵ A review of the membership of the SPWG will indicate that generation and transmission owners comprised a disproportionately high percentage of the membership; there are no proportional representation rules for participation in PJM working groups and no sector weighted voting on working group proposals. The senior PJM stakeholder committees do require sector weighted voting in accordance with the PJM Operating Agreement.

⁶ It is not entirely clear why PJM chose to rename the Scarcity Pricing Working Group; the term “scarcity pricing” is more in accordance with the language of economics and of prior work on scarcity pricing issues in the industry. It appears from the gist of informal discussion that PJM management decided at an early stage in the stakeholder process to conform the name of its filing to correspond to the “operating reserve shortage” language of Order 719.

and forwarded the results to PJM's Markets and Reliability Committee for consideration. The Markets and Reliability Committee voted on the submitted proposals on a sector-weighted basis, which requires two-thirds majority sector vote to pass a motion. None of the proposals received the required two-thirds majority sector vote, and only two of the proposals – PJM's and SeverStal Sparrows Point LLC, received a simple majority. PJM subsequently requested that the MRC vote be considered as representative of the sector vote – no formal vote of the PJM Members Committee was ever taken on the various proposals. PJM subsequently filed its Shortage Pricing tariff proposal with the Commission on June 18, 2010.

COMMENTS AND PROTEST

PJM's market design has been subject to constant revision and change since PJM was first designated as an Independent System Operator in 1997 pursuant to *Order 888*⁷ (PJM was designated in 2001 as a Regional Transmission Operator pursuant to *Order 2000*.⁸) While each market design change directed by your Commission has addressed a specific perceived problem, the general rationale for each of these major market modifications has been to further the National policy to develop and improve the efficiency of competitive wholesale electricity generation markets in which buyers and sellers set price and promote innovation, not central planners or regulators.

⁷ *Pennsylvania-New Jersey-Maryland Interconnection*, et al., 81 FERC ¶ 61,257 (1997).

⁸ *PJM Interconnection, L.L.C.*, etc., 96 FERC ¶ 61,061 (2001)

A. Operating Reserve Demand Curve and Reserve Penalty Factors

Your Commission has sought to require organized markets to implement scarcity pricing in *Order 719* to promote goals of economic efficiency and to further develop true competitive markets:

192. In this Final Rule, the Commission adopts the proposed rule on price formation during times of operating reserve shortage. The Commission continues to find that existing rules that do not allow for prices to rise sufficiently during an operating reserve shortage to allow supply to meet demand are unjust, unreasonable, and may be unduly discriminatory. In particular, they may not produce prices that accurately reflect the value of energy and, by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation.

193. When bid caps are in place, it is not possible to elicit the optimal level of demand or generator response, thereby forgoing the additional resources that are needed to maintain reliability and mitigate market power. This, in turn, increases the likelihood of involuntary curtailments and contributes to price volatility and market uncertainty. Further, by artificially capping prices, price signals needed to attract new market entry by both supply- and demand-side resources are muted and long-term resource adequacy may be harmed. Without accurate prices that reflect the true value of energy, we cannot expect the optimal integration of demand response into organized markets.

194. Therefore, we are taking action to remove such barriers to demand response by requiring price formation during periods of operating shortage to more accurately reflect the value of such energy during such shortage periods...

Order 719, at P. 193-194.

The Commission sought to avoid prescribing a “one size fits all” approach to price formation during operating reserve shortages. Recognizing that there are regional differences and market design differences among RTOs and ISOs your Commission stated “that any change in market rules to implement the proposed reforms must consider

the issue of market power abuse, recognize regional differences in market rules, and be based on a sound factual record”. *Order 719* at P. 168.

PJM’s Order 719 Shortage Pricing proposal includes ambitious and far-reaching market design revisions. However, PJM’s proposal is clearly deficient in one major respect – the proposal does not produce prices that “accurately reflect the value of energy”. Instead, PJM has proposed what amounts to a vertical demand curve – when any amount of reserves are committed, PJM proposes that prices immediately rise to the full extent of PJM’s proposed penalty factor. This is not in accordance with FERC’s intent that prices correspond to the “value” of energy and reserves. As stated in the attached affidavit, the value of reserves gradually increases as the probability of loss of load increases. The first few megawatts of a reserve shortage carry a relatively low probability of loss of load. As a result, the incremental value of these reserves is relatively low. As the reserve shortage increases, the probability of loss of load increases. At the point where the reserve shortage is substantial, the probability of a loss of load (and need for PJM to take emergency measures such as emergency purchases, voltage reduction, or manual load dump) is relatively high and the corresponding value of reserves is very high and approaches the value of lost load, or VOLL.

As Mr. Wilson explains (*Affidavit* at 18) a “stepped” operating reserve demand curve better satisfies the Commission’s *Order 719* objectives, better represents the real value of operating reserves and reduces the vulnerability of Shortage Pricing to gaming and market power attempts.

He recommends that an Operating Reserve Demand Curve with at least three steps, consistent with *Order 719*,⁹ be adopted.

Note that under the operating reserve demand curve approach, the *maximum* level to which energy and operating reserve prices can rise should be a relatively unimportant characteristic of the pricing rules because this price level should be achieved only under extreme conditions when the risk of having to resort to manual load dump is quite high. This should be expected to occur rarely (if at all), and if the market is working efficiently (meaning, prices rise to the maximum level only when they really need to, rather than due to poorly structured demand curves, market power, gaming, “false positives” or other illegitimate reasons), all stakeholders should recognize the appropriateness of high price levels under such extraordinary circumstances. The operating reserve demand curve should provide for operating reserve prices that rise as the degree of shortage increases, consistent with the incremental value of reserves under various system circumstances. Prices should not rise to high levels when operating reserves are close to target levels; under such conditions, the risk to the system, and the value of incremental operating reserve, is low.

Wilson Affidavit, at 8.

Mr. Wilson proposes that three steps be included at 10%, 20% and 70% of the reserve requirement. Step 1 would price reserves at \$250/MWh, Step 2, representing a larger reserve shortage, at \$400/MWh and Step 3 at \$850/MWh. Wilson Affidavit at 26. It is important to note that Mr. Wilson’s suggested operating reserve demand curve is identical to PJM’s Proposal in 2011, given the PJM-proposed phase-in, and only differs in 2012 in the 10% segment by a relatively small price difference (\$250 v \$400).

⁹ *Order 719* appears to assume that demand curves submitted in compliance with the rule will contain multiple steps corresponding with the value of reserves:

Under the third approach, RTOs and ISOs would establish a demand curve for operating reserves, which establishes a predetermined schedule of prices according to the level of operating reserves. As operating reserves become shorter, the price increases.

Order 719, at P 221.

A stepped demand curve prices reserves much more closely to the actual value of such reserves relative to system conditions. The Conditional Loss of Load Expectation (“CLOLE”) is a measure of expected frequency of load loss in an hour, given a quantity of operating reserve. It increases as the reserve shortage increases. Reserves have value because they reduce the chance of load loss, and the incremental value of reserves is roughly the CLOLE times the VOLL. Wilson Affidavit at 15. When reserves fall to very low levels, CLOLE rises toward 1, the value of reserves approaches VOLL, and the system operator will take emergency measures such as voltage reductions or manual load dumps to preserve reserves. However, when reserves are close to the requirement, the incremental value of reserves is very low.

The CLOLE will rise continuously as reserves decline, so if the CLOLE is very low when reserves equal the requirements, it is also very low when reserves are only a few MW above or below the requirement. Taking 0.001 as the value of CLOLE when reserves equal the requirements (PJM has not quantified this, and I believe the CLOLE is likely considerably lower than this probability), the value of the last increment of operating reserve PJM normally acquires is roughly VOLL times the CLOLE, or $\$3,500/\text{MWh} \times 0.0001 = \$3.50/\text{MWh}$. That is, if the Reserve Requirement is 1,700 MW and PJM has acquired so far 1,699 MW, the value of the last MW to meet the requirement would also be very roughly $\$3.50/\text{MWh}$.

Wilson Affidavit at 17.

However, under PJM’s Shortage Pricing proposal as filed, the last increment of reserve to satisfy the full requirement is priced several hundred times its value estimated based on VOLL and the CLOLE.

This flaw in the PJM proposal is exacerbated by the fact that it also exposes PJM’s market to greatly increased risk of false positives and gaming opportunities. Under the PJM proposal, any shortage of Synchronized reserve, no matter how small, triggers a

\$1,700 price for reserves and a corresponding increase in the price of energy. Thus minor generator ramping problems or other operational issues that require the very short term use of minor amounts of synchronized reserve – and which present no significant reliability or operational dangers – may trigger huge increases in the cost of energy, well above any legitimate calculation of the value of reserves used.

Worse, PJM proposes in its Shortage Pricing proposal that when reserves are short both in a designated reserve zone and in the larger PJM Region that its \$850 penalty factor be *doubled* to \$1700. This would be true regardless of the amount of the reserve shortage – thus if a reserve zone AND the PJM region were short of even a single megawatt of the lower-valued Primary reserve each, reserve prices would rise to \$1700 in the zone. This makes little sense when analyzed:

When reserves are short in a Reserve Zone they will have elevated value. When, in addition, reserves are also short in the surrounding RTO Region, the value of reserves in the Reserve Zone is somewhat higher, because such reserves not only lower the outage risk (CLOLE) in the Reserve Zone, but also have the potential to reduce the outage risk for the RTO Region. However, the increase in the value of operating reserves located in the Reserve Zone, due to the fact that the RTO Region also has a reserve shortage, would generally be small and far less than the doubling of the value that would result from the proposed approach. This is because the circumstances that could lead to an actual outage in the Reserve Zone and in the RTO Region are likely highly correlated. Incremental operating reserve located in the Reserve Zone only increases in value due to a reserve shortage in the RTO Region to the extent there could be an actual outage in the RTO Region while, at the same time, there was no outage in the Reserve Zone. If, instead, load loss in the RTO Region would likely occur simultaneous with load loss in the Reserve Zone, the presence of a simultaneous reserve shortage in the RTO Region adds little to the incremental value of operating reserve in the Reserve Zone. This suggests that when there is a reserve shortage in a nested Reserve Zone and simultaneously in the RTO Region (or a surrounding Reserve Zone), rather than doubling the Penalty Factor and reserve value, a much smaller increment should be used, reflecting the degree of correlation in the two areas' conditional outage risks.

Wilson Affidavit at 24, citation omitted.

Based on Mr. Wilson's analysis he suggests a value of \$400/MWh for the penalty factor for nested zones, noting that further analysis might suggest a different value.

PJM identifies its reserves as Primary or Secondary. Primary Reserves can respond within 10 minute and are further subdivided into Synchronized and Non-synchronized reserves. Secondary reserves are classified as those that can respond within 30 minutes. PJM suggests in its filing that existing electric reliability organization rules promulgated by NERC and Reliability *First* Corporation require it to always acquire the full reserve requirement, prohibiting use of a stepped operating reserve demand curve. PJM's Affidavit incorrectly suggests that PJM's present contingency reserve requirements are "mandated":

In order to implement the operating reserve demand curve approach for all reserves that are deployed by PJM operators in real-time operations, PJM is proposing changes to its reserve markets to incorporate a Non-synchronized Reserve Market that explicitly and transparently accounts for *mandated Synchronized and Primary Reserve requirements to which PJM already operates* in real-time and to provide complete market signals regarding the costs of meeting the Primary Reserve requirement to properly implement shortage pricing.

PJM Affidavit at 18 (emphasis supplied).

In reality, however, PJM's Primary Reserve Requirement *exceeds* NERC mandated contingency requirements.

The Primary Reserve requirement in both RFC and Mid-Atlantic *is equal to 150 percent of the single largest contingency in each region.*

PJM Affidavit at 8-9 [emphasis supplied].

PJM's primary (also called contingency) and synchronized (also called spinning) reserve requirements, however, presently exceed the NERC and RFC standards. The NERC standard for contingency reserves is NERC Standard BAL-002-0¹⁰ *Disturbance Control Performance*, adopted by the NERC Board of Trustees on February 8, 2005 (Effective April 1, 2005) and requires reserves be carried equal to at least 100% of the most severe single loss of generation. The standard states:

R.3.1 As a minimum, the Balancing Authority or Reserve Sharing Group *shall carry at least enough Contingency Reserve to cover the most severe single contingency*. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies. (Underlining added).

NERC Standard BAL-002-0 (Effective April 1, 2005). PJM's Primary reserve requirement calls for 150%.

PJM is a member of the RFC Reliability Organization, and follows the RFC regional standard developed pursuant to NERC Reliability Standard BAL-002. RFC's present standard requires spinning reserves of at least 50% of the most severe single contingency:

R.1.1 Have a minimum Operating Reserves – Spinning requirement of at least 50% of the Balancing Authority's most severe single contingency and the remainder of the Contingency Reserves to be made up of any combination of Operating Reserves – Spinning and Operating Reserves – Supplemental.

¹⁰ Exhibit PaPUC-3, attached as an Appendix to this Protest. RFC Standard BAL-002-RFC-02 is attached as Exhibit PaPUC-4.

Reliability First Standard BAL-002-RFC-02 Operating Reserves, approved May 9, 2007 (Effective May 9, 2007).

PJM's Synchronized reserve requirement calls for 100% of the largest contingency¹¹. PJM's assertion that it is "mandated" by NERC and/or RFC to keep its present reserve requirements is incorrect and these standards do not preclude use of an operating reserve demand curve.

B. Energy & Ancillary Services Offset

Order 719 emphasized the Commission's intent that each regional organized market is free to propose a reserve shortage pricing construct consistent with its regional differences. One significant "regional difference" that applies to the PJM wholesale market is the RPM capacity construct.¹² As the Commission is well aware, RPM is based upon a set of tariff provisions that have been both controversial in development and

¹¹ *PJM Manual 10: Pre-Scheduling Operations*, Revision 25 effective January 1, 2010, Section 3: Reserve Requirements, p. 16, available at <http://www.pjm.com/~media/documents/manuals/m10.ashx>.

¹² The initial filing by PJM of a proposed RPM construct was at FERC Docket ER05-1410 on August 31, 2005. That and subsequent filings have resulted in no less than 123 orders dealing with revisions, settlements, challenges, technical conferences, compliance filings, modifications and "improvements" to RPM, a topic which still generates controversy and billions of dollars of revenue for PJM capacity resource owners. Below are listed 11 major orders of your Commission relating to RPM, capacity and reliability issues:

1. *PJM Interconnection L.L.C.*, **Initial Order On Reliability Pricing Model**, 115 FERC ¶61,079 (2006)
2. *PJM Interconnection L.L.C.*, **Order Denying Rehearing And Approving Settlement Subject To Conditions**, 117 FERC ¶61,331 (2006)
3. *PJM Interconnection L.L.C.*, **Order On Rehearing And Clarification And Accepting Compliance Filing**, 119 FERC ¶61,318 (2007)
4. *PJM Interconnection L.L.C.*, **Order Denying Rehearing**, 121 FERC ¶61,173 (2007)
5. *PJM Interconnection L.L.C.*, **Order On Compliance Filing**, 122 FERC ¶61,264 (2008)
6. *PJM Interconnection L.L.C.*, **Order On Motion**, 123 FERC ¶61,037 (2008)
7. *PJM Interconnection L.L.C.*, **Order Conditionally Accepting Compliance Filing**, 124 FERC ¶61,065 (2008)
8. *PJM Interconnection L.L.C.*, **Order On Motion For Technical Conference**, 124 FERC ¶61,272 (2008)
9. *PJM Interconnection L.L.C.*, **Order On Clarification**, 127 FERC ¶61,104 (2009)
10. *PJM Interconnection L.L.C.*, **Order On Clarification And Rehearing And On Compliance Filings**, 128 FERC ¶61,157 (2009)
11. *PJM Interconnection L.L.C.*, **Order Accepting Compliance Filing Denying Rehearing and Requiring Further Compliance Filing**, 131 FERC ¶61,168 (2010).

application. RPM has frequently been revised since its initial approval. However the fundamental provisions have remained more or less constant since it was originally proposed by PJM in 2006. It is appropriate for the Commission to conclude that the harmonization of RPM and “Scarcity Pricing” revenues is a problem that must be addressed as a “regional difference.”

Load serving entities are required to purchase an amount of capacity equal to their three-year ahead capacity obligation from qualifying PJM capacity resources. The revenues transferred from buyers to sellers under the RPM construct provide revenue to capacity owners and amount to several billions of dollars every year. In return, capacity owners are obligated under RPM rules to make their contractually committed capacity available to PJM for reliability purposes. As discussed in the Wilson affidavit (at 34-35), the capacity obligation imposed upon load serving entities who serve retail customers is calculated based on very conservative probabilistic modeling of load and capacity for the delivery year which tends to increase the amount of capacity procured through RPM.

Although in the past, PJM has urged this Commission in various filings to approve RPM and subsequent modifications as essential to preserving system reliability and ensuring timely investment in resource adequacy, here PJM mentions RPM’s reliability function only in passing.¹³ However, the introduction of a reserve scarcity pricing

¹³ PJM’s discussion of RPM’s role in procuring capacity and reliability appears on pages 34-35 of its cover letter and simply cites page 37 of its attached affidavit:

First, the PJM Proposal relies on an operating reserve demand curve which increases prices in the energy and reserve markets in an agreed upon manner. As the system moves into a reserve shortage, prices in the reserve markets rise to their penalty factor levels, and the price of energy rises beyond the reserve penalty factor levels. As energy prices rise, demand participating in the PJM market with a willingness to pay at or below the prevailing price will reduce usage as they are no longer willing to pay that price for energy. On

element into PJM's existing design raises the need to adjust both RPM and Shortage Pricing rules to prevent over-compensation for resource adequacy so as to avoid double recovery by existing generation assets for providing the same level of system reliability.

Resource adequacy and reserves may be incented by a capacity construct, such as RPM, by energy/reserve shortage pricing, as PJM proposes in Shortage Pricing, or by both. If both constructs are employed, in order to prevent double charging for the same level of reliability, the two mechanisms must be harmonized and work together.

Operating reserve pricing and the RPM capacity construct both are directed at having adequate resources for reliability, operating in different timeframes. The reformed rules for pricing during operating reserve shortages will attract additional supply- and demand-side resources during times of system stress, increasing reliability. These rules will also increase the prices and revenues available to all resources that contribute to reliability during such times. It is very important that

the supply side, as energy prices rise, non-RPM resources internal to PJM or external to PJM not already providing energy have an incentive to provide energy from this remaining capacity as the incentive to do so rises with the market price for energy. Second, the PJM Proposal in implementing an operating reserve demand curve framework is also implementing joint and simultaneous optimization and clearing of energy and reserve markets. As discussed above, joint and simultaneous optimization of energy and reserves on a five-minute basis will ensure that the prices of energy and reserve are consistent with dispatch and reliability needs in real-time operations, and are a transparent indicator of true system conditions. The consistency of prices with dispatch will significantly reduce the need for PJM to manually dispatch units in order to maintain energy balance and some level of reserves during shortage conditions. The need to pay resources out-of-market opportunity cost payments that provide the right incentives to follow dispatch instructions, and are non-transparent signals regarding system conditions, should be significantly reduced. The posted market prices of energy and reserve serve as the transparent indication of the true state of the system being in a reserve shortage in addition to providing the correct incentives to follow dispatch.

Third, the PJM Proposal allows emergency demand resources and emergency purchases of generation to set price in the PJM Energy Market. Under the current tariff provisions, these resources are generally not permitted to set energy market prices. From a market perspective, emergency DR and purchases taken as given provide the appearance of reduced system demand and if only non-emergency generation resources are allowed to set price, then prices during a reserve shortage may be artificially suppressed in spite of the current or approaching shortage condition. The suppression of prices does not attract additional demand response or generation as mandated by the Commission.

Moreover, the emergency demand resources or emergency purchases of energy at high willingness to pay or higher offers may be marginal for maintaining energy balance and reserves and only paying them their bids or offers out-of-market through uplift payments leaves the true state of system conditions nontransparent to other potential supply or demand resources that may be available.

PJM's RPM resource adequacy construct, operating in the months- to years-ahead time frame, take these impacts (both megawatts and dollars) into account, lest RPM acquire excess capacity at an excessive cost.

Wilson Affidavit at 34.

PJM here has proposed no explicit changes to the existing RPM rules. As a result shortage revenues simply flow through the RPM E&AS offset calculations for future delivery years, distorting whatever investment signal that RPM delivers.

The current E&AS offset is calculated on an historical basis. The RPM price is calculated by reference to the net cost of new entry ("Net CONE") and is established by subtracting from a hypothetical combustion turbine reference unit's estimated levelized cost of construction ("CONE") an estimate of the reference unit's anticipated net earnings from E&AS markets over the life of the project (the "E&AS Offset").

In concept, the RPM E&AS offsets are supposed to reflect expectations of future E&AS market revenues. However, because a forward-looking approach to estimating future net E&AS earnings has never been developed, instead the RPM E&AS Offsets have been calculated based on a three-year historical average. In addition to the E&AS Offset for the Net CONE calculation, historical three-year average *unit-specific* E&AS offsets are determined and subtracted from estimated unit-specific avoidable costs to set the RPM offer caps for existing units.

PJM severely weakens its RPM construct, scrambling the future capacity prices by offsetting revenues from present day reserve shortage events as offsets to capacity

payments for future delivery years. RPM's very reason for existence is to provide intelligible long term economic investment for future delivery years – PJM's proposal undercuts the *raison d'être* of its own capacity construct. Both Mr. Wilson and the IMM state that this is a serious flaw in the Shortage Pricing proposal that must be corrected.

Mr. Wilson proposes that instead of adopting the IMM's "True Up" proposal (IMM Protest at 33) that will encourage sellers to clear resources in the Day Ahead market to avoid being trued up in the Real-Time market, that the existing historically based RPM E&AS offset be replaced with a forward-looking offset, and a transitional revenue offset be implemented. The proposed transitional revenue offset would work as follows:

- a. Capacity sellers would retain the greater of RPM revenues or shortage revenues for each delivery year. For the purpose of determining whether shortage revenues exceeded RPM revenues, shortage revenues would be estimated based on the operation of a "reference unit" (combustion turbine), not actual unit performance. If, based on this measure, shortage revenues were greater than the RPM payment, the capacity seller would retain all actual earned shortage revenues but receive no RPM payment for the year. If instead, according to this measure, shortage revenues were less than the RPM payment, the capacity seller would receive an RPM payment equal to the difference between the RPM payment and the reference unit's estimated shortage revenue.

Wilson Affidavit at 42. The proposed approach would true-up all shortage revenues, whether received in the Real-time market or in the Day-ahead market in expectation, and would also have the advantage of leaving strong incentives to perform in place.

C. “False Positive Triggering”

Both Mr. Wilson (Wilson Affidavit at 31) and the IMM (IMM Protest and Compliance Proposal at 46-49) express concern over the lack of attention in PJM’s filing to the problem of false positive scarcity events. Mr. Wilson explains that:

A shortage pricing false positive is an instance when prices rise to levels consistent with the presence of a shortage or near-shortage condition, but the system actually has no shortage or a much less severe shortage. False positives would occur due to flaws in the shortage pricing and related market rules, perhaps exacerbated by market participant strategies to exploit the flaws.

Wilson Affidavit at 31.

Actual instances of false positives have occurred in MISO during ramping hours; this is not a theoretical problem. In addition, because of the way that PJM has chosen to structure its reserve pricing proposal (separate demand curves for primary and synchronized reserves) Shortage Pricing events may be triggered by unusual system conditions that pose no or an extremely low threat to reliability. Wilson Affidavit at 22-23.

Your Commission should direct that PJM make a compliance filing discussing how false positive shortage events may occur on its system and propose appropriate tariff provisions.

D. Emergency Circuit Breaker Requirement

Although discussed in some level of detail during stakeholder discussions and included in proposals considered in the stakeholder process, PJM chose not to include any provision in its Shortage Pricing proposal dealing with a market failure resulting from extraordinary events or a disruption of the physical infrastructure necessary to

support the efficient based pricing of reserve shortages. The consequences of such market failure could be extremely damaging – a lengthy period of energy prices tied to the extreme limits proposed by PJM (\$1,700 reserve / \$2,700 energy) during a period when load would be unable to mitigate such prices is daunting to contemplate.

PJM's proposal must be modified by inclusion of a "circuit breaker" provision to limit market prices and costs in the event of an extraordinary disruption of the PJM wholesale market. Mr. Wilson recommends that such a provision, activated by an order of the Commission, would compensate energy and ancillary services above \$1,000/MWh based on cost plus an adder instead of setting higher market clearing prices. He suggests that a high frequency of shortage pricing would trigger a PJM filing to report the circumstances, and the Commission would control the initiation and termination of the circuit breaker provision. Wilson Affidavit at 33.

E. Proposal to Allow Emergency Demand Response and Purchases to Set Price

PJM has proposed to allow emergency demand response, emergency purchases from outside the RTO Region, or generation from emergency segments of generators already on-line and operating to set real time marginal energy price -- a provision which was not required by the provisions of Order 719 and is not an essential part of PJM's shortage pricing proposal.

The IMM notes that PJM lacks adequate telemetry and metering capability for emergency demand response resources. In addition, emergency resources are not subject to mitigation and such emergency resources may be owned by entities that own or control

other generation resources in the bid stack, a situation that presents open opportunity for market manipulation.

While Mr. Wilson states that the goal of wholesale market design should be to see price-driven dispatch of as many resources as possible, PJM should defer allowing emergency purchases and demand response to set price until telemetry and metering as well as market power concerns are able to be timely addressed.

II. CONCLUSION

The PaPUC respectfully requests that the Commission consider these Comments and issue an order directing PJM to make a further compliance tariff filing accordingly.

Respectfully submitted,

/s/ John A. Levin

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July 30, 2010

EXHIBITS

PaPUC-1	Affidavit of James F. Wilson
PaPUC-2	Wilson CV
PaPUC-3	NERC Standard BAL-002-0
PaPUC-4	RFC Standard BAL-002-RFC-02

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

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Docket No. ER09-1063-004

**AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF COMMENTS AND PROTEST OF
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF COMMENTS AND PROTEST OF
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION**

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**AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF COMMENTS AND PROTEST OF
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION**

I. Introduction

1. My name is James F. Wilson. I am an economist, principal of Wilson Energy Economics, and affiliate of LECG, LLC. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

2. I have 25 years of consulting experience to the electric power and natural gas industries. Many of my past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, and market power. Other engagements have included contract litigation and damages; pipeline rate cases; forecasting and market assessment; evaluating allegations of market manipulation; probabilistic modeling of utility planning problems; and a wide range of other issues arising in these industries. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients.

3. I have submitted affidavits and presented testimony in proceedings of the Federal Energy Regulatory Commission (“Commission”), state regulatory agencies, and U.S. district court. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is Exhibit PaPUC-2, attached hereto.

4. I have been involved in electricity restructuring and wholesale market design for over twenty years in PJM, New England, Ontario, California, Russia, and other regions. I have also been involved in issues of reliability planning, resource adequacy, and peak load forecasting. With regard to the PJM system, I have been involved in a broad range of market design and planning issues over the past several years. I followed the Shortage Pricing Working Group stakeholder process that led to the PJM Filing and participated in some of its meetings.

5. This affidavit was prepared at the request of the Pennsylvania Public Utility Commission. On June 18, 2010, PJM Interconnection, L.L.C. (“PJM”) filed a package of tariff

revisions to establish new market rules for times of shortage or near-shortage in operating reserves (“PJM Filing”, “PJM Proposal”) supported by the affidavit of Paul M. Sotkiewicz, Ph.D. (“Sotkiewicz Affidavit”). I have been asked to review and evaluate the PJM Filing and recommend whether the proposals should be accepted or some modifications are warranted. Specifically, I was asked to evaluate the PJM Proposal’s consistency with economic efficiency, the interests of market buyers and Pennsylvania electricity consumers, and compliance with the principles set forth in relevant Commission orders. I was also asked to review and consider the alternative compliance proposal and supporting statement filed on July 18, 2010 by Monitoring Analytics, the Independent Market Monitor for PJM (“IMM”, “IMM Proposal”, “IMM Statement”).

II. Summary of Recommendations

6. Revisions to PJM’s rules for pricing during operating reserve shortages have the potential to increase the reliability and efficiency of PJM’s markets, encouraging additional resources and load reductions during times of system stress. The PJM Proposal includes changes to rules for pricing during operating reserve shortages and other related changes to the PJM market rules.

7. The fundamental structure of the PJM Proposal is generally consistent with the requirements of Order 719¹ and the shortage pricing mechanisms approved by the Commission and implemented by other RTOs. However, several elements of the PJM Proposal should be modified to ensure that it leads to efficient pricing and does not burden electricity consumers with additional costs without commensurate benefits. In addition, changes are needed to PJM’s resource adequacy market rules to reflect the reliability and generator revenue impacts of the new shortage pricing rules. These changes are summarized in the following paragraphs and in Table 1, below.

A. Operating Reserve Demand Curve and Penalty Factors

8. The PJM Proposal calls for application of the “operating reserve demand curve” approach to shortage pricing, with dispatch reflecting joint optimization of energy and operating

¹ Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008).

reserves. Maximum prices for both Synchronized Reserves and Primary Reserves are set to \$850/MWh after a transition period, leading to a maximum possible price of \$1,700/MWh for operating reserves and \$2,700/MWh for energy.

9. Energy and operating reserve prices should reflect and be consistent with system conditions. \$1,700/MWh and \$2,700/MWh are not excessive operating reserve and energy prices, respectively, when operating reserves are extremely short and the risk of having to curtail firm load is significantly elevated. However, the PJM Proposal allows prices to rise to these levels when there is little or even no operating reserve shortage, due to the single-step form of the operating reserve demand curve PJM has proposed. In addition, PJM's proposed approach of simply summing the Penalty Factors when two reserve products are short, or when nested zones are both short, increases prices to very high levels that under some circumstances are not justified by system conditions and the corresponding value of operating reserves. PJM's proposed operating reserve demand curve and the proposed additive approach to multiple reserve zones should be changed to better align operating reserve and energy prices with actual system conditions and the value of energy and operating reserves under those conditions. Specifically, the proposal should be modified to use an operating reserve demand curve with at least three steps. This would set prices that better correspond to the value of reserves, reduce incentives to exercise market power, and provide a better fit with other elements of PJM's proposal; it would also be more consistent with Order 719 and the practices of other RTOs. These benefits and recommendations are described in greater detail in a later section of this affidavit.

B. Resource Pricing and Price Formation

10. PJM proposes to allow emergency demand response and emergency purchases to set price. However, these resources are not subject to mitigation and the proposal raises market power concerns. These proposed changes are not fundamental or essential to the implementation of shortage pricing, and PJM should defer them until some experience with shortage pricing has been gained. This will provide time to address the market power concerns and also the lack of telemetry and metering for emergency demand resources.

11. PJM also proposes that when emergency actions such as voltage reduction or manual load dump are taken, prices will be administratively held at the maximum levels. PJM should provide more specific details (tariff language) for how it plans to treat such emergency

actions under the full range of system conditions under which they could be taken, how pricing would work for the duration of the emergency actions, and how pricing based on supply and demand would be restored. PJM's proposal should minimize the extent and duration of this administrative override of the pricing mechanism.

C. Market Buyer Protections

12. While shortage pricing rules are deliberately designed to allow very high prices when necessary, legitimate shortage pricing events should not occur or be extremely rare on the PJM system over the next several years. This is because PJM already has procured a substantial amount of excess capacity for all times through May 31, 2014 through its Reliability Pricing Model ("RPM") capacity construct, and peak load growth is expected to be slow after 2014.² However, if the mechanism is not well designed, or if extreme events occur, shortage pricing may not be so inconsequential.

13. Shortage pricing rules necessarily increase the incentives to exercise market power due to the potential for higher energy and operating reserve prices they afford. While the PJM Proposal includes some market power protections, additional protections are needed. The IMM Statement raises several additional concerns that should be addressed, and some potentially risky, non-essential elements of the PJM Proposal should be delayed until operational experience has been gained with the mechanism.

14. Experience in other RTOs suggests that routine or transient system conditions can trigger shortage pricing events when there is little or no actual shortage or threat to reliability. PJM did not address this potential problem in its proposal. PJM should have discussed how such shortage pricing "false positives" could potentially occur under its proposal and how its proposal minimizes vulnerability to them. PJM should be directed to provide this discussion and correct its proposal to provide additional protections against any such vulnerabilities.

15. Despite excess capacity on the PJM system, and even with market power mitigation rules in place, shortage pricing could potentially cause many hours of very high prices and substantial transfers of wealth from consumers to producers due to any of the following types of causes: common mode failure affecting multiple capacity resources, such as the loss of

² PJM Load Forecast Report, January 2010, Table B-1 (showing the PJM RTO summer peak load growing at 1.4%, 1.2%, and 1.1% in 2015, 2016 and 2017, respectively).

a major electric or natural gas transmission facility or a legislative or judicial action that would shut down multiple generating plants; a flaw in the new market rules allowing repeated “false positives” for shortage pricing, possibly exacerbated by supplier strategies to exploit the flaw; or repeated exercise of market power or gaming due to a failure to anticipate and mitigate all such strategies in designing the rules. An enormous transfer of wealth from consumers to producers in a very short period of time through the operation of the shortage pricing mechanism under such circumstances could make a bad situation much worse for consumers while creating an undeserved windfall for suppliers. PJM should implement an added layer of protection against potential instances of unjustified, “runaway” shortage pricing in the form of an “emergency circuit breaker” provision that would only be initiated by Commission order, and I suggest a way such protection could be structured.

D. Interaction of Shortage Pricing with Resource Adequacy and RPM

16. The proposed rules for pricing during operating reserve shortages contribute to resource adequacy and reliability, operating in the day-of and day-ahead time frame. PJM also has rules and markets for resource adequacy operating in the planning time frame of months to years ahead, specifically, its RPM capacity construct. RPM and its price and quantity parameters must be coordinated and consistent with PJM’s shortage pricing rules. Both the additional revenues that result from the new rules and the additional supply and demand reductions they attract need to be reflected in setting RPM parameters to avoid procuring excess capacity at excess cost.

17. The PJM Proposal fails to adapt its existing RPM resource adequacy rules to the new shortage pricing approach and should be modified to correct this omission. In particular, revenues from shortage pricing should be reflected in RPM without an unnecessary multi-year lag, as would result from the PJM Proposal. The shortcomings of RPM’s historical-average energy and ancillary services offset methodology are exacerbated by shortage pricing, and this mechanism should eventually be replaced with a forward-looking approach. In the meanwhile, a shortage pricing true-up should be implemented, and I suggest how such a mechanism should be structured. The additional supply and additional demand reductions resulting from the new rules also should be reflected in the amount of capacity to be acquired through RPM.

18. These recommendations are summarized in Table 1. In the remainder of this affidavit I further explain the need for these changes and describe the recommendations in more detail. The IMM Proposal includes several differences from the PJM Proposal. I share the IMM's concerns regarding the increased potential for market power resulting from shortage pricing, and I support some but not other of the IMM's specific proposed changes to the PJM Proposal, as noted in several places in this affidavit.

Table 1: Summary of Recommended Changes to the PJM Proposal

Operating Demand Curve and Penalty Factors:

- Implement Operating Reserve Demand Curve with three steps:
- 10% of Reserve Req't @ \$250/MWh, 20% @ \$400/MWh, 70% @ \$850/MWh
- Second penalty factor for nested zones = \$400/MWh

Resource Pricing and Price Formation:

- Defer allowing emergency demand response and purchases to set price
- Monitor Day-ahead DEC's above \$1,000/MWh for evidence of market power
- PJM to provide further details of treatment of voltage reductions or load dump

Market Buyer Protections:

- PJM to address vulnerabilities to false positives
- PJM to address IMM's concerns about market power
- Implement emergency "circuit breaker" provision

Connecting Shortage Pricing to Resource Adequacy and RPM:

- Implement forward-looking Energy and Ancillary Services Offset (longer term)
- Implement transitional shortage revenue true-up based on reference resource
- Reflect non-RPM capacity attracted by shortage pricing in capacity requirements

19. The remainder of this affidavit is organized as follows. The next section presents some key principles that should guide the design of the shortage pricing mechanism and the related changes to PJM's market rules. The final section discusses the PJM Proposal and describes the specific modifications that I recommend. Both of these sections address elements of the PJM Proposal in the same four categories as reflected in this summary section: The

operating reserve demand curve and penalty factors; resource pricing and price formation; market buyer protections; and the interaction between shortage pricing and PJM's RPM resource adequacy construct.

III. Market Rules for Pricing during Operating Reserve Shortages: Key Principles

A. The Operating Reserve Demand Curve Approach

20. Historically, system operators dealt with circumstances of low operating reserves through an escalating sequence of administrative, emergency actions; prices and markets played little or no role. As noted in Order 719, allowing prices to rise during periods when operating reserves are relatively low encourages new sources of supply and price-responsive demand reductions, contributing to reliability and efficiency. Over the coming years, we can expect peak loads to become increasingly manageable and price-responsive through both demand response programs (under which demand reductions are promised in advance) and also as a result of loads becoming increasingly responsive to real-time price signals as a result of smart grid developments. Allowing prices to rise when operating reserves are relatively low both encourages the development of such resources and also makes use of them to balance supply and demand at times of system stress without having to resort to manual load dumps, voltage reductions, or other "emergency" measures.

21. The operating reserve demand curve approach provides a framework for pricing during times of low operating reserves. In Order 719 the Commission described the approach as follows:

Under the third approach, RTOs and ISOs would establish a demand curve for operating reserves, which establishes a predetermined schedule of prices according to the level of operating reserves. As operating reserves become shorter, the price increases. (P 221)

22. The operating reserve demand curve approach is also consistent with Order 719's call for "prices that accurately reflect the value of energy" (P 192): the value of incremental operating reserve is high when reserves are significantly below the desired levels, and the value of incremental reserve is low when the amounts considered needed to provide a very high level of reliability have been obtained.

23. Note that under the operating reserve demand curve approach, the *maximum* level to which energy and operating reserve prices can rise should be a relatively unimportant

characteristic of the pricing rules because this price level should be achieved only under extreme conditions when the risk of having to resort to manual load dump is quite high. This should be expected to occur rarely (if at all), and if the market is working efficiently (meaning, prices rise to the maximum level only when they really need to, rather than due to poorly structured demand curves, market power, gaming, “false positives” or other illegitimate reasons), all stakeholders should recognize the appropriateness of high price levels under such extraordinary circumstances. The operating reserve demand curve should provide for operating reserve prices that rise as the degree of shortage increases, consistent with the incremental value of reserves under various system circumstances. Prices should not rise to high levels when operating reserves are close to target levels; under such conditions, the risk to the system, and the value of incremental operating reserve, is low.

B. Resource Pricing and Price Formation

24. PJM’s markets and dispatch will be most efficient if all supply and demand resources are dispatched based on prices reflecting the willingness to generate or to reduce consumption. The concept of “emergency” resources that are invoked administratively on an out-of-market basis should be phased out. Allowing emergency resources to appear in the dispatch stack at prices that reflect their willingness to generate or to reduce consumption will result in more elastic supply and demand at high price levels and improve the efficiency of system operation and pricing when operating reserves are relatively low. As the amount of demand response on the PJM system grows, it becomes inefficient for all of it to be invoked administratively and simultaneously, as shown in recent PJM analyses under the subject “Demand Response Saturation.”³

25. Resource classifications and dispatch rules reflecting the historical, administrative approaches to coping with system stress, triggered based on whether reserves have or have not fallen below a specific level or whether PJM has or has not declared an “emergency”, are inconsistent with the operating reserve demand curve concept and efficient price-driven dispatch, and should be minimized. However, this goal must be balanced against the risk of unintended

³ Tom Falin, Manager, Resource Adequacy Planning, PJM, *Demand Response Saturation Analysis*, presentation to Markets and Reliability Committee, May 18, 2010, slides 8 and 9 (showing that when all demand response is

results or market power as a more market-driven approach to system operation during times of system stress is implemented. For some types of resources, revised definitions, better measurement or market power mitigation may be needed before they can be treated in this manner.

C. The Need for Additional Market Buyer Protections

26. The PJM Proposal introduces rules intended to raise prices during operating reserve shortages and increase the maximum energy price from \$1,000/MWh to \$2,700/MWh. It creates new markets for operating reserve products and replaces out-of-market purchases with purchases that set market-clearing prices earned by all providers of a service. While the various changes have legitimate purposes, the theoretical basis for them assumes market power either does not exist or is effectively mitigated. Complex packages of rule changes also risk creating unanticipated gaming strategies through which market participants are able to benefit by exploiting weaknesses in the rules. This suggests that in implementing substantial changes to market rules as PJM has proposed, it can be wise to err on the side of caution and pursue a staged approach, delaying non-essential, potentially risky changes until some experience has been gained. This also suggests there is value to anticipating the possibility of extremely costly malfunctions of the mechanism and putting in place provisions for limiting unwarranted impacts on consumers.

D. Connecting Pricing during Operating Reserve Shortages to Resource Adequacy

27. Market rules for pricing during operation reserve shortages operate in the day-ahead, hour-ahead and real-time time frames to acquire sufficient resources to maintain reliable system operation. These rules influence decisions such as generating unit start-up, shut-down and operating levels, and actions by loads to reduce consumption. “Resource adequacy” refers to rules, procedures and markets that operate months and years in advance toward the same objective – sufficient resources to ensure reliability. Resource adequacy rules and markets (RPM) are intended to influence the longer-term decisions to build or retire generating plants or to implement new demand response.

invoked during the same six-hour period, the daily peak is reduced by less than the amount of the demand response and the full value of the demand response is not realized).

28. While an effective resource adequacy approach results in adequate capacity to meet planning reliability standards (“one day in ten years”), this does not obviate the need for and value of shortage pricing, as there is always some chance of a combination of events leading to low reserves. Rules for pricing during operating reserve shortages and rules pertaining to resource adequacy are both needed, and there are important connections between the two.

- a. The Megawatts: Improved rules allowing higher prices during operating reserve shortages attract additional non-RPM resources and load reductions and reduce the amount of capacity that must be arranged in advance through RPM to provide the target level of reliability.
- b. The Dollars: Rules allowing higher prices during operating reserve shortages reduce RPM capacity needs and also flatten and spread the peak loads through additional price-responsive demand. As a result, peaking generating plants will see more hours of profitable operation to provide energy and operating reserves and higher net revenues. This will reduce the amount of revenue peaking plants will require through RPM.

29. These connections to resource adequacy may be relatively modest at first but will grow as the market adapts to the new shortage pricing regime. The package of changes to the rules at this time should recognize and anticipate the growing connections between pricing during operating reserve shortages and resource adequacy. The resource adequacy construct should recognize the increasing revenue opportunities presented by the revised shortage pricing rules, and this link should not include substantial lags. The resource adequacy construct should also recognize the reduced RPM capacity needs resulting from the revised shortage pricing rules.

30. The market design changes adopted in this proceeding should not include features that will impede or discourage the associated market adaptations or that will have to be fundamentally changed as the market evolves. Note that if resource adequacy is not adapted to the reduced capacity needs resulting from revised shortage pricing rules, the result will be excess capacity at excess cost. Current resource adequacy rules are already highly conservative (based on the “one day in ten years” standard and various conservative assumptions) and if, in addition, they fail to recognize the potential impact of shortage pricing on peak period supply and demand reductions, there could continue to be substantial excess capacity for many years. If that occurs,

shortage pricing will be nearly superfluous, and price-responsive demand and other market developments may be delayed.⁴

IV. Shortage Pricing Proposal: Discussion and Recommendations

31. This section discusses various elements of the PJM Proposal in greater detail and provides further explanation of the recommended changes to it.

A. Operating Reserve Demand Curve and Penalty Factors

1. Background: Operating Reserves and Reserve Requirements

32. Operating reserves – capacity standing ready to produce energy quickly if required -- are arranged to be able to deal with possible contingencies and unexpected events such as sudden generation outages or unexpectedly high load. Operating reserves are valuable because they allow operating the system with a very high level of reliability and reduce the risk of loss of load.

33. PJM classifies operating reserves into “Primary” reserves that can respond within 10 minutes and “Secondary” reserves that can respond within 30 minutes. The shortage pricing proposal pertains only to Primary (10 minute) reserves. Primary reserves are further classified into “Synchronized” and “Non-Synchronized” reserves, defined in the PJM Manuals as follows:⁵

Synchronized Reserve is reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM dispatcher and must be provided by equipment electrically synchronized to the system.

Non-Synchronized Reserve is reserve capability that can be fully converted into energy or load that can be removed from the system within 10 minutes of the request from the PJM dispatcher and is provided by equipment not electrically synchronized to the system.

34. While both Synchronized and Non-Synchronized reserves must be able to respond in 10 minutes, Synchronized reserves are required to be electrically synchronized and, therefore, are considered more reliable and valuable than Non-Synchronized reserves.⁶ While PJM has

⁴ This concept is further developed in Wilson, James F., *Reconsidering Resource Adequacy*, Part 2 (Public Utilities Fortnightly, May 2010), p. 45. http://www.fortnightly.com/exclusive.cfm?o_id=355.

⁵ *PJM Manual 10: Pre-Scheduling Operations*, Revision 25 effective January 1, 2010, Section 3: Reserve Requirements, p. 16, available at <http://www.pjm.com/~media/documents/manuals/m10.ashx>.

⁶ PJM Manual 10, p. 17.

operated markets to acquire Synchronized reserves, it not operated a market for Primary reserves or obtained firm commitments to provide it, and it has not paid for provision of Primary reserves. As described by the IMM, PJM has not carefully measured or tracked Primary Reserves.⁷

35. PJM establishes a Reserve Requirement for Synchronized reserve “at the discretion of PJM after careful review to ensure appropriate system reliability and maintain compliance with applicable NERC [North American Electric Reliability Corporation] and Regional Reliability Organization requirements.”⁸ PJM also establishes a separate, larger Reserve Requirement for Primary reserve (sum of Synchronized and Non-Synchronized reserve). The applicable Regional Reliability Organization is ReliabilityFirst Corporation (“RFC”) for all of the RTO except the Dominion sub-zone.

36. The applicable NERC and RFC reserve standards are defined in NERC’s Standard BAL-002-0⁹ and RFC’s Standard BAL-002-RFC-02.¹⁰ NERC’s Standard BAL-002-0 requires (section R3.1) that Primary reserves (also called “Contingency” reserves) cover the most severe single contingency. PJM establishes a higher Primary Reserve Requirement in its manuals: 150 percent of the largest unit for the RFC area, and 1,700 MW for the Mid-Atlantic zone.¹¹

37. RFC’s Standard BAL-002-RFC-02, section R1, calls for a Balancing Authority to “have a documented methodology” to determine its reserve requirements, or to meet various default requirements specified in the standard, including a Synchronized reserve requirement (referred to as “Spinning” reserve) of at least 50% of the most severe single contingency. PJM establishes a higher Synchronized Reserve Requirement in its manuals: equal to the Largest Unit for the RFC area and for the Mid-Atlantic zone.¹²

38. The Sotkiewicz Affidavit states (p. 9) that PJM establishes the reserve requirements based on system conditions and they are usually around 1,300 MW for

⁷ IMM Statement, p. 41.

⁸ PJM Manual 10, p. 18.

⁹ NERC’s BAL-002-0, Disturbance Control Performance, is available at <http://www.nerc.com/files/BAL-002-0.pdf> and is included as Exhibit PaPUC-3.

¹⁰ RFC’s BAL-002-RFC-02, Operating Reserves, is available at <http://www.rfirst.org/Documents/Standards/Approved/BAL-002-RFC-02.pdf> and is included as Exhibit PaPUC-4.

¹¹ PJM Manual 13, p. 11.

¹² PJM Manual 13, p. 11.

Synchronized Reserve and about 2,000 MW for Primary Reserve for the RTO Region (RFC portion). For the Mid-Atlantic zone, the Synchronized Reserve Requirement is usually around 1,150 MW and the Primary Reserve Requirement around 1,700 MW, according to the Sotkiewicz Affidavit.

2. The Value of Energy and Operating Reserves Under Shortage Conditions

39. Order 719 reflected a concern that energy prices in RTO markets did not rise high enough and reflect the value of energy when operating reserves are short, providing inadequate price signals and harming reliability.

The Commission continues to find that existing rules that do not allow for prices to rise sufficiently during an operating reserve shortage to allow supply to meet demand are unjust, unreasonable, and may be unduly discriminatory. In particular, they may not produce prices that accurately reflect the **value of energy** and, by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation. (Order 719, P 192, emphasis added)

40. The value of energy is quantified by focusing on the impact on firm consumers when their consumption must be curtailed, often called the Value of Lost Load, or “VOLL”. The PJM Filing and Sotkiewicz Affidavit cite the \$3,500/MWh value for VOLL that was developed by the Midwest Independent Transmission System Operator (MISO) as a parameter of its Commission-approved shortage pricing rules.¹³ While arguments are made for lower or higher values for VOLL for use in shortage pricing, the \$3,500/MWh value falls within a broad range of reasonableness and a re-examination of VOLL is not needed for the purposes of evaluating the proposed shortage pricing rules. (A much higher, \$25,000/MWh estimate of VOLL for certain types of customers, cited in the Sotkiewicz Affidavit, is not an appropriate value to use for consideration of shortage pricing rules.¹⁴)

¹³ PJM Filing, p. 25, and Sotkiewicz Affidavit, p. 17, citing Midwest Independent System Operator, Inc., 122 FERC ¶ 61,172 (2008) at P 215.

¹⁴ The VOLL for use in shortage pricing should reflect the average value of lost load for the customers most likely to be curtailed and lose service when reserves fall to low levels, under the likely circumstances of the curtailment. A manual load dump due to low reserves would likely take the form of a rotating blackout, with customers likely to lose service for only a short period. The Sotkiewicz Affidavit (at footnote 45 and 53) cites a report by Lawrence Berkeley Laboratories for the \$25,000/MWh value. This is an estimated VOLL for large and medium commercial and industrial customers. As the LBL report notes (p. 28), “larger customers are likely to have both backup generation and power conditioning.” This will be especially true of customers who place a high value on service. Thus, while some customers’ VOLL may be high, they most likely are not exposed to the quality of service provided by PJM or a possible rotating blackout and their VOLL is not relevant here.

41. Operating reserves are valuable because they reduce the risk of loss of load. If operating reserves were allowed to fall close to zero the system would be at risk of a potentially catastrophic transmission system failure and wide-spread outage. At such levels of operating reserve, the incremental value of each megawatt of reserves would be well in excess of VOLL due to the high risk of a major outage affecting many customers. Instead of allowing reserves to fall to such levels, system operators take controlled actions such as voltage reduction or manual load dump to preserve the reserves needed to operate the transmission system reliably; in principle, such actions would be taken when the value of incremental reserves is approaching VOLL, because each megawatt of curtailed firm load would create approximately one megawatt of operating reserve. This minimum amount of operating reserve is, of course, much lower than the Primary or Synchronized Reserve Requirement, which are set to provide a high level of reliability to firm customers and avoid needing to curtail them to maintain reserves.

42. At any level of operating reserves, the incremental value of one additional megawatt of operating reserve depends on how the incremental megawatt would further reduce the risk of having to curtail firm load in the hour to preserve minimum operating reserve. The expected frequency of load loss in an hour, given a quantity of operating reserve, can be called the Conditional Loss of Load Expectation, or CLOLE. The value of incremental operating reserve is roughly the CLOLE times the VOLL. To see this, suppose the RTO has 1699 MW of operating reserve and is evaluating the last megawatt to meet the Reliability Requirement of 1700 MW. Suppose the risk of having to curtail firm load to preserve minimum operating reserve, when reserves are at this level, is considered to be one tenth of one percent (0.1% or probability = 0.001). If the extra megawatt of reserve is not acquired, with probability 0.001 the RTO will later have to curtail an additional megawatt to preserve minimum operating reserve in the hour. Therefore the expected cost to the system, if the additional megawatt of reserve is not acquired now, is $0.001 \times 1 \text{ MW} \times \$3,500/\text{MWh} = \$3.50/\text{MWh}$. This suggests that to purchase reserves optimally and efficiently under these assumptions, the RTO should acquire this last megawatt if it is available at a price less than \$3.50/MWh.

43. The concept that the incremental value of reserves is based on the reduction in the expected load loss and the value of lost load, and that the operating reserve demand curve should

reflect this value, is widely accepted.¹⁵ The concept is reflected explicitly in the MISO tariff provisions for shortage pricing, although in a very conservative form.¹⁶ The Commission has recognized that the operating demand curve values should reflect the value of reserves at various deficiency levels in approving shortage pricing rules for other RTOs:

As explained by Mr. Jones, the demand curves allow the market prices to reflect the reliability value of capacity and regulation capability to the market at various deficiency levels on both a market wide and zonal basis. When the market for energy or one of the ancillary services products is deficient, the pricing rules reflect the reliability value of this deficiency in the market price for both the deficient product and the other products.¹⁷

44. As operating reserves decline, the CLOLE rises. When reserves are extremely low and voltage reductions or manual load dump very likely, each incremental megawatt of reserve obviates the need for close to an expected megawatt of load loss, and the value of incremental operating reserve approaches the VOLL. Thus, it is appropriate that shortage pricing rules allow the prices of energy and operating reserve to rise to close to VOLL levels under such extreme circumstances when a voltage reduction or manual load dump becomes very likely. PJM's proposal accomplishes this, allowing for maximum energy and reserve prices of \$2,700/MWh and \$1,700/MWh, respectively.

45. The Reserve Requirements have been chosen to provide a very high level of reliability, so under normal conditions when PJM is able to acquire its full Reserve Requirement for both reserve products (Synchronized and Primary), the CLOLE is extremely low. In most hours of the year, operating reserve is abundantly available and its cost is very low

¹⁵ See, for instance, Potomac Economics, Ltd., *Report on Shortage Pricing*, filed May 15, 2009 in FERC Docket No. RM07-19, p. 7 (“If purchased optimally, reserves should be purchased only until the cost of procuring additional reserves equals the incremental reduction in the expected cost of losing load.”); Hogan, William W., *Scarcity Pricing and Locational Operating Reserve Demand Curves*, presented June 2, 2010 at FERC Technical Conference on Unit Commitment Software, Docket No. AD10-12, p. 10-23 (“the loss of load probabilities times the locational VOLL yields the operating reserve demand...”); Market Surveillance Committee of the California ISO (Frank A. Wolak, James Bushnell, and Benjamin F. Hobbs), *Opinion on Reserve Scarcity Pricing Design*, December 2, 2009, p. 4 (reserve scarcity demand curve values should be set based on the change in loss-of-load probability and value of lost load); Centolella, Paul A., *Scarcity Pricing: Enabling Price Responsive Demand*, June 18, 2009, p. 12 (operating reserve demand curve slope reflects declines in LOLE and value of expected unserved energy).

¹⁶ Midwest ISO FERC Electric Tariff, Schedule 28, Section III (referring to the estimated conditional probability of a loss of load and setting VOLL to \$3,500/MWh) and Midwest ISO, Energy and Operating Reserve Markets Business Practices Manual BPM-002-r7, effective March 11, 2010, p. 5-11 and Exhibit 5-1 (also referring to the conditional probability of a loss of load).

¹⁷ Midwest Independent System Operator, Inc., 122 FERC ¶ 61,172 (2008) at P 215.

(the average cost of Synchronized Reserve in the Mid-Atlantic subzone was under \$10/MWh in 2009¹⁸). Given the low cost of incremental operating reserve in most hours, if PJM believed increasing the Synchronized or Primary Reserve Requirements would appreciably reduce the CLOLE, it would have exercised its discretion to do so. The CLOLE will rise continuously as reserves decline, so if the CLOLE is very low when reserves equal the requirements, it is also very low when reserves are only a few MW above or below the requirement. Taking 0.001 as the value of CLOLE when reserves equal the requirements, as in the example above (PJM has not quantified this, and I believe the CLOLE is likely considerably lower than this probability when reserves are close to the requirement), the value of the last increment of operating reserve PJM normally acquires is roughly VOLL times the CLOLE, or $\$3,500/\text{MWh} \times 0.001 = \$3.50/\text{MWh}$. That is, if the Reserve Requirement is 1,700 MW and PJM has acquired so far 1,699 MW, the value of the last MW to meet the requirement would also be very roughly $\$3.50/\text{MWh}$.

3. PJM's Proposed Operating Reserve Demand Curve

46. The PJM Filing states (p. 3) that its proposal utilizes an operating reserve demand curve, consistent with Order 719, but also acknowledges (p. 24), "The PJM Proposal is a simple form of demand curve that assigns a high price beginning with the first megawatt of reserve shortage." However, the Commission described the operating reserve demand curve approach to shortage pricing in Order 719 as "establish[ing] a predetermined schedule of prices according to the level of operating reserves. As operating reserves become shorter, the price increases." (P 221). Under the PJM Proposal, for each reserve product, the entire Reserve Requirement is acquired at a price up to the Penalty Factor. If PJM's proposal is a demand curve, it's a "vertical" demand curve with a single step. PJM's proposed demand curve is unlike the operating demand curves of other RTOs which include multiple steps.¹⁹ The vertical operating reserve demand curve leads to inefficient prices and has other drawbacks, described below, and

¹⁸ Monitoring Analytics, *2009 State of the Market Report for PJM*, p. 392.

¹⁹ See, for instance, California ISO Tariff section 27.1.2.3.2 (describing the Scarcity Reserve Demand Curve for Non-Spinning Reserve with three steps, 0 MW to 70 MW, 70 MW to 210 MW, and greater than 210 MW of shortage); or NYISO Tariff Rate Schedule 4 – Payment for Supplying Operating Reserves, section 15.4.7(g) (describing the Operating Reserve Demand Curve for total 30-minute reserves with three steps, 0 MW to 200 MW, 200 MW to 400 MW, and greater than 400 MW of shortage).

the PJM Proposal should be modified to include at least three steps in the operating reserve demand curve.

47. Under the PJM Proposal, PJM would pay up to the Primary Reserve Penalty Factor (ultimately, \$850/MWh) to make sure it acquires the last increment of Primary reserve, more than 100 times its value, estimated above as roughly \$3.50/MWh.

48. To pay up to \$850/MWh for an increment of reserve that provides only \$3.50/MWh in value to consumers is economically irrational and inefficient. PJM does not assert that its operating reserve demand curve leads to prices consistent with or in any way related to the incremental value of these reserves right up to the Reserve Requirement. Instead, the Sotkiewicz Affidavit suggests that the Reserve Requirements are “mandated” so PJM is required to purchase the entire amount (p. 18). The PJM Filing states (at p. 21) “Capacity available in PJM to be assigned as reserves, regardless of its cost, will be assigned as reserves” and suggests that PJM would purchase reserves on an out-of-market basis if available even at prices above the \$850/MWh Penalty Factor. However, as described above, PJM has discretion in setting its Reserve Requirements and sets them above the levels required by NERC and RFC. To the extent NERC, RFC, or PJM reliability standards or practices are being correctly interpreted by PJM as precluding use of an operating reserve demand curve, the Commission should direct that those rules or standards be modified.

49. While purchasing operating reserves right up to the full Reliability Requirement at any price is a questionable practice, under the current Tariff, the impact on consumers is small. Circumstances leading to high prices for operating reserves occur infrequently and the excess cost of each instance is not large (when 100 MW worth \$3.50/MWh are purchased at \$850/MWh, the excess cost is $(\$850/\text{MWh} - \$3.50/\text{MWh}) \times 100 \text{ MW} = \$84,650/\text{hour}$).

50. However, under the PJM Proposal, the cost to consumers of such inefficient purchases would be compounded by using the excessive price as a market-clearing price to be paid to all providers of operating reserve in the hour. In addition, the incremental operating reserve purchase can raise the cost of energy through the joint optimization of energy and operating reserves, potentially increasing the cost to consumers to many millions of dollars. This potentially turns a minor inefficiency into a major inefficiency and a major burden on wholesale market buyers and end use consumers.

51. The PJM Proposal should be modified to include at least three steps in the operating reserve demand curves, to bring prices more in line with value (a specific proposal is described later in this section). There are multiple advantages to a stepped operating reserve demand curve compared to PJM's proposed vertical demand curve.

- a. The prices paid for operating reserve when quantities are close to the target amounts would be much closer to the value of the reserves (while remaining safely in excess of the value).
- b. Hours with shortage pricing would more closely correspond to the hours when there is an actual operating reserve shortage. Under the PJM Proposal, PJM will pay high prices for reserves, up to \$850/MWh, in hours when the Reserve Requirement is satisfied and there is no operating reserve shortage.
- c. The need for shortage pricing, when it occurs, will more often be reflected in cleared reserve quantities at least slightly below the target levels. Under the PJM Proposal, when shortage pricing results in prices up to \$850/MWh, stakeholders will simply have to believe that had PJM not paid such high prices, there might have been a reserve shortage; to identify whether in fact a reserve shortage would have occurred would require examining the entire set of energy and operating reserve offers and reconstructing the joint optimization of energy and reserves and associated opportunity cost calculations.
- d. The risk of exercise of market power or gaming to raise operating reserve prices would be lower with a stepped demand curve. It is well known that with a vertical demand curve (and inelastic demand more generally) there is higher vulnerability to gaming or exercise of market power to raise price.
- e. Attempts to raise prices through gaming or exercise of market power may also be deterred by the fact that with a stepped curve, prices can only be raised to high levels if there is some reduction (however small) of reserves below the target amounts. Under the PJM Proposal, sellers could raise reserve prices to \$850/MWh without any reduction in reserves below the target amounts.
- f. In addition, as described in the following subsections, a stepped demand curve would go a long way to mitigate the inefficient impacts of PJM's proposal to

apply additive penalties factors when operating reserves shortages occur for two reserve products or for nested zones.

52. A stepped demand curve would also better conform to the requirements and guidance of Order 719. In particular:

- a. Order 719 stated at P 251, “As to when these pricing rules would go into effect, it is when the RTO or ISO has an operating reserve shortage.” The PJM Proposal sets shortage prices when the full requirement is acquired and there is no shortage.
- b. Order 719 stated at P 221, “As operating reserves become shorter, the price increases.” PJM’s vertical demand curve for each reserve product does not accomplish this.
- c. Order 719 at P 192 called for “prices that accurately reflect the value of energy”, and a stepped operating reserve demand curve more accurately matches prices paid to value.

53. The Sotkiewicz Affidavit (at p. 22) suggests that if the Penalty Factors are set too low, these prices could “inappropriately be a part of the calculation of energy prices potentially leading to higher energy prices than would be necessary.” However, this should not be the case, as the operating reserve demand curve limits the willingness to pay for operating reserve and the maximum opportunity cost within the joint optimization of energy and operating reserves; a lower limit should not have the impact of raising energy prices. This statement may reflect a shortcoming in the envisioned logic for joint optimization, which is not described in detail in the PJM Filing, Sotkiewicz Affidavit, or proposed tariff language. If so, the logic should be further developed to not inappropriately raise energy prices when operating reserve cost exceeds the willingness to pay as reflected in the operating reserve demand curve.

4. Additive Penalty Factors for Multiple Reserve Products

54. The PJM Proposal calls for establishing separate operating reserve demand curves for two operating reserve products, Synchronized Reserve and Primary Reserve (sum of Synchronized and Non-Synchronized Reserve). Under the PJM Proposal, the price for each product can rise to the Penalty Factor for the product (\$850/MWh is proposed for each product) when otherwise the Reserve Requirement cannot be satisfied. When PJM is otherwise unable to acquire the Reserve Requirement for Primary Reserve and for Synchronized Reserve

simultaneously, it is proposed that the price for Synchronized Reserve, which can contribute to both requirements, would be \$1,700/MWh ($\$850 + \850) and energy prices could be as high as \$1,000/MWh more than this, or \$2,700/MWh.

55. As with the proposed vertical demand curve shape, this proposed approach fails to result in prices that reasonably correspond to the value of reserves under various circumstances, for two reasons. First, a Primary reserve shortage is a less serious circumstance, while a Synchronized reserve shortage is a much more serious condition, as the Sotkiewicz Affidavit recognizes (p. 12).

56. Second, the simple additive approach does not result in prices consistent with the seriousness of the operating reserve circumstances across the range of possible combinations of Primary and Synchronized reserve shortages, especially in light of the proposed vertical demand curves.

57. Table 2 shows that the two-product additive approach with vertical demand curves leads to prices that are substantially inconsistent with the value of reserves under various circumstances. While some of these combinations may be extremely unlikely, the PJM Proposal allows them, which could create gaming opportunities and false positives. The examples are based on a Synchronized Reserve Requirement of 1,150 MW and a Primary Reserve Requirement of 1,700 MW (typical values for the Mid-Atlantic zone).

58. In Table 2, cases A, B, D and E all represent very similar conditions with reserves close to or equal to the requirements (so very low incremental value of reserves), but these cases result in very different prices. Cases B and C represent very different levels of system stress, but the resulting operating reserve prices would be the same. Similarly, cases E and F represent very different levels of system stress but the same operating reserve prices.

**Table 2: Penalty Factors Under Various Reserve Shortage Circumstances
(based on PJM Proposal and typical Mid-Atlantic reserve requirements)**

Case	Primary Reserves	Synchronized Reserves	Seriousness of System Conditions	Primary/Sync Resv. Prices
A	$\geq 1,700$ MW (full Req't)	$\geq 1,150$ MW (full Req't)	Normal; no reserve shortage	\$0 / \$0
B	1,690 MW (slightly short)	1,150 MW (full Req't)	Minor; small Primary reserve shortage	\$850 / \$850
C	1,150 MW (no Non-Sync)	1,150 MW (full Req't)	More serious; all Sync but no Non-Sync reserves	\$850 / \$850
D	1,690 MW (slightly short)	1,140 MW (slightly short)	Small Primary, Sync shortages; not a very serious condition? But false positive?	\$850 / \$1700
E	1,700 MW (full Req't)	1,140 MW (slightly short)	Small Sync shortage; not a very serious condition? But false positive?	\$0 / \$850
F	1,700 MW (full Req't)	200 MW (severely short)	Very serious condition But false positive?	\$0 / \$850

59. While very high reserve and energy prices are justified when the system is at greater risk, the proposed approach with vertical demand curves and additive Penalty Factors does not accomplish this. It results in a very poor correspondence between price and risk or value, potentially setting very high prices when there is virtually no reserve shortage (as in cases B, D or E) or the same reserve price across a wide range of system conditions (comparing case B to C, or case E to F).

60. While some of these examples may be unrealistic and unlikely to occur, I doubt anyone can predict with any confidence how market participants will respond to these new market rules and how likely various outcomes may be once they are implemented. The market rules should be designed to provide a strong correspondence between prices and value under a broad range of circumstances, even if some of the circumstances are considered impossible or unlikely to occur, or it may create opportunities for gaming or risk of false positives.

61. Note also that having two reserve products with additive penalty factors does not result in or approximate an operating reserve demand curve with two steps. As the examples above demonstrate, either Sync or Primary Reserve can become quite low while the Penalty Factor remains \$850/MWh, but if both are just slightly short the \$1,700/MWh price can apply.

62. The Sotkiewicz Affidavit (at p. 25) suggests that as system stress increases, first Primary reserves will be short, and if the situation further worsens, Synchronized reserves may also become short. However, the PJM Proposal, applying separate operating reserve demand curves for Synchronized and Primary reserves, allows for a Synchronized reserve shortage when there is no Primary reserve shortage. This should occur rarely if at all (because available Non-Synchronized reserves can essentially be converted to Synchronized reserves by calling them to produce energy, allowing other units to be backed down to provide Synchronized reserves), and may indicate a false positive when it does occur.

63. If Sync can only be short when Primary reserves are very low, a single operating demand curve for both products, with steps recognizing when Sync reserves begin to go short, would result in a better match between reserve price and value and prevent such false positives. PJM should consider using a single operating reserve demand curve for the two products.

5. Additive Penalty Factors for Nested Reserve Regions

64. PJM also proposes to sum the penalty factors when reserves are short in a Reserve Zone and in the RTO Region. Again, this is not justified based on reserve value and results in inefficient pricing.

65. When reserves are short in a Reserve Zone they will have elevated value. When, in addition, reserves are also short in the surrounding RTO Region, the value of reserves in the Reserve Zone is somewhat higher, because such reserves not only lower the outage risk (CLOLE) in the Reserve Zone, but also have the potential to reduce the outage risk for the RTO Region. However, the increase in the value of operating reserves located in the Reserve Zone, due to the fact that the RTO Region also has a reserve shortage, would generally be small and far less than the doubling of the value that would result from the proposed approach. This is because the circumstances that could lead to an actual outage in the Reserve Zone and in the RTO Region are likely highly correlated. Incremental operating reserve located in the Reserve Zone only increases in value due to a reserve shortage in the RTO Region to the extent there could be an actual outage in the RTO Region while, at the same time, there was no outage in the Reserve Zone. If, instead, load loss in the RTO Region would likely occur simultaneous with load loss in the Reserve Zone, the presence of a simultaneous reserve shortage in the RTO

Region adds little to the incremental value of operating reserve in the Reserve Zone.²⁰ This suggests that when there is a reserve shortage in a nested Reserve Zone and simultaneously in the RTO Region (or a surrounding Reserve Zone), rather than doubling the Penalty Factor and reserve value, a much smaller increment should be used, reflecting the degree of correlation in the two areas' conditional outage risks.

6. Phase-In of Penalty Factors

66. PJM proposes to phase in the full penalty factors: beginning with \$250/MWh in 2011, the penalty factors would increase to \$400/MWh in 2012 and \$550/MWh in 2013 before achieving the proposed final value of \$850/MWh in 2014. The purpose of the transition is to “allow market participants a period of time to gain experience with the new mechanism and to become more comfortable with hedging against higher prices that are associated with reserve shortage conditions.” Sotkiewicz Affidavit, p. 28. PJM’s proposal results in phasing in the penalty factors over three years, from 2011 to 2014, consistent with the phase-in example noted in Order 719 (P 254). Phasing in the maximum penalty factors is prudent, as the implementation of shortage pricing entails substantial changes to PJM’s rules and markets. The phase-in is especially important under PJM’s proposal involving vertical demand curves and additive penalty factors for multiple reserve products or zones. If steps are added to the operating reserve demand curve, the phase-in proposal would be interpreted as setting annual maximums for the prices on each step of the curve.

7. Operating Reserve Demand Curve and Penalty Factors: Recommendations

67. Based on the discussion in this section, I recommend the PJM Proposal be modified to include multiple steps in the operating reserve demand curves and to lower the second Penalty Factor when nested zones are short:

68. **Stepped Operating Reserve Demand Curve.** The operating reserve demand curves should be modified to have at least three steps. To keep the structure simple while achieving the most important distinctions, I suggest three steps equal to 10%, 20% and the remaining 70% of the reliability requirement, priced at \$250/MWh, \$400/MWh and \$850/MWh.

²⁰ For a rigorous discussion of locational operating reserve pricing that supports and generalizes this example, see Hogan, William W., *Scarcity Pricing and Locational Operating Reserve Demand Curves*, presented June 2, 2010 at the FERC Technical Conference on Unit Commitment Software, Docket No. AD10-12, p. 19-27.

Of course, these steps and prices should be set so that the prices remain well above the incremental value of operating reserve at each level of reserve. If PJM presents analysis suggesting that the value of reserves at these levels might exceed these prices (I consider this unlikely to be the case), the steps or prices should be adjusted.

69. **Synchronized/Primary Reserve Prices and Penalty Factors.** If steps are added to each operating reserve product's demand curve as recommended above, the inefficiency of using additive operating reserve prices and penalty factors for the two reserve products would be mitigated and I would recommend no changes to the two penalty factors. However, consideration should also be given to implementing a single operating demand curve for Primary and Synchronized reserves.

70. **Nested Zone Penalty Factor.** The PJM Proposal should also be modified to apply a much smaller second Penalty Factor when reserves are short in a Reserve Zone and in a surrounding zone, consistent with the relatively small increment in the value of nested zone operating reserve that likely results from this circumstance. I suggest \$400/MWh. This value should reflect the estimated likelihood that curtailment could occur in the surrounding zone when curtailment was not occurring in the nested zone, as described above.

71. **Penalty Factor Phase-In.** With a stepped demand curve, PJM's proposed transitional penalty factors (\$250/MWh for 2011, \$400/MWh for 2012, and \$500/MWh for 2013) would be applied as maximum values for all steps for each year. Thus, my proposal compares to the PJM Proposal in the following way:

- a. In 2011, there is no difference between my proposal and PJM's Proposal. All steps of the operating reserve demand curves would be priced at \$250/MWh, and the second penalty factor for nested zones would also be \$250/MWh.
- b. In 2012, the only difference would be the relatively small price difference (\$250/MWh compared to \$400/MWh) applicable to the last 10% up to the Reserve Requirement. The nested zone value would be the same (\$400/MWh).
- c. In 2013 and later years, there would be a price difference for the two smaller steps (10% and 20%) and for the nested zone penalty factor.

B. Resource Pricing and Price-Setting

72. The PJM Proposal includes various changes related to its shortage pricing proposal intended to improve resource pricing and price formation. Some of these changes are discussed in this section.

1. Relaxation of the Price Cap on Day-Ahead Bids

73. PJM proposes to raise the price cap on demand and virtual bids in the Day-ahead market to the maximum price level that may be attained in the Real-time market (\$2,700/MWh). This is necessary to allow Day-ahead prices to equilibrate with Real-time market prices when shortage pricing is anticipated and Real-time market prices in excess of \$1,000/MWh are expected. The Sotkiewicz Affidavit describes how a \$1,000/MWh price cap in the Day-ahead market, when market participants anticipate much higher prices in the Real-time market, would lead to gaming strategies and a need to pro-rate offers to clear supply and demand. Sotkiewicz Affidavit, p. 31. I agree that the \$1,000/MWh price cap in the Day-ahead market should be lifted if much higher prices are possible in the Real-time market to prevent such gaming and inefficiency.

74. However, while necessary, this change does raise additional market power concerns. Suppliers clearing large portfolios of capacity mainly in the Day-ahead market may have an incentive to offer virtual bids (“DECs”) at prices even above the prices they expect in the Real-time market reflecting shortage, in order to raise the Day-ahead price even above expected Real-time prices. While the DEC bids may make a loss, this could be more than compensated by a higher price earned by the capacity sold in the Day-ahead market if the price there is raised. I do not see how this can be mitigated, so the IMM should monitor it carefully.

2. Emergency Demand Response and Emergency Purchases Setting Price

75. PJM proposes that prices in the Real-time market can be set by emergency demand response, emergency purchases from outside the RTO Region, or generation from emergency segments of generators already on-line and operating. PJM states that this allows Real-time prices to reflect system conditions and the actual marginal cost of energy at any time.

76. The IMM recommends retaining the current rules which do not allow emergency demand response or emergency purchases to set price. IMM states that allowing such resources to set price raises new market power concerns because such offers are not subject to mitigation and may be submitted by entities in a position to benefit by higher Real-time market prices.

IMM also states that allowing emergency demand response to set price would reduce the dispatch fidelity because these resources are not required to have the telemetry, metering and specific bus location required of dispatchable resources.

77. Allowing these resources to appear in the dispatch stack at prices that reflect their willingness to generate or to reduce consumption will result in more elastic supply and demand at high price levels and improve the efficiency of system operation and pricing when operating reserves are relatively low. The goal should be to see price-driven dispatch of as many resources as possible.

78. However, these reforms raise market power concerns, and are not fundamental or essential to the implementation of shortage pricing. PJM should defer these changes until some experience with shortage pricing has been gained and it is able to address the market power concerns and also the lack of telemetry and metering for emergency demand resources.

3. Price Formation under Voltage Reduction or Manual Load Dump

79. PJM also proposes how emergency actions such as a voltage reduction or manual load dump will be treated under the shortage pricing rules. Because such actions may reduce system load by a substantial amount, they could potentially relieve operating reserve shortages and, thereby, lower prices, which according to PJM would send the wrong price signal.

80. Such actions are generally taken only when the system is already in both a Primary and Synchronized reserve shortage,²¹ and PJM proposes to maintain prices reflective of the combined penalty factors (\$1,700/MWh) when such actions are taken. However, PJM provides no details of how this would be done, how the system would be balanced when prices may exceed the level that matches supply and demand, and how it would return to normal pricing based on the joint optimization of energy and operating reserves.

81. These emergency actions have the same effect as a huge customer dropping off the system, which naturally would tend to reduce prices. While prices should not decline sharply when these administrative actions are taken, it is also true that the proposed approach leaves the system in a state under which prices are no longer reflecting the actual state of supply and

²¹ PJM Manual 13: Emergency Operations, Section 2: Capacity Emergencies, p. 17 (a voltage reduction alert is implemented when the estimated operating reserve capacity is less than the forecasted synchronized reserve requirement).

demand. PJM should provide more detail in its Tariff regarding how it plans to treat such emergency actions under the full range of system conditions under which such actions could be taken, how pricing would work for the duration of the emergency actions, and how pricing based on supply and demand would be restored. PJM's proposal should minimize the extent and duration of this administrative override of the shortage pricing mechanism.

C. Market Buyer Protections

82. Shortage pricing allows energy and operating reserve prices to rise to much higher levels than was possible in the past; this greatly increase the incentives for market participants to take actions to try to raise prices. In addition, shortage pricing reduces out-of-market purchases and sets market-clearing prices based on the shortage pricing. This greatly increases the potential impact of high prices on consumer costs. For these reasons, shortage pricing should be implemented with careful attention to ways the rules could lead to incorrect or inefficient results, and ways market participants might be able to exploit the rules.

83. The PJM Proposal reflects inadequate attention to the potential impacts of the proposed shortage pricing rules and related changes on consumers in several respects, discussed in this section. The Sotkiewicz Affidavit expresses the view that "reserve shortages should be highly infrequent occurrences in the presence of a resource adequacy construct such as RPM" (p. 6) and "since scarcity/shortage events occur so infrequently, there should be no real concern about a significant or measurable transfer of wealth from suppliers to load" (p. 26). Even allowing that the latter statement probably intended to acknowledge concerns regarding transfers of wealth from load to suppliers (transfers the other direction do not occur), the statement suggests that the designers of the PJM Proposal fail to appreciate the potentially game-changing nature of the proposed package of changes and the risk that it could lead to unintended and very costly results. While market participants, including both suppliers and consumers, have behaved in certain ways in the past during times of system stress, the PJM Proposal creates new incentives and opportunities that could lead to entirely new strategies and substantially different results.

1. Shortage Pricing False Positives

84. A shortage pricing false positive is an instance when prices rise to levels consistent with the presence of a shortage or near-shortage condition, but the system actually has

no shortage or a much less severe shortage. False positives would occur due to flaws in the shortage pricing and related market rules, perhaps exacerbated by market participant strategies to exploit the flaws. The PJM Filing does not even discuss the risk of false positives or claim that the PJM Proposal will not be vulnerable to false positives, which have been a concern and a problem under other RTO's shortage pricing rules²² and could have much larger impacts on the PJM system. The IMM expresses the view (IMM Statement, p. 42) that the PJM Proposal is vulnerable to this problem.

85. PJM should provide additional discussion of how false positives could potentially occur and how its proposal minimizes vulnerability to false positives, and correct the rules or propose additional protections against any vulnerabilities that may remain.

2. Market Power and Market Power Mitigation

86. The PJM Proposal calls for eliminating the current rules that relax market power mitigation during scarcity events, so that mitigation applies during hours of shortage pricing. However, the IMM Statement notes several market power concerns that result from the PJM Proposal:

- a. Increased incentive to exercise market power, and reduced protection against it, resulting from increasing the maximum energy price from \$1,000/MWh to \$2,700/MWh (p. 19);
- b. Potential exercise of market power in the Day-ahead market resulting from lifting the \$1,000/MWh cap on Day-ahead market offers (p. 22);
- c. Impact of separate offers for energy and within-hour synchronized reserves (p. 47);
- d. Lack of a must-offer requirement for synchronized reserves (p. 49);
- e. Allowing emergency demand response to set price (p. 59);
- f. Allowing emergency purchases to set price (p. 61).

87. While I discuss some of these concerns elsewhere in this affidavit, I have not evaluated all of these concerns. It is very difficult to forecast the strategies market participants may be able to devise in response to multiple changes to PJM's market rules. PJM should

²² See, for instance, Potomac Economics, 2005 State of the Markets Report, New York ISO, pages 84-86 (finding a substantial number of 15-minute intervals with shortage pricing but no actual shortage).

address these concerns and adjust its proposal to provide stronger protections against exercise of market power. In light of these concerns, some of the non-essential elements of the PJM Proposal should be delayed until operational experience has been gained with the mechanism.

3. Shortage Pricing Emergency “Circuit Breaker” Provision

88. Operating reserve shortages should be very rare over the next several years due to the PJM system’s present excess capacity. However, despite excess capacity, there could potentially be many hours of shortage pricing and substantial transfers of wealth from consumers to suppliers due to any of the following types of causes:

- a. A common mode failure affecting multiple capacity resources, such as the loss of a major electric or natural gas transmission facility or a group of generating units. This could result from an act of God (e.g., extreme weather), or by legislative, regulatory or judicial action (e.g., shutting down coal or nuclear plants based on an interpretation of environmental, safety or public health laws), or a terrorist act, to give a few examples.
- b. A flaw in the new market rules allowing repeated false positives for shortage pricing, possibly exacerbated by supplier strategies to exploit the flaw.
- c. Substantial, repeated exercise of market power or gaming to cause shortage pricing and high prices, which could be possible if these strategies are not fully anticipated and mitigated in designing the shortage pricing rules.

89. Should the PJM system encounter an extreme situation resulting in insufficient capacity and operating reserves day after day, PJM should of course continue to acquire resources, including very high-priced resources, as needed to operate the system reliably and maintain service to as many customers as possible. However, should circumstances occur that result in the shortage pricing mechanism setting very high reserve and energy prices on multiple hours day after day, it could rapidly cause an enormous transfer of wealth from consumers to producers, making a bad situation for consumers even worse while causing a windfall for suppliers. This concern led to discussion in the stakeholder process of “force majeure” type provisions that would trigger a suspension of some aspects of the shortage pricing mechanism under certain extreme circumstances. The topic was discussed in the Shortage Pricing Working Group and a force majeure proposal was voted on at the Markets and Reliability Committee, gaining substantial support.

90. The PJM Proposal should be modified to include what could be called an emergency “circuit breaker” provision that could be activated only by Commission order. The provision might work as follows:

- a. **Circuit Breaker Provision.** PJM would add to its Tariff rules that, if activated by Commission order, would prescribe that all purchases of energy or ancillary services above a price threshold (such as \$1,000/MWh) would temporarily be compensated on an out-of-market basis (cost plus an adder) rather than establishing market-clearing prices above the threshold.
- b. **Trigger for PJM Filing.** The rules would also specify that, should the cumulative hours of shortage pricing exceed a threshold (say, 30 hours over a 10-day period), or should PJM prospectively expect that hours of shortage pricing may exceed a threshold (for instance, due to an event resulting in a loss of facilities), PJM must file with the Commission within a very short period a description of the recent and/or anticipated circumstances and a rough estimate of the potential impact on prices and consumers. PJM would also file any additional information it felt might be useful to the Commission for determining whether it would be appropriate to activate the circuit breaker provisions.
- c. **Activation and Termination of Circuit Breaker Provisions.** The circuit breaker provisions would only go into effect upon an order of the Commission, and the Commission would also determine the circumstances under which normal pricing would be resumed.

91. Other approaches could be followed for protecting consumers from extended periods of very high prices under the shortage pricing rules and the unwarranted transfers of wealth they could cause. However, because such a circumstance would likely arise quite suddenly and the Commission typically only addresses problems with market rules prospectively, there is value in anticipating such instances and having tariff rules and a process in place for addressing such instances in a timely manner.

92. It is also worth noting that for some scenarios that could lead to an extended period of shortage pricing, the duration of the situation might depend to a great extent upon the actions of an entity that happens to benefit from the shortage pricing and transfer of wealth it causes. Many scenarios of major generation or transmission outages leading to shortage pricing would involve facilities owned and maintained by PJM entities that also own or are affiliated with considerable portfolios of generation that would earn the shortage prices. Such entities’ incentives to bring the affected generation or transmission facilities back into service as soon as possible will be compromised by the very high prices resulting from the shortage pricing rules. A circuit breaker provision would mitigate this unfortunate incentive to some extent.

D. Interaction of Shortage Pricing with Resource Adequacy and RPM

93. Order 719 recognized the connection between shortage pricing and capacity markets and required RTOs to address this in their shortage pricing compliance filings.

Shortage pricing in an emergency and capacity markets for long-term resource adequacy assurance serve largely distinct purposes, but we agree that they should not work at cross purposes. Adding any new element to a market design can have effects on the other elements. We require that each RTO and ISO address in its compliance filing how its selected method of shortage pricing interacts with its existing market design. Order 719, P 204.

94. Operating reserve pricing and the RPM capacity construct both are directed at having adequate resources for reliability, operating in different timeframes. The reformed rules for pricing during operating reserve shortages will attract additional supply- and demand-side resources during times of system stress, increasing reliability. These rules will also increase the prices and revenues available to all resources that contribute to reliability during such times. It is very important that PJM's RPM resource adequacy construct, operating in the months- to years-ahead time frame, take these impacts (both megawatts and dollars) into account, lest RPM acquire excess capacity at an excessive cost.

95. The Sotkiewicz Affidavit suggests that shortage pricing is needed, despite the presence of RPM, because capacity is acquired through RPM only "to meet *expected* peak system and energy market conditions" (p. 6, emphasis in original) and resource adequacy requirements are "based on expected peak weather conditions and forecast economic conditions" (p. 6-7). The Sotkiewicz Affidavit suggests that some combination of extreme realizations of peak weather, economic conditions, or supply resource performance would lead to reserve shortage conditions (p. 7). These statements about how the RPM capacity requirements are established are incorrect. The modeling used to determine the Reliability Requirements to be acquired through RPM is probabilistic and represents very extreme outcomes for peak load multiple standard deviations about expected loads.²³ The modeling also probabilistically represents very extreme combinations of generator outages. The assistance available from neighboring systems is also represented probabilistically, and these and other assumptions also reflect various very

²³ 2009 PJM Reserve Requirement Study, p. 15, available at <http://www.pjm.com/documents/~media/documents/reports/2009-pjm-reserve-requirement-study.ashx>.

conservative choices. This probabilistic and very conservative modeling approach then determines the amount of capacity required to provide a very high level of reliability -- “one day in ten years.” In addition, all of these assumptions are revisited annually, and if conditions change and estimated requirements increase as a delivery year approaches, RPM rules call for acquiring additional capacity through incremental auctions. The Sotkiewicz Affidavit states, “Had the RPM construct procured enough capacity to account for the extreme realization, the cost of maintaining such a *level* of capacity would drive up the price of capacity in the RPM and the amount of capacity procured increasing overall wholesale market expenditures to guard against low probability, extreme realizations of weather, economic activity, and supply resource performance.” In fact, the RPM construct already does procure enough capacity to account for low probability, extreme realizations, and it already does drive up wholesale market expenditures. This is why shortage pricing should be a different way, rather than an additional way, for capacity suppliers to be compensated for contributing to reliability in times of peak demand or low supply.

96. With respect to shortage revenues, PJM proposes to allow the extra revenues to flow through the existing mechanism whereby net energy and ancillary services (“E&AS”) earnings are reflected in the RPM construct through the existing E&AS “offsets”. The IMM proposes an approach to offsetting certain shortage revenues against RPM payments in the year the shortage revenues occur. With respect to the impact of shortage pricing on capacity requirements, neither PJM nor IMM made any proposal.

1. PJM’s Proposal: The Existing RPM E&AS Offsets

97. RPM is designed to provide additional “capacity” payments that are considered necessary because it is believed net revenues from PJM’s E&AS markets are inadequate to attract and retain sufficient generating capacity to provide desired levels of reliability. Consistent with this concept, a sloped capacity “demand” curve is constructed based around a price equal to the estimated amount a “reference unit” (combustion turbine) would have to earn from RPM capacity payments to break even over the life of the unit. This price (“Net CONE”) is established by subtracting from the reference unit’s estimated levelized cost of construction (“CONE”) an estimate of the reference unit’s anticipated average net earnings from E&AS markets over the life of the project (the “E&AS Offset”). For example, if CONE is \$200/MW-day and the E&AS Offset is \$40, this concept suggests that Net CONE is \$160/MW-day, and

RPM is designed to provide the additional \$160/MW-day the combustion turbine is considered to need to make construction worthwhile. If the E&AS Offset rises to \$70 (for instance, due to higher electricity prices, or new shortage pricing rules) the amount the reference unit would need to earn from RPM declines to \$130/MW-day. Net CONE, and the RPM capacity demand curve, would be lowered, and RPM clearing prices would also decline.

98. In concept, the RPM E&AS offsets are supposed to reflect expectations of future E&AS market revenues. However, because a forward-looking approach to estimating future net E&AS earnings has never been developed, instead the RPM E&AS Offsets have been calculated based on a three-year historical average. In addition to the E&AS Offset for the Net CONE calculation, historical three-year average *unit-specific* E&AS offsets are determined and subtracted from estimated unit-specific avoidable costs to set the RPM offer caps for existing units.

99. A pulse of extra E&AS revenues, as could result from shortage revenues, will increase the E&AS Offsets, lowering the RPM capacity demand and supply curves and, as a result, lowering RPM clearing prices and revenues. However, because the E&AS Offsets are calculated based on three-year historical averages, a pulse of extra E&AS revenues in, say, 2011 will be reflected in the E&AS offsets calculated for the RPM auctions held in 2012, 2013, and 2014 to determine capacity prices and revenues for the 2015/2016, 2016/2017, and 2017/2018 delivery years, respectively. Thus, under the current approach, a pulse in E&AS revenues in one year only affects RPM parameters and prices for the delivery years four, five and six years later, when market conditions may be very different.

100. In addition, the impact on future RPM revenues through the E&AS offsets of a pulse of extra E&AS revenues at any time may be greater or less than the magnitude of the pulse, depending primarily on the clearing point on the RPM demand curve (the IMM Statement, Appendix B presents some scenarios in this regard).

101. A three-year historical average is a very poor proxy or estimate for E&AS revenues three additional years into the future. For example, if the years 2008 to 2010 had been characterized by excess capacity and low E&AS earnings, the E&AS offsets used in the RPM auctions held in 2011 for the 2014/2015 delivery year would be low, and the Net CONE and offer cap values would be high, resulting in higher RPM prices for that delivery year. But if market participants and potential entrants actually expect E&AS revenues in 2014 to be much

higher than they were during 2008-2010 (due, for instance, to shortage pricing rules, or reduced capacity excess), the higher RPM parameters and prices would not be necessary or appropriate to attract and retain sufficient capacity for that delivery year. Similarly, if E&AS revenues were higher during the historical period than the market expects going forward, the RPM construct may offer prices that are too low. This approach results in RPM parameters that may be substantially out of sync with market expectations.

102. That the historical three-year average is a poor approach to determining the E&AS Offsets has been recognized by stakeholders, PJM's consultant,²⁴ and the Commission.²⁵ In 2008 through the PJM Capacity Market Evolution Committee, stakeholders attempted to work out the details of a replacement approach. PJM proposed a forward-looking E&AS offset based on forward fuel or electricity prices,²⁶ while the IMM proposed an ex post true-up of scarcity revenues.²⁷ However, no alternative approach has received sufficient stakeholder support.

103. Shortage pricing will make the flaws of the existing E&AS offset approach more costly and disruptive to the RPM mechanism. Shortage revenues are likely to be very uneven from year to year, making total E&AS revenues much more volatile; in years with hot summers (such as 2006 or 2010), and in years when capacity is relatively tight (for whatever reasons), there could be many hours of shortage pricing and substantial shortage revenue, while in years with excess capacity or a mild summer, there may be no shortage pricing events at all. As the IMM describes (IMM Statement, p. 36-37), because pulses of shortage revenues would only affect RPM prices for delivery years several years following the shortage events, RPM price signals would be well out of sync with anticipated capacity and capacity revenue needs. Therefore, shortage pricing, by making E&AS earnings larger and more volatile, exacerbates the disconnect between a historical average E&AS offset and anticipated market conditions and

²⁴ The Brattle Group, *Review of PJM's Reliability Pricing Model (RPM)*, June 30, 2008, p. 53-54 (stating that E&AS Offsets based on historical averages can result in uneconomic and inaccurate price signals, and recommending alternatives, such as a forward looking offset with an ex post true-up).

²⁵ PJM Interconnection, L.L.C., 124 FERC ¶ 61,272, Order on Motion for Technical Conference, P 45 ("Given the critical importance of Net CONE to RPM, PJM and its stakeholders need to thoroughly review and refine the methodology for determining energy and ancillary services revenue offsets...").

²⁶ PJM, *Methodology for Computing Forward Looking E&AS Offsets in RPM with a Stylized Example*, presented at Capacity Market Evolution Committee meeting, September 29, 2008.

²⁷ Monitoring Analytics, *Summary of Position of Independent Market Monitor for PJM on RPM Market Design Issues*, Capacity Market Evolution Committee meeting, October 6, 2008.

E&AS earnings. While a better approach to determining the E&AS Offsets has always been needed, with shortage pricing the need becomes more urgent. E&AS earnings should increase over the coming years due to increasing price-responsive demand and other market reforms, further contributing to the need for reform of the historical E&AS Offset approach.

104. In addition, for delivery years through 2013/2014, RPM parameters were set without anticipation of shortage pricing, resulting in higher RPM prices than would have been set had the E&AS offset anticipated future shortage pricing. If resources earning these RPM prices also earn shortage revenues in these delivery years, arguably they will have been paid twice for the same reliability service, which would be undeserved and unfair to the consumers paying the bills.

105. For these reasons, PJM's proposal to simply allow shortage revenues to flow through the existing RPM E&AS Offset calculations should be revised. Basing RPM parameters for a delivery year on market prices and revenues four to six years in the past is no longer acceptable. The PJM Proposal also allows duplicative payments for shortage events and for RPM for delivery years through 2013/2014.

2. The IMM Proposal for a Shortage Revenue "True Up"

106. The IMM proposes a Shortage Pricing Revenue True Up Mechanism (IMM Statement, p. 33) to offset shortage revenues against capacity payments in the same year. Under the IMM proposal, capacity resources (that is, resources that have cleared in RPM and will receive RPM capacity payments) would not retain shortage revenues unless and to the extent those revenues exceed the resource's RPM payment in a delivery year. The example is given of a capacity resource that receives \$100/MW-day from RPM and on three days of shortage pricing during the delivery year stood to receive \$120/MW-day in shortage revenue, but would receive only the \$20/MW-day amount in excess of the RPM payment. Had the shortage revenues been less than \$100/MW-day, the resource would receive no shortage revenues. For this calculation, IMM proposes that shortage revenues are identified based on the impact of the penalty factors when they are added to energy prices under the shortage pricing rules. Because shortage pricing occurs directly only in the real-time market, only revenues earned in the real-time market would be subject to the proposed True Up mechanism. Also, the True Up applies only to the amount of capacity cleared in RPM, not any additional capacity that might be available from the same resource.

107. However, the IMM's proposed true-up would not reflect shortage revenues in RPM in a timely and effective manner. The main problem with the IMM proposal is that it will likely result in very little of the shortage revenues being trued up. Under most circumstances, capacity sellers will not expect annual shortage revenues to exceed the RPM payment (certainly not early in the delivery year when there has been little or no shortage pricing as yet) and, therefore, would expect that under this True Up mechanism, any shortage revenues they might earn would not be retained. As a result, on days when a chance of shortage pricing is anticipated, capacity sellers would strongly prefer to clear in the Day-ahead market where they will retain all revenues, rather than the Real-time market where any shortage revenues would be lost through the True Up mechanism. Capacity sellers would also expect that the Day-ahead market price will reflect the expectation of shortage revenues in the Real-time market due to arbitrage using INCs and DECs. Loads would also prefer the Day-ahead market under these circumstances, as prices will be less volatile there and possibly lower to the extent arbitrage is incomplete. As a result, it can be expected that on days when shortage pricing is considered a possibility, nearly all the output of capacity sellers will clear in the Day-ahead rather than the Real-time market and there will be very little capacity seller shortage revenue captured by the True Up mechanism. Day-ahead weather and load forecasts are fairly accurate, so some of the days and hours when high demand may lead to shortage pricing should be reasonably predictable. Capacity sellers clearing in the Day-ahead market will in fact earn shortage revenues (prices in the Day-ahead market should reflect expected Real-time shortage prices, due to arbitrage), but these earnings will not be captured by the True Up mechanism that operates only on Real-time revenues.

108. A second problem with the IMM proposal is that it identifies shortage revenues based on operating reserve prices equal to the penalty factor. With PJM's proposed vertical demand curve and Penalty Factors equal to \$850/MWh, operating reserve prices can rise to close to \$850/MWh and this would not be considered shortage revenue under the IMM's proposed True-Up because the penalty factor does not yet apply. With the recommended stepped operating reserve demand curve, revenues would be classified as shortage revenues once operating reserve prices equaled the price on the first step of the curve.

109. Finally, a lesser problem with the IMM True Up proposal is that, to the extent there are sales subject to the true up, it can weaken the capacity seller's incentive to perform. If

a capacity seller's output clears in the Real-time market and, in addition, the seller anticipates its annual shortage revenue to be less than the RPM payment, the seller will anticipate that the shortage portion of the prices earned will not be retained. Thus, the incentive to perform is weakened and even eliminated for any portion of the capacity for which the cost (including any opportunity cost) exceeds the non-shortage portion of the price. However, the RPM penalty provisions provide additional incentives to perform.

3. Recommendation for Reflecting Shortage Revenues in RPM

110. Neither the PJM Proposal, with its substantially lagged reflection of shortage revenues in RPM, nor the IMM True Up proposal, which could result in very little true up of shortage revenues for capacity sellers, adequately connects shortage pricing to the RPM construct. In addition, neither proposal addresses the broader problem that RPM's E&AS Offset, based on a historical average, does not accurately forecast future E&AS earnings with or without shortage revenues. Nor would either proposal address the problem that RPM prices have been set through May 31, 2014 without consideration of the shortage pricing rules that will be in effect beginning in 2011.

111. The existing RPM E&AS Offset approach based on a historical average should be replaced with a properly forward-looking E&AS Offset, with or without a provision for true-up based on actual delivery year revenues, as has been discussed in the past. The revised E&AS Offset and True Up approach should address all E&AS revenues, including shortage revenues without distinction.

112. As a transitional measure for the delivery years for which RPM auctions have already been run (and perhaps an additional year or two until a replacement E&AS Offset approach is implemented), an effective true up mechanism could be put in place that might work as follows:²⁸

- a. Capacity sellers would retain the greater of RPM revenues or shortage revenues for each delivery year. For the purpose of determining whether shortage revenues exceeded RPM revenues, shortage revenues would be estimated based on the

²⁸ This shortage revenue offset is similar to that proposed by DTE Energy Trading in the Shortage Pricing Working Group process, available at <http://www.pjm.com/~media/committees-groups/committees/mc/20100603/20100603-item-04-dte-energy-trading-alternative-proposal.ashx>.

operation of a “reference unit” (combustion turbine), not actual unit performance. If, based on this measure, shortage revenues were greater than the RPM payment, the capacity seller would retain all actual earned shortage revenues but receive no RPM payment for the year. If instead, according to this measure, shortage revenues were less than the RPM payment, the capacity seller would receive an RPM payment equal to the difference between the RPM payment and the reference unit’s estimated shortage revenue.

- b. In calculating the reference unit shortage revenues, it would be assumed that the reference unit sells its output into the Real-time market. Because the shortage revenues expected to be available in the Real-time market should also be reflected in the Day-ahead market prices through arbitrage, this will be a reasonable estimate of shortage revenues even though most capacity clears in the Day-ahead market. Alternatively, it could be assumed that the reference unit split its output between the Day-ahead and Real-time markets based on the actual proportions in each hour, and the shortage revenue earned in the Day-ahead market would be the difference between the actual Day-ahead price and the Real-time price net of the shortage portion of the price when there is shortage.

113. This approach corrects the main problem with the IMM’s proposed True Up, as it captures shortage revenues, whether earned directly in the Real-time market or in expectation in the Day-ahead market. In addition, it has the advantage of leaving all incentives to perform in place. Because shortage revenues are estimated based on the performance of a reference unit, not actual performance, at the margin a capacity seller retains all earned revenues. The amount by which the RPM payment may be reduced due to shortage pricing is independent of actual unit performance.

114. PJM criticizes revenue offset mechanisms on two grounds. First, PJM states that a revenue offset “violates the Commission’s criteria regarding incentives for new demand response and generation investment as such a policy introduces uncertainty regarding revenue streams from the RPM commitment three years forward.” PJM Filing, p. 44. However, the revenue offset mechanism actually *reduces* investor’s uncertainty about future revenues. Shortage revenues are highly volatile, and a revenue offset mechanism makes the *sum of* RPM payment plus shortage payment much more stable and predictable than a mechanism with an

RPM payment that is invariant to shortage revenues. Potential investors naturally are concerned with total revenues, and potential uncertainty in total revenues, more than individual revenue components.

115. Second, PJM suggests that a revenue offset mechanism violates Commission policy regarding “comparable treatment and compensation during reserve shortage conditions” because RPM and non-RPM resources would be treated differently. PJM Filing, p. 44. This too is incorrect. RPM resources are being paid to provide a reliability service. They have been promised a payment in advance in return for their contribution to reliability. Non-RPM resources have made no such advance commitment, so it is entirely appropriate that these two types of resources are treated differently under the shortage rules. In any case, under the recommended offset approach described above, RPM resources do in fact receive and retain actual shortage revenues earned, just like non-RPM resources, while the RPM payment is reduced based on estimated reference resource shortage revenue earnings. Therefore, PJM’s two objections to an offset mechanism are incorrect. The recommended revenue offset approach is consistent with the Commission’s policies and Order 719’s call for shortage pricing proposals to consider interactions with capacity constructs.

4. Linking the Shortage Pricing Mechanism to Capacity Requirements

116. Shortage pricing will attract additional non-RPM supply resources and additional demand reductions during periods of system stress. These additional resources reduce the amount of capacity that must be arranged in advance through RPM to meet reliability standards.

117. PJM’s existing methodologies²⁹ for determining the amount of capacity to be procured through RPM (the Reliability Requirements for the RTO Region and for Locational Deliverability Areas) will not anticipate the additional supplies and demand reductions resulting from a shortage pricing mechanism. The methodology determines the amount of capacity required to satisfy reliability standards (assuming a very conservative amount of assistance from neighboring systems), and it is assumed that this amount of capacity must be procured through

²⁹ PJM’s approach to determining its installed reserve margin and Reliability Requirements is documented in *2009 PJM Reserve Requirement Study*, available at <http://www.pjm.com/documents/~media/documents/reports/2009-pjm-reserve-requirement-study.ashx>.

RPM. Shortage pricing is designed to attract non-RPM supply- or demand-side resources, and such resources are assumed to be zero in the determination of capacity requirements.

118. If the resources attracted by the shortage pricing mechanism are not reflected, the Reliability Requirements will be larger than necessary, RPM will acquire excess capacity, and capacity prices and costs will be excessive as a result. In addition, the excess capacity depresses E&AS prices and revenues, lowering the value of demand response and price-responsive demand and potentially discouraging and delaying the further implementation of smart meters and devices.

119. The PJM Proposal should be modified to explicitly call for reflecting the impacts of shortage pricing on future capacity requirements. Specifically, estimates of the additional non-RPM supply and demand response that will become available during peak periods should be reflected in the modeling to estimate capacity needs to meet the applicable reliability standards. Because RPM rules include “incremental auctions” closer to each delivery year through which additional capacity can be procured if needed, it is not necessary to apply highly conservative assumptions in estimating Reliability Requirements three years in advance. Therefore, forward-looking estimates of the impacts of shortage pricing should be used rather than delaying until actual historical data becomes available.

120. This completes my affidavit.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

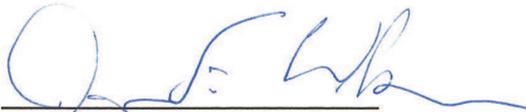
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Docket No. ER09-1063-006

**AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF COMMENTS AND PROTEST OF
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION**

James F. Wilson, being first duly sworn, states he is the same James F. Wilson whose Affidavit in Support of Comments and Protest of the Pennsylvania Public Utility Commission accompanies this affidavit; and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.



James F. Wilson

Subscribed and sworn before me, a Notary Public in and for the State of Maryland

this 30 day of July, 2010.



Notary Public
My Commission expires:

MONIQUE M MAGTIBAY
NOTARY PUBLIC
MONTGOMERY COUNTY
MARYLAND
My Commission Expires 01/31/2014

James F. Wilson
Principal, Wilson Energy Economics
and Affiliate, LECG

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SUMMARY

James F. Wilson has over 25 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, and market power issues. Other recent engagements have involved resource adequacy and capacity market issues, contract litigation and damages, forecasting and market evaluation, pipeline rate cases, and evaluating allegations of market manipulation, among many other issues arising in these industries. Mr. Wilson also spent five years in Russia advising on the reform, restructuring and development of the Russian electricity and natural gas industries for the World Bank and other clients.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC, and he remains an Affiliate of LECG. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal*, *Electricity Journal*, *Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.

EDUCATION

MS, Engineering-Economic Systems, Stanford University, 1982
BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Testimony in support of proposed changes to a forward capacity market mechanism.
- Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
- Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
- Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
- Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.
- Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.

- Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
- Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
- Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism's design; prepared a detailed report. Evaluated the impacts of the mechanism's flaws on prices and costs and prepared testimony in support of a formal complaint.
- Analyzed impacts and potential damages of natural gas migration from a storage field.
- Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
- Prepared affidavit evaluating a pipeline's application for market-based rates for interruptible transportation and the potential for market power.
- Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
- Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.
- Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
- Evaluated market power issues raised by a possible gas-electric merger.
- Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under FERC policy.
- Prepared an expert report on damages in a natural gas contract dispute.
- Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
- Prepared testimony evaluating natural gas procurement incentive mechanisms.
- Analyzed the need for and value of additional natural gas storage in the southwestern US.
- Evaluated market issues in the restructured Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
- Affidavit on current conditions in western natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
- Testified regarding the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
- Testified regarding the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
- Evaluated the causes of California natural gas price increases during 2000-2001; testified in a Federal Energy Regulatory Commission proceeding regarding the possible exercise of market power to raise natural gas prices at the California border.
- Advised a major US utility with regard to the Federal Energy Regulatory Commission (FERC) proposed Standard Market Design and its potential impacts on the company.
- Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
- Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Submitted testimony on price mitigation measures to the FERC.
- Summarized and critiqued wholesale and retail restructuring and competition policies for electric power and natural gas in select US states, for a Pacific Rim government contemplating energy reforms.
- Presented testimony regarding divestiture of hydroelectric generation assets, potential market power issues, and mitigation approaches to the California Public Utilities Commission.

- Reviewed the reasonableness of an electric utility's wholesale power purchases and sales in a restructured power market during a period of high prices.
- Presented an expert report on failure to perform and liquidated damages in a natural gas contract dispute.
- Presented a workshop on Market Monitoring to a group of western electric utilities in the process of forming a Regional Transmission Organization.
- Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
- Developed recommendations for mitigating the locational market power that exists when transmission is constrained, as part of a package of congestion management reforms.
- Provided analysis in support of a transmission owner involved in a contract dispute with generators providing services related to local grid reliability.
- Authored a report on the recommended role of regional transmission organizations in market monitoring for the Edison Electric Institute, submitted by them to the FERC.
- Prepared market power analyses in support of two California electric generators' applications to FERC for market-based rates for energy and ancillary services.
- Analyzed western electricity markets and the potential market power of a large producer under various asset acquisition or divestiture strategies.
- Testified before the New Mexico Public Utility Commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.
- Advised a major Canadian electric utility on restructuring issues, including: market design and trading arrangements; contractual approaches to mitigating market power; measures for ensuring adequate generating capacity.
- Prepared a market power analysis in support of an acquisition of generating capacity in the New England market.
- Advised a California utility regarding reform strategies for the California natural gas industry, addressing a broad range of market power issues and policy options for providing system balancing services.

EARLIER PROFESSIONAL EXPERIENCE

ICF RESOURCES, INC., Fairfax, VA, 1997–1998.

Project Manager

- Reviewed, critiqued and submitted testimony on a New Jersey electric utility's restructuring proposal, as part of a management audit for the state regulatory commission.
- Assisted a group of US utilities in developing a proposal to form a regional Independent System Operator (ISO).
- Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
- Provided analytical support to the Secretary of Energy's Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability and on liability issues.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator (NUG) contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
- Designed an auction process for divestiture of a Northeastern electric utility's generation assets and entitlements (power purchase agreements).

- Participated in several projects involving analysis of regional power markets and valuation of existing or proposed generation assets.

IRIS MARKET ENVIRONMENT PROJECT, 1994–1996.

Project Director, Moscow, Russia

Established and led a policy analysis group advising the Russian Federal Energy Commission and Ministry of Economy on economic policies for the electric power, natural gas, oil pipeline, telecommunications, and rail transport industries (*the Program on Natural Monopolies*, a project of the IRIS Center of the University of Maryland Department of Economics, funded by USAID). Major activities and projects included:

- Advised on industry reforms and the establishment of federal regulatory institutions.
- Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
- Developed policy conditions for the IMF's \$10 billion Extended Funding Facility.
- Performed industry diagnostic analyses with detailed policy recommendations for electric power (1994), natural gas, rail transport and telecommunications (1995), oil transport (1996).

Independent Consultant stationed in Moscow, Russia, 1991–1996

Projects for the WORLD BANK, 1992-1996:

- Bank Strategy for the Russian Electricity Sector. Developed a policy paper outlining current industry problems and necessary policies, and recommending World Bank strategy.
- Russian Electric Power Industry Restructuring. Participated in work to develop recommendations to the Russian Government on electric power industry restructuring.
- Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
- Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
- World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.
- Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.

Other consulting assignments in Russia, 1991–1994:

- Project leader for start-up phase of the joint Russian-American Electric Power Alternatives Study on power sector development and investment; also participated in a project on electric power restructuring, for Hagler Bailly.
- Advised the US Agency For International Development on the establishment of energy industry technical assistance programs in Russia.
- Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute For Energy Research of the Russian Academy of Sciences.
- Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992

Senior Associate, 1985-1992.

- For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement

strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches:

- Bulk Power Contracting Strategies. Led project to develop EPRI's pilot POWERMIX model for bulk power contract planning.
 - Natural Gas Contracting Strategies. Developed the Gas Contract Mix model for distribution companies to evaluate spot purchase and long term contracting strategies under circumstances of industry deregulation and market uncertainty.
 - Fuel Contracting Strategies. Led a series of projects to develop EPRI's Fuel Contract Mix Model and methodology and transfer it to industry. The methodology assists electric and gas utilities evaluate and select coal, natural gas, and fuel oil strategies under circumstances of fuel market and other uncertainties.
- Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following FERC Order 436.
 - Analyzed long term coal and rail alternatives for a midwest electric utility, including alternative coal supply regions, suppliers and contract structures; spot/contract mix; rail arrangements; slurry pipeline; power purchases; conversion to gas.
 - Led project to evaluate bulk power purchase alternatives and strategies for a New Jersey electric utility. Developed model for analyzing power purchases.
 - Performed a financial and economic analysis of a proposed hydroelectric project.
 - For a natural gas pipeline company serving the Northeastern US, forecasted long-term natural gas supply and transportation volumes through analysis of customers' supply choices and likely actions. Developed a forecasting system for staff use.
 - Analyzed potential benefits of diversification of gas suppliers for a mid-continent gas pipeline company.
 - Led project to evaluate and make recommendations on uranium contracting strategies, including long-term contract purchases, spot purchases, and stockpiling actions, for an eastern electric utility.
 - For a western "baby bell", analyzed telecommunications services markets under deregulation, developed and implemented a pricing strategy model. Evaluated potential responses of residential and business customers to changes in the client's and competitors' services and prices as a result of liberalization of telecommunications markets.
 - Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
 - Analyzed long-term natural gas supply strategies and spot purchasing strategies for a California natural gas distribution company.
 - Analyzed oil and natural gas contracting strategies for a California electric utility. Evaluated standby supply options for low-sulfur fuel oil.

TESTIMONY AND AFFIDAVITS

ISO New England, Inc. and New England Power Pool, Federal Energy Regulatory Commission Docket No. ER10-787-000 on Forward Capacity Market Revisions: Direct Testimony On Behalf Of The Connecticut Department of Public Utility Control, March 30, 2010; Direct Testimony in Support of First Brief of the Joint Filing Supporters, July 1, 2010.

PJM Interconnection, L.L.C., Federal Energy Regulatory Commission Docket No. ER09-412-006: Affidavit In Support of Protest of Indicated Consumer Interests, January 19, 2010.

In the Matter of the Application of Ohio Edison Company, et al For Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Public Utilities Commission of Ohio Case No. 09-906-EL-SSO: Direct Testimony on Behalf of the

Office of the Ohio Consumers' Counsel, December 7, 2009; deposition, December 10, 2009, testimony at hearings, December 22, 2009.

Application of PATH Allegheny Virginia Transmission Corporation for Certificates of Public Convenience and Necessity to Construct Facilities: 765 kV Transmission Line through Loudon, Frederick and Clarke Counties, Virginia State Corporation Commission Case No. PUE-2009-00043: Direct Testimony on Behalf of Commission Staff, December 8, 2009.

PJM Interconnection, L.L.C., Federal Energy Regulatory Commission Docket No. ER09-412-000: Affidavit On Proposed Changes to the Reliability Pricing Model On Behalf Of RPM Load Group, January 9, 2009; Reply Affidavit, January 26, 2009.

PJM Interconnection, L.L.C., Federal Energy Regulatory Commission Docket No. ER09-412-000: Affidavit In Support of the Protest Regarding Load Forecast To Be Used in May 2009 RPM Auctions, January 9, 2009.

Maryland Public Service Commission et al v. PJM Interconnection, L.L.C., Federal Energy Regulatory Commission Docket No. EL08-67-000: Affidavit in Support Complaint of the RPM Buyers, May 30, 2008; Supplemental Affidavit, July 28, 2008.

PJM Interconnection, L.L.C., Federal Energy Regulatory Commission Docket No. ER08-516-000: Affidavit On PJM's Proposed Change To RPM Parameters On Behalf Of RPM Buyers, March 6, 2008.

PJM Interconnection, L.L.C., Reliability Pricing Model Compliance Filing, Federal Energy Regulatory Commission Docket Nos. ER05-1410 and EL05-148: Affidavit Addressing RPM Compliance Filing Issues on Behalf of the Public Power Association of New Jersey, October 15, 2007.

TXU Energy Retail Company LP v. Leprino Foods Company, Inc., US District Court for the Northern District of California, Case No. C01-20289: Testimony at trial, November 15-29, 2006; Deposition, April 7, 2006; Expert Report on Behalf of Leprino Foods Company, March 10, 2006.

Gas Transmission Northwest Corporation, Federal Energy Regulation Commission Docket No. RP06-407: Reply Affidavit, October 26, 2006; Affidavit on Behalf of the Canadian Association of Petroleum Producers, October 18, 2006.

PJM Interconnection, L.L.C., Reliability Pricing Model, Federal Energy Regulatory Commission Docket Nos. ER05-1410 and EL05-148: Supplemental Affidavit on Technical Conference Issues, June 22, 2006; Supplemental Affidavit Addressing Paper Hearing Topics, June 2, 2006; Affidavit on Behalf of the Public Power Association of New Jersey, October 19, 2005.

Maritimes & Northeast Pipeline, L.L.C., Federal Energy Regulatory Commission Docket No. RP04-360-000: Prepared Cross Answering Testimony, March 11, 2005; Prepared Direct and Answering Testimony on Behalf of Firm Shipper Group, February 11, 2005.

Dynegy Marketing and Trade v. Multiut Corporation, US District Court of the Northern District of Illinois, Case. No. 02 C 7446: Deposition, September 1, 2005; Expert Report in response to Defendant's counterclaims, March 21, 2005; Expert Report on damages, October 15, 2004.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.04-03-021: Prepared Testimony, Policy for Throughput-Based Backbone Rates, on behalf of Pacific Gas and Electric Company, May 21, 2004.

Gas Market Activities, California Public Utilities Commission Order Instituting Investigation I.02-11-040: Testimony at hearings, July, 2004; Prepared Testimony, Comparison of Incentives Under Gas Procurement Incentive Mechanisms, on behalf of Pacific Gas and Electric Company, December 10, 2003.

Application of Red Lake Gas Storage, L.P., Federal Energy Regulatory Commission Docket No. CP02-420, Affidavit in support of application for market-based rates for a proposed merchant gas storage facility, March 3, 2003.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.01-10-011: Testimony at hearings, April 1-2, 2003; Rebuttal Testimony, March 24, 2003; Prepared Testimony, Performance of the Gas Accord Market Structure, on behalf of Pacific Gas and Electric Company, January 13, 2003.

Application of Wild Goose Storage, Inc., California Public Utilities Commission proceeding A.01-06-029: Testimony at hearings, November, 2001; Prepared testimony regarding policies for backbone expansion and tolls, and potential ratepayer benefits of new storage, on behalf of Pacific Gas and Electric Company, October 24, 2001.

Public Utilities Commission of the State of California v. El Paso Natural Gas Co., Federal Energy Regulatory Commission Docket No. RP00-241: Testimony at hearings, May-June, 2001; Prepared Testimony on behalf of Pacific Gas and Electric Company, May 8, 2001.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.99-09-053: Prepared testimony regarding market power consequences of divestiture of hydroelectric assets, December 5, 2000.

San Diego Gas & Electric Company, *et al*, Federal Energy Regulatory Commission Docket No. EL00-95: Prepared testimony regarding proposed price mitigation measures on behalf of Pacific Gas and Electric Company, November 22, 2000.

Application of Harbor Cogeneration Company, Federal Energy Regulatory Commission Docket No. ER99-1248: Affidavit in support of application for market-based rates for energy, capacity and ancillary services, December 1998.

Application of and Complaint of Residential Electric, Incorporated vs. Public Service Company of New Mexico, New Mexico Public Utility Commission Case Nos. 2867 and 2868: Testimony at hearings, November, 1998; Direct Testimony on behalf of Public Service Company of New Mexico on retail access issues, November, 1998.

Management audit of Public Service Electric and Gas' restructuring proposal for the New Jersey Board of Public Utilities: Prepared testimony on reliability and basic generation service, March 1998.

PUBLISHED ARTICLES

Forward Capacity Market CONEfusion, July 2010, forthcoming in Electricity Journal.

Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid, Public Utilities Fortnightly, May 2010.

Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness?, Public Utilities Fortnightly, April 2010.

A Hard Look at Incentive Mechanisms for Natural Gas Procurement, with K. Costello, National Regulatory Research Institute Report No. 06-15, November 2006.

Natural Gas Procurement: A Hard Look at Incentive Mechanisms, with K. Costello, Public Utilities Fortnightly, February 2006, p. 42.

After the Gas Bubble: An Economic Evaluation of the Recent National Petroleum Council Study, with K. Costello and H. Huntington, Energy Journal Vol. 26 No. 2 (2005).

High Natural Gas Prices in California 2000-2001: Causes and Lessons, Journal of Industry, Competition and Trade, vol. 2:1/2, November 2002.

Restructuring the Electric Power Industry: Past Problems, Future Directions, Natural Resources and Environment, ABA Section of Environment, Energy and Resources, Volume 16 No. 4, Spring, 2002.

Scarcity, Market Power, Price Spikes, and Price Caps, Electricity Journal, November, 2000.

The New York ISO's Market Power Screens, Thresholds, and Mitigation: Why It Is Not A Model For Other Market Monitors, Electricity Journal, August/September 2000.

ISOs: A Grid-by-Grid Comparison, Public Utilities Fortnightly, January 1, 1998.

Economic Policy in the Natural Monopoly Industries in Russia: History and Prospects (with V. Capelik), Voprosi Ekonomiki, November 1995.

Meeting Russia's Electric Power Needs: Uncertainty, Risk and Economic Reform, Financial and Business News, April 1993.

Russian Energy Policy through the Eyes of an American Economist, Energeticheskoye Stroitelstvo, December 1992, p 2.

Fuel Contracting Under Uncertainty, with R. B. Fancher and H. A. Mueller, IEEE Transactions on Power Systems, February, 1986, p. 26-33.

OTHER ARTICLES, REPORTS AND PRESENTATIONS

Forward Capacity Market CONEfusion, Advanced Workshop in Regulation and Competition, 29th Annual Eastern Conference of the Center for Research in Regulated Industries, Rutgers University, May 21, 2010.

One Day in Ten Years? Resource Adequacy for the Smart Grid, revised draft November 2009.

Approaches to Local Resource Adequacy, presented at Electric Utility Consultants' Smart Capacity Markets Conference, November 9, 2009.

One Day in Ten Years? Resource Adequacy for the Smarter Grid, Advanced Workshop in Regulation and Competition, 28th Annual Eastern Conference of the Center for Research in Regulated Industries, Rutgers University, May 15, 2009.

Resource Adequacy in Restructured Electricity Markets: Initial Results of PJM's Reliability Pricing Model (RPM), Advanced Workshop in Regulation and Competition, 27th Annual Eastern Conference of the Center for Research in Regulated Industries, Rutgers University, May 15, 2008.

Statement at Federal Energy Regulatory Commission technical conference, Capacity Markets in Regions with Organized Electric Markets, Docket No. AD08-4-000, May 7, 2008.

Raising the Stakes on Capacity Incentives: PJM's Reliability Pricing Model (RPM), presentation at the University of California Energy Institute's 13th Annual POWER Research Conference, Berkeley, California, March 21, 2008.

Raising the Stakes on Capacity Incentives: PJM's Reliability Pricing Model (RPM), report prepared for the American Public Power Association, March 14, 2008.

Comments on GTN's Request for Market-Based Rates for Interruptible Transportation, presentation at technical conference in Federal Energy Regulatory Commission Docket No. RP06-407, September 26-27, 2006 on behalf of Canadian Association of Petroleum Producers.

Comments on Policies to Encourage Natural Gas Infrastructure, and Supplemental Comments on Market-Based Rates Policy For New Natural Gas Storage, State of the Natural Gas Industry Conference, Federal Energy Regulatory Commission Docket No. AD05-14, October 12 and 26, 2005.

After the Gas Bubble: A Critique of the Modeling and Policy Evaluation Contained in the National Petroleum Council's 2003 Natural Gas Study, with K. Costello and H. Huntington, presented at the 24th Annual North American Conference of the USAEE/IAEE, July 2004.

Comments on the Pipeline Capacity Reserve Concept, State of the Natural Gas Industry Conference, Federal Energy Regulatory Commission Docket No. PL04-17, October 21, 2004.

Southwest Natural Gas Market and the Need for Storage, Federal Energy Regulatory Commission's Southwestern Gas Storage Technical Conference, docket AD03-11, August 2003.

Assessing Market Power in Power Markets: the "Pivotal Supplier" Approach and Variants, presented at Electric Utility Consultants' Ancillary Services Conference, November 1, 2001.

Scarcity and Price Mitigation in Western Power Markets, presented at Electric Utility Consultants' conference: What To Expect In Western Power Markets This Summer (conference chair), May 1-2, 2001.

Market Power: Definition, Detection, Mitigation, pre-conference workshop, with Scott Harvey, January 24, 2001.

Market Monitoring in the U.S.: Evolution and Current Issues, presented at the Association of Power Exchanges' APEX 2000 Conference, October 25, 2000.

Ancillary Services and Market Power, presented at the Electric Utility Consultants' Ancillary Services Conference (New Business Opportunities in Competitive Ancillary Services Markets), September 14, 2000.

Market Monitoring Workshop, presented to RTO West Market Monitoring Work Group, June 2000.

Screens and Thresholds Used In Market Monitoring, presented at the Conference on RTOs and Market Monitoring, Edison Electric Institute and Energy Daily, May 19, 2000.

The Regional Transmission Organization's Role in Market Monitoring, report for the Edison Electric Institute attached to their comments on the FERC's NOPR on RTOs, August, 1999.

The Independent System Operator's Mission and Role in Reliability, presented at the Electric Utility Consultants' Conference on ISOs and Transmission Pricing, March 1998.

Independent System Operators and Their Role in Maintaining Reliability in a Restructured Electric Power Industry, ICF Resources for the U. S. Department of Energy, 1997.

Rail Transport in the Russian Federation, Diagnostic Analysis and Policy Recommendations, with V. Capelik and others, IRIS Market Environment Project, 1995.

Telecommunications in the Russian Federation: Diagnostic Analysis and Policy Recommendations, with E. Whitlock and V. Capelik, IRIS Market Environment Project, 1995.

Russian Natural Gas Industry: Diagnostic Analysis and Policy Recommendations, with I. Sorokin and V. Eskin, IRIS Market Environment Project, 1995.

Russian Electric Power Industry: Diagnostic Analysis and Policy Recommendations, with I. Sorokin, IRIS Market Environment Project, 1995.

PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

July 2010

Standard BAL-002-0 — Disturbance Control Performance

Introduction

1. **Title:** Disturbance Control Performance

2. **Number:** BAL-002-0

3. **Purpose:**

The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

4. **Applicability:**

4.1. Balancing Authorities

4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)

4.3. Regional Reliability Organizations

5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently

Standard BAL-002-0 — Disturbance Control Performance

than annually, their probable contingencies to determine their prospective most severe single contingencies.

- R4.** A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:
- R4.1.** A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.
- R4.2.** The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.
- R5.** Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:
- R5.1.** The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.
- or
- R5.2.** The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.
- R6.** A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.
- R6.1.** The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.
- R6.2.** The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.

C. Measures

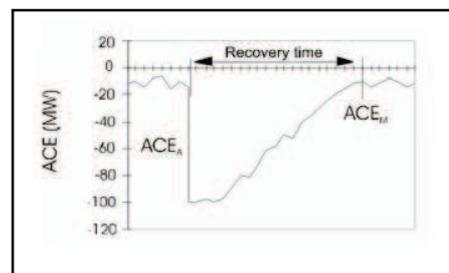
- M1.** A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

Standard BAL-002-0 — Disturbance Control Performance

For loss of generation:

if $ACE_A < 0$
then

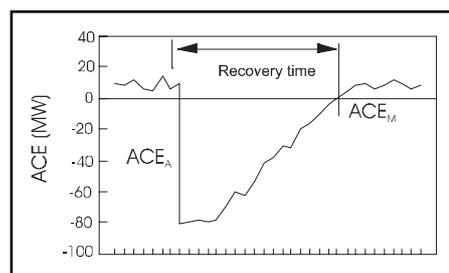
$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$



if $ACE_A \geq 0$

then

$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

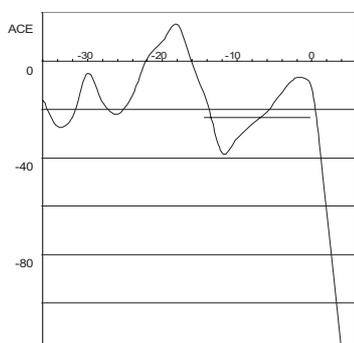


where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15 \text{ min}}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of $ACE_A = -25 \text{ MW}$.



Standard BAL-002-0 — Disturbance Control Performance

The average percent recovery is the arithmetic average of all the calculated R_i 's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Reliability Organization must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.4. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

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Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

- 2.1. Level 1:** Value of the average percent recovery for the quarter is less than 100% but greater than or equal to 95%.
- 2.2. Level 2:** Value of the average percent recovery for the quarter is less than 95% but greater than or equal to 90%.
- 2.3. Level 3:** Value of average percent recovery for the quarter is less than 90% but greater than or equal to 85%.
- 2.4. Level 4:** Value of average percent recovery for the quarter is less than 85%.

E. Regional Differences

None identified.

Standard BAL-002-0 — Disturbance Control Performance

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata

Standard BAL-002-RFC-02 — Operating Reserves

A. Introduction

1. **Title:** **Operating Reserves**
2. **Number:** **BAL-002-RFC-02**
3. **Purpose:**
To establish a ReliabilityFirst Corporation (ReliabilityFirst) requirement for Operating Reserves to support NERC Reliability Standard BAL-002.
4. **Applicability:**
Balancing Authorities (BA) within ReliabilityFirst footprint
5. **Effective Date:** May 9th, 2007

B. Requirements

- R1 Each Balancing Authority, either individually or through participation in a Reserve Sharing Group, shall have a documented methodology to determine its Operating Reserves-Spinning and Operating Reserves-Supplemental, including the limitations, if any, upon the amount of interruptible load that may be included as Contingency Reserves that is used to plan for the next operating day, or shall¹: *[Violation Risk Factor: Lower]*²
- R1.1 Have a minimum Operating Reserves – Spinning requirement of at least 50% of the Balancing Authority’s most severe single contingency and the remainder of the Contingency Reserves to be made up of any combination of Operating Reserves – Spinning and Operating Reserves – Supplemental.
- R1.2 Implement its Contingency Reserve upon the contingent loss of generation equal to 80% or more of its most severe single contingency
- R1.3 Not allocate interruptible load as Operating Reserves-Spinning.
- R1.4 Not allocate more than 25% of Operating Reserves-Supplemental as interruptible load.
- R1.5 Document the requirements under R1.1 through R1.4 in a methodology to plan for the next operating day.
- R2 The same portion of any resource shall not be counted more than once as Contingency Reserves by multiple Balancing Authorities. *[Violation Risk Factor: Lower]*

¹ NERC BAL-002 defines the minimum Contingency Reserves requirement applicable to Balancing Authorities and Reserve Sharing Groups

² Violation Risk Factors indicates the level of risk to the interconnection that an associated non-compliance may have.

Standard BAL-002-RFC-02 — Operating Reserves

- R2.1 The Balancing Authority shall document any amount of resources within its Balancing Authority Area designated as Contingency Reserves by another Balancing Authority.
- R2.2 The Balancing Authority shall document any amount of resources outside its Balancing Authority Area included in its Contingency Reserves.
- R3 On an annual basis the Balancing Authority, either individually or through participation in a Reserve Sharing Group, shall review and update its methodology followed under R1. [*Violation Risk Factor: Lower*]
- R4 Each Balancing Authority shall document its most severe single contingency, as used in R1 for the determination of the Contingency Reserve requirement, and projected resources for Contingency Reserves for the peak hour of the next operating day for its Balancing Authority Area as follows³: [*Violation Risk Factor: Lower*]
- R4.1 Each Balancing Authority shall document its required and projected resources in MWs for Contingency Reserves identifying the amount designated as Operating Reserve – Spinning and Operating Reserve – Supplemental, and the amount of interruptible load included as Contingency Reserves, if any, in accordance with R1.

C. Measures

- M1 Each Balancing Authority shall have evidence of its methodology in accordance with R1.
- M2 Each Balancing Authority shall have documentation in accordance with R2.
- M3 Each Balancing Authority, either individually or through participation in a Reserve Sharing Group, shall have evidence that it reviewed and updated its methodology in accordance with R3.
- M4 Each Balancing Authority shall have documentation in accordance with R4.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility
ReliabilityFirst Corporation

- 1.1.1 On a monthly basis, Balancing Authorities shall report by exception or self reporting to the Compliance Monitor any instances where the Balancing Authority projected that it might be deficient in meeting its reserve obligation absent implementing emergency procedures.

³ This information may be requested by the Reliability Coordinator under NERC IRO-004 R4

Standard BAL-002-RFC-02 — Operating Reserves

1.1.2 On an Annual basis or less the Balancing Authority can be subject to compliance monitoring at the discretion of the Compliance Monitor.

1.2 Compliance Monitoring Period and Reset Time Frame

Compliance Monitoring Period – Daily

Reset period - One calendar month

1.3 Data Retention

The documented methodology and daily plans must be held for the current calendar year plus previous calendar year

1.4 Additional Compliance Information

None

2. Violation Severity Levels⁴

2.1 Lower: There shall be a lower violation if the following condition exists:

2.1.1 The Balancing Authority has not documented its Contingency Reserves for one individual day within the calendar month in accordance with R4.

2.2 Moderate: There shall be a moderate violation if the following condition exists:

2.2.1 The Balancing Authority has not documented its Contingency Reserves for two to four individual days within the calendar month in accordance with R4.

2.3 High: There shall be a high violation if the following condition exists:

2.3.1 The Balancing Authority has not documented its Contingency Reserves for five to nine individual days within a calendar month in accordance with R4.

2.4 Severe: There shall be a severe violation if any of the following conditions exists:

2.4.1 The Balancing Authority has not documented its Contingency Reserves for ten or more individual days within a calendar month in accordance with R4.

2.4.2 The Balancing Authority accounted for the same portion of any resource capacity as Contingency Reserves as another Balancing Authority in violation of R2.

⁴ Violation Severity Levels indicate to what degree the standard was not met, not the level of risk to the interconnection that an associated non-compliance may have.

- 2.4.3 The Balancing Authority did not review and update its methodology in accordance with R3
- 2.4.4 The Balancing Authority has not specified its reserve requirements in its methodology or documented its methodology for allocation of Contingency Reserves in accordance with R1.

The following are definitions of terms used in this Standard

NOTE: These definitions are consistent with the NERC Glossary as of the effective date of this Standard but may differ if the NERC Glossary changes.

AGC: Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load resource balance within this area.

Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Operating Reserve - Supplemental: The portion of Operating Reserve consisting of:

- Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or
- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Operating Reserve – Spinning: The portion of Operating Reserve consisting of:

- Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or
- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Reliability Coordinator: The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

Standard BAL-002-RFC-02 — Operating Reserves

Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

E. IntraRegional Differences

None

F. Notes

Balancing Authorities are permitted to define Supplemental (30 Minute) Reserves as an option.

Version History

Version	Date	Action	Change Tracking
RFC-OPR-001-0	12/12/05	Approved by ReliabilityFirst Board	
RFC-OPR-001-1 1 st Draft	08/16/06 Through 09/17/06	Posted for 1 st 30-Day Comment Period	
RFC-OPR-001-1 2 nd Draft	10/30/06 Through 11/28/06	Posted for 2 nd 30-Day Comment Period	
RFC-OPR-001-1 3 rd Draft	12/15/06 Through 01/15/07	Posted for 3 rd 30-Day Comment Period	
RFC-OPR-001-1 4 th Draft	02/21/07 Through 03/07/07	Posted for 15-Days prior to Membership Ballot	
RFC-OPR-001-1 4 th Draft	03/12/07 Through 03/26/07	Posted for 15-Day Membership Ballot	
RFC-OPR-001-1 4 th Draft	03/30/07	Removed Regulating Reserve and Regulation Service Definition	Errata
RFC-OPR-001-1 4 th Draft	03/30/07 Through 04/28/07	Posted for 30-Days prior to Board Action	
BAL-002-RFC-02 4 th Draft	04/12/07	Changed Standard Number - BAL-002-RFC-02	Conforming Change
BAL-002-RFC-02 Approved	05/09/07	Changed Effective Date - May 9 th , 2007 Changed Header - Standard BAL-002-RFC-02 — Operating Reserves Changed Footer - Approved by ReliabilityFirst Board of Directors: May 9 th , 2007 Effective Date: May 9 th , 2007	Conforming Change due to RFC Board Approval

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each party designated on the official service list compiled by the Secretary in Docket ER09-1063-004.

Dated at Harrisburg, Pennsylvania this 30th day of July, 2010.

s/ John A. Levin
Assistant Counsel
Pennsylvania Public Utility Commission