

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

PJM Power Providers Group
v. PJM Interconnection, L.L.C.

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Docket No. EL11-20-000

PJM Interconnection, L.L.C.

Docket No. ER11-2875-000

(not consolidated)

**AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF PROTEST OF
NEW JERSEY RATE COUNSEL**

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I. Introduction

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

2. I have over twenty-five 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. 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 JFW-1 attached hereto.

3. 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, planning and capacity market issues over the past several years.

4. Since PJM proposed the Reliability Pricing Model (“RPM”) capacity construct in 2005 I have prepared numerous affidavits, reports, and analyses of RPM. My work has been supported by state commissions, consumer advocates, industrial customers, public power entities, and electric distribution companies. With regard to the primary issue in this proceeding (minimum offer prices for new generation), I submitted affidavits in the New England proceeding on this issue last year.

5. On February 11, 2011, PJM Interconnection, L.L.C. (“PJM”) filed tariff revisions to the Minimum Offer Price Rule (“MOPR”) associated with its Reliability Pricing Model (“RPM”) capacity construct. PJM requests the Commission to accept the proposed tariff revisions with an effective date of April 13, 2011, in order that the new rules be in effect for the RPM base residual auction scheduled for May 2011 for the 2014/2015 delivery year.

6. This affidavit was prepared at the request of the New Jersey Division of Rate Counsel. I was asked to review the PJM Filing and comment on the proposed tariff changes. I was also asked to comment on the complaint that addresses similar issues filed on February 1, 2011 by the PJM Power Providers Group (“P3”) in Docket No. EL11-20.

II. Summary

7. The Minimum Offer Price Rule, or MOPR, was included in the RPM rules to mitigate the potential for capacity buyers with the incentive and ability to do so to exercise market power to suppress capacity market prices. It is appropriate to include a well-structured rule with this purpose in the PJM Tariff. The MOPR was developed through the settlement discussions that led to the Commission’s approval of RPM in 2006.

8. Over seven base residual auctions for seven delivery years, the MOPR has never been invoked. Nor has any party alleged that there were offers in these auctions to which the rule should have applied. To the extent the problem addressed by the MOPR exists, the rule apparently has been sufficient to date.

9. The PJM and P3 filings are in response to possible actions by states to encourage development of major new power plants. The existing MOPR includes an exemption for resources that are developed pursuant to “a state regulatory or legislative mandate to resolve a projected capacity shortfall.” PJM Tariff Att. DD Section 5.14(h)(1). PJM and P3 are concerned that the existing MOPR’s state exemption and other provisions could allow states to cause new resources to be built in order to suppress capacity prices.

10. Some of the changes proposed by PJM would strengthen the MOPR and remove ambiguities in the rule, which could improve it by ensuring that it would apply under those circumstances when it should apply, should they arise. However, while the MOPR is intended to mitigate attempts to exercise market power to suppress capacity prices, PJM (and to a far greater extent P3) seek to fundamentally change the purpose of the rule and substantially broaden the intervention in the market that will result from it. PJM states that its proposed changes to the

MOPR have “a single focus and purpose – preventing uneconomically low sell offers from new entry generation plants.” PJM Filing, p. 5. Accordingly, the MOPR would no longer have to do with mitigating attempts to exercise market power to suppress capacity prices, and instead the rule would apply to any offers deemed “uneconomically low” according to the proposed criteria (which, as I will explain in detail, are deeply flawed). The PJM proposal would also revise the exemption for state-mandated resources in a manner that could thwart state initiatives that are economically rational and have legitimate purposes (P3 would simply eliminate the state exemption). PJM’s proposals, and the P3 proposals to an even greater extent, have the potential for considerable harm to consumers and the market by discouraging new entry and denying capacity payments to new generation that has been built for legitimate business and/or state policy purposes and not as an exercise of market power.

11. The PJM and P3 proposals appear to be motivated by greatly exaggerated impressions of the risk of deliberate attempts to suppress capacity market prices. In justifying proposed changes to the MOPR, both the PJM and P3 filings repeatedly refer to hypothetical deliberate attempts to suppress capacity prices. However, the likelihood that a PJM load-serving entity or other capacity buyer would find such manipulation beneficial is extremely low. The only “attempts” alleged in either filing pertain to state actions undertaken to assist in getting new resources built. Such state initiatives are highly transparent and, therefore, can easily be reviewed and evaluated on a case by case basis to determine whether they represent attempts to inappropriately suppress capacity prices rather than pursue legitimate state interests. In any case, PJM’s and P3’s many vague references to the potential for deliberate attempts to manipulate the capacity market are irrelevant to the changes they propose, because both call for mitigating any and all offers deemed “uneconomically low” without regard to whether they reflect any attempt to suppress capacity prices.

12. The MOPR could be strengthened to more clearly address the risk that a capacity buyer (or government agency or other entity with the incentive to do so) would attempt to bring new resources to the market and offer them at low prices in order to suppress capacity market prices. The MOPR provisions should apply to all instances where the ability and incentive to suppress capacity market prices are present and the actions appear motivated by the intent to suppress capacity market prices. However, a revised MOPR should also be designed so as not to interfere with the normal competitive process by which new resources are brought to the market

by entities that have no incentive to suppress capacity market prices and who offer the new resources at competitive prices to try to win a capacity supply obligation (I use the word “competitive” in its classic meaning here – priced to be successful and to sell in the marketplace¹).

A. The Proposed Changes to the MOPR Will Prevent Competitive Offers From Economic New Entry Generation, Creating A Substantial Barrier to New Entry

13. PJM’s misguided proposal to mitigate offers deemed “uneconomically low”, and its proposed criterion applying an administrative calculation, are based on a fundamental misconception regarding how major new resources are developed and offered into RPM. The proposal rests on the belief that the sponsors of new power plants will (or should) offer their projects into RPM’s auctions at prices based on their full levelized cost of new entry net of an estimate of net earnings from energy and ancillary services markets, and allow the auction result to determine whether or not they will build the resource. While there is a superficial logic to this concept of market conduct that is appealing on first glance, the notion is conceptually flawed and not supported by any sound business or economic logic; in fact, the sponsors of new power plants generally will not, and certainly should not be forced to, offer their plants into an RPM auction at prices determined in this manner. Decisions to build new long-lived power plants are rationally based on a long-term view of plant economics, and sponsors will generally not submit their decision to the result of an auction whose outcomes are notoriously volatile and which in any case determine a capacity payment for only a single year. Instead, decisions to build major new power plants generally occur outside of RPM and then are reflected in offers into RPM that the sponsors fully expect will clear.

14. The evidence of seven RPM base residual auctions is clear – new resources are typically offered at low, competitive offer prices with the intent to win a capacity supply obligation in the auction. New power plants, including combined cycle (“CC”) and combustion turbine (“CT”) plants, have consistently been offered into RPM at prices far below Net CONE. For the most recent base residual auction (2013/2014 delivery year), PJM reported that 1,670.4

¹ Merriam-Webster’s online dictionary defines “competitive” as follows: 1) relating to, characterized by, or based on competition, 2) inclined, desiring, or suited to compete.

MW of new generation capacity was offered, and all of it – all 1,670.4 MW – cleared.² Most of this capacity (961.1 MW) was offered and cleared in the Rest of RTO region, meaning it was offered at a price no greater than \$27.73/MW-day, a small fraction of Net CONE. In the base residual auction that attracted the most offers for new generation (2011/2012; there were thirteen offers for new CTs and CCs, compared to no more than 7 in any other base residual auction³), 1,135 MW of new combined cycle capacity was offered.⁴ PJM’s Independent Market Monitor (“IMM”) reported that only 43.5 MW of combined cycle capacity was offered at a price greater than \$35/MW-day in this auction, far below the clearing price of \$110/MW-year, or Net CONE, which was higher still.⁵ While the amount of capacity from new power plants offered and cleared in the various auctions is not consistently reported, the available facts make it clear that new power plants are most often offered at prices well below Net CONE. New resources are apparently offered at low, competitive prices whether the sponsor is a net buyer, net seller, or entity with no existing market position; and without regard to whether the resource is located in an LDA where the new resource may have a large impact on RPM clearing prices or the Rest of RTO region where little impact on clearing prices can be expected. Despite this evidence, PJM remains loyal to the Net CONE theory, suggesting that it would expect “very few” offers from new CCs or CTs to be priced significantly below Net CONE.⁶

15. This evidence shows that, according to PJM’s proposed screen, nearly all of the offers from new power plants into RPM to date would have been deemed “uneconomically low” by a wide margin. These proposals also reflect the flawed presumption that whether or not a resource or its offer price is or is not “economic” can be assessed based on comparison to a price benchmark for a single year; obviously, this indicator is likely to be volatile and inaccurate. Whether or not a new power plant is economic can only be assessed based on its longer-term economics.

² PJM, 2013/2014 RPM Base Residual Auction Results, Table 6B p. 16.

³ PJM Filing p. 14 footnote 26.

⁴ PJM, 2011/2012 RPM Base Residual Auction Results, Table 5 p. 8.

⁵ MMU, Analysis of the 2011/2012 RPM Auction Revised October 1, 2008, Table 7 p. 15.

⁶ “PJM receives relatively few sell offers in the RPM base auctions each year that are based on new combined cycle or combustion turbine power plants. And very few of those would be expected to submit offers significantly below the net cost of new entry each year.” PJM Filing, p. 14, citation omitted.

16. In addition, PJM proposes to mitigate new resources for at least three years (with the duration depending upon when the mitigated resource actually clears), creating risk that a new resource will not receive a capacity supply obligation for multiple years through no fault of its own (for instance, if prices fall due to subsequent new entry or transmission enhancements). These proposals would create a substantial barrier to the entry of economic new resources. Especially in smaller LDAs, incumbents would be able to price their older, high-cost existing generation pennies below the mitigated offer price of a planned new power plant (and the asset class minimum offer prices will be known in advance), clearing their generation at the maximum possible price and causing the new plant to fail to clear. This would disrupt the normal process by which older plants are replaced by newer, more efficient and cleaner ones.

17. PJM's misconception about how new power plants are (or should be) offered into the RPM capacity spot market reflects a more fundamental misconception about how major new power plants are (or should be) financed and built. As is widely recognized, and the PJM Filing also acknowledges, major new power plants cannot be financed and built relying solely on spot energy, ancillary services and capacity markets, and a long-term contract or some other longer-term assurance of future revenues is required (p. 21).

PJM continues to receive comments from new entry project developers, representatives of the investment community, and proponents of state support for new entry, that new entry requires greater revenue certainty from competitive wholesale markets than the market rules currently provide.

18. However, PJM (and P3) appear to believe that these spot markets should be the sole source of revenue for financing new power plants, and that states and load-serving entities should stand by passively and allow RPM prices to rise to the point where such revenues might lead to new construction. While this view had more plausibility several years ago when RPM was designed, the industry has since changed. There are two major reasons why the notion that new construction should rely solely on spot market revenues should be rejected.

19. First, contrary to expectations based on the misconception about how new entry would be priced, the RPM spot capacity prices are highly volatile. Therefore, such revenues will be heavily discounted by potential investors. While it may be that allowing RPM prices to rise high enough would stimulate some new investment, this would be economically inefficient as an enormous risk premium would be reflected in the costs. In the longer-term markets for new

capacity, both buyers and sellers prefer longer-term commitments and the price stability and assurance of supply that go with longer-term arrangements.

20. Second, and perhaps more important, resource additions are increasingly being selected based on a range of attributes that RPM and the other PJM spot markets do not value. Decisions to build major new power plants must consider environmental attributes, fuel diversity, and operational characteristics, among other factors, and long-term contracting decisions will also reflect preferences for demand-side, renewable or other specific types of resources.

21. Despite this reality, PJM suggests that the RPM rules can be changed (in particular, the New Entry Price Adjustment, or “NEPA”) so as to obviate the need for bilateral contracts or other sources of revenue to support construction of new power plants (p. 21).

Rather than rely on out-of-market mechanisms that are available only to a handful of select resources, the better approach would be to enhance PJM’s rules for in-market revenue assurances.

22. Contrary to this suggestion, it is very unlikely that RPM can be modified to provide sufficient support for new entry to obviate the need for “out-of-market” mechanisms such as bilateral contracts in an efficient manner. RPM is a capacity spot market, balancing one year of supply and demand and awarding one-year commitments; it is very unlikely that stakeholders will find a way to stretch RPM to provide multi-year price assurance to new resources in a manner that will be both effective in attracting new resources and reasonably efficient. As a capacity spot market, RPM will clear sufficient existing and new resources in each zone each year to meet reliability needs, and the clearing prices will reflect the marginal resource needed for reliability in each year, rising to high levels when necessary.

23. For these reasons, it should be accepted that states and load-serving entities will become more proactive in arranging for their future capacity needs, not less, as PJM and P3 appear to desire. Accordingly, the MOPR rule should not be changed based on the assumption that new entry should rely exclusively on spot market revenues, an assumption that is deeply embedded in the proposed screens and mitigation. Nor should it be assumed that the barriers to the construction of new generation that will result from PJM’s proposed changes to the MOPR will be offset by a new NEPA rule that offers multi-year price guarantees to those same plants

and, therefore, it is acceptable to thwart efforts by states and load-serving entities to encourage new entry.

24. Nor would it be sound policy to impose minimum offer prices on new generation to attempt to achieve some theoretically necessary capacity price level. Capacity spot market prices must rise and fall over time to balance supply and demand in response to changing conditions, and RPM is designed to set its price this way. This results in the appropriate short-term price signal for the need for capacity for a specific delivery year. As in many spot markets, capacity spot prices may most often be below net long-run average costs (which in any case are changing over time) but rise to much higher levels when necessary.

25. Mitigating offers from new power plants indiscriminately as PJM proposes would be very bad policy. A revised and strengthened MOPR should not interfere with the normal competitive process by which new resources compete for capacity supply obligations as they become available to the market, which would be a very significant barrier to entry. Nor should a revised MOPR interfere with the clearing of new resources that have been brought to the market under programs or incentives that pursue legitimate public policy objectives such as addressing local reliability concerns or encouraging types of resources that are preferred based on environmental or other characteristics. RPM, as a capacity spot market, does not recognize the value of these characteristics.

B. Summary of Recommendations on Specific MOPR Provisions

26. While I see no need to change the MOPR under the hasty schedule requested by PJM, recognizing that the Commission may approve changes at this time, I discuss its provisions and PJM's proposed changes to them in some detail in my affidavit, and provide recommendations. My primary recommendations can be summarized as follows:

- The purpose of the MOPR should continue to be to mitigate potential exercise of buyer market power and should not be changed to “preventing uneconomically low offers” from new entry generation;
- Because Net CONE is a very imperfect proxy for a competitive offer price, the offer screen and substitute price should reflect a substantial discount off the nominal values;
- Market participants should be afforded the opportunity to justify unit-specific offer prices through a Net CONE or Net Present Value analysis reflecting a sponsor's forecasts of all revenues, including capacity revenues or revenues under

a bilateral contract; unit-specific incremental costs; and incentives offered for preferred resource attributes;

- Mitigation should apply for one year unless a resource is being used in an attempt to suppress capacity market prices;
- Real, not nominal, levelization of CONE is appropriate for the MOPR;
- The “net buyer” and impact tests in the current MOPR should be retained but improved;
- The exemption for state-mandated resources should be retained but improved.

27. The remainder of this affidavit is organized as follows. The next section explains why there is no urgent need to change the generic MOPR rule at this time. Section IV discusses the proposed criterion for judging and mitigating “economically low” offers from new generation and provides recommendations in regard to MOPR screens and mitigation. Section V comments on and provides recommendations in regard to various other proposed changes to the MOPR.

III. There Is No Urgent Need to Change the MOPR Rule

28. PJM and P3 ask the Commission to implement multiple, complex changes to PJM’s RPM capacity construct on a very hasty schedule. However, there does not appear to be a need to implement any changes to the MOPR on such an urgent basis. On the other hand, the potential for harm if the proposed changes are implemented is substantial.

29. As noted in the Summary of this affidavit, the only immediate issue that has led to the P3 and PJM filings is the potential impact of state actions in New Jersey and Maryland to help get new generation built in those states. New Jersey Rate Counsel’s Protest, and the affidavit of Robert M. Fagan, describe New Jersey’s initiative and the reasons for it. One entity that might receive support to build a new power plant through the New Jersey initiative, West Deptford Energy, L.L.C. (“WDE”), has already filed with the Commission a request for approval of a unit-specific offer price,⁷ and it can be expected that any other similarly situated entities would likely do the same if they deem necessary. I expect other parties will provide information

⁷ Request of West Deptford Energy, LLC for Commission Determination that its Unit-Specific Minimum Capacity Sell Offer is Justified Pursuant to PJM’s Minimum Offer Price Rule, and Requests For Protection of Confidential Bid-Related Information and Expedited Treatment, West Deptford Energy, LLC, Docket No. ER11-2936-000 (Feb. 22, 2011) (“WDE Filing”).

on the process underway in Maryland, which could also lead to filings before the Commission. Because the issues that have been raised have already been put before the Commission (and the proposed rules would also result in these issues going before the Commission), there does not appear to be an urgent need to modify PJM's generic rules for addressing potential attempts by capacity buyers to suppress capacity prices.

30. As P3's witness Dr. Roy Shanker notes, load-serving entities in PJM are unlikely to be in a position to find exercise of buyer market power attractive on their own.⁸ This is especially true for the upcoming auction, because, due to transmission enhancements and lower demand, only a few very small Locational Deliverability Areas ("LDAs") are likely to have prices separate from the large MAAC LDA's price in this auction. This means that most PJM load-serving entities will be buying capacity in a large, multi-state market area, and the benefits of any price suppression they might be able to cause would be shared with many other buyers, making it unlikely to be profitable.

31. Specifically, it is unlikely that the Southwest MAAC or Eastern MAAC zones will separate from the larger MAAC zone in this auction. In both zones the peak load forecast and Reliability Requirements have declined while the transmission capacity available to import capacity into the zones (the Capacity Emergency Transfer Limit, or "CETL")⁹ has increased. As a result of these changes, the amount of capacity PJM will attempt to acquire in this auction has declined, relative to the last auction, by 1,535 MW in SWMAAC and 1,497 MW in EMAAC.¹⁰ SWMAAC did not have a separate price in the last auction, and PJM's sensitivity analyses based on the 2013/2014 base residual auction showed that just 400 MW of additional supply in the PS North zone would have eliminated any price differential between EMAAC and MAAC in that auction.¹¹ Thus, it is unlikely there will be a price differential between either of these zones and MAAC unless there are substantial retirements.

⁸ Shanker testimony, pp 13-15.

⁹ The Capacity Emergency Transfer Limit ("CETL") values determine the amount of an LDA's reliability requirement that can be satisfied with resources located outside the LDA.

¹⁰ PJM, 2013/2014 RPM Base Residual Auction Planning Period Parameters, and PJM, 2014/2015 RPM Base Residual Auction Planning Period Parameters.

¹¹ PJM, Scenario Analysis Results, Scenario 16.

32. These changes also mean that the IMM's estimates of the potential impact of new generation on RPM prices and costs (which have been interpreted as suggesting that New Jersey and Maryland have strong incentives to attempt to suppress capacity prices) are outdated and overstated.¹² The IMM's analyses were based on the results of the 2013/2014 base residual auction and did not take into account the changes in peak load forecast and transmission capacity for the upcoming auction. In addition to the reduced demand for capacity in the SWMAAC and EMAAC zones noted above, the demand for capacity in the broader MAAC zone has also declined, by 2,189 MW (again, summing the decrease in the MAAC Reliability Requirement and the increase in CETL). These declines will have a moderating impact on prices, and potential price impacts, in the upcoming auction.

33. The IMM analysis also estimated that of the total impact of new generation on capacity costs, three-quarters occurs outside New Jersey (in Delaware, Pennsylvania, Maryland, and the District of Columbia, primarily), and only about one quarter occurs in New Jersey.¹³ The New Jersey fraction is likely to be even smaller for the next auction due to the moderated capacity demand and the fact that EMAAC is unlikely to have a separate price. As the Commission has recognized, the incentive for a state to attempt to suppress capacity prices is reduced in a multi-state RTO such as PJM due to the dispersion of the potential benefits of any such attempt across a multi-state area.¹⁴

34. Furthermore, the IMM report estimated the impacts of 1,000 MW or 2,000 MW of additional new capacity in New Jersey. However, as the auction date nears, it appears increasingly unlikely that even 1,000 MW of new capacity may result from the New Jersey initiative. The one resource that has applied to the Commission for a unit-specific offer price, WDE, is proposing a unit that would provide 620.8 MW of unforced capacity, less than 2/3 of the 1,000 MW evaluated in the IMM report.¹⁵

¹² Monitoring Analytics, Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market, January 6, 2011; and Monitoring Analytics, Impact of Maryland PSC's Proposed RFP on the PJM Capacity Market, January 28, 2011.

¹³ Comparing the revenue impacts for New Jersey from tables 4 and 8 to the overall impacts for PJM from tables 2 and 6.

¹⁴ *New York Independent System Operator, Inc.*, 124 FERC ¶ 61,301, (2008) P 37.

¹⁵ WDE Filing, p. 1 (installed capacity of 650 MW) and Attachment A, Joint Affidavit, p. 28 (EFORd of 4.49%).

35. While the need to change the MOPR rule is doubtful, the potential harm from the proposed changes is substantial. PJM proposes to screen and mitigate all offers from new gas-fired generation. With the recently growing abundance of natural gas due to new shale gas supplies and new environmental regulations affecting coal generation, natural gas is likely to remain the fuel of choice for major new power plants in the PJM region. The proposed mitigation would create considerable uncertainty and risk for the developer of a new gas-fired plant. Even if recent and forecast energy, ancillary services, and capacity prices suggest that a plant is needed, and the sponsor is able to arrange a bilateral contract to provide adequate revenue assurance to finance the project, under PJM's proposed rules there would remain considerable risk that the project would not receive a capacity supply obligation and capacity payment for one or more years. RPM prices in LDAs are quite volatile from year to year, primarily due to changes to load forecasts and CETL values¹⁶ (changes in market rules and offered generation and demand response also contribute to volatility), and this volatility could cause a new plant to fail to clear if it is forced to offer at the Net CONE-based price levels PJM proposes to impose. Under PJM's proposal, even if market conditions suggest a need for a plant at one time, there will always be risk that market conditions will change and the mitigation will result in the plant failing to clear, at no fault of its own.

36. The issues of concern are already before the Commission, the potential impacts of the New Jersey and Maryland initiatives in the upcoming auction, if any, are likely to be much less than suggested by earlier estimates, and the potential harm from the proposals is substantial. Consequently, the Commission should decline to approve changes to the MOPR's generic provisions on an emergency basis. Nevertheless, recognizing that the Commission may approve some changes, the following sections of this affidavit comment on and make recommendations regarding the various elements of the MOPR rule and PJM's proposed changes to them.

¹⁶ Recently, CETL values have changed substantially from year to year, sometimes for reasons that have to do with changes to modeling assumptions that would be difficult to predict. From the 2012/2013 to the 2013/2014 base residual auction, PJM reduced the CETLs for MAAC and EMAAC by 1,917 and 1,984 MW respectively. PJM reported that the reduction to the MAAC CETL was primarily due to a change to the "load distribution in the system model" in the Northern Virginia region. For EMAAC, the decrease was due to the removal of the Susquehanna-Roseland transmission project. For the 2014/2015 delivery year, PJM increased the CETLs for MAAC and EMAAC by 1,234 and 1,094 MW respectively. PJM reported that the increase for MAAC was due to the addition of a substation and transformer to off-load a facility that was limiting the CETL for 2013/2014. The increase for EMAAC resulted from a reduction in the size of a merchant transmission project and another change in the load distribution in the system model that off-loaded a limiting facility.

IV. PJM's Proposal to Mitigate "Uneconomically Low" Offers from New Generation

37. As noted in the Summary, while the MOPR provision was designed to mitigate the potential for exercise of buyer market power, PJM proposes to fundamentally change the MOPR's purpose to preventing "uneconomically low" offers from all new generation without consideration of whether an offer might represent an attempt to suppress capacity prices. I strongly recommend against this change to the MOPR's purpose, for the reasons described in the Summary and further supported throughout this affidavit. However, recognizing that the Commission may accept this proposed change to the MOPR's purpose, in the final sections of my affidavit I comment on and recommend changes to PJM's proposals recognizing that the Commission may accept this change to the purpose of the MOPR.

38. The most critical element of market rules designed to mitigate low-priced offers is the criterion used to determine whether mitigation will be applied and to set the replacement offer price that will be imposed in such instances. Under PJM's proposal such a criterion is applied in three ways: 1) as the initial screen used to identify offers deemed "uneconomically low"; 2) as the basis for the substitute offer price to be imposed when offers fail the screen; and 3) as the criterion to be applied in evaluating project-specific justifications of offer prices. Under PJM's proposal, a calculation based on the Net CONE concept (discussed further below) would be used in all three applications.

39. Specifically, PJM proposes to screen offer prices by comparing them to 90% of the asset class (CC or CT) reference unit's Net CONE by CONE Area, or 70% of the reference CT's Net CONE by CONE Area for other types of resources. Proposed Tariff Att. DD, Section 5.14(h)(4). Offers that fail the screen would be mitigated to the same applicable screen level (proposed Tariff Att. DD, Section 5.14(h)(4)) unless the sponsor has received a determination from the Commission allowing a different offer level. PJM proposes that unless the sponsor receives an exemption based on a state-mandated requirement, the determination from the Commission must find that the proposed offer price is permissible because it is "consistent with the competitive, cost-based, fixed, nominal levelized, net cost of new entry were the resource to rely solely on revenues from PJM administered markets (i.e., were all output from the unit sold in PJM-administered spot markets, and the resource received no out-of-market payments)." Proposed Tariff Att. DD, Section 5.14(h)(5). That is, the tariff language appears to require that

the Commission's determination apply the same Net CONE-based approach as reflected in the screens.

40. This section of my affidavit explains several ways the proposed screens and mitigation based on Net CONE preclude competitive offer prices from new generation. The current MOPR applies the same approach, however, it includes features such as the "net buyer" and impact tests that ensure the mitigation would be applied only when the circumstances are consistent with the possibility of an exercise of market power and, therefore, infrequently. Consequently, the flaws in this approach to screening and mitigation are relatively benign under the current rules. However, under PJM's proposal to mitigate a much broader class of offers that fail the screen without regard to whether an attempt to exercise market power may be involved, the flaws in the Net CONE concept would result in mitigated offer prices well above competitive levels under common circumstances, creating a substantial barrier to entry. This section comments on the proposed Net CONE-based screens and recommends changes to the screens and also to the criteria to be applied in evaluating project-specific offers.

A. Screening and Mitigating Offers Based on the Net CONE Concept Precludes Competitive Offers From Economic New Generation

41. Under the Net CONE concept, costs are levelized, to place them on an annual basis, and a proxy for long-run average net energy and ancillary services ("E&AS") revenues is netted from this cost. The difference ("Net CONE") is then assumed to represent a competitive offer for new generation into RPM, while a lower value (below a 10% discount off Net CONE, to reflect uncertainty about its calculation) is considered below the competitive level and uneconomically low.

42. To see the shortcomings of Net CONE as a proxy or estimate of a competitive offer price it is necessary to return to first principles.¹⁷ In competitive markets, sellers acting competitively price their output based on marginal or incremental cost; if price exceeds this level, they make a sale and at least some profit, but if price is below this level, sale of an extra unit would be uneconomic because the additional cost incurred would exceed the price. For existing plants, this competitive price level for capacity is the "avoidable cost" level to which

¹⁷ A further discussion of these issues is in Wilson, James F., *Forward Capacity Market CONEfusion*, The Electricity Journal Vol. 23 Issue 9, November 2010.

offers are mitigated, and does not reflect plant construction costs which are no longer incremental (they are “sunk costs” for existing plants). For new plants not yet under construction or contracted, all of the construction cost (CONE) is presumably incremental.

43. Applying the same fundamental principle (that a competitive offer price equals incremental cost) in the case of a new plant, the sponsor should be willing to build if its expected stream of energy, ancillary services, capacity, and any other revenues over the life of the project exceeds the present value of all of the anticipated costs to build and operate the plant (of course, risk must also be considered and can be treated as an additional cost). If present value revenues fall short of present value cost, the sponsor would need to find an additional source of revenue equal to the present value difference, or to reduce cost by the same amount, for the project to be economic. If present value revenues are expected to exceed present value cost, the sponsor believes the project is economic and will plan to proceed with construction.

44. The Net CONE calculation deviates from this fundamental economic concept in two significant ways. First, it is a levelized or annual value rather than a present value. Second, future capacity revenues are excluded from the calculation. These characteristics cause a screen based on the Net CONE calculation to be a flawed indicator of a competitive offer price under common circumstances.

45. To see the flaws in the Net CONE approach, consider a simple example of a sponsor who believes present value E&AS revenues will be \$720/MW over the life of the plant, capacity payments will be \$300/MW, and present value cost will be \$1,200/MW. Cost exceeds revenue and the plant is not economic; additional revenue equivalent to present value \$180/MW over the life of the plant ($\$1,200 - \$720 - \$300$) would be needed to make the plant profitable to build. Under the financial assumptions used in PJM’s Net CONE calculation, levelized (annual) values are about 1/6 of present values,¹⁸ so the corresponding levelized values are \$200/MW-year for CONE, \$120/MW-year for E&AS, and \$50/MW-year for capacity payments, so the shortfall on an annualized basis is \$30/MW-year.

46. Net CONE under this example is \$80/MW-year ($\$200/\text{MW-year CONE} - \$120/\text{MW-year E\&AS}$) because the Net CONE calculation does not include future capacity

¹⁸ PJM Filing, Attachment C (Cost of New Entry Combined Cycle Power Plant Revenue Requirements for PJM Interconnection, L.L.C.), Table 1, p.6.

revenues. Under the Net CONE concept, the sponsor's economic offer price is considered to be Net CONE, or \$80/MW-year. However, suppose the sponsor offers the resource at this price into the first RPM base residual auction and it clears at this price, but the sponsor's expectations of future costs and revenues, including future capacity payments (\$50/MW-year), prove correct. Despite clearing in the first auction, the project would lose present value \$150/MW over the life of the project, because it would receive \$30/MW-year less than it needs to break even in capacity payments in all years but the first year (so the loss is the \$180/MW present value shortfall minus the \$30/MW above expectations received for capacity in the first year). Given the sponsor's expectations in this simple example, the economically rational offer price into the first auction (the price needed for the project to break even over the life of the plant, given the sponsor's expectations), is \$230/MW-year (the expected capacity payment, \$50/MW-year, plus the entire present value shortfall, \$180/MW). In this example the Net CONE value is not the economic or competitive offer price for this project given the sponsor's expectations.

47. Suppose instead the sponsor's forecast of capacity revenues is present value \$540/MW, or \$90/MW-year. The sponsor now expects the project to be profitable on the basis of the present value over the life of project (\$720/MW E&AS plus \$540/MW capacity exceeds \$1,200/MW CONE). The Net CONE calculation is unchanged and still suggests the "competitive" offer price should be \$80/MW-year. However, under these expectations, the project breaks even over its lifetime as long as it receives at least \$30/MW-year in the first capacity auction (the expectation was for present value \$720/MW E&AS + \$540/MW capacity = \$1,260/MW, and if the first capacity payment is \$30/MW-year, rather than the expected \$90/MW-year, total revenue still equals CONE). Under these expectations the rational offer price in the first auction is \$30/MW-year (assuming this exceeds any net going forward or opportunity cost). In this example, Net CONE again is not the sponsor's competitive offer price and in this case Net CONE is considerably higher than the sponsor's competitive offer price.

48. These examples illustrate that the Net CONE concept fails to accommodate a project sponsor's expectations of future total revenues including capacity revenues. And because it focuses on levelized (annualized) rather than present values and excludes expectations of future capacity revenues, the Net CONE calculation does not accurately estimate an economic or break-even offer price level for a project's first RPM auction, which may be much higher or lower. The Net CONE calculation can be understood to impose the assumption that whatever

capacity price is received in the first auction will also be received in all future auctions over the life of the plant, as if RPM offered a long-term commitment, which it does not. The Net CONE calculation can be understood to estimate the long-run average capacity price a facility would need, under the assumed CONE and E&AS values, to break even. But this is an answer to the wrong question. The first auction will only determine the capacity price for the first year of operation, and a new entrant acting competitively will formulate an offer price taking this into account.

B. Market Participants Should Be Permitted to Justify Offer Prices Based on a Net Present Value Analysis

49. These flaws in the Net CONE approach have two implications for mitigation under the MOPR. First, these flaws, in addition to the substantial uncertainty about CONE and E&AS values, suggest that the screens and mitigation should be set at levels well under 100% of the nominal Net CONE values (this is discussed further below). In addition, market participants should be permitted to justify their offer prices based on a net present value (“NPV”) calculation as an alternative to the Net CONE calculation. While it may not be practical or entail too much discretion to allow market participants to justify their offer prices based on a project-specific net present value calculation to PJM or the IMM, they should at least be permitted to do so in applying to the Commission for approval of a project-specific offer price.

50. In its simplest form, the only differences in a net present value analysis would be that CONE, E&AS and Net CONE are expressed in present value terms, and expectations of future capacity revenues may also be reflected. The economic offer price for the project’s first RPM auction would be the difference between the present value of all costs and the present value of all anticipated energy, ancillary services, capacity and other revenues (excluding only the capacity revenues from the first auction), as suggested by the above examples.

51. Allowing a present value analysis accommodates demonstrating competitive offer prices that cannot be demonstrated under the Net CONE approach. For example, suppose a sponsor anticipates that PJM will soon implement shortage pricing rules that will cause E&AS revenues to increase, and also expects that these higher E&AS revenues will not be reflected in RPM parameters and clearing prices until a lag of several years has passed; such expectations

would be consistent with PJM's proposal for shortage pricing that is currently before the Commission.¹⁹ Thus, while RPM prices are supposed to adjust over time to the level of E&AS revenues, the sponsor may expect that over several years the sum of E&AS and capacity prices will be elevated. These expectations can easily be quantified in a present value analysis to determine the present value impact on a project's economics, but the Net CONE calculation does not accommodate any forecast of future capacity prices or their relationship to E&AS revenues.

52. As another example, a sponsor may expect that power plant construction costs will continue to rise while E&AS revenues will lag behind, resulting in increasing Net CONE values in future years and, accordingly, increasing RPM capacity prices. If so, the sponsor will expect future capacity prices to exceed his Net CONE value, and his facility to be very profitable over its period of operation, as long as the facility can be built under current construction costs. These expectations could justify a competitive offer well below the current Net CONE, which could be demonstrated only through a net present value analysis.

C. Market Participants Should Be Permitted to Justify Offer Prices Based on Their Project-Specific Incremental Costs and Revenues

53. Another shortcoming of the proposed approach to screening and mitigating new entry offers is that the calculations assume the entire construction cost for a resource is incremental cost. In essence, the screen is based on the assumption that a decision to build the unit has not yet been made, there are as yet no "sunk" costs or other commitments, and the sponsors can walk away from the project at little or no cost. This is of course not always the case.

54. As noted above, a competitive offer price is based on incremental cost. For existing resources, construction costs are no longer incremental and it is recognized that a competitive offer price is based on incremental or avoidable cost. New plants may also have costs that are already sunk and no longer incremental, and the sponsor would not include these costs in formulating a competitive offer price. A Net CONE or NPV calculation that assumes all costs are incremental will determine a minimum offer price above the competitive level if in fact substantial costs are no longer incremental. If a project has sunk costs, but it is forced to offer

¹⁹ PJM Interconnection, L.L.C. Compliance Filing filed June 18, 2010 in docket no. ER09-1063-004 (to establish pricing for operating reserve shortages).

into RPM at a higher price that fails to recognize the sunk costs, it is being forced to offer at a price above true incremental cost, and this could cause it to lose out on an economical capacity supply obligation that provides some fixed cost recovery, an inefficient result. Therefore, in presenting plant-specific costs and revenue expectations to justify RPM offer prices, a sponsor should be permitted to demonstrate that some costs are sunk and, therefore, should not be included in the calculation of a competitive offer price. Costs are sunk if they are already spent, or contractually committed to be spent, and not realistically recoverable or salvageable or only with substantial loss.

55. The above discussion describes how a competitive offer price is determined, given the actual status of a project, which may reflect some sunk costs or contractual commitments. However, if there are already sunk costs or contractual commitments to build, it is also appropriate to question whether the earlier decision to build or contract the unit (when all costs were incremental) appears to have been economic or not. If the decision to build the new unit appears to have been uneconomic (that is, the plant's potential revenues over the life of the plant do not appear to justify its cost), then it raises the further question of whether the decision to build or contract the plant was an exercise of market power to suppress capacity prices.

56. If the decision to build the plant (treating all costs as incremental) appears uneconomic, but there is no basis for finding the decision to be an exercise of market power (the sponsor lacks incentive, the potential impact on price is small, etc.) then it would not be appropriate to mitigate the plant to a price level that ignores sunk costs or contractual commitments. In markets, bad decisions are punished in the marketplace, and mitigation would inappropriately make an apparently bad situation worse for the sponsor. Nor is there any basis for mitigating the offer in order to hold other sellers harmless, at consumers' expense, for one seller's bad decision (if that is what it is). If the sponsors or other entities that caused the plant to be built made what may appear to others to be a bad decision but no inappropriate intent was involved, the sponsors should be allowed to make the best of the situation by offering the unit into markets at cost-based, competitive prices that reflect their actual incremental cost excluding sunk costs. Similarly, if a plant has arranged revenues under a bilateral contract, or receives incentives under a state program, these payments change the plant's competitive offer price, and this should be recognized unless the contract or incentive represents an attempt to suppress capacity prices.

57. On the other hand, if the decision to build, contract, or offer an incentive represented an attempt to suppress capacity prices, the project should be mitigated to deter such actions, and imposing a price above the level that represents a competitive offer (given the status of the plant) could be warranted. This is of course an inefficient result but warranted if (and only if) the plant represents an exercise of market power.

D. PJM's Proposal to Constrain How the Commission Would Evaluate Project-Specific Offer Prices Should Be Rejected

58. PJM recognizes that a project sponsor should be permitted to demonstrate that its project's cost or revenue expectations differ from those reflected in the Net CONE calculations (p. 14).

Indeed, in many cases, since the MOPR screen is only a screen, capacity market sellers may offer a perfectly adequate explanation why their new entry offer is significantly below the Net Asset Class Cost of New Entry. A seller's specific project may legitimately have lower fixed costs, or higher reasonable revenue expectations (or a combination of both) relative to PJM's generic determination of the net costs for the particular asset class.

59. However, the proposed tariff language attempts to dictate that the Commission must judge offers in a way that would preclude justifying competitive offers under common circumstances.

(5) A Sell Offer meeting the criteria in subsection (4) shall be permitted if the Capacity Market Seller ... obtains a determination from FERC prior to such auction, that such Sell Offer is permissible because it is either (A) **consistent with the competitive, cost-based, fixed, nominal levelized, net cost of new entry were the resource to rely solely on revenues from PJM administered markets (i.e., were all output from the unit sold in PJM-administered spot markets, and the resource received no out-of-market payments)**; or (B) the Sell Offer is based on new entry that is pursuant to a state-mandated requirement ... (proposed Tariff Att. DD, Section 5.14(h)(5), emphasis added)

60. This proposed tariff language attempts to force the Commission to apply this specific analytical approach, which I have explained is flawed and precludes competitive offer prices. In supporting its offer price, a sponsor should be permitted to present any of the following:

- A specific forecast of net energy, ancillary services, and capacity revenues over the life of the project;
- Long-term revenues provided under a bilateral contract;

- Incentives in recognition of preferred resource attributes that are not valued in RPM;
- Incremental costs that exclude sunk costs (costs already spent or committed);
- A net present value comparison of total anticipated net revenues from all sources (including capacity payments) over the life of the project compared to present value costs;
- A net present value or Net CONE calculation based on incremental costs excluding any sunk costs.

61. Unless these factors are considered in the evaluation of a project-specific offer price, competitive offers will be disallowed, an inefficient result. Again, as noted above, if the project was originated with the intent to suppress capacity market prices, it may be appropriate to mitigate it without consideration of its contracts, incentives, or sunk costs, despite the fact that this imposes an offer price level that is above the economically efficient, competitive level given the status of the plant and sponsor's expectations.

E. Mitigation Should Apply For One Year Unless a Resource Is Found to Represent an Attempt to Exercise Buyer Market Power

62. Under the current MOPR a new resource is mitigated in the first year for which it qualifies to offer into RPM. In subsequent years, the resource is no longer new and is mitigated in the same manner as other existing resources. PJM proposes to change this aspect of the rule to impose mitigation for additional years. Specifically, PJM proposes to impose mitigation until the resource, despite mitigation, clears, and to mitigate for two additional years beyond that. Proposed Tariff Att. DD, Section 5.14(h)(4).

63. If a resource has been developed and is being offered into RPM in an attempt to suppress capacity prices, it is appropriate to mitigate the resource for multiple years as it would suppress capacity market prices for multiple years. However, if the MOPR's purpose changes to mitigating offers deemed uneconomically low, and, therefore, the MOPR will mitigate resources that are not being used to suppress capacity prices, the duration of mitigation should be limited to one year. Under PJM's proposal, a resource that is not being used to exercise market power could be prevented from clearing and receiving a capacity supply obligation for several years. For instance, if other entry, or new transmission facilities, lower RPM clearing prices below the offer price floor imposed on the resource, it could fail to clear even though the clearing prices exceed the resource's going forward cost and it is economic. This is plainly unacceptable and a

serious barrier to entry, as it would impose substantial risk on future projects due to the unpredictability of market conditions and RPM clearing prices. It would also be unfair to resources that may at present be in an advanced stage of development under the current rules. However, if unit-specific offer prices can be justified as I have recommended (reflecting actual incremental costs and anticipated revenues in a net present value analysis), the impact of imposing mitigation for multiple years might be relatively benign.

64. Once a resource clears in RPM, it is likely that by the following year, it will be under construction with a substantial amount of its construction cost already invested or committed. As discussed in an earlier subsection, competitive offer prices take into account only those costs that are incremental, not sunk costs. If the sponsors of a resource made what appears to be a bad decision (the resource appears uneconomic according to the screens), but no inappropriate intent was involved, the sponsors should be allowed to make the best of their situation by offering the unit into markets at cost-based, competitive prices that reflect their actual incremental cost excluding sunk costs. Mitigation would not be justified and would inappropriately impose additional cost and risk on the sponsors.

65. While the presence of the resource will, like any resource, tend to lower capacity prices, this is not inappropriate as long as the resource was not built with the goal of price suppression. There is no basis for attempting to undo the impact of such a resource on capacity clearing prices under these circumstances.

66. The current MOPR duration, one year, should be retained as the default. PJM, the IMM, or any market participant could file under FPA section 206 to have mitigation extended for any resource they feel ought to be mitigated longer.

F. A Larger Discount From the Net CONE Values Should Be Used to Reflect Uncertainty About the Parameters and the Shortcomings in the Net CONE Approach

67. As described earlier, the levelized Net CONE calculation is a flawed estimate of a competitive offer price. In addition, it must also be recognized that the CONE and E&AS inputs to the calculation are highly uncertain. For these reasons, basing the screens and mitigation on a high percentage of the nominal Net CONE values (PJM proposes 90%) would preclude many

competitive offers. Larger discounts off the nominal values should be considered. For the New York ISO the Commission has accepted 75%.²⁰

68. Plant construction and other costs will vary considerably from project to project, as will the sponsors' reasonable expectations of revenue opportunities. An example of the many ways a project's costs and revenues can differ from those assumed for the reference unit is seen in the recent WDE Filing, cited above. While costs may vary, expectations of future energy, ancillary services and capacity revenues are likely to be even more varied. In competitive markets, the entrants are likely to be those participants with the most favorable views of future market conditions and/or various cost advantages, and by taking risks based on their expectations they stand to be rewarded or punished in the marketplace. Unless there is evidence of exercise of market power, participants should be entitled to reflect their reasonable expectations of future energy, ancillary services and also capacity revenues in justifying offer prices into RPM.

69. PJM suggests (p. 2) that the thresholds in the MOPR are intended to "identify a lower bound on a reasonable new entry offer." PJM justifies the proposed 90% threshold under what could be considered a "10% rule", citing FERC precedent for 10% adders or discounts.²¹ However, PJM proposes to apply the 10% to Net CONE, which is a difference between two highly variable and uncertain values, CONE and the E&AS offset. If the goal is to recognize uncertainty in the estimation of these values, the 10% rule should be applied to gross CONE and the E&AS offset values separately. Applying the 10% rule to Net CONE implicitly assumes the uncertainty and variability in the CONE and E&AS calculations are 100% correlated, which is implausible.

70. Applying the 10% rule only to gross CONE, with no adjustment to E&AS, suggests setting the threshold at 83% to 87% for CTs and even lower values (50% to 82%) for CCs, based on the values in the PJM Filing, Attachment D.²² Recognizing the additional uncertainty in the E&AS value by applying a 10% increase would suggest even lower thresholds;

²⁰ *New York Independent System Operator, Inc.*, 124 FERC ¶ 61,301, (2008) P 32.

²¹ PJM Filing, p. 12 ("Tolerating a ten percent downward tolerance from estimated costs also is consistent with the Commission's long-standing acceptance of ten percent adders to costs as just and reasonable... In a similar vein, the Commission accepted a ten percent reduction to a PJM estimate as being within the zone of reasonableness.")

²² PJM Filing, Attachment D, 2011 MOPR Screen for Combined Cycle Power Plant and 2011 MOPR Screen for Combustion Turbine Power Plant, comparing the Net CONE values to those values calculated after reducing CONE ten percent.

in the 75% to 85% range for CTs and much lower for CCs. Based on these observations, one conservative approach would be to set the threshold to the Net CONE ratio resulting from the 10% rule applied to CONE, or 80%, whichever is greater. Such thresholds would still be higher than a “lower bound on a reasonable new entry offer” under many common circumstances.

G. A Single Screen and Minimum Offer Price Should Apply In Each LDA

71. PJM proposes to screen and set minimum offer prices based on asset class, by LDA. However, it makes little sense to set different offer floor prices for different types of resources that are competing in the same market based solely on the relative parameters of the Net CONE calculation. The difference in the CC and CT Net CONE values primarily reflect differences in the historical average energy and ancillary services prices, and these differences are unlikely to be consistent with market participants’ expectations of future revenue opportunities. Minimum offer prices that differ by asset class arbitrarily determine which type of resource will be allowed to underbid the other.

72. Similarly, to provide a level playing field for resources within an LDA that might span more than one CONE area (such as MAAC), the applicable floor price for all mitigated resources for the purpose of clearing the LDA should be the lowest applicable floor price of the CONE areas partly or wholly within the LDA. It makes little sense to allow resources in SWMAAC to offer at lower prices than similar resources in EMAAC when both are competing in the MAAC zone. Again, the differences in the Net CONE calculations by CONE area will primarily reflect differences in the historical E&AS values, which may not be consistent with expectations about these differences in future years (especially considering that high E&AS revenues typically reflect transmission constraints, which lead to transmission enhancements to resolve the constraints, which will moderate the E&AS prices). This means that a resource might fail to clear in EMAAC but then clear in MAAC due to a lower applicable minimum offer price.

H. The Proposed Increases in Gross CONE Should Be Rejected

73. PJM also proposes some clarifications to the MOPR regarding CONE and Net CONE, and substantial increases to the CONE values applicable to the MOPR. While the clarification that the MOPR should use net rather than gross CONE values is appropriate, the

increases in the CC CONE values should be rejected. These values can be increased, if appropriate, through the normal CONE update process, so it is not necessary to make these changes on an emergency basis. The proposed increases in the CC CONE values should be rejected because they are based on outdated information – in particular, they do not reflect recent declining turbine prices, as noted in the affidavit attached to the recent WDE filing.²³

I. Real (Not Nominal) Levelization of CONE is Appropriate for the MOPR

74. The PJM Filing proposes to change the levelization approach for placing the cost of new entry and corresponding revenue requirement on an annual basis, as required for the Net CONE calculation. This change would increase the first year gross CONE values by 17%, and it has a much larger percentage impact on Net CONE values. The proposed Net CONE values to be used in the MOPR shown in Attachment D to the PJM Filing are higher by 23% to over 100% due to the nominal levelization assumption.²⁴

75. The PJM Filing does not provide an accurate or clear interpretation of the significance or implications of the levelization assumption (and this issue exists only due to the conceptual flaws of the Net CONE approach; there is no such issue in a net present value analysis). PJM refers to the current use of a real levelized revenue requirement for the MOPR as a “downward reduction” and suggests that it results in offers below cost (p. 8):

If a project’s power sales agreement and financing are based on a nominal levelized approach, then offering the plant into RPM at only a real levelized first-year price would be in effect offering below the project’s claimed costs.

76. This claim is misleading. As PJM notes, both approaches to levelizing gross CONE result in the same present value stream of revenue requirements. Whether real or nominal levelization is appropriate has to do not with the financing arrangement, but with the sponsor’s expectations about how energy, ancillary services and capacity revenues will change over time, because in principle, the plant hopes to recover through RPM its cost *net* of energy and ancillary services revenues.

²³ WDE Filing, Joint Affidavit of Joseph R. Esteves et al, public version, p. 11.

²⁴ Comparing the Net CONE values shown in Attachment D to the values that would result from using the real levelization assumption (without the 17% CONE increase). The impact varies depending upon the size of the E&AS offset.

77. Within the CONE estimate, costs are assumed to escalate at 2.5% per year, essentially an assumed level of inflation. It would seem reasonable for a project sponsor to assume that net energy, ancillary services, and capacity revenues are also likely to escalate at 2.5% per year (of course, some sponsors may expect these revenues to escalate at a somewhat higher or lower rate over time). Using the real levelization approach, annual revenue requirements are calculated that also reflect this assumed rate of inflation. As a result, net energy and ancillary services revenues represent a constant fraction of the revenue requirement over time, and the assumed necessary capacity payment (Net CONE, the difference between the CONE-based revenue requirement and the assumed E&AS revenues) also rises at the rate of inflation and represents a constant fraction of the revenue requirement over time. This would seem to be a sensible approach to estimating the required capacity payments over the life of the project, including in the first year, as the Net CONE approach is intended to do.

78. Under the nominal levelization approach, the revenue requirement is calculated to be a constant value (in nominal terms) over the 20 year life of the plant. In real (inflation-adjusted) terms, under this assumption the revenue requirement is highest in the first year and shrinks at the rate of inflation over time, so in year 20 it is just 63% of the original value. If net energy and ancillary services revenues increase at the rate of inflation over time, the necessary capacity payment (Net CONE, the difference between the constant revenue requirement and the increasing E&AS revenue) declines over time in nominal terms, and declines even more sharply in real, or inflation-adjusted terms. Thus, the first year Net CONE value would greatly overstate the capacity price needed by the plant for it to be economic.

79. As a specific example, consider the parameters for the combined cycle unit in CONE Area 2, from Attachment D to the PJM Filing. PJM's gross CONE value is \$424.30/MW-day and E&AS is \$339.45/MW-day, resulting in Net CONE of \$84.85/MW-day, all values in installed capacity ("ICAP") terms. These values are based on the proposed nominal levelization approach. Under these assumptions, while Net CONE is \$84.85/MW-day in the first year, if E&AS revenues simply increase with inflation Net CONE declines to under \$50/MW-day in year 5 and to zero by year 11; during the second ten years of the assumed project life, E&AS revenues exceed the revenue requirement by amounts that increase each year. If capacity payments are assumed to equal Net CONE the first year and then rise by the rate of inflation over time (a reasonable assumption), the plant will fully recover the revenue requirement in ten years

and over-recover the revenue requirement by 17% (present valuing using the assumed 12% interest rate) over 20 years. Even if capacity prices merely remain constant at the Net CONE level of \$84.85/MW-day over time (so declining in real terms), the plant will fully recover the revenue requirement in 11 years and over-recover its revenue requirement by 14% over 20 years.

80. While some entrants may choose to adopt highly conservative assumptions about future E&AS and capacity market revenues, such assumptions should not be the default values used in a screen for “uneconomically low” offers intended to identify a reasonable lower bound on a competitive offer price. PJM’s proposal to switch to a nominal levelization of the gross CONE values for the purpose of the MOPR should be rejected.

81. PJM also attempts to justify use of the higher CONE value that results from nominal levelization by suggesting that entrants have market power and should attempt to exercise it to raise capacity prices (p. 8).

But even if otherwise consistent with the project’s agreements, an RPM bidding strategy that assumes the project will be able to claim a higher price in future years, after it is no longer a new entry unit, would be subject to question. Generally speaking, a new-entry unit will have the greatest leverage in an RPM auction, and therefore can command the highest price, when its entire investment is avoidable, i.e., before the plant is built and its costs become sunk. A seller legitimately concerned with recovering its project’s costs over time through RPM therefore would be expected to offer its plant at the highest permissible first-year price, i.e., that produced by the nominal levelized approach.

82. This justification should be rejected. The MOPR screen should not be designed on the assumption that entrants have market power and “leverage” in the capacity market and should be attempting to offer at the “highest permissible first-year price” in order to “command the highest price”, and, therefore, to instead offer at a cost-based, competitive price would be “uneconomically low” and should be mitigated.

83. PJM recognizes that it can be appropriate to formulate an offer price based on real levelized cost (p. 8).

This is not to say that such a bidding strategy is never appropriate. But the current MOPR screen incorrectly assumes it is always appropriate, and thus provides a possible avenue for uncompetitively low offers.

84. However, real levelization is consistent with the assumption that energy, ancillary services and capacity prices will rise at the rate of inflation over time; how can it be considered “inappropriate” for an entrant to adopt that assumption? The nominal levelization approach is

consistent with the assumption that these revenues will be constant in nominal terms and declining in real terms over time. Market participants are entitled to their opinions about future market developments, and it would be inappropriate to impose the unrealistic assumption of declining real prices implicit in the proposed use of nominal levelization.

85. In his 2005 affidavit in support of the RPM application, PJM's market monitor, Dr. Joseph Bowring, discussed this same levelization issue in the context of the RPM demand curve's Net CONE parameter (not the MOPR), and recognized that "an actual competitive offer by a potential entrant could reasonably be based on either method of levelizing the revenue requirements."²⁵ In recognition of the fact that competitive offers could be based on either approach, he recommended use of the higher Net CONE value that results from the nominal levelization approach to set the demand curve's Net CONE value, in order to not "exclude" entrants choosing the higher offer prices resulting from that approach:²⁶

It is appropriate to base the CONE calculation and therefore the demand curve on the nominal levelized payment stream in order to ensure that the market rules do not exclude reasonable competitive offers. If potential entrants make offers at the real levelized net cost of new entry, they will appropriately win the auction, the clearing price would equal the real levelized net cost of new entry and there will not be an issue. However, if potential entrants determine that a competitive offer is equal to the nominal levelized payment stream then a demand curve based on the nominal levelized payment stream would result in the same price as the demand curve based on the real levelized payment stream, assuming all new entry offers at the same price.

86. For the purpose of the MOPR, this same principle – a desire to not exclude competitive offers – calls for use of the lower Net CONE values based on the real levelized approach, in order to not prohibit competitive offers that reflect this assumption. That CONE is levelized using different assumptions for the purpose of the MOPR and the demand curve is consistent with the different purposes of Net CONE in these two sections of the PJM tariff.

²⁵ Affidavit of Joseph E. Bowring on Behalf of PJM Interconnection, L.L.C., August 31, 2005, Docket No. ER05-1410, p. 9.

²⁶ *Id.*, p. 9-10.

V. Comments and Recommendations on Other MOPR Provisions

87. PJM proposes a number of other changes to the MOPR, of which some clarify or further develop existing provisions. This section of my affidavit comments on these other elements of the existing MOPR and the specific proposals in the PJM Filing.

A. The Net Buyer and Impact Tests Should Be Retained But Improved

88. The current MOPR includes a “net buyer” test that should be retained but improved. Most market participants offering new capacity are not substantial net buyers and have no incentive to attempt to suppress capacity prices and mitigating their offers would merely prevent normal competitive conduct. Also, application of the rule to net sellers could provide a means for a net seller to evade the seller market power mitigation provisions and withhold planned new resources. A net seller could plan new resources (discouraging other, competitive new entry), but effectively withhold the resources from RPM through the MOPR mitigation. This would further magnify the barrier to entry created by the MOPR rule.

89. The “net buyer” test should be further developed to extend to all circumstances that raise concerns. The definition should be revised to apply to offers by contractual counterparties of net buyers. The definition should also recognize that while state programs and policies to encourage new resources generally have legitimate public policy objectives, such policies could also be used with the goal of suppressing capacity market prices, and the resources resulting from any such attempt should be subject to mitigation. While PJM claims that the net buyer test should be eliminated because it is “too easily gamed” (p. 16), if properly revised it would apply to all plausible scenarios.

90. The current MOPR also includes an impact test, a common feature of market power mitigation measures. The impact test should be retained but further developed. Offers that have little or no impact on clearing prices (for instance, because they represent a small quantity of new resource, or were offered at prices close to market-clearing prices) should not be mitigated. Mitigating offers from new resources that would have little or no impact on clearing prices may cause them to not clear, with another resource (likely a high-cost older resource with much shorter remaining useful life) clearing instead.

91. However, the impact thresholds specified in the current MOPR rule are quite loose, allowing price impacts up to \$25/MW-day or 20% to 30% of the clearing price, depending upon LDA size. These thresholds should be reduced to the 5% to 10% range.

B. The Exemption for Resources Built Under a State Mandate Should Be Retained But Improved

92. The existing MOPR recognizes that mitigation should not apply to new resources that come into existence as a result of a state initiative in pursuit of legitimate public policy objectives. However, as PJM notes, the existing language places PJM in the position of judging whether the exemption applies. PJM correctly proposed that the Commission make the determination as to whether a specific state initiative falls within the tariff's exemption.

93. PJM proposes that for a resource to be exempted on this basis the sponsor should have to file under FPA Section 206. This seems to inappropriately place the burden of proof on the sponsor, effectively treating the state initiative as guilty until proven innocent. States or resources seeking to use the exemption should not have to show that proceeding without an exemption would be unjust and unreasonable.

94. PJM also proposes to change the current exemption criteria. PJM proposes that to qualify under the exemption, in addition to the state program pursuing a "legitimate state objective", the Commission would also have to find that the sell offer "would not lead to artificially depressed capacity prices or directly and adversely impact FERC's ability to set just and reasonable rates for capacity sales in the PJM Region or any affected Locational Deliverability Area." Proposed Tariff Att. DD, Section 5.14(h)(5). This proposed additional criterion is vague and unnecessary. If the resource is being built under a state mandate, it will likely be offered at a low price with intent to clear, in the same way that existing resources, or new projects whose sponsors have decided to proceed, will be offered. Because the resource fulfills a legitimate state objective, there would be no basis for interfering with an offer based on the resource's net avoidable cost. Rather than change the state exemption criteria, the Commission should simply keep the existing criteria in place and remove PJM's decision-making role. Alternatively, if a provision like that proposed by PJM is adopted, it should be clarified to state that an offer greater than or equal to the resource's net avoidable cost would be consistent with the requirement that the offer not "artificially depress" capacity prices or lead to unjust and unreasonable capacity prices.

C. The Exemptions for Certain Resource Categories Should Be Retained But Improved

95. The existing MOPR exempts long lead-time resources such as nuclear and coal for which much of the construction cost will already have been invested when the resource is first offered into an RPM base residual auction. The high cost and long lead time of such plants makes it exceedingly unlikely they would be built for the purpose of suppressing capacity market prices. PJM proposes to exempt additional resource types (wind and solar), however, it is unclear why other resource types (such as other types of renewables), that at least in theory could also be used in an attempt to exercise market power, are exempted, and this discrimination may not be justified. In any case, PJM, the IMM, or any market participant could file under FPA section 206 to have the offers from an exempted resource mitigated if they believed there was evidence of an attempt to manipulate capacity prices, so it is reasonable to focus mitigation on those resources that seem the most likely to be used in any effort to manipulate capacity prices.

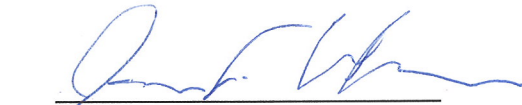
96. The existing MOPR does not apply to self-supply resources, which under the tariff are “treated as committed” in the RPM clearing process (Tariff Att. DD, Section 5.2). PJM states that it never intended to exempt self-supply offers from application of the MOPR. However, RPM was always intended to be a residual market, and the right to self supply was a fundamental element of the original settlement; if all capacity buyers self-supplied all required resources, there would be nothing for RPM to do. Indeed, the MOPR rule refers to self-supply, as PJM acknowledges (without going into detail); it recognizes that self-supply resources are dispatched first, and at zero price. Tariff Att. DD, Section 5.14(h)(4). Nevertheless, under a MOPR intended to mitigate buyer market power, new resources that are found to represent attempts to suppress capacity market prices should be mitigated whether or not they have been designated as self-supply.

97. This completes my affidavit.

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

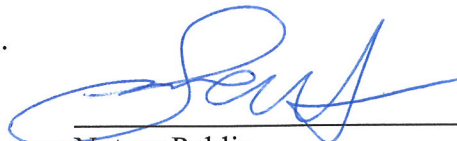
PJM Power Providers Group)	Docket No. EL11-20-000
v. PJM Interconnection, L.L.C.)	
)	
PJM Interconnection, L.L.C.)	Docket No. ER11-2875-000
)	
)	(not consolidated)
)	

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



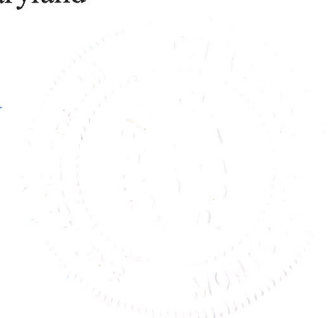
James F. Wilson

Subscribed and sworn before me, a Notary Public in and for the State of Maryland
this 4th day of March, 2011.



Notary Public
My Commission expires:
09/17/2011

**SAID ABDEL-HALIM
NOTARY PUBLIC
MONTGOMERY COUNTY
MARYLAND
MY COMMISSION EXPIRES 09/17/2011**



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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. 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

- Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
- Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
- Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
- Participated on a panel teleseminar on natural gas price forecasting.
- Affidavit evaluating a shortage pricing mechanism and recommending changes.
- 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.
- 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 electric utility.
- 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' telecommunications services and prices.
- 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

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North American Electric Reliability Corporation, Federal Energy Regulatory Commission Docket No. RM10-10, Comments on Proposed Reliability Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 23, 2010.

In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, Maryland Public Service Commission Administrative Docket PC22, Comments and Responses to Questions On Behalf of Southern Maryland Electric Cooperative, October 15, 2010.

PJM Interconnection, L.L.C., Federal Energy Regulatory Commission Docket No. ER09-1063-004 (PJM compliance filing on pricing during operating reserve shortages): Affidavit In Support of Comments and Protest of the Pennsylvania Public Utility Commission, July 30, 2010.

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; Supplemental Testimony in Support of Second Brief of the Joint Filing Supporters, September 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.

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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.

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Forward Capacity Market CONEfusion, Electricity Journal Vol. 23 Issue 9, November 2010.

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

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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).

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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.

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National Regulatory Research Institute Teleseminar: Forecasting Natural Gas Prices, panelist, July 28, 2010.

Comments on the NARUC-Initiated Report: Analysis of the Social, Economic and Environmental Effects of Maintaining Oil and Gas Exploration Moratoria On and Beneath Federal Lands (February 15, 2010) submitted to NARUC on June 22, 2010.

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.

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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.

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PROFESSIONAL ASSOCIATIONS

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