OCC EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider	)	Case No. 14-1693-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority	)	Case No. 14-1694-EL-AAM

(PUBLIC VERSION)

DIRECT TESTIMONY
OF
JAMES F. WILSON

On Behalf of
The Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215-3485

September 11, 2015

TABLE OF CONTENTS

PAGE

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A1. 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.

Q2. PLEASE DESCRIBE YOUR EXPERIENCE AND QUALIFICATIONS.

A2. I have thirty 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, state regulatory agencies, and a U.S. district court.

I have been involved in electricity restructuring and wholesale market design for over twenty years in PJM, New England, California, Russia, and other regions. With regard to the PJM system, I have been involved in a broad range of market design, planning, resource adequacy and capacity market issues over the past several years. 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 Attachment JFW-1 attached hereto.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A3. I am testifying on behalf of the Ohio Consumers' Counsel ("OCC").

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO ("PUCO")?

A4. Yes. I testified in Case No. 14-1297-EL-SSO (the application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for approval of an Electric Security Plan); Case No. 14-841-EL-SSO (the application of Duke Energy Ohio for approval of an Electric Security Plan); Case No. 13-2385-EL-SSO (the application of Ohio Power Company for approval of an Electric Security Plan); Case No. 12-426-EL-SSO (the application of The Dayton Power and Light Company for approval of a Market Rate Offer); Case No. 12-1230-EL-SSO (the application of Ohio Edison Company, The Cleveland

Electric Illuminating Company, and The Toledo Edison Company for approval of an Electric Security Plan); and Case No. 09-906-EL-SSO (the application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for approval of a Market Rate Offer). This prior testimony was presented on behalf of the Ohio Consumers' Counsel (and, with respect to Case No. 14-1297-EL-SSO, the Northeast Ohio Public Energy Council).

Q5. WHAT IS THE PURPOSE AND SCOPE OF YOUR TESTIMONY?

A5. In this proceeding Ohio Power Company ("AEP Ohio") seeks approval of a proposal to enter in a power purchase agreement ("PPA", "Affiliate PPA") with an affiliate, with the cost of the purchased generation, net of market revenues, passed on to customers through a PPA Rider. The PUCO authorized the PPA Rider earlier this year only as a placeholder, with an initial rate of zero.[1] The February Order stated that AEP Ohio would have to justify any cost recovery through the PPA Rider in a future proceeding, and all implementation details of the PPA Rider would also be determined in that proceeding.

My assignment was to review AEP Ohio's application, supporting testimony, workpapers, and discovery in this proceeding and to evaluate certain issues with respect to the potential impact of the proposal on customers. Specifically, I was

[1] Opinion and Order in Case No. 13-2385-EL-SSO, February 2015 (February Order").

asked to review AEP Ohio's estimate of the cost to customers under the proposed Affiliate PPA and PPA Rider, and to provide an alternative estimate; to discuss the resource adequacy issues that have been raised in this proceeding; to evaluate the claimed benefits of the arrangement as a hedge; and to discuss incentive issues that would be raised by the proposed arrangement. Finally, I was also asked to provide recommendations with respect to the sharing of financial risk between AEP Ohio and its customers, should the proposal be approved in some form.

II. BACKGROUND – THE PROPOSED AFFILIATE PPA AND PPA RIDER

Q6. PLEASE DESCRIBE THE PROPOSED AFFILIATE PPA AND THE ASSOCIATED PPA RIDER.

A6. The proposed arrangement is described in the direct testimony of AEP Ohio's witness Kelly D. Pearce. Under the Affiliate PPA, AEP Ohio would purchase the output of several power plants (the "PPA Units") wholly or partly owned by AEP Generation Resources ("AEPGR") for the entire commercial operational life of the units, under a FERC-jurisdictional PPA.[2] The output of these plants, along with output associated with AEP Ohio's entitlement to a portion of the output of two generating plants under another PPA ("ICPA")[3] with the Ohio Valley Electric

[2] Exhibit KDP-1, Summary of Major Terms, Power Purchase and Sale Agreement.

[3] Amended and Restated Inter-Company Power Agreement ("ICPA"), available at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12594881.

Corporation ("OVEC"), (collectively, the "Indicated Generation"), would be sold into the wholesale markets operated by PJM Interconnection, L.L.C. ("PJM").

Through the PPA Rider, AEP Ohio would collect from customers, on a non-bypassable basis, the costs of the plants included in the Affiliate PPA (including a return on invested capital) and of the OVEC entitlement, net of the capacity, energy and ancillary services market revenues earned from the sales into the PJM markets. Thus, the PPA Rider could increase or decrease customer bills, depending upon whether the Indicated Generation's costs turn out to be greater or less than the associated market revenues.

Q7. PLEASE DESCRIBE THE GENERATION ASSETS PROPOSED TO BE INCLUDED IN THE AFFILIATE PPA.

A7. The PPA Units are described in the direct testimony of company witness Toby L. Thomas, and are summarized in Table 1. The OVEC entitlement is supplied from two coal-fired plants owned by OVEC (together with a wholly-owned subsidiary), that are also shown in Table 1. AEP Ohio is a Sponsoring Company entitled to 19.93 percent of the capacity and energy provided by the OVEC plants. Other companies in the AEP family are also parties to the OVEC ICPA and are Sponsoring Companies; AEP's total share of OVEC output is 43.47 percent.

Table 1: Units Proposed to be Included in the Affiliate PPA and PPA Rider

Plant, Unit	County (Ohio)	In-Service Date	Fuel	Installed Capacity (MW)	AEP Per-cent	AEP Installed Capacity (MW)	Forced Outage Rate	AEP Un-forced Capacity (MW)
Cardinal 1	Jefferson	1967	coal	585	100%	585.0	8.1%	537.7
Conesville 4	Coshocton	1973	coal	780	43.5%	339.3	23.9%	258.2
Conesville 5	Coshocton	1976	coal	405	100%	405.0	10.1%	364.2
Conesville 6	Coshocton	1978	coal	405	100%	405.0	6.7%	378.0
Stuart 1 [1]	Brown	1971	coal	585	26%	150.0	12.1%	131.8
Stuart 2	Brown	1970	coal	585	26%	150.0	11.6%	132.6
Stuart 3	Brown	1972	coal	585	26%	150.0	13.9%	129.1
Stuart 4	Brown	1974	coal	585	26%	150.0	14.3%	128.6
Zimmer 1 [2]	Clermont	1991	coal	1,300	25.4%	342.9	20.9%	271.4
Kyger Crk [3]	Gallia	1955	coal	1,086	19.9%	216.1	21.3%	170.0
Clifty Crk	Jefferson (IN)	1955	coal	1,304	19.9%	259.5	15.9%	218.3
Total						3,152.8		2,719.9

Sources: Direct Testimony of Toby L. Thomas; Pearce Workpaper WP-1.
Notes: [1] The Stuart plant is operated by Dayton Power & Light; [2] the Zimmer plant is operated by Dynegy, Inc.; [3] The Kyger Creek and Clifty Creek plants are owned and operated by OVEC/IKEC.

Q8. WHAT DID THE FEBRUARY ORDER CONCLUDE, WITH REGARD TO AEP OHIO'S PPA RIDER PROPOSAL?

A8. The February Order stated (p. 25) that the Commission was not persuaded that the proposal would provide customers with sufficient benefit commensurate with the rider's potential cost, and approved the PPA Rider only on a placeholder basis. The February Order stated that that in any future proceeding in which AEP Ohio might request cost recovery through the PPA Rider, it would have to address, at a minimum, the following factors, which the Commission would consider in deciding whether to approve the proposal (p. 25):

i. financial need of the generating plant;

ii. necessity of the generating facility, in light of future reliability concerns, including supply diversity;

iii. description of how the generating plant is compliant with all pertinent environmental regulations and its plan for compliance with pending environmental regulations; and

iv. the impact that a closure of the generating plant would have on electric prices and the resulting effect on economic development within the state.

The February Order further required that a proposal for recovery through the PPA Rider must include the following (pp. 25-26):

v. provide for rigorous Commission oversight of the rider, including a proposed process for a periodic substantive review and audit;

vi. commit to full information sharing with the Commission and its Staff;

vii. include an alternative plan to allocate the rider's financial risk between both the Company and its ratepayers; and

viii. include a severability provision that recognizes that all other provisions of an Electric Security Plan would continue, if the PPA rider is invalidated, in whole or in part at any point, by a court of competent jurisdiction.

Q9. WHICH OF THESE FACTORS WILL YOUR TESTIMONY ADDRESS?

A9. My testimony primarily addresses the potential cost to customers of the proposed arrangement. Of these additional factors, my testimony addresses the required alternative plan to allocate the rider's financial risk between AEP Ohio and its customers.

III. SUMMARY AND RECOMMENDATIONS

Q10. PLEASE SUMMARIZE YOUR OBSERVATIONS REGARDING RESOURCE ADEQUACY IN PJM AND IN OHIO.

A10. The AEP witnesses attempt to raise various concerns about resource adequacy in PJM. However, resource adequacy is in good shape in PJM and specifically in Ohio. Through PJM's three-year-forward Reliability Pricing Model ("RPM") capacity construct, reserve margins well above target levels have been maintained, with capacity commitments now in place through May 31, 2019. A large wave of retirements has been absorbed without a spike in capacity prices, with the retiring capacity to be replaced by a mix of new gas-fired power plants, uprates to existing units, demand response, energy efficiency, imports from adjacent areas, wind, and other types of resources.

Q11. DID AEP OHIO PROVIDE AN ESTIMATE OF THE IMPACT OF THE PROPOSED AFFILIATE PPA ON CUSTOMERS?

A11. Yes. Witness Pearce provided the estimated annual net revenue or cost over the arrangement through 2024 under three scenarios (Exhibit KDP-2, included here as Exhibit JFW-1; hereafter, "PPA Rider Forecast"). The three scenarios are a base case, a 5% Lower Load Forecast Case, and a 5% Higher Load Forecast Case; Exhibit KDP-2 also presents the average of the High Load and Low Load cases. Results are presented with two assumptions regarding a CO2 tax and additional near-term capacity revenues.

All of AEP Ohio's cases rely on energy prices [redacted] than recent forward prices, as I will show later in this testimony. Consequently, I will focus on the 5% Lower Load Case, which has the [redacted] energy price assumptions. Based on this case, including a CO2 tax assumption and excluding a small amount of additional near-term capacity revenue, the total cost to customers is $0.9 billion over the ten years (or $0.8 billion, net present value at a five percent discount rate), under AEP Ohio's PPA Rider Forecast. That is, under AEP Ohio's Low Load case, the costs associated with the Indicated Generation would exceed the market value by $0.9 billion over the ten-year period, and this net cost would be collected from AEP Ohio's customers through the PPA Rider over the period.

Under the other scenarios that I consider much less likely, including some with alternate assumptions about capacity revenues, the cost to customers is less or there is a net credit, as shown in Exhibit JFW-1 (Exhibit KDP-2).

Q12. PLEASE SUMMARIZE YOUR ASSESSMENT OF THE ESTIMATED NET COST TO CUSTOMERS UNDER AEP OHIO'S PPA RIDER FORECAST.

A12. Any analysis of a resource's future costs and market revenues relies upon multiple, uncertain assumptions and forecasts, including energy, ancillary services and capacity market prices, fuel prices, environmental and other regulations, the resource's fixed costs, and the resource's operation and generation. Consequently, the results of the PPA Rider Forecast are necessarily highly uncertain. Of course, when forecasts reach many years into the future, the likelihood that they will be close to actual values becomes much lower.

The various PPA Rider Forecast cases, including the Low Load case, rely on forecasts suggesting that energy and capacity prices will [redacted] in the coming years. While something like this might occur, these forecasts are [redacted] with market participants' expectations as reflected in forward market prices for energy and natural gas.

In addition, because capacity prices are supposed to only provide the "missing money" not provided by energy prices, market dynamics determine that capacity and energy revenues are substitutes; so the notion that capacity and energy prices would [redacted] is especially unlikely.

Consequently, I conclude that AEP Ohio's PPA Rider Forecast represents an inaccurate and unreliable estimate of the potential future net costs to customers of the Indicated Generation through the proposed PPA Rider, primarily due to the speculative nature of the price assumptions used in the analysis. The net cost to customers of the proposed PPA Rider would likely be much greater than suggested by AEP Ohio's PPA Rider Forecast.

Q13. PLEASE DESCRIBE HOW YOU PREPARED YOUR ALTERNATIVE ESTIMATE OF THE POTENTIAL COST TO CUSTOMERS OF THE PROPOSED AFFILIATE PPA AND PPA RIDER.

A13. I prepared an alternative estimate, where I changed only the assumed hourly electricity price assumptions, and reflected this in updated generation estimates. I also updated capacity price assumptions based on recent auction results. For my estimate I accepted all other assumptions from the PPA Rider Forecast, despite concerns, discussed in this testimony, about some of those assumptions.

Q14. PLEASE FURTHER EXPLAIN HOW YOU DEVELOPED AND USED THE HOURLY ELECTRICITY PRICES FOR YOUR ANALYSIS.

A14. I started with the hourly prices from AEP Ohio's Low Load case, because these prices were closest to recent forward prices and also reflected more dispersion than the prices under the Weather Normalized case. I adjusted these prices to be consistent with recent AD Hub peak and off-peak forward prices on a monthly average basis. I then used the hourly generation values that corresponded to the hourly prices from the Low Load case, and "re-dispatched" so that there would be no generation in any hours when this would result in losses. This is a conservative assumption, because due to ramp rates and other operational constraints, coal plants may at times have to operate at a loss in some hours in order to be able to capture net revenues in other, adjacent hours.

Q15. DOES YOUR APPROACH RESULT IN THE INDICATED GENERATION EARNING THE AD HUB PEAK AND OFF-PEAK FORWARD PRICES, ON AVERAGE?

A15. No; under this approach, the average prices earned in peak and off-peak hours are greater than the AD Hub forward prices. This is because the Low Load case hourly prices reflect considerable dispersion (from $0/MWh to $205/MWh, as adjusted), and the plants do not run when prices are below variable cost.

Q16. ***WHAT IS THE COST TO CUSTOMERS OF THE PROPOSED AFFILIATE PPA AND PPA RIDER UNDER YOUR ALTERNATIVE ESTIMATE?***

A16. Under these assumptions, the cost to customers through the PPA Rider over the ten-year period would be a cumulative $1.8 billion, or $1.4 billion on a net present value basis. These results are shown in Table 2, with additional detail in Exhibit JFW-2. There are losses and costs passed through to customers in every year of the analysis, ranging from $151 million to $240 million per year. Over the ten years, compared to an average total market revenue of $66.2/MWh, the PPA Units' average cost is $85.3/MWh, as shown in Table 2 and Exhibit JFW-2.

Table 2: Summary of Revised PPA Cost Estimate

($ in millions)	Oct-Dec 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	TOTAL ($bil.)	NPV ($ bil.)
Net Gen. (000 GWh)	3.4	14.7	13.3	11.9	9.2	8.3	9.4	8.0	7.6	7.9	93.6	
Total Revenue	154	725	674	644	581	578	657	700	721	766	$6.2	$4.9
Total Costs	215	883	863	867	821	808	852	886	871	922	$8.0	$6.3
Revenue - Cost	(60)	(157)	(189)	(224)	(240)	(230)	(195)	(186)	(151)	(156)	**($1.8)**	**($1.4)**
Total Rev. $/MWh	45.3	49.3	50.8	54.3	63.2	69.7	69.6	87.2	95.0	97.5	66.2	
Total Cost $/MWh	63.1	60.0	65.0	73.2	89.4	97.4	90.3	110.4	114.9	117.4	85.3	

Q17. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE POTENTIAL VALUE TO CUSTOMERS OF THE PROPOSED AFFILIATE PPA AS A LONG-TERM HEDGE AGAINST THE VOLATILITY OF FUTURE MARKET PRICES.

A17. AEP Ohio's claims regarding the value of the proposed arrangement as a hedge are based on greatly overstated estimates of the potential volatility of electricity prices in PJM. While prices can be volatile at times due to extreme weather, such periods last days or weeks, and the impacts on annual average prices are greatly moderated.

Customers receiving their electric supply under the proposed Standard Service Offer ("SSO") will be served under one- to three-year full requirements contracts established through periodic auctions, and, therefore, would not be exposed to substantial market price volatility. The PPA Rider would add a potentially volatile element to such customers' bills. Customers choosing competitive retail electric service would select among the available offerings according to their preferences, and could choose offerings that hedge prices and provide greater stability to the extent that is desired. For such customers, the PPA Rider, which will be updated annually, could potentially move contrary to, or in the same direction as, the market-based prices these customers pay at any time. I conclude that the potential for the proposed PPA Rider to act as a hedge of volatile market prices or contribute to price stability is doubtful (due to the time lag).

Over the longer-term, whether the proposed arrangement would increase or decrease customers' bills will depend upon whether the Indicated Generation's costs are greater than or less than the associated market revenues. As noted above, I expect that the costs are very likely to exceed the revenues.

Q18. PLEASE SUMMARIZE YOUR OBSERVATIONS REGARDING INCENTIVES ISSUES RAISED BY THE PROPOSED AFFILIATE PPA AND PPA RIDER.

A18. The AEP companies have a substantial amount of generation in PJM. The AEP companies already have strong incentives to attempt to raise energy and capacity prices. With the revenues associated with a part of the portfolio passed through to customers through the PPA Rider, the incentive to economically withhold these resources from the markets would be strengthened.

Q19. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE PROPOSED AFFILIATE PPA AND THE TREATMENT OF THE INDICATED GENERATION COSTS.

A19. I recommend that the Affiliate PPA be rejected. Through the PPA Rider, it would shift onto customers the net cost and risk associated with AEP Ohio's affiliate's ownership of generation and the contractual relationship with OVEC. This net cost could be considerable; under my conservative estimate, $1.8 billion ($1.4 billion net present value), and it could be much higher.

In addition, because the Affiliate PPA and PPA Rider simply pass the net cost through to customers, the incentive to manage the costs, and to maximize revenues, is eliminated. Any incremental price stability the arrangement might provide by serving as a type of hedge (which I consider doubtful), would be of little value compared to the expected net cost, and risk of even higher cost to customers.

Q20. IF THE PUCO FINDS THE NOTION OF PROVIDING CUSTOMERS A LONG-TERM PHYSICAL HEDGE ATTRACTIVE, WHAT APPROACH WOULD YOU RECOMMEND?

A20. If the PUCO wishes to provide customers a long-term physical hedge, the best approach would be to identify clear objectives for the physical hedge, and then hold a competitive procurement to acquire the resources that could best provide the hedge and satisfy all other objectives of the procurement.

Q21. IF THE PUCO CHOOSES TO APPROVE THE AFFILIATE PPA IN SOME FORM, WHAT WOULD YOU RECOMMEND REGARDING THE ALLOCATION OF FINANCIAL RISK BETWEEN THE COMPANY AND CUSTOMERS?

A21. If the PUCO chooses to approve the Affiliate PPA in some form, I recommend that the PPA Rider be modified to reduce the cost and risk to customers and restore some incentive to AEP Ohio to control costs and maximize operation and revenue. This could be accomplished by setting a benchmark for the PPA Rider net cost (the net cost of the Affiliate PPA including the OVEC entitlement) and using a sharing mechanism for net costs or benefits relative to the benchmark, rather than collecting 100 percent of the net cost from customers. I describe how such an incentive mechanism could be designed in the last section of my testimony.

Q22. WHAT APPROACH TO ALLOCATING THE FINANCIAL RISK WOULD YOU PROPOSE, IF THE PUCO IS PRIMARILY CONCERNED ABOUT THE SURVIVAL OF THE INDICATED GENERATION OVER THE NEXT FEW YEARS?

A22. If the goal is primarily to help the Indicated Generation bridge through the next few years, an incentive mechanism structure could also be used. With this objective, the incentive mechanism should share costs during an initial period (for instance, the ESP Period), but then return benefits, should they occur, more rapidly to customers after the initial period. The arrangement could terminate once the benefits to customers reach a threshold. I further explain how such a mechanism could be designed in the last section of my testimony.

Q23. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A23. The next section of my testimony further explains that resource adequacy is in good shape in PJM. Section V critiques AEP Ohio's PPA Rider Forecast and provides my alternative calculation, showing that the Affiliate PPA would likely be very costly for customers. In Section VI I evaluate the claimed benefit of the proposal as a hedge. Section VII of my testimony discusses incentive problems created by the proposed arrangement. The final section explains why, if any Affiliate PPA is approved, an alternative approach to allocating the financial risk is essential, and proposes how that might be done.

IV. RESOURCE ADEQUACY IS IN GOOD SHAPE IN PJM AND IN OHIO

Q24. AEP OHIO'S WITNESSES VEGAS (PP. 19-25) AND PEARCE (P. 21) EXPRESS CONCERNS ABOUT RESOURCE ADEQUACY IN PJM AND IN OHIO. FIRST, PLEASE SUMMARIZE HOW PJM MAINTAINS RESOURCE ADEQUACY WITHIN ITS FOOTPRINT.

A24. PJM maintains resource adequacy primarily through its Reliability Pricing Model ("RPM") capacity construct, first deployed for the 2007/08 delivery year. Under RPM, PJM holds annual auctions to acquire commitments to provide the capacity needed for resource adequacy on a three-year-forward basis.

Q25. HAS PJM BEEN ABLE TO MAINTAIN RESOURCE ADEQUACY IN PJM, AND SPECIFICALLY FOR OHIO CONSUMERS, THROUGH RPM?

A25. Yes. Ohio is part of the large, generation-rich "Rest of RTO" region that extends from western Pennsylvania to Illinois, and down to Kentucky, West Virginia, and

Virginia. At the RTO level, PJM has consistently cleared capacity on a three-year-forward basis in excess of the target reserve margins, as shown in Exhibit JFW-3. The excess cleared quantity has typically been about four percent, and is no less than 3.5 percent for every delivery year from 2012/13 through 2018/19. Note that this accounting does not include a substantial quantity of capacity that failed to clear in RPM and is still in operation. Of course, actual delivery year reserve margins are generally somewhat different from the three-year-forward RPM results, due to changes in the load forecast, sell-back of excess cleared quantities, and perhaps other changes that may occur as the delivery year approaches.

Q26. AEP OHIO WITNESS VEGAS ALSO SUGGESTS THAT CAPACITY PRICES UNDER RPM HAVE BEEN VOLATILE (P. 11, P. 21). PLEASE PRESENT THE APPLICABLE CAPACITY PRICES, AND COMMENT ON THIS.

A26. The RPM prices for the Rest of RTO region are also shown in Exhibit JFW-3. The Rest of RTO capacity prices have been reasonably stable in the $100 to $175/MW-day range over the twelve RPM delivery years to date, with the exception of four delivery years when prices were lower: 2007/08, the very first year; 2012/13 and 2013/14, primarily due to substantial increases in demand response resources in the auctions for those years;[4] and 2016/17, primarily due to a large increase in imports into the RTO region, along with new entry within PJM, in the auction for that year.[5] The Rest of RTO capacity prices have not been volatile in the usual sense of that term, which suggests occasional price spikes –as Exhibit JFW-3 shows, Rest of RTO capacity prices have not spiked.

Q27. WITNESS PEARCE SUGGESTS THAT THE REGION IS IN THE "MIDDLE" STAGES OF A WAVE OF RETIREMENTS, AND NEW PLANTS WILL NOT BE BUILT IN TIME TO AVOID AN ADVERSE IMPACT ON RELIABILITY (P. 21). HOW HAVE THE RETIREMENTS AFFECTED RESOURCE ADEQUACY AND RPM RESULTS?

A27. The retirements have been absorbed with very little impact on resource adequacy or RPM results. Because RPM acquires capacity commitments on a three year forward basis, the large wave of retirements was primarily addressed in the RPM auctions held in 2009 to 2012, for the 2012/13 through 2015/16 delivery years.

Exhibit JFW-4 shows the retirements to date and planned retirements in the PJM footprint, for the 2010 to 2020 period, according to PJM's lists. A total of 24,889

---

[4] PJM, *2012/13 RPM Base Residual Auction Results*, p. 1 and Figure 2 p. 10, and PJM, *2013/14 RPM Base Residual Auction Results*, p. 1.

[5] PJM, *2016/17 RPM Base Residual Auction Results*, p. 31.

MW has already retired from 2010 to mid-2015, while at this time plans have been announced to retire another 2,745 MW by 2020.

From a resource adequacy and capacity planning perspective, the PJM region is quite far along in dealing with the wave of retirements. Of the 2,745 MW of planned future retirements, all but 135 MW are planned to retire by May 31, 2019. Accordingly, RPM, through which sufficient capacity has already been acquired through May 31, 2019, has already obtained commitments to replace all but 135 MW of these additional planned retirements. Put another way, replacement capacity has already been acquired for 27,499 MW (99.5%) of the 27,634 MW scheduled to retire from 2010 to 2020.

Q28. WITNESS VEGAS SUGGESTS THAT RETIRING GENERATION IS NOT BEING REPLACED (P. 19). IS THIS CORRECT?

A28. No. As shown above, there has been substantial new entry that, combined with other new resources including demand response and imports, has consistently resulted in reserve margins well above targets. PJM already holds commitments to provide capacity well in excess of targets through May 31, 2019.

In addition, there are over 10,000 MW of additional, potential new power plants that have never cleared in RPM, and are eligible to offer into RPM at any offer price (exempt from RPM's Minimum Offer Price Rule).[6] This capacity may be offered and cleared in future RPM base residual or incremental auctions, should the capacity be needed and the developers consider the time ripe.

Q29. MIGHT THE OWNERS OF SOME OF THE CAPACITY THAT IS NOT PRESENTLY SLATED TO RETIRE AND HAS CLEARED IN RPM CHANGE THEIR MINDS, AND DECIDE TO RETIRE THE UNITS BEFORE THE CAPACITY COMMITMENTS ARE FULFILLED?

A29. Yes, this is always possible, for instance this may occur due to new environmental policies and evolving market conditions. To retire before the RPM commitments are fulfilled, the owners would have to acquire replacement capacity either on a bilateral basis, or through RPM's additional "incremental auctions" that are held periodically for each delivery year to facilitate such adjustments. Historically, there has been plenty of replacement capacity offered into the incremental auctions (including existing and new generation that failed to clear in the base residual auction, incremental demand response, and existing plant uprates, among other types) such that the incremental auction clearing prices have generally been below base residual auction prices. Should the owners retire the units without acquiring replacement capacity, they would face stiff penalties under RPM.

[6] PJM, 2018/19 RPM Base Residual Auction Results, table p. 7.

In addition, PJM studies every requested deactivation to determine whether it raises any reliability issues, and may request a delay of the deactivation date to allow transmission reinforcements if necessary. When a retirement is delayed due to reliability concerns, the plant operates under a cost-based arrangement in the meanwhile.

Q30. WHAT TYPES OF RESOURCES HAVE BEEN ACQUIRED THROUGH RPM TO REPLACE THE RETIRING GENERATION?

A30. A diverse mix of resource has been acquired through RPM to replace the retired generation and meet the rather modest load growth that has or is expected to occur. In addition to over 22,000 MW of new combined cycle units, there have been substantial amounts of new combustion turbines, new steam units and uprates to existing steam units, wind, demand response, energy efficiency, and imports from resources located in adjacent regions.[7]

Q31. WHILE THERE HAS BEEN SUBSTANTIAL NEW ENTRY IN PJM, HAS THERE BEEN NEW ENTRY SPECIFICALLY IN THE MARKET REGION THAT INCLUDES OHIO?

A31. Yes. The Rest of RTO region that includes Ohio has had, and through RPM is expected to continue to have, excess capacity, despite the wave of retirements

[7] PJM, 2018/19 RPM Base Residual Auction Results, pp. 21-26.

(Exhibit JFW-3). This reflects sufficient commitments of new capacity to offset the retirements, as noted above. Despite the excess capacity, over 10,000 MW of new generation located in the Rest of RTO region has cleared in the 2014/15 through 2018/19 RPM base residual auctions.[8]

Of course, most new entry has been in eastern PJM, where higher RPM prices have indicated capacity has been more needed. Capacity in eastern PJM contributes to resource adequacy throughout PJM, including in Ohio, while capacity located in the Rest of RTO region contributes to resource adequacy primarily in the Rest of RTO region, because there can be constraints into eastern PJM.

Q32. IS NEW ENTRY OCCURRING IN OHIO?

A32. Yes. The latest RPM auction may have cleared resources planned for Ohio, however, this data is not public. There are presently five substantial new gas-fired power plants under construction or proposed for Ohio:

i. The 869-MW Oregon Clean Energy Center, a combined-cycle natural-gas fired generation facility to be located in Oregon, Ohio, has cleared in RPM and obtained financing,

[8] PJM, RPM Base Residual Auction Results reports for the 2014/15 through 2018/19 delivery years, Table 2A in each report, showing a total of 9,960 MW unforced capacity cleared in RTO outside of MAAC.

and is presently under construction. (PJM interconnection queue project Y1-069).

ii. Carroll County Energy (Y2-050) is a 700 megawatt natural gas fired power generation facility under construction in Carroll County and expected to be online in December 2017.

iii. Tenaska has proposed to convert its Rolling Hills Generating Station (X3-051) in Wilkesville, Vinton County, to a 1,414 MW station including baseload combined cycle and peaking combustion turbine units.

iv. NTE Energy plans to construct, own and operate the Middletown Energy Center (Z1-079), a 525 MW combined cycle unit in Middletown, Butler County, with commercial operation planned for early-mid 2018.

v. Clean Energy Future is planning an 800 MW combined cycle plant near Lordstown in Trumbull County (Z2-028).

PJM's generation interconnection queue currently includes over 4,300 MW of new, Ohio, gas-fired generation for the 2016/17 through 2019/20 delivery years.[9] Of course, in light of the continuing excess capacity circumstances in the Rest of

[9] PJM's list of active interconnection requests is available at http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx.

RTO region (shown in Exhibit JFW-3), some of the projects identified above may be delayed or cancelled.

Q33. WITNESS VEGAS ASSERTS THAT OHIO MAY BECOME "GREATLY RELIANT" ON NEIGHBORING STATES FOR GENERATION. IS THIS TRUE, AND IS IT A CAUSE FOR CONCERN?

A33. Ohio is unlikely to become "greatly reliant" on neighboring states, and in any case, net interchange with neighboring states is not a cause for concern. The transmission system serving the western PJM region is quite strong, and other than the ATSI zone in northern Ohio, transmission constraints have generally not limited economic power transfers in and around Ohio.

In any case, Ohio has consumed more electricity than generating plants located on Ohio soil have generated for a long time. Exhibit JFW-5 shows Ohio generation and net interchange since 1990 based on data from the U.S. Energy Information Administration ("EIA"). The data shows that Ohio has received more electricity across its borders than it has sent across since at least 1990. This may reflect that some of the states adjoining Ohio may have had lower cost fuel supply, and may have been relatively less industrialized and populated than Ohio, resulting in preferred sites for power plants. If Ohio consumers are partially served by power plants on the other side of the Ohio River, or in other areas adjacent to Ohio, this is not a cause for concern.

Also, note that Ohio is situated on or near the Marcellus and Utica shale formations, which are substantial and relatively new sources of low-cost natural gas. This helps to explain why there are several gas-fired generation projects under development for Ohio, as discussed above.

Q34. AEP OHIO WITNESS WITTINE POINTS OUT THAT MANY OF THE PROPOSED GENERATION PROJECTS IN PJM'S INTERCONNECTION QUEUE ARE ULTIMATELY NEVER CONSTRUCTED (PP. 4-6). IS THIS A CAUSE FOR CONCERN?

A34. No, this is not a cause for concern at all. The amount of generation actually being built has been the amount needed (actually, a bit more than the amount needed, resulting in reserve margins above target levels; Exhibit JFW-3). So there is no cause for concern about the quantity of generation successfully completing the interconnection process.

It is true that of all the generation that *starts* the interconnection process, only a fraction ultimately completes the process. However, this simply reflects that developers bring forward a large number of proposals, which is also a sign that the process is working and PJM is considered an attractive region for new capacity. The question to ponder is not why such a small fraction of the projects in the queue is ultimately built, but why developers propose so many more projects than are ultimately needed.

Q35. WITNESS WITTINE ALSO NOTES THAT SOME PROJECTS ARE ULTIMATELY BUILT OVER TEN YEARS AFTER THEY WERE FIRST PROPOSED (P. 7). IS THIS A CAUSE FOR CONCERN?

A35. No. While some projects are delayed by various regulatory and other hurdles, these and other projects are also delayed or cancelled because they simply are not yet needed. The need for new generation depends largely on load growth, and load growth has been slow or non-existent over the past ten years. Again, the amount of new generation ultimately being constructed has been more than the amount needed to replace retiring capacity, satisfy load growth, and maintain target reserves in PJM.

Q36. WITNESS VEGAS ALSO ASSERTS THERE ARE FLAWS IN PJM'S CAPACITY MARKET (P. 18, P. 21). PLEASE COMMENT ON THE ALLEGED FLAWS.

A36. Witness Vegas first notes that RPM clears a single year at a time, and suggests this is a flaw because investors prefer long-term commitments. This is not a flaw, this has always been a feature of RPM. RPM results show that many investors are willing to move forward on this basis. And market participants are free to enter into bilateral contracts, or other long-term physical or financial hedges, if they so choose.

Witness Vegas also suggests there are other flaws, mentioning imports on non-firm transmission, speculative bidding, and summer-only demand response (p. 21). However, these issues were addressed two years ago. The last two base residual auctions, for the 2017/18 and 2018/19 delivery years, reflected new, tighter capacity import rules, so the impact of this change has already been reflected in RPM results for these years. New rules further restricting demand response participation in the capacity market have resulted in declining quantities of cleared demand response in the auctions for 2016/17 and 2017/18 (the quantity held steady in the most recent auction, for 2018/19). The allegation regarding "speculative" bidding also mainly pertains to demand response, and was also largely addressed by the earlier rule changes that led to reduced demand response participation. And PJM's recently-approved Capacity Performance package of changes includes further strengthening of the RPM construct.[10]

While witness Vegas suggests that these alleged "flaws" are outstanding, witness Pearce's testimony acknowledges that these issues have already been addressed by rules changes (pp. 26-28).

[10] 151 FERC ¶ 61,208, Order on Proposed Tariff Revisions, June 9, 2015 ("Capacity Performance Order"), Docket No. ER15-623.

Q37. WITNESS VEGAS ALSO ALLEGES THAT MARKET FLAWS HAVE LED TO CAPACITY PRICES THAT ARE "SUPPRESSED" (P. 21) AND "ARTIFICIALLY DEPRESSED" (P. 22). IS THIS TRUE?

A37. No. For some past RPM auctions, a case can be made that certain issues raised or lowered the clearing prices from what they otherwise would have been. These issues can include barriers to entry (will raise prices), market power (will raise prices), and various market design elements (which may raise or lower prices), among others. However, with respect to the Rest of RTO prices that are relevant to this proceeding, one problem has consistently dominated all others – PJM's load forecasts have greatly overstated future capacity needs. The various other issues that have allegedly impacted various recent auctions do not come close to offsetting the upward impact on RPM prices of excessive load forecasts and reliability requirements.

Q38. PLEASE PRESENT FACTS REGARDING PJM'S EXCESSIVE LOAD FORECASTS.

A38. Exhibit JFW-6 shows the forecasted peak load growth reflected in the RPM auction parameters for each RPM base residual auction (from the last-available weather-normalized peak at the time of the applicable forecast, to the forecasted three-year-forward peak used in RPM), compared to the actual load growth over the same period. For the 2009 through 2014 delivery years, the forecasts anticipated five to over nine percent total peak load growth, while actual four-year growth was never more than one percent, and was negative in some instances. The over-forecast was generally six percent or more of the peak load, or roughly 8,000 to 12,000 MW for the RTO Region. The reliability requirement used in RPM further increases the error by the Forecast Pool Requirement, another eight percent.

As Exhibit JFW-6 suggests, the problem is chronic and continuing, and there is no basis for expecting that the most recent forecasts will be accurate. PJM staff acknowledges the problem and has recently been developing enhancements to the forecasting methodology,[11] but it is not yet clear what changes will be implemented, and the extent to which they will correct the problem.

Therefore, while the various market design "flaws" alleged by the AEP Ohio witnesses have been addressed, as discussed above, it is not at all clear that the over-forecasting problem, by far the largest distortion to RPM prices, will be addressed.

[11] See, for instance, posted materials for the September 2, 2015 Load Analysis Subcommittee meeting, available at http://www.pjm.com/committees-and-groups/subcommittees/las.aspx.

Q39. WITNESS VEGAS OBSERVES THAT CAPACITY PRICES HAVE BEEN WELL BELOW THE ADMINISTRATIVE "NET CONE" VALUES CALCULATED BY PJM (P. 22), AND SUGGESTS THAT RPM PRICES DO NOT SUPPORT NEW-BUILD GENERATION (P 18). WHAT DOES THIS MEAN, AND IS IT A CONCERN?

A39. While the administrative Net CONE parameter is supposed to represent the capacity price needed for new entry, it in fact greatly overstates true Net CONE. This is clear from the fact that over several years now, there has been more than sufficient new entry to offset retirements and maintain reserves well above target levels, with capacity prices well below this administrative parameter.

While there are likely numerous reasons the administrative Net CONE values are wrong, a few can easily be identified. First, it should be noted that this parameter's main role is as the price parameter of the RPM sloped capacity demand ("VRR") curve. As such, higher Net CONE values raise the demand curve and capacity clearing prices. So it is no surprise that over the ten years since RPM was first proposed, various minute details of the Net CONE calculation have consistently been subject to lobbying in stakeholder processes by stakeholders interested in higher RPM clearing prices. Indeed, the calculated administrative Net CONE more than doubled from $161.71/MW-day for the 2009/10 delivery year to $342.23/MW-day for 2014/15.[12]

One obvious flaw in the calculation is the use of an historical average to represent estimated future energy and ancillary services earnings. Especially following an extended recession, this value will greatly overstate entrants' true expectations of future market earnings. While stakeholders have long recognized this as a flaw, attempts to fix it, which would lower Net CONE values and RPM clearing prices, have repeatedly been blocked.

The flow of new capacity into PJM, in both constrained areas with higher capacity prices and in the Rest of RTO region where prices have been in the $100 to $175/MW-day range, suggest that developers believe they can profitably bring new capacity to the market with capacity prices well below the administrative Net CONE values. That is, "true Net CONE" is apparently much lower.

The fact that clearing prices have been below Net CONE is not a cause for concern, but instead a sign that the market is working reasonably well. And should developers decide they need higher capacity prices to enter the PJM

[12] See RPM Planning Parameters for each auction, available at http://www.pjm.com/markets-and-operations/rpm.aspx.

market, they will offer new capacity at higher prices, and RPM, which employs a sloped demand curve, will clear at higher prices.

Q40. MUCH OF THE NEW CAPACITY IS GAS-FIRED, AND WITNESS PEARCE INSINUATES THAT NATURAL GAS GENERATORS MAY FACE FUEL SUPPLY CHALLENGES AND BE LESS RELIABLE (PP. 23-24). WILL GAS-FIRED POWER PLANTS BE UNRELIABLE IN THE COMING YEARS?

A40. No. During the "polar vortex" event in 2014 there were instances of gas-fired generators in eastern PJM that had not arranged firm fuel supply, and that were unable to acquire fuel supply during the extremely cold days. However, PJM has implemented new tariff rules to ensure that the power plants it relies upon for winter reliability have firm fuel supplies.[13] Specifically, the new rules will require capacity providers to arrange firm fuel supply in order to be considered "Capacity Performance" resources eligible for capacity payments, and will impose substantial penalties for non-performance. Consequently, in the future the gas-fired power plants needed for reliability will have firm fuel arrangements.

In any case, Ohio is crisscrossed with natural gas pipelines, making it an unlikely region to experience gas pipeline constraints.

---

[13] 151 FERC ¶ 61,208, Order on Proposed Tariff Revisions, June 9, 2015 ("Capacity Performance Order"), Docket No. ER15-623.

I also note that in contrast to the electric power industry, where expanding transmission capacity can be very difficult due to contentious issues including siting and cost recovery, natural gas industry transmission capacity typically expands fairly readily in response to market indications that new capacity is needed. At the present time there are numerous natural gas pipeline expansions occurring in and around PJM, including many to address recent constraints and to transport the new Marcellus and Utica shale supplies to markets.

Q41. WITNESS VEGAS PROVIDES FIGURES SHOWING VOLATILE ENERGY PRICES DURING THE "POLAR VORTEX" PERIOD IN 2014 (PP. 9-10); WITNESS PEARCE POINTS TO THIS PERIOD AS AN EXAMPLE OF THE POTENTIAL BENEFITS OF THE PROPOSED AFFILIATE PPA. PLEASE COMMENT ON THIS.

A41. First, it should be noted that the high prices in January 2014 mainly affected eastern PJM where there were high natural gas prices; this is illustrated Exhibit JFW-7, showing 2014 averages real-time prices from the 2014 State of the Markets Report for PJM, prepared by PJM's market monitor.[14] While the 2014 prices averaged over $60/MWh in some areas of eastern PJM, Western PJM and Ohio prices were much lower (around $40/MWh).

[14] Monitoring Analytics, *2014 State of the Market Report for PJM*, March 12, 2015.

The polar vortex was a very extreme event after 19 relatively mild winters, and it revealed many winterization and fuel supply problems that have since largely been addressed (under similar conditions in winter 2015, the forced outage rate was much improved; 13.4 percent, compared to 22 percent during the polar vortex).[15]

As noted above, PJM has implemented new rules that increase the penalties for non-performance and require firm fuel supplies. Consequently, when such extreme weather occurs again, it can be expected that plant performance and fuel supply will be much improved, and the extreme prices that occurred in January 2014 are much less likely.

V. THE PROPOSED AFFILIATE PPA IS LIKELY TO BE VERY COSTLY TO AEP OHIO'S CUSTOMERS

Q42. PLEASE DESCRIBE HOW AEP OHIO ESTIMATED THE DOLLAR AMOUNTS THAT WOULD BE COLLECTED FROM CUSTOMERS UNDER THE PROPOSED PPA RIDER, IF THE AFFILIATE PPA IS APPROVED.

A42. The PPA Rider Forecast, summarized in witness Pearce's Exhibit KDP-2, is based on a simulation of the market operation of the various plants through 2024,

[15] PJM, *2015 Winter Report*, May 13, 2015, p. 5.

using an hourly, chronological production cost model. The simulation was based on electricity and fuel price forecasts developed internally and supported by witness Bletzacker's testimony. The hourly dispatch results in unit-level hourly generation, market revenues and costs. These costs and revenues were combined with plant fixed costs and RPM capacity revenues to forecast the annual amounts that would be collected through the PPA Rider. The simulation was performed with two additional scenarios, apparently based on raising and lower all load levels by five percent. Inputs and outputs of the PPA Rider Forecast were provided in workpapers and discovery.[16]

Q43. WHAT IS THE ESTIMATED COST TO CUSTOMERS DURING THIS PERIOD BASED ON AEP OHIO'S PPA RIDER FORECAST?

A43. Witness Pearce's Exhibit KDP-2, included here as Exhibit JFW-1, summarizes the results, showing the estimated annual net revenue or cost to 2024 under three scenarios: a base case, a 5% Lower Load Forecast Case, and a 5% Higher Load Forecast Case (Exhibit KDP-2 also presents the average of the High Load and Low Load cases). Results are presented with two assumptions regarding a CO2 tax and additional near-term capacity revenues.

[16] Pearce workpaper WP_1 Competitively Sensitive Confidential; response to SC RPD-1-008c Confidential Attachment 1 Supplemental June 5, 2015; response to SC RPD-2-027 Confidential Attachment 1 Supplemental June 5, 2015, among others.

Of the three cases, the one with the [redacted] energy prices is the 5% Lower Load Forecast Case; the other cases rely on prices [redacted], as I will show later in this testimony. Consequently, I will focus on the 5% Lower Load Case. Based on this case, including a CO2 tax assumption and excluding a small amount of additional near-term capacity revenue, the total cost to customers is $0.9 billion over the ten years. Exhibit KDP-2 does not perform a present value calculation, it presents only a simple sum of the costs over the ten-year period. Using a five percent discount rate, the net present value of the cost to customers over the ten year period, under this case would be $0.8 billion. That is, according to this scenario, the cost of the Indicated Generation output would exceed the market value by $0.8 billion over the ten-year period. This is the net cost that would be collected from AEP Ohio's customers through the proposed PPA Rider over the period.

Under the other scenarios that I consider much less likely, including some with alternate assumptions about capacity revenues, the cost to customers is less or there is a net credit, as shown in Exhibit JFW-1 (Exhibit KDP-2).

Q44. AEP OHIO WITNESSES TESTIFY THAT THE PPA UNITS ARE CURRENTLY UNECONOMIC AND MIGHT BE RETIRED IF THE AFFILIATE PPA IS NOT APPROVED. HOW THEN DOES THE PPA RIDER FORECAST SUGGEST THAT OVER TEN YEARS THERE COULD BE A NET CREDIT FOR CUSTOMERS?

A44. AEP Ohio's PPA Rider Forecast is based on many assumptions developed internally, however the most critical assumptions have to do with energy and capacity prices. While the PPA Units currently have costs well in excess of market revenues, AEP Ohio's forecasts show [redacted] over the coming years.

These assumptions are shown in Exhibit JFW-8 for the Low Load case. Under AEP's energy price forecast, which was prepared in 2013, average energy prices across all hours (Around the Clock, or "ATC") [redacted]. Capacity prices [redacted], from the most recent auction result for 2018/19 ($164.77/MWday) to [redacted].

Q45. HOW DO AEP OHIO'S WITNESSES RECONCILE THEIR CLAIMS THAT THE AFFILIATE PPA WILL BE A GOOD DEAL FOR CUSTOMERS OVER TEN YEARS, WITH THEIR STATEMENTS THAT THE PPA UNITS HAVE A FINANCIAL NEED (PEARCE P. 31)?

A45. They do not reconcile these positions. AEP is a very large company (market capitalization approximately $26 billion) in the business of building electric generation and transmission facilities, among other activities. For such facilities, enormous costs are incurred up front and recovered over decades of service.

According to most of Mr. Pearce's scenarios shown in Exhibit KDP-2, the PPA Units may see losses over the next few years, but will be profitable over the coming ten years. If AEP is unwilling to suffer short-term losses to reap profits over a ten-year horizon, it is in the wrong business. A more likely explanation is that AEP Ohio's real view of the market is not as rosy as Mr. Pearce's analysis presented in this proceeding suggests.

Q46. PLEASE COMMENT ON AEP OHIO'S ENERGY AND CAPACITY PRICE ASSUMPTIONS USED IN THE PPA RIDER FORECAST.

A46. These price assumptions are highly speculative, and very unlikely to be realized. Forward electricity prices reflect [redacted], nor do publicly available projections, for instance, from EIA.

I also note that capacity prices, in concept, are expected to provide the "missing money," the difference between the cost to build a new power plant and its anticipated earnings in energy and ancillary services markets or through a bilateral contract. Therefore, if energy prices rise, the missing money decreases, and capacity prices should decline. So it would seem particularly unlikely that capacity and energy prices [redacted], as Mr. Bletzacker's forecast predicts, especially when there has been adequate new entry resulting in excess capacity at the current energy and capacity price levels.

Q47. HAVE YOU REVIEWED OTHER ASSUMPTIONS AND CALCULATIONS USED IN AEP OHIO'S PPA RIDER FORECAST?

A47. I reviewed some of the testimony and discovery regarding other assumptions underlying the calculations. However, my testimony and my alternative estimate focus on the critical energy and capacity price assumptions, because those assumptions have a large impact on the results, and AEP Ohio's forecasts are particularly questionable. In particular, I gave some attention to AEP Ohio's coal price forecasts and plant fixed cost projections.

Q48. PLEASE BRIEFLY COMMENT ON AEP OHIO'S COAL PRICE FORECASTS.

A48. I reviewed AEP Ohio's coal price forecasts, and determined to accept and not adjust them. These forecasts vary considerable from plant to plant, reflecting differences in sources, coal characteristics, contractual commitments, and transportation costs. However, the forecasts reflect rates of increase [redacted] EIA forecasts.

Q49. PLEASE BRIEFLY COMMENT ON AEP OHIO'S PROJECTIONS OF PLANT FIXED COSTS.

A49. I also reviewed the plant fixed cost projections, and determined not to change them. However, I note that AEP Ohio's witness Thomas clearly suggests that if the Affiliate PPA is approved, AEP Generation Resources, the owner or part owner of the PPA Units and OVEC units, will embark on a spending spree. The ability to pass all costs through to customers will release them from the tough decisions about which capital expenditures are justified by potential market revenues, and which can be deferred.

Specifically, witness Thomas states that the current low level of market revenue for these plants has made "any type of long-term and significant investment very difficult to justify", and that the affiliate PPA would allow the company to "take a longer-term view when making investments" in the plants, leading to "a different investment strategy" (p. 12). Apparently, many expenditures have been deferred, and there would seem to be a good chance that capital expenditures may significantly increase for these plants under an Affiliate PPA that allows them to pass through all costs.

Q50. RETURNING NOW TO THE CRITICAL ENERGY PRICE ASSUMPTIONS, HOW DO MR. BLETZACKER'S FORECASTS COMPARE TO FORWARD PRICES FOR ENERGY?

A50. His energy price forecasts are [redacted] current forward prices, as shown in Exhibit JFW-9A. This exhibit compares the annual averages of Mr. Bletzacker's forecast hourly electricity prices for peak periods to the corresponding peak period forward prices for the AEP Dayton ("AD") Hub point.

Mr. Bletzacker's forecasts are [redacted] the AD Hub forward prices under all three scenarios (High Load, Normal Weather, and Low Load). His lowest forecast, the Low Load case, has annual average on-peak prices [redacted] from 2016 on, while AD Hub forwards remain close to $40/MWh on an annual average basis. After 2020, Mr. Bletzacker's energy prices [redacted], apparently due to the assumption that [redacted] will have this impact.

Exhibit JFW-9A also shows natural gas forward prices for the Dominion South and Henry Hub locations, indicating a major reason why the AD Hub forwards remain at moderate levels – natural gas is actually cheaper at this time in and around Ohio than at the primary North American pricing point at Henry Hub in Louisiana, and these low natural gas prices are not expected to rise very much over the coming years.

Exhibit JFW-9B presents the same price information with monthly detail. Even under the Low Load case, Mr. Bletzacker's monthly average on-peak prices are around [redacted] for most months over the coming years, and peak in the summer over [redacted]; by contrast, AD Hub forward prices are generally [redacted], in the $30 to $50 range. Mr. Bletzacker's off-peak prices (not shown) [redacted], however, the Indicated Generation does not earn much net revenue in these lower-priced hours.

Q51. HOW DO YOU INTERPRET THESE FORWARD PRICES; DO THEY REPRESENT A FORECAST OF FUTURE PRICES?

A51. Electricity forward prices result from market participants' actions to lock in or hedge future prices for electricity sales or purchases. The reported forward prices summarize actual transactions for future delivery months. Both buyers and sellers value the forward price certainty that results from such transactions. The reported forward prices reflect what buyers and sellers collectively consider to be fair prices for electricity in the various future delivery months. While the forward curve is not a forecast, it reflects market participants' expectations of future prices.

Q52. DO FORWARD PRICES ANTICIPATE THE POTENTIAL FOR EXTREME WEATHER AND PRICE SPIKES?

A52. Absolutely. Such concerns are a key motivation for market participants to hedge, and forward prices reflect this. In fact, after the high prices in January 2014, forward prices for future winter periods rose sharply, for multiple years into the future. This is reflected in Exhibit JFW-9B, which shows that while peak period forward prices [redacted] AEP Ohio's forecast that was developed in 2013 before the polar vortex period, the prices [redacted] for winter months. Again, forward prices are what buyers and sellers collectively consider fair prices for electricity in future delivery months, and they definitely reflect the potential for periods of high prices due to extreme weather or any other cause.

Q53. IF MARKET PARTICIPANTS BELIEVED MR. BLETZACKER'S FORECAST OF ELECTRICITY PRICES, HOW WOULD THIS BE REFLECTED IN FORWARD PRICES?

A53. If market buyers believed Mr. Bletzacker's forecast, they would consider current forward prices [redacted], and seek to [redacted]. This [redacted] would [redacted], as reflected in the forecast.

Similarly, if sellers believed Mr. Bletzacker's forecast, they would be [redacted], and they would [redacted]

[redacted]. This behavior too would cause [redacted] on forward prices.

Q54. WHAT IS THE MAIN DRIVER OF ELECTRICITY PRICES IN THE PJM REGION?

A54. The main driver is natural gas prices. Natural gas prices and energy prices (especially peak period prices) tend to move together in the PJM region. AEP Ohio's witness Bletzacker acknowledges this, stating (p. 4), "... natural gas prices will set Ohio's on-peak power prices for the foreseeable future."

Q55. WHAT DO NATURAL GAS FORWARD PRICES SUGGEST WITH RESPECT TO FUTURE NATURAL GAS AND ENERGY PRICES?

A55. Forward prices for natural gas are also shown in Exhibits JFW-9A and JFW-9B, and do not suggest expectations of sharply rising natural gas prices at any time over the horizon. So to the extent natural gas prices drive energy prices, it seems doubtful that energy prices will [redacted], even when CO2 policy comes into effect.

Q56. HOW HAVE FORECASTS OF NATURAL GAS BEEN TRENDING OVER RECENT YEARS?

A56. Forecasts of natural gas prices have been trending downward over the past several years, primarily due to shale gas development driving natural gas prices down.

Exhibit JFW-10 provides a few recent EIA projections that reflect this downward trend. Exhibit JFW-10 shows that in its latest monthly update (Short Term Energy Outlook, September 2015), EIA's forecasts of natural gas prices for 2015 and 2016 are down sharply from the forecast in its Annual Energy Outlook 2015 released only months ago.

Q57. PLEASE SUMMARIZE RECENT TRENDS IN U.S. NATURAL GAS RESERVES AND PRODUCTION.

A57. These developments were summarized in a report by EIA released in December 2014, *U.S. Crude Oil and Natural Gas Proved Reserves, 2013.*[17] This annual report provides details on oil and natural gas *proved reserves*, defined (at p. 1) as the estimated volumes that analysis of geologic and engineering data demonstrates with reasonable certainty (meaning a probability of recovery of 90 percent or greater) are recoverable under existing economic and operating conditions.

With regard to U.S. natural gas proved reserves, the report states the following:

i. U.S. proved reserves of natural gas increased sharply in 2013 to a new record level. The increase in proved natural

[17] U.S. Energy Information Administration, *U.S. Crude Oil and Natural Gas Proved Reserves, 2013*, December 2014, available at http://www.eia.gov/naturalgas/crudeoilreserves/pdf/uscrudeoil.pdf.

gas reserves in 2013 was more than double the U.S. natural gas production that year. (p. 1.)

ii. The increase in U.S. proved reserves is largely a result of the further exploration and development of the Marcellus shale region, which includes Pennsylvania, West Virginia, Ohio and New York, and other shale gas development. Ohio's neighbors Pennsylvania and West Virginia reported the largest net increases in proved reserves of all the states in 2013 (13.5 and 8.3 Trillion cubic feet, or Tcf, respectively). (p. 10.) Pennsylvania and West Virginia were also first and second in total discoveries. At present, only Texas has greater shale gas reserves than Pennsylvania or West Virginia. p. 14, Figure 13. Ohio's proved natural gas reserves also increased substantially, by 2 Tcf. (p. 22.)

iii. In 2013, production from the Marcellus shale region was 1.3 Tcf, while the proved reserves increased 22.1 Tcf to 64.9 Tcf. (p. 15. Table 4.)

Q58. WHAT ARE THE IMPLICATIONS OF THE SUBSTANTIAL INCREASES IN PROVED RESERVES?

A58. Due to new discoveries, proved reserves have been growing much faster than production and consumption. This helps to explain why natural gas price forecasts have been coming down year by year, and why the future dates when prices are expected to cross thresholds such as $5/MMBtu or $6/MMBtu continue to be pushed out.

Q59. WHAT DO YOU CONCLUDE REGARDING MR. BLETZACKER'S ELECTRICITY PRICE FORECAST?

A59. It is possible that the market will be surprised, and electricity prices will [redacted], in the coming years. These prices are uncertain, and Mr. Bletzacker's forecast is one possible scenario. However, there would not appear to be much basis for considering this a likely scenario at this time.

Q60. TURNING NOW TO AEP OHIO'S CAPACITY PRICE FORECAST, PLEASE COMMENT ON THE VIEW THAT CAPACITY PRICES WILL [redacted].

A60. The PJM region has seen and continues to see sufficient new entry by gas-fired and other types of generation under the recent capacity price levels. According to some financial analysts' estimates, new combined cycle power plants are economic at recent capacity price levels.[18] In addition, PJM's interconnection queue currently includes 40,000 MW of proposed gas-fired power plants, in addition to many other projects. So it is not clear that the market would support higher capacity prices, and even more doubtful that the market would support [redacted].

However, capacity prices reflect administrative rules established by PJM, and PJM has recently changed those rules in ways that raised prices in the most recent RPM base residual auction, to the $164.77/MW-day level. Further increases may occur when the Capacity Performance transition ends, for the 2020/21 delivery year.

So while a [redacted] in capacity prices seems unsupported by market dynamics and unlikely, I consider it more likely than Mr. Bletzacker's forecasted [redacted]. And, as I explained earlier, capacity prices provide the missing money not provided by energy prices, so if energy (or capacity) prices rise substantially, the other should be expected to fall.

[18] US Electric Utilities & IPPs, *Further Thoughts on the RPM Auction*, May 28, 2014, pp. 6-7 (evaluating the economics of entry for new combined cycle units, and concluding that the economics are "quite strong").

Q61. TURNING NOW TO YOUR ESTIMATE OF THE COST TO CUSTOMERS OF THE PROPOSED AFFILIATE PPA, PLEASE DESCRIBE THE ASSUMPTIONS YOU ADOPTED FOR YOUR ESTIMATE.

A61. I based my estimate on AEP Ohio's PPA Rider Forecast, Low Load scenario, making only a very few changes, as suggested in the discussion above. In particular, I made the following changes to AEP Ohio's PPA Rider Forecast:

i. I changed the hourly energy prices, instead using energy prices consistent with recent forward prices. Specifically, I began with AEP Ohio's hourly energy prices under the Low Load scenario, as these prices were closest to the AD Hub forward prices, and also reflected more dispersion than the prices under the Weather Normal case. I scaled these hourly prices to match, on average by month and peak/offpeak, AD Hub Day-Ahead forward prices.[19] (For each year of the analysis, this resulted in lowering the prices somewhat in most months, and raising them in other months.) For months beyond the period of the forward prices (beyond October 2020), I scaled AEP Ohio's hourly

[19] Specifically, forward prices from September 5, 2015 were accessed from CME Group, which describes itself as the world's leading and most diverse derivatives marketplace. The AD Hub futures prices accessed were PJM AEP Dayton Hub Day-Ahead Calendar-Month 5 MW Futures, Peak and Off-Peak (contracts D7 and R7), available at http://www.cmegroup.com/trading/energy/electricity/pjm-aep-dayton-hub-off-peak-calendar-month-day-ahead-lmp-swap-futures_contract_specifications.html and http://www.cmegroup.com/trading/energy/electricity/pjm-aep-dayton-hub-peak-calendar-month-day-ahead-lmp-swap-futures_contract_specifications.html.

prices using the same peak and off-peak factors as calculated for the same month in the prior year. I performed no locational adjustment to the hourly prices, despite the fact that at some locations locational prices are generally somewhat lower than AD Hub prices.

ii. Based on these updated prices, I "re-dispatched" the PPA Units to ensure there were no losses in any hour. That is, if AEP Ohio's analysis showed generation in an hour by a unit but the adjusted price was now less than the unit's variable cost (including fuel, consumables, and CO2 cost), the generation was zeroed to eliminate the potential loss. Lacking hourly generation quantities for the OVEC units, I assumed these units would run at full capacity in all profitable hours. I also performed one sensitivity analysis to my re-dispatch assumption.

iii. I also updated AEP Ohio's capacity price projection based on recent auction results (a base residual auction for the 2018/19 delivery year, and capacity performance transition auctions for the 2016/17 and 2017/18 delivery years). Other than those minor revisions, I used AEP Ohio's capacity price projection for 2019 to 2024 [redacted], despite my doubts, expressed earlier in this testimony, that capacity prices will follow such a path.

Q62. WHAT IS THE COST TO CUSTOMERS OF THE PPA RIDER BASED ON YOUR ANALYSIS?

A62. Under these assumptions, the cost to customers through the PPA Rider over the ten-year period would be a cumulative $1.8 billion over the ten-year period, or $1.4 billion on a net present value basis. These results are shown in Table 2 and Exhibit JFW-2 presented earlier. There are losses and costs passed through to customers in every year of the analysis, ranging from $151 million to $240 million. Over the ten years, compared to an average total market revenue of $66.2/MWh, the PPA Units' average cost is $85.3/MWh, as shown in Table 2. The output of these units [redacted] compared to AEP Ohio's forecasts, because under my assumptions, the units are assumed to not operate during hours when energy prices are below variable cost, and, accordingly, [redacted].

Q63. PLEASE PROVIDE A CRITIQUE OF THIS ESTIMATE; DO YOU CONSIDER IT A CONSERVATIVE ESTIMATE OF THE POTENTIAL COST?

A63. I consider my estimate conservative; the cost to customers could be much higher, for a number of reasons.

i. First, I used AEP Ohio's forecast of [redacted] capacity prices. As I have described, the evidence has been that current capacity prices attract more than enough new entry.

ii. Second, I accepted the pattern reflected in AEP Ohio's energy price forecast of [redacted] energy prices [redacted]. I consider this doubtful, because PJM energy prices increasingly tend to reflect natural gas rather than coal generation costs (as AEP Ohio's witness Bletzacker acknowledges, noted above), and natural gas-fired plants emit roughly half the CO2 per MWh as coal plants. This assumption results in the PPA Units' losses actually declining in the years when CO2 policy is in effect under the Low Load case, an illogical result.

iii. Third, I accepted AEP Ohio's plant fixed cost assumptions, despite concerns that, under the proposed arrangement, the AEP companies would have no incentive to control costs, and, as noted above, AEP Ohio's witness Thomas has made it clear that the investment strategy will change if pass-through of all costs is allowed.

On the other hand, the PPA Units could have outcomes better than I have estimated, should coal prices be lower than AEP Ohio's forecast, or energy prices higher than market participants' expectations reflected in forward prices.

Q64. YOU MENTIONED THAT YOU PERFORMED SENSITIVITY ANALYSIS TO YOUR RE-DISPATCH ASSUMPTION. PLEASE DESCRIBE THIS.

A64. My analysis began with the hourly prices and unit generation from the Low Load case, and I then re-dispatched against the modified prices to eliminate any hours in which losses could occur. This approach could miss some additional profitable hours, because the modified prices were increased in some hours with the adjustment to AD Hub prices. To test how much impact this could have on the results, I also performed a calculation under which I dispatched all units at their full installed capacity in all hours when energy prices exceeded the unit variable cost. This sensitivity analysis greatly overstates the potential revenues the units could earn, because it assumes the units could capture all profitable hours with full output. This totally ignores planned and forced outages, and also start-up times, ramp rates, and minimum operating levels, which prevent any such "perfect" dispatch scenario. Under this unrealistic and infeasible assumption, the cost to customers declines from $1.4 billion to $1.1 billion in net present value. Based on this sensitivity analysis, I conclude that a more detailed re-dispatch would have little impact on the result. Based on this sensitivity analysis and the other conservative assumptions in my analysis, I conclude that the $1.4 billion estimate of the net present value cost to customers is conservative.

Q65. ACCORDING TO YOUR ALTERNATIVE SCENARIO, THE INDICATED GENERATION RESOURCES DO NOT PRODUCE REVENUES IN EXCESS OF THEIR COSTS OVER THE COMING TEN YEARS. DOES THIS SUGGEST THAT SOME OF THESE PLANTS MAY NO LONGER BE ECONOMIC TO OPERATE?

A65. Yes; this analysis does call into question whether these resources are economic, and it suggests that perhaps some of the plants (or some units) should instead be retired or repowered.[20] AEP Ohio's witness Vegas acknowledges that the plants may not be economic and that difficult decisions about whether to retire or attempt to sell the plants may be faced in the near future (p. 14).

Q66. HOW WOULD SUCH DIFFICULT DECISIONS BE MADE, IF THE PROPOSED AFFILIATE PPA IS IN PLACE?

A66. This is a problematic aspect of the proposed arrangement. If recent trends in electricity prices continue and it appears these losses will persist for several more years, it would mean some of these plants should probably be retired. But under the proposed arrangement, AEP Ohio, and the affiliated owners of these generating plants, would have no incentive to make the hard choices, as they will be guaranteed customer-funded full cost recovery, plus a return on investment, for

[20] Repowering is the process of replacing older power stations with newer ones, which may result in improved efficiency, increased capacity, or reduced environmental impacts.

many years to come. This is a fundamental problem with the proposed Affiliate PPA and PPA Rider, as I will further discuss in a later section of this testimony.

VI. THE VALUE TO CUSTOMERS OF THE AFFILIATE PPA AS A HEDGE IS DOUBTFUL AND DOES NOT JUSTIFY THE SUBSTANTIAL COST

Q67. WITNESS PEARCE PRESENTS A "HIGH LOAD" CASE, WHICH HE CLAIMS CAPTURES THE IMPACT THE LOAD VOLATILITY CAN HAVE ON THE PPA RIDER REVENUES AND COSTS (PP. 11-12). FIRST, PLEASE DESCRIBE THIS HIGH LOAD CASE.

A67. Mr. Pearce describes the High Load case as intended to "show what can happen when loads differ from normal, such as during severe winter or summer seasons or due to other factors such as changes in the economy." p. 13. The High Load case is apparently based on hourly prices provided by witness Bletzacker, which are then run through the same hourly dispatch model used for AEP Ohio's other cases. On the basis of this approach, Mr. Bletzacker asserts (p. 10), "From 2015 to 2030, a sustained 5% load increase results in a 18.5% around-the-clock ("ATC") wholesale price increase…"

Q68. HOW DID WITNESS BLETZACKER CALCULATE THE PRICES FOR THE HIGH LOAD CASE?

A68. Mr. Bletzacker explains (p. 10) that he quantified how PJM power prices change when load deviates from average by "examining the PJM merit-order stack" while holding all assumptions other than load unchanged. That is, he calculated the price impact of moving five percent up the merit order stack.

Q69. PLEASE COMMENT ON THIS APPROACH TO CALCULATING THE POTENTIAL VOLATILITY OF PJM POWER ANNUAL AVERAGE ATC PRICES.

A69. This is a totally unrealistic estimate of the potential impact of higher loads on annual average prices, and of the potential volatility of PJM power prices. Mr. Bletzacker has greatly overstated the potential volatility, by 1) ignoring how the supply stack would shift, both over the short-term and long-term, in response to a large change in load, and 2) modeling an unrealistic five percent increase in load over all hours of the year.

Mr. Bletzacker's approach is reasonable for calculating the price impact of a sudden, unexpected increase in load relative to supply, for instance, the impact of a major generating unit tripping offline. However, a five percent increase in load does not occur suddenly or unexpectedly. As load increases hour to hour and day to day, additional units are dispatched, and the merit-order stack changes. System operation involves maintaining a mix of base-load, mid-merit, and peaking plants, and as load levels rise, additional plants are dispatched. As a result, the merit-order stack may shift in a similar way to load over time, resulting in much smaller changes in prices than under Mr. Bletzacker's assumption of a fixed supply stack.

Furthermore, while a five percent increase in load can indeed occur due to severe winter or summer weather, such weather is very unlikely to persist for more than a few weeks per season; it is totally unrealistic to assume such weather and resulting prices over 52 weeks and ten years, as Mr. Bletzacker has done. Instead, annual average prices will reflect the impact of periods of severe weather averaged together with many other periods of less extreme weather. So in addition to overstating the short-term impact of severe weather, Mr. Bletzacker has also unrealistically assumed such weather could persist for 52 weeks.

Over longer periods of time, load can increase five percent due to economic growth. However, such economic growth develops slowly over a period of years, and is anticipated well in advance. Such load growth would lead to new entry and/or deferred retirements, again changing the supply stack and dampening or eliminating any impact on prices.

As a result of these flaws, Mr. Bletzacker's approach greatly overstates the potential volatility of PJM power prices.

Q70. MR. BLETZACKER USED A MERIT-ORDER STACK TO ESTIMATE THE RELATIONSHIP BETWEEN LOAD LEVELS AND ENERGY PRICES. IS ACTUAL DATA ON THIS RELATIONSHIP AVAILABLE?

A70. Yes. A better approach to understanding how prices change with loads is to simply examine actual hourly load levels and corresponding locational prices. Such data suggests that five percent changes in load have much less than an 18.5 percent impact on prices. For example, Exhibit JFW-11 shows the relationship between AEP zone load and AEP zone locational prices for a typical peak hour (noon to 1 PM) across all days in 2013. The trend reflects roughly a six percent increase in price as a result of a five percent increase in load (coefficient 0.0024, from the exhibit, x 5% x 20,000 MW / $40/MWh).

Q71. MR. PEARCE CLAIMS THAT CUSTOMERS WOULD SEE A "VOLATILITY REDUCTION BENEFIT" OF $1/MWH FROM THE PPA RIDER (P. 16). PLEASE COMMENT ON THIS.

A71. The alleged benefit is based on a simple average of the High Load and Low Load cases; this makes no sense, because the High Load case, extended over 10 years (rather than a few weeks), is totally unrealistic (as explained above), and, therefore, no probability should be assigned to it.

Q72. WOULD THE AFFILIATE PPA AND PPA RIDER TEND TO STABILIZE SSO CUSTOMERS' RATES?

A72. The Affiliate PPA and PPA Rider would not necessarily lead to more stable rates for SSO customers. SSO customers are served by one- to three-year full requirements contracts resulting from competitive auctions. As a result of this process, the rates SSO customers pay will be established through blending the results of multiple auctions held months or years in advance of delivery. The rate resulting from each auction will tend to reflect forward prices at the time of the auction plus a markup. Forward prices for delivery periods several months or a few years out tend to be fairly stable. Consequently, the rates paid by SSO customers will tend to be fairly stable over time. This has been seen in the auctions held over the past several years to serve various Ohio utilities' SSO customers.

The PPA Rider will be reconciled on an annual basis. Therefore, it will result in a bill credit or charge in each year depending upon whether market prices were relatively high or low in the prior year. The PPA Rider amounts to be collected from customers in one year will tend to be positive [or negative] when PJM market prices were relatively low [or high] in the *prior* year, which would generally occur due to the peculiar weather and other conditions of that year. Thus, as SSO customers' rates change from year to year reflecting movements in forward prices, the changes in the PPA Rider amounts may move the same direction or the opposite direction to SSO rates. It cannot be assumed, therefore, that PPA Rider will tend to hedge or stabilize SSO customers' rates.

The important point is that, as described in the prior section of this testimony, the PPA Rider, passing through the costs of the Indicated Generation, is likely to result be very costly to customers over the long term. Any impact it may have on the year to year "stability" of rates is likely to be relatively unimportant to SSO customers.

Q73. FOR CUSTOMERS WHO ARE SUPPLIED BY COMPETITIVE RETAIL SUPPLIERS, WOULD THE PPA RIDER TEND TO STABILIZE THEIR RATES?

A73. Customers who are instead served by competitive retail suppliers may be exposed to market price fluctuations, or may pay fairly stable rates, depending upon the choices they make that reflect their preferences. The potential impact of the proposed Affiliate PPA and PPA Rider on the trajectory of such customers' rates would also depend on the extent to which the Indicated Generation net costs in one year are uncorrelated or anti-correlated with the costs at which the customer will be supplied in the following year, when the Indicated Generation net costs will be collected through the PPA Rider. To the extent the PPA Rider amounts might be uncorrelated with market price fluctuations and tend to stabilize some customers' bills, they would do so primarily for those customers who have by their choices indicated a preference for market-based prices rather than stable prices. Again, the PPA Rider would be lagged one year, so its amounts could move in the same direction or opposite direction to the rates shopping customers are paying at any time.

Customers supplied by competitive retail suppliers have made decisions about how they wish their electric supply to be priced as market prices rise and fall, balancing cost, risk, and other considerations. The PPA Rider would add an additional element that might work counter to customers' desires and choices.

Q74. FOR CUSTOMERS WHO HAVE ENTERED INTO LONGER-TERM FULL REQUIREMENTS SUPPLY ARRANGEMENTS, WOULD THE PPA RIDER PROVIDE BENEFITS?

A74. No. Such customers are even more hedged than SSO customers.

VII. THE AFFILIATE PPA ELIMINATES INCENTIVES TO CONTROL COSTS AND MAXIMIZE REVENUES, WHILE CREATING THE ABILITY AND INCENTIVE TO EXERCISE MARKET POWER

Q75. YOU STATED THAT THE PPA RIDER ARRANGEMENT WOULD CREATE PROBLEMATIC INCENTIVES. CAN YOU GIVE A SPECIFIC EXAMPLE?

A75. Yes. Consider, for example, future programs to reduce power plant fixed costs. Under market arrangements, if the plant operators were able to reduce fixed costs, it would increase the profits to their owners, primarily AEP Ohio's affiliate in this instance. Consequently, the plant owners would have incentives to pressure plant management to accomplish any such potential cost improvements.

By contrast, under the proposed arrangement, the Indicated Generation's actual costs net of market revenues would be passed through to retail customers. The plant owners operating under such arrangements would, therefore, see no benefit from any such cost reductions, and would have little if any reason to encourage management to pursue them.

Q76. AEP OHIO'S AFFILIATES OWN OTHER ELECTRIC GENERATION IN THE PJM MARKETS. DOES THIS RAISE ANY ISSUES WITH REGARD TO THE PROPOSED AFFILIATE PPA?

A76. Yes. The Indicated Generation competes with AEP Ohio's affiliates' other generation in the PJM markets. Under the PPA Rider, AEP Ohio would not benefit from incremental Indicated Generation sales and net revenues, as these would pass through to customers. However, incremental output from these plants will tend to reduce the energy prices available to the other affiliated plants in the western PJM market area.

Therefore, AEP Ohio would have some incentive to run these plants in a manner that would benefit the affiliated generation. Specifically, they would have incentives to run them less, and to offer them at higher prices, to support higher clearing prices. This could lead to realizing less than the full value of the Indicated Generation assets in the PJM markets, and higher net costs to customers under PPA Rider. It would also tend to raise the energy prices paid by all other consumers in the same market area to the benefit of AEP Ohio's unregulated affiliate.

Q77. WOULD YOU EXPECT AEP OHIO TO ALWAYS MAKE COMPETITIVE OFFERS IN THE PJM MARKETS?

A77. No. AEP Ohio affiliates own a considerable amount of capacity in PJM. In light of these substantial holdings, it makes sense for AEP companies to consider market conditions in formulating bidding strategies for energy and capacity markets, to maximize shareholder value. Offering some capacity at higher prices, for example, can contribute to higher clearing prices earned by the rest of the portfolio. Such economic withholding can be profitable for a company such as AEP with a large portfolio, even if it reduces total sales somewhat.

Q78. AEP OHIO HAS PROPOSED THAT PUCO STAFF WOULD PERIODICALLY REVIEW THE PPA RIDER GENERATION COSTS AND REVENUES. WOULD SUCH OVERSIGHT ADDRESS THESE CONCERNS ABOUT THE INCENTIVES CREATED BY THE ARRANGEMENT?

A78. No. Such oversight would not affect the weak incentives to control costs and maximize revenues, or the incentive and ability to exercise market power, created by the proposed arrangement. While perhaps AEP Ohio's affiliate would not engage in obvious and transparent withholding strategies, there are many complexities involved in plant operation and bidding that provide broad scope for justifying a range of strategies. I understand this topic will be further discussed by other OCC witnesses.

VIII. AN ALTERNATIVE PLAN TO ALLOCATE FINANCIAL RISK IS ESSENTIAL IF ANY AFFILIATE PPA IS APPROVED

Q79. WHAT DO YOU RECOMMEND WITH REGARD TO THE PROPOSED AFFILIATE PPA?

A79. I recommend that the PUCO simply deny AEP Ohio's request for the Affiliate PPA, finding that the costs and risks of the Indicated Generation should not be imposed on customers. The proposal would shift the costs and risks associated with the Indicated Generation to customers, while eliminating the owners' incentives to manage the costs and risks of these plants, and that should not be allowed.

Q80. IF THE PUCO FINDS THE NOTION OF PROVIDING CUSTOMERS A LONG-TERM PHYSICAL HEDGE ATTRACTIVE, WHAT APPROACH WOULD YOU RECOMMEND?

A80. If the PUCO wishes to provide customers a long-term physical hedge, the best approach would be to hold a competitive procurement. First, the PUCO would identify the objectives of the procurement and the criteria for evaluating proposals. For example, the evaluation of offered resources might consider environmental characteristics, reliability and fuel supply, fuel and resource diversity, and operational flexibility, in addition to cost and other characteristics.

Q81. YOU MENTIONED EARLIER THAT THE FEBRUARY ORDER REQUIRES AEP OHIO TO PROPOSE AN ALTERNATIVE PLAN TO ALLOCATE FINANCIAL RISK. SHOULD THE PUCO DECIDE TO MOVE FORWARD WITH AN AFFILIATE PPA IN SOME FORM, WOULD SUCH AN ALTERNATIVE PLAN BE IMPORTANT?

A81. Yes, an alternative plan to allocate financial risk would be crucial. As discussed in the previous sections of my testimony, the Affiliate PPA, as proposed by AEP Ohio, is likely to be very expensive for customers. In addition, it would eliminate any incentive for AEP Ohio or the affiliated owners of the Indicated Generation to control costs or to maximize revenues. In fact, as noted in the previous section, due to AEP Ohio's large portfolio in PJM, there would actually be an incentive to not maximize revenues.

Q82. DID AEP OHIO PROPOSE AN APPROACH TO ALLOCATING FINANCIAL RISK?

A82. No. Witness Vegas claims (p. 29) that AEP Ohio's proposal properly allocates risk based on the possibility that recovery through the PPA Rider could be disallowed, or the Affiliate PPA might not be renewed, as a result of Commission review and audit. However, this falls far short of allocating financial risk to AEP Ohio. I understand that other OCC witnesses will explain why the review and audit provisions fall short of addressing the incentive issues that would arise under the proposed affiliate PPA.

Q83. HOW WOULD YOU PROPOSE THAT THE FINANCIAL RISKS OF AN AFFILIATE PPA BE ALLOCATED BETWEEN AEP OHIO AND CUSTOMERS, IF AN AFFILIATE PPA IS APPROVED?

A83. If the Affiliate PPA is not rejected, a less preferred approach would be to modify it (or the associated PPA Rider) so that the arrangement is cost-neutral for customers, at least in an ex ante, forecast expected value sense, and so that the actual net cost or benefit of the Indicated Generation would be shared between AEP Ohio (and/or its affiliates) and customers. Such a sharing rule would provide customers some protection, and would also restore some of the incentives to the AEP companies to maximize revenues and minimize costs that the Affiliate PPA and PPA Rider, as proposed, eliminate.

Q84. PLEASE ELABORATE ON HOW SUCH A SHARING RULE MIGHT WORK.

A84. A sharing rule could take the form of a typical incentive mechanism. First, a "benchmark" for the Indicated Generation net cost would be established. The benchmark could be established based on a one-time projection of the resources' expected market value, or it could be determined based on a formula that takes into account actual market prices and perhaps other uncertainties over time. For example, if my alternative calculation were used as the benchmark, the expected $1.4 billion net present value cost would be shifted to AEP Ohio, if my assumptions were to prove correct.

Then each year, if the actual Indicated Generation net cost equals the market-based benchmark value, the PPA Rider would be zero and have no effect. Whenever actual net cost differs from the benchmark, the sharing rule would take effect. For instance, the sharing rule might call for half of the net cost or benefit relative to the benchmark to be passed through to customers through PPA Rider, with half retained by AEP Ohio (and perhaps passed through to AEP Ohio's affiliate through the PPA arrangement).

Under this approach, in effect, AEP Ohio (and/or its affiliate) would be rewarded through the PPA Rider when the Indicated Generation is valuable relative to the market-based benchmark, and AEP Ohio would bear half the cost when it is costly relative to the benchmark. But the risk to AEP Ohio would be reduced by sharing the cost or benefit relative to the benchmark 50/50 with customers. The cost and risk to customers would similarly be reduced by centering the arrangement on a market-based benchmark (so there is no built-in subsidy), and imposing only 50 percent of the cost or benefit relative to the benchmark on customers.

Q85. WHAT ARE THE ADVANTAGES OF THIS APPROACH COMPARED TO THE AFFILIATE PPA AND PPA RIDER AS AEP OHIO HAS PROPOSED THEM?

A85. There are three advantages to this modification of the arrangement.

i. First, by establishing in advance an explicit benchmark (or benchmark formula) based on expected market conditions, there is no built-in subsidy or ex ante expected amount to be collected from customers through PPA Rider. While AEP Ohio suggests that the arrangement will result in a net benefit to customers over the coming years, using more reasonable forecasts in the estimate results in a substantial expected cost to customers ($1.4 billion net present value), as explained in an earlier section of this testimony. If the benchmark reflects an unbiased estimate of the expected market value, the expected cumulative value for customers over the coming years would be zero, at least at the time it is established (AEP Ohio or its affiliates would bear the expected cost of the arrangement).

ii. Second, as a result of the sharing rule, AEP Ohio and its affiliates would have more incentive to maximize revenues and minimize costs, incentives that are eliminated under the proposed PPA Rider.

iii. Third, the risk to customers would be 50 percent mitigated by such a sharing rule, compared to the proposed Affiliate PPA and PPA Rider (in addition to removing the subsidy).

Q86. AEP OHIO'S WITNESS PEARCE STATES THAT THE PPA UNITS HAVE A NEAR TERM FINANCIAL NEED (P. 31), BUT APPARENTLY BELIEVES THE UNITS WILL BECOME PROFITABLE IN THE COMING YEARS (EXHIBIT KDP-2). IF THE FINANCIAL NEED IS ONLY SHORT-TERM, WOULD YOUR PROPOSED SHARING RULE ADDRESS THIS?

A86. No. The proposed sharing rule would be based on a benchmark that reflects the forecast market value of the assets, which would reflect the unfavorable near-term circumstances. It would not provide the near-term subsidy that the Affiliate PPA, as proposed, would provide, and that Mr. Pearce and Mr. Vegas suggest is needed.

Q87. IF THE PUCO WILL NOT APPROVE THE AFFILIATE PPA AND PPA RIDER AS PROPOSED, BUT WOULD LIKE TO HELP THE INDICATED GENERATION SURVIVE THROUGH THE NEAR-TERM TO THE POSSIBLE BETTER DAYS, WHAT MECHANISM WOULD YOU PROPOSE?

A87. If the goal is primarily just to help the generation bridge through the next few years, an incentive mechanism structure could also be used, but the structure should be different. One approach could be the following. During an initial period, such as the first three years, the PPA Rider would operate as AEP Ohio has proposed, except that 50 percent of the net cost or benefit of the Indicated Generation rather than 100 percent would be collected from customers through the PPA Rider. This would likely result in customers providing a substantial, if partial, subsidy during the initial period.

After the initial period, the sharing rule would change to 25 percent to customers for annual net costs and 75 percent for net benefits. This asymmetric sharing rule would continue until such time as customers were made whole for the cost and risk incurred in the first years of the arrangement, if this ever occurs. For instance, the termination rule might call for the PPA Rider and/or the associated Affiliate PPA to terminate once the net present value of the benefits to customers reached 50 percent of the maximum cumulative present value net cost to customers during the initial period. If the termination condition is never met, customers would continue to asymmetrically share in the net costs or revenues for a maximum of ten years.

Q88. WHAT WOULD BE THE ADVANTAGES OF THIS APPROACH?

A88. There are two advantages to this approach.

i. First, AEP Ohio and/or its affiliate would incur only 50 percent of the net cost of the Indicated Generation during the coming years, helping them through this difficult period. Customers would incur the other 50 percent.

ii. Second, customers might eventually realize a net benefit to the arrangement, if indeed prices rise such that the Indicated Generation becomes economic.

This approach would result in some incentives to maximum revenues and control costs, and it would potentially result in the PPA Rider and Affiliate PPA terminating earlier, returning all cost and revenue responsibility to the owners.

In addition, compared to AEP Ohio's proposal, this approach might better accommodate a difficult decision to retire some or all of the Indicated Generation in the coming years.

Q89. DO YOU RECOMMEND THE PUCO CONSIDER THESE ALTERNATIVE APPROACHES?

A89. I recommend that the proposed Affiliate PPA be rejected and none of the cost and risk of the Indicated Generation be imposed on customers. These alternative approaches for allocating financial risk should be considered only if an Affiliate PPA will be allowed in some form.

Q90. DOES THIS COMPLETE YOUR PRE-FILED TESTIMONY?

A90. Yes it does. However, I understand that I may be asked to update or supplement my testimony based on new information that may become available.

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony of James F. Wilson, PUBLIC VERSION, on Behalf of the Office of the Ohio Consumers' Counsel* was served via electronic transmission this 11th day of September, 2015 upon the parties below.

/s/ Jodi J. Bair
Jodi J. Bair
Assistant Consumers' Counsel

SERVICE LIST

Steven.beeler@puc.state.oh.us
Werner.margard@puc.state.oh.us
haydenm@firstenergycorp.com
jmcdermott@firstenergycorp.com
scasto@firstenergycorp.com
jlang@calfee.com
talexander@calfee.com
myurick@taftlaw.com
tony.mendoza@sierraclub.org
todonnell@dickinsonwright.com
tdougherty@theOEC.org
twilliams@snhslaw.com
jeffrey.mayes@monitoringanalytics.com
ricks@ohanet.org
tobrien@bricker.com
mhpetricoff@vorys.com
mjsettineri@vorys.com
glpetrucci@vorys.com
mdortch@kravitzllc.com
joliker@igsenergy.com
mswhite@igsenergy.com
sechler@carpenterlipps.com
gpoulos@enernoc.com
sfisk@earthjustice.org
Kristin.henry@sierraclub.org
chris@envlaw.com

Attorney Examiners:

Sarah.parrot@puc.state.oh.us
Greta.see@puc.state.oh.us

stnourse@aep.com
mjsatterwhite@aep.com
msmckenzie@aep.com
mkurtz@BKLlawfirm.com
kboehm@BKLlawfirm.com
jkylercohn@BKLlawfirm.com
sam@mwncmh.com
fdarr@mwncmh.com
mpritchard@mwncmh.com
Kurt.Helfrich@ThompsonHine.com
Scott.Campbell@ThompsonHine.com
Stephanie.Chmiel@ThompsonHine.com
lhawrot@spilmanlaw.com
dwilliamson@spilmanlaw.com
charris@spilmanlaw.com
Stephen.Chriss@walmart.com
Schmidt@sppgrp.com
Bojko@carpenterlipps.com
hussey@carpenterlipps.com
mfleisher@elpc.org
msmalz@ohiopovertylaw.org
cmooney@ohiopartners.org
ghull@eckertseamans.com
msoules@earthjustice.org
jennifer.spinosi@directenergy.com
laurie.williams@sierraclub.org

Exhibit JFW-1: AEP Ohio Exhibit KDP-2

FORECASTED OHIO PPA RIDER IMPACTS
COMBINED CARDINAL, CONESVILLE, STUART, ZIMMER and OVEC
October 31, 2015 through December 31, 2024
Dollars in Millions (Nominal)

Year	2015 (Oct-Dec)	2016	2017	2018	2019	2020	2021	2022	2023	2024	TOTALS
5% Higher Load Forecast											
PJM Revenues, excluding PJM Capacity Performance	$188	$1,271	$1,328	$1,385	$1,426	$1,480	$1,659	$1,758	$1,734	$1,785	$14,020
Agreement Costs, including CO_2 tax	$233	$1,058	$1,088	$1,171	$1,220	$1,248	$1,287	$1,549	$1,503	$1,588	$11,946
Net PPA Rider Credit / (Charge) excl. PJM CP, including CO_2 tax	($35)	$213	$239	$214	$206	$231	$372	$207	$230	$197	$2,074
Net with Maximum PJM Capacity Performance, excluding CO_2 tax	($35)	$275	$338	$251	$206	$231	$372	$493	$502	$462	$3,113
Average of High Load and Low Load Forecast											
PJM Revenues, excluding PJM Capacity Performance	$180	$1,057	$1,070	$1,168	$1,189	$1,249	$1,359	$1,538	$1,495	$1,539	$11,845
Agreement Costs, including CO_2 tax	$228	$1,019	$1,029	$1,110	$1,138	$1,178	$1,198	$1,477	$1,419	$1,474	$11,271
Net PPA Rider Credit / (Charge) excl. PJM CP, including CO_2 tax	**($48)**	**$38**	**$42**	**$58**	**$51**	**$71**	**$161**	**$60**	**$76**	**$65**	**$574**
Net with Maximum PJM Capacity Performance, excluding CO_2 tax	($48)	$100	$138	$95	$51	$71	$161	$326	$324	$319	$1,537
Weather Normalized Case											
PJM Revenues, excluding PJM Capacity Performance	$180	$993	$1,038	$1,151	$1,202	$1,246	$1,325	$1,462	$1,484	$1,542	$11,644
Agreement Costs, including CO_2 tax	$230	$1,042	$1,064	$1,136	$1,186	$1,211	$1,240	$1,490	$1,478	$1,536	$11,613
Net PPA Rider Credit / (Charge) excl. PJM CP, including CO_2 tax	($50)	($49)	($26)	$15	$16	$34	$85	($8)	$6	$7	$31
Net with Maximum PJM Capacity Performance, excluding CO_2 tax	($50)	$13	$71	$53	$16	$34	$85	$261	$270	$277	$1,031
5% Lower Load Forecast											
PJM Revenues, excluding PJM Capacity Performance	$162	$842	$813	$952	$953	$1,018	$1,060	$1,319	$1,256	$1,294	$9,669
Agreement Costs, including CO_2 tax	$223	$980	$969	$1,050	$1,056	$1,107	$1,110	$1,406	$1,335	$1,360	$10,597
Net PPA Rider Credit / (Charge) excl. PJM CP, including CO_2 tax	($62)	($137)	($156)	($98)	($103)	($89)	($50)	($87)	($79)	($67)	($927)
Net with Maximum PJM Capacity Performance, excluding CO_2 tax	($62)	($75)	($80)	($60)	($103)	($89)	($50)	$159	$146	$156	($39)

Exhibit JFW-2: Revised PPA Rider Cost Estimate

[redacted]

Exhibit JFW-4: Generation Retirements in PJM, 2010 to 2020 (MW)

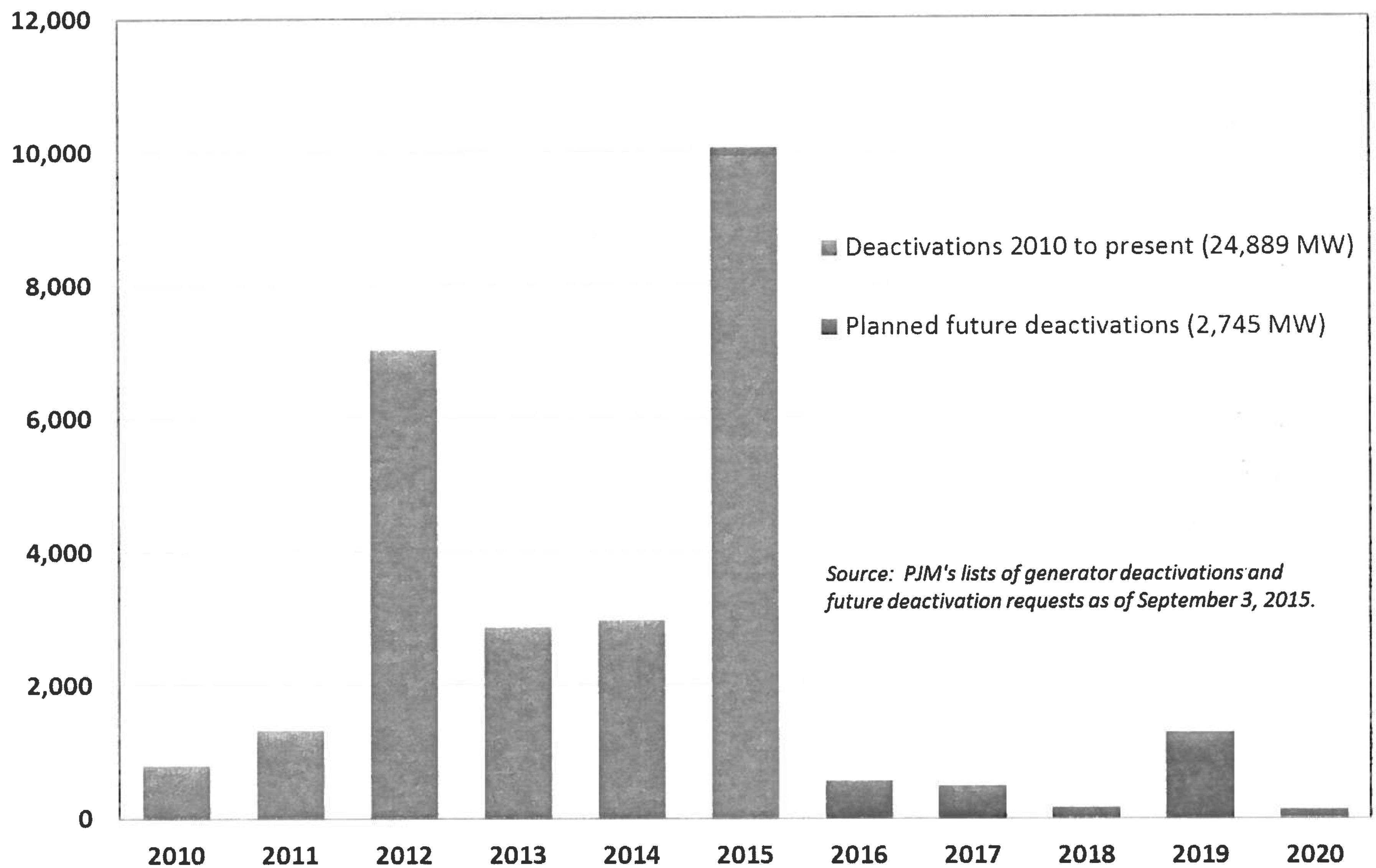


Exhibit JFW-4: Generation Retirements in PJM, 2010 to 2020

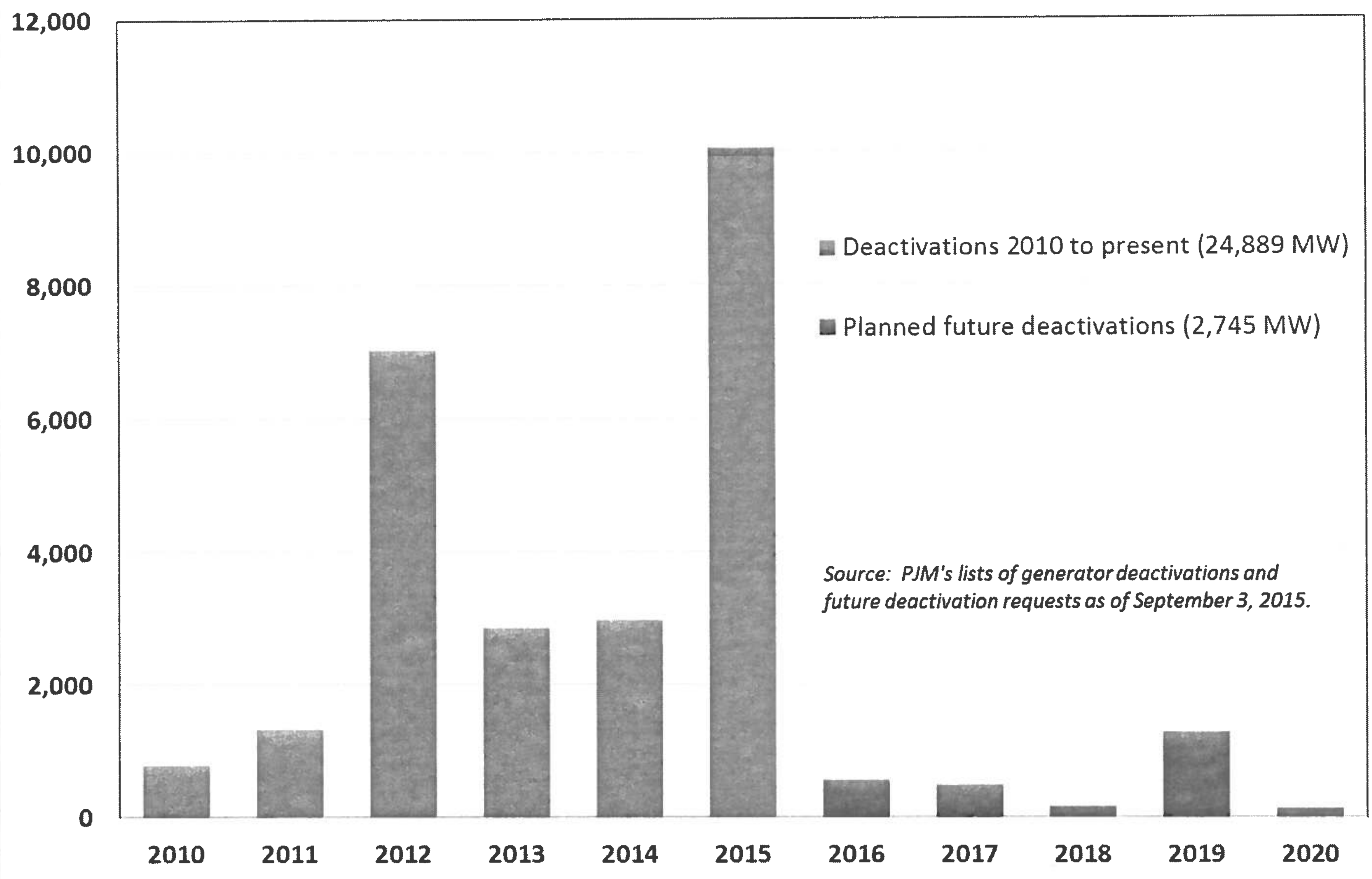


Exhibit JFW-5: Ohio Electric Generation and Net Interstate Trade, 1990 - 2013
(Annual GWh)

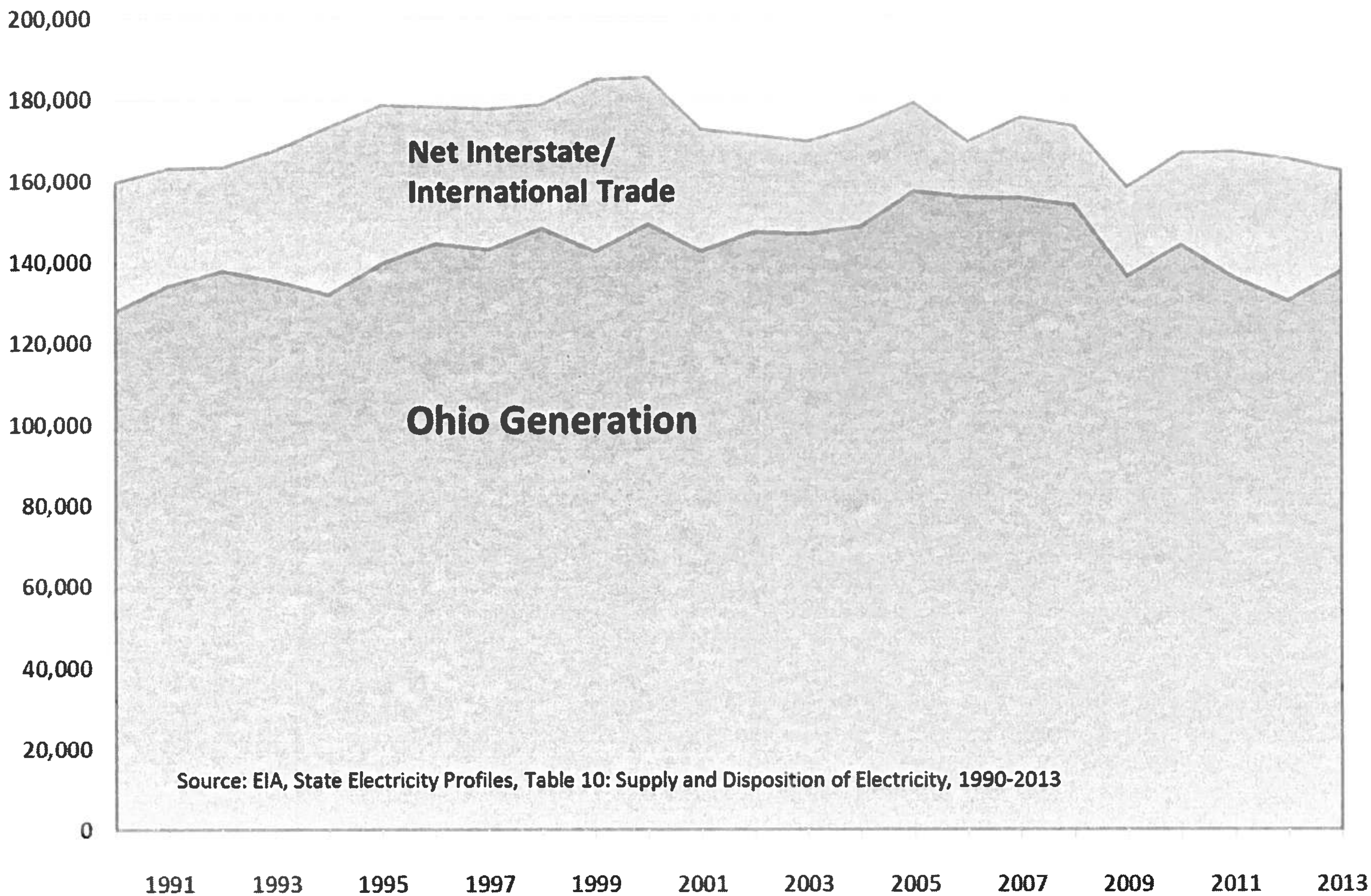
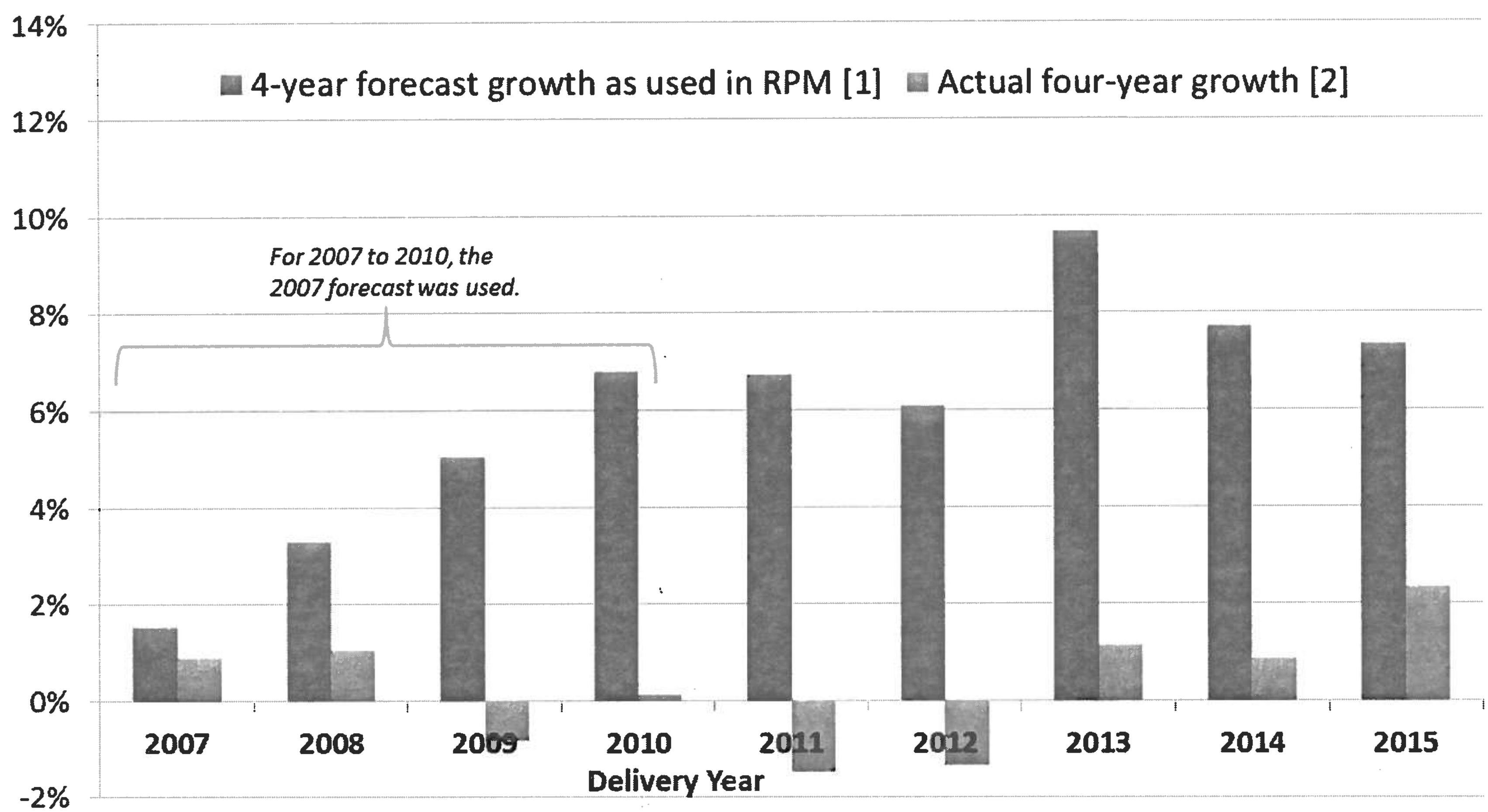


Exhibit JFW-6: PJM Forecast v Actual Peak Load Growth for RPM RTO Region



[1] **Forecast growth as used in RPM** compares the three year forward forecast for a delivery year to the weather-normalized actual peak load for the year prior to the forecast (for example, for the 2011 delivery year, the growth from the 2007 weather-normalized peak to 2011 based on the Jan. 2008 forecast); for 2007 through 2010 delivery years, the 2007 forecast and 2006 weather-normalized actuals were used.
[2] **Actual/updated growth** compares the actual weather-normalized peak (or updated forecast, for 2015) to the same weather-normalized peak load (for the 2011 delivery year, growth from the 2007 weather-normalized peak to the 2011 weather-normalized peak). All values adjusted to consistent delivery year RTO geographic footprint.

Exhibit JFW-7: Load-weighted Real-Time LMPs, 2014

(from Monitoring Analytics' 2014 State of the Market Report for PJM, p. 115)

Figure 3-29 PJM real-time, load-weighted, average LMP: 2014

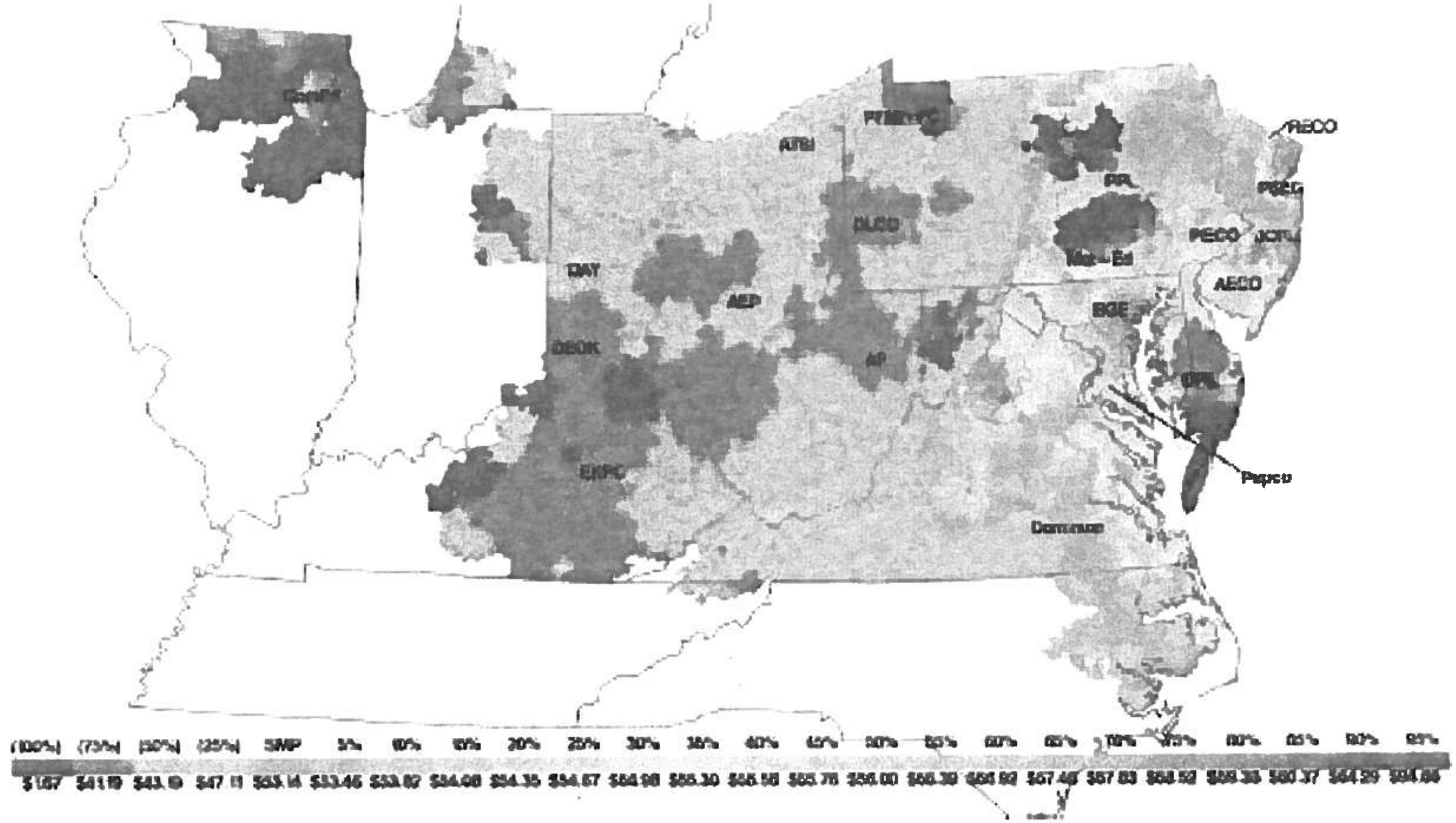


Exhibit JFW-8: AEP Ohio Energy and Capacity Price Assumptions

[redacted]

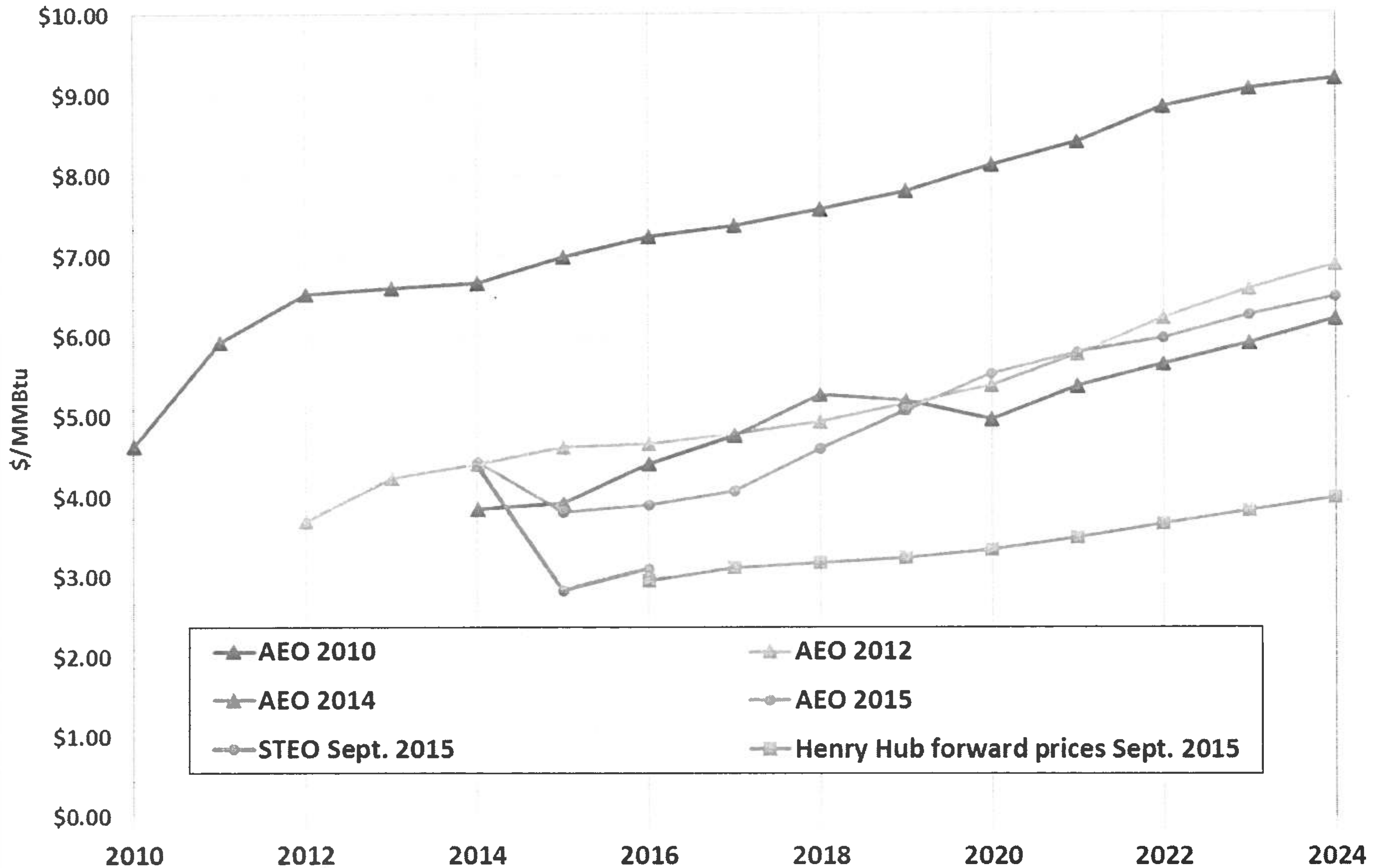
Exhibit JFW-9A: AEP Ohio Forecast Peak Hour Prices and AD Hub Forward Prices

[redacted]

Exhibit JFW-9B: AEP Ohio Forecast Peak Hour Prices and AD Hub Forward Prices

[redacted]

Exhibit JFW-10: EIA Projections of Henry Hub Natural Gas Prices



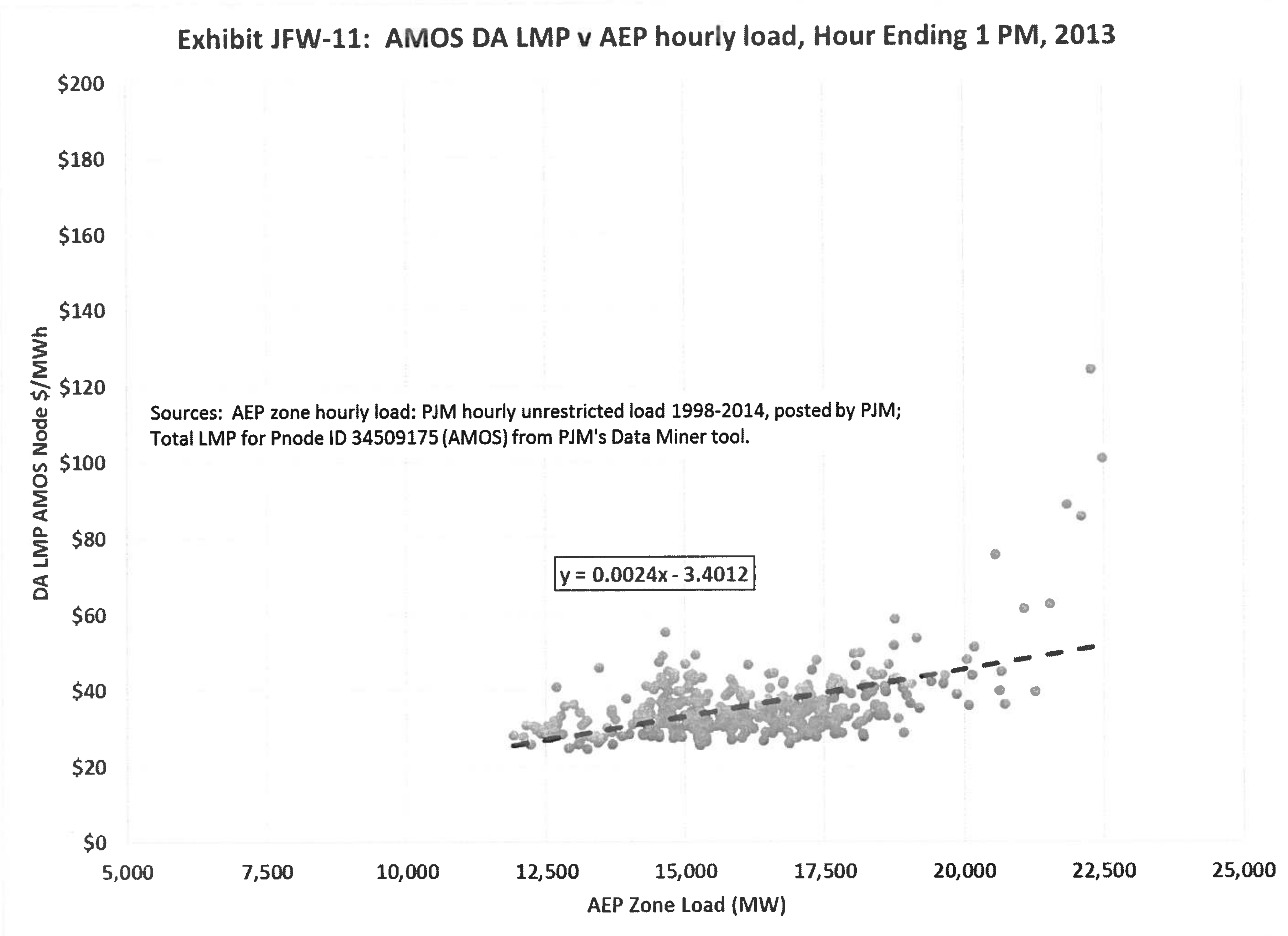


Exhibit JFW-11: AMOS DA LMP v AEP hourly load, Hour Ending 1 PM, 2013
$200
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
DA LMP AMOS Node $/MWh
Sources: AEP zone hourly load: PJM hourly unrestricted load 1998-2014, posted by PJM;
Total LMP for Pnode ID 34509175 (AMOS) from PJM's Data Miner tool.
y = 0.0024x - 3.4012
5,000
7,500
10,000
12,500
15,000
17,500
20,000
22,500
25,000
AEP Zone Load (MW)

James F. Wilson
Principal, Wilson Energy Economics

4800 Hampden Lane Suite 200
Bethesda, Maryland 20814 USA

Phone: (240) 482-3737
Cell: (301) 535-6571
Fax: (240) 482-3759
Email: jwilson@wilsonenec.com
www.wilsonenec.com

SUMMARY

James F. Wilson is an economist with 30 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, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He 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.

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.

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.

EDUCATION

MS, Engineering-Economic Systems, Stanford University, 1982

BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.
- Panelist on a FERC technical conference on capacity markets.
- Affidavit on the potential for market power over natural gas storage.
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.
- Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
- Participated in a panel teleseminar on resource adequacy policy and modeling.
- Affidavit on opt-out rules for centralized capacity markets.
- Affidavits on minimum offer price rules for RTO centralized capacity markets.
- Evaluated electric utility avoided cost in a tax dispute.
- Advised on pricing approaches for RTO backstop short-term capacity procurement.

- 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.

EARLIER PROFESSIONAL EXPERIENCE

LECG, LCC, Washington, DC 1998–2009.
Principal

- 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 Federal Energy Regulatory Commission ("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 market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
- Testimony on 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.
- Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
- Testimony on the causes of California natural gas price increases during 2000-2001 and 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's 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. Testimony on price mitigation measures.
- 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 electric utilities in the process of forming an RTO.
- 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 locational market power, 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 role of regional transmission organizations in market monitoring.
- Prepared market power analyses in support of 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 a state commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.
- 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 market power issues and policy options for providing system balancing services.

ICF RESOURCES, INC., Fairfax, VA, 1997–1998.
<u>Project Manager</u>

- 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.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator 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):

- 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:

- 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 gas industry unbundling and restructuring.
- 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; power purchases; conversion to gas.
- Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
- 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. Developed a forecasting system for staff use.
- Analyzed potential benefits of diversification of suppliers for a natural gas pipeline company.
- Evaluated uranium contracting strategies 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 oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS

Indicated Market Participants v. PJM Interconnection, L.L.C., FERC Docket No. EL15-88, Affidavit on behalf of the Joint Consumer Representatives and Interested State Commissions, August 17, 2015.

ISO New England Inc. and New England Power Pool Participants Committee, FERC Docket No. ER15-2208, Testimony on Behalf of the New England States Committee on Electricity, August 5, 2015.

Joint Consumer Representatives v. PJM Interconnection, L.L.C., FERC Docket No. EL15-83, Affidavit in Support of the Motion to Intervene and Comments of the Public Power Association of New Jersey, July 20, 2015.

In the Matter of the Tariff Revisions Filed by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., Regulatory Commission of Alaska Case No. U-14-111, Testimony on Behalf of Matanuska Electric Association, Inc., May 13, 2015.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 14-1297-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel and Northeast Ohio Public Energy Council, December 22, 2014; deposition, February 10, 2015; supplemental testimony May 11, 2015; second deposition May 26, 2015.

PJM Interconnection, L.L.C., FERC Docket No. ER14-2940 (RPM Triennial Review), Affidavit in Support of the Protest of the PJM Load Group, October 16, 2014.

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 14-841-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, September 26, 2014; deposition, October 6, 2014; testimony at hearings, November 5, 2014.

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 13-2385-

EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, May 6, 2014; deposition, May 29, 2014; testimony at hearings, June 16, 2014.

PJM Interconnection, L.L.C., FERC Docket No. ER14-504 (Clearing of Demand Response in RPM), Affidavit in Support of the Protest of the Joint Consumer Advocates and Public Interest Organizations, December 20, 2013.

New England Power Generators Association, Inc. v. ISO New England Inc., FERC Docket No. EL14-7, Testimony in Support of the Protest of the New England States Committee on Electricity, November 27, 2013.

Midwest Independent Transmission System Operator, Inc., FERC Docket No. ER11-4081, Affidavit In Support of Brief of the Midwest TDUs, October 11, 2013.

ANR Storage Company, FERC Docket No. RP12-479, Prepared Answering Testimony on behalf of the Joint Intervenor Group, April 2, 2013; Prepared Cross-answering Testimony, May 15, 2013; testimony at hearings, September 4, 2013.

In the Matter of the Application of The Dayton Power and Light Company for Approval of its Market Rate Offer, Public Utilities Commission of Ohio Case No. 12-426-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, March 5, 2013; deposition, March 11, 2013.

PJM Interconnection, L.L.C., FERC Docket No. ER13-535 (Minimum Offer Price Rule), Affidavit in Support of the Protest and Comments of the Joint Consumer Advocates, December 28, 2012.

In the Matter of the Application of Ohio Edison Company, et al for Authority to Provide for a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 12-1230-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, May 21, 2012; deposition, May 30, 2012; testimony at hearings, June 5, 2012.

PJM Interconnection, L.L.C., FERC Docket No. ER12-513, Affidavit in Support of Protest of the Joint Consumer Advocates and Demand Response Supporters (changes to RPM), December 22, 2011.

People of the State of Illinois *ex rel.* Leon A. Greenblatt, III v Commonwealth Edison Company, Circuit Court of Cook County, Illinois, deposition, September 22, 2011; interrogatory, Feb. 22, 2011.

In the Matter of the Application of Union Electric Company for Authority to Continue the Transfer of Functional Control of Its Transmission System to the Midwest Independent Transmission System Operator, Inc., Missouri PSC Case No. EO-2011-0128, Testimony in hearings, February 9, 2012; Rebuttal Testimony and Response to Commission Questions On Behalf Of The Missouri Joint Municipal Electric Utility Commission, September 14, 2011.

PJM Interconnection, L.L.C., and PJM Power Providers Group v. PJM Interconnection, L.L.C., FERC Docket Nos. ER11-2875 and EL11-20 (Minimum Offer Price Rule), Affidavit in Support of Protest of New Jersey Division of Rate Counsel, March 4, 2011, and Affidavit in Support of Request for Rehearing and for Expedited Consideration of New Jersey Division of Rate Counsel, May 12, 2011.

PJM Interconnection, L.L.C., FERC Docket No. ER11-2288 (Demand response "saturation" issue), Affidavit in Support of Protest and Comments of the Joint Consumer Advocates, December 23, 2010.

North American Electric Reliability Corporation, FERC 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., FERC 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, FERC 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., FERC 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., FERC 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., FERC Docket No. ER09-412-000: Affidavit In Support of the Protest Regarding Load Forecast To Be Used in May 2009 RPM Auction, January 9, 2009.

Maryland Public Service Commission et al v. PJM Interconnection, L.L.C., FERC 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., FERC Docket No. ER08-516: 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, FERC Docket Nos. ER05-1410 and EL05-148: Affidavit Addressing RPM Compliance Filing Issues on Behalf of the Public Power Association of New Jersey, October 15, 2007.

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

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

PJM Interconnection, L.L.C., Reliability Pricing Model, FERC 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., FERC 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., FERC 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., FERC 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*, FERC 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, FERC Docket No. ER99-1248: Affidavit in support of application for market-based rates for energy, capacity and ancillary services, December 1998.

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

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

PUBLISHED ARTICLES

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

OTHER ARTICLES, REPORTS AND PRESENTATIONS

Panel on Load Forecasting, Organization of PJM States, Inc. Spring Strategy Meeting, April 13, 2015.

Panelist for Session 2: Balancing Bulk Power System and Distribution System Reliability in the Eastern Interconnection, Meeting of the Eastern Interconnection States' Planning Council, December 11, 2014.

Panel: Impact of PJM Capacity Performance Proposal on Demand Response, Mid-Atlantic Distributed Resources Initiative (MADRI) Working Group Meeting #36, December 9, 2014.

Panel: Applying the Lessons Learned from Extreme Weather Events – What Changes Are Needed In PJM Markets and Obligations? Infocast PJM Market Summit, October 28, 2014.

Panel on RPM: What Changes Are Proposed This Year? Organization of PJM States, Inc. 10th Annual Meeting, Chicago Illinois, October 13-14, 2014.

Panel on centralized capacity market design going forward, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7, September 25, 2013; post-conference comments, January 8, 2014.

Economics of Planning for Resource Adequacy, NARUC Summer Meetings, Denver, Colorado, July 21, 2013.

The Increasing Need for Flexible Resources: Considerations for Forward Procurement, EUCI Conference on Fast and Flexi-Ramp Resources, Chicago, Illinois, April 23-24, 2013.

Panel on RPM Issues: Long Term Vision and Recommendations for Now, Organization of PJM States, Inc. Spring Strategy Meeting, April 3, 2013.

Comments On: The Economic Ramifications of Resource Adequacy Whitepaper, peer review of whitepaper prepared for EISPC and NARUC, March 24, 2013.

Resource Adequacy: Criteria, Constructs, Emerging Issues, Coal Finance 2013, Institute for Policy Integrity, NYU School of Law, March 19, 2013.

Panel Discussion – Alternative Models and Best Practices in Other Regions, Long-Term Resource Adequacy Summit, California Public Utilities Commission and California ISO, San Francisco, California, February 26, 2013.

Fundamental Capacity Market Design Choices: How Far Forward? How Locational? EUCI Capacity Markets Conference, October 3, 2012.

One Day in Ten Years? Economics of Resource Adequacy, Mid-America Regulatory Conference Annual Meeting, June 12, 2012.

Reliability and Economics: Separate Realities? Harvard Electricity Policy Group Sixty-Fifth Plenary Session, December 1, 2011.

National Regulatory Research Institute Teleseminar: The Economics of Resource Adequacy Planning: Should Reserve Margins Be About More Than Keeping the Lights On?, panelist, September 15, 2011.

Improving RTO-Operated Wholesale Electricity Markets: Recommendations for Market Reforms, American Public Power Association Symposium, panelist, January 13, 2011.

Shortage Pricing Issues, panelist, Organization of PJM States, Inc. Sixth Annual Meeting, October 8, 2010.

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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

August 2015