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**

DIRECT TESTIMONY OF
PAUL CHERNICK

ON BEHALF OF
SIERRA CLUB

REDACTED VERSION

Resource Insight, Inc.

SEPTEMBER 11, 2015

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I. Identification and Qualifications

Q: Please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Incorporated, which is located at 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: In June 1974, I received a Bachelor of Science degree from the Massachusetts Institute of Technology from the Civil Engineering Department. In February 1978 I received a Master of Science degree in Technology and Policy from the Massachusetts Institute of Technology.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have worked as a consultant in utility regulation and planning. From 1981 to 1986 worked as a research associate at Analysis and Inference. In 1986, I founded and became president of PLC, Incorporated, which was renamed Resource Insight, Incorporated in 1990. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plants under construction, ratemaking for excess and/or uneconomical investments entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further described in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified as an expert nearly three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-three states, six Canadian provinces, and two U.S. federal agencies. A large number of those cases involved power supply planning; evaluation of potential resources, including purchased-power agreements (PPAs); restructuring of electric markets; and power procurement for restructured utilities.

Q: Have you testified previously before the Public Utilities Commission of Ohio?

A: Yes. I testified in the following proceedings:

- In Cases No. 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP, on behalf of the City of Cincinnati on the treatment of demand-side management (DSM) in the Cincinnati Gas and Electric Long Term Forecast Report for 1992.
- In Case No. 95-203-EL-FOR, on behalf of the Campaign for an Energy Efficient Ohio on cost-effectiveness tests for electric DSM.
- In Case 03-2144-EL-ATA, on behalf of Green Mountain Energy on the pricing of standard-offer service.
- In Case No. 05-1444-GA-UNC, on behalf of the Ohio Consumers' Counsel (OCC) on energy-efficiency analysis and planning.

I have also advised and assisted the Ohio Consumers' Counsel and other parties on a number of issues related to various Ohio utilities.

II. Introduction

Q: On whose behalf are you testifying in this rate case proceeding?

A: I am testifying on the behalf of Sierra Club.

Q: What is the purpose of your testimony?

A: I address the request of Ohio Power Company (AEP Ohio or OPCo) for approval of a life-of-unit purchased-power agreement (the Affiliate PPA, or just PPA) to purchase energy and capacity from the entitlements of its affiliate AEP Generation Resources (AEPGR) in nine coal units and AEP Ohio's own entitlements in eleven units owned by the Ohio Valley Electric Corporation (OVEC):[1]

- Cardinal 1
- Conesville 4, 5, and 6
- Stuart 1–4
- Zimmer
- Clifty Creek 1–5
- Kyger Creek 1–6

Of these nine units, AEPGR owns 100% of Cardinal 1 and Conesville 5 and 6; all the other units are co-owned.

These entitlements total 3,111 MW (Vegas Amended Direct Testimony, at 12), of which 2,671 is owned by AEPGR and 440 is owned by OVEC. AEP projects that these resources would cover approximately 39% of AEP Ohio's average load (Pearce Amended Direct at 17, lines 9-10).[2]

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[1] Clifty Creek is owned by the Indiana-Kentucky Electric Corporation, an OVEC subsidiary, but AEP refers to it as an OVEC unit. The OVEC entitlements would not be part of the PPA, since AEP Ohio already owns this capacity and cannot enter into a contract with itself. For simplicity, I will refer to the entire proposal as being covered by the PPA. Also, the actual flow-through of costs to ratepayers would occur through the PPA Rider; if the PUCO approved the PPA, but not its inclusion in the PPA Rider, it is not clear how AEP Ohio would recover its costs. I will avoid repeatedly saying "the PPA and the inclusion of the PPA costs under the PPA Rider," with the understanding that the references to the effect of the PPA on ratepayers assume that PUCO approves cost recovery through the PPA rider or another mechanism.

[2] AEP Ohio filed the May 2015 Amended Application seeking approval of the Affiliated PPA, OVEC PPA, and the PPA Rider. All references to direct testimony in my testimony are to

Under the proposed PPA, AEP Ohio would pay to AEPGR the costs of owning and operating the PPA units, and would receive the revenues from the sale of the energy, capacity, and ancillary services from those units into the PJM market. AEP Ohio also seeks in this proceeding approval to pass through to customers in a PPA Rider the net of the costs incurred and the revenues accrued under the PPA. Such net costs would be passed through to customers, regardless of who supplies their generation services.[3]

Q: What issues do you consider?

A: I address a series of questions vital to the Commission's review of the proposed PPA and the PPA Rider through which the PPA costs would flow:

- Would AEP Ohio ratepayers likely incur significant costs or save money under the proposed PPA Rider?
  - Did AEP include the full costs of these units in its analysis?
  - How reasonable are AEP's projections of market electric energy prices and market capacity prices?
  - What is the likely effect of the PPA on AEPGR's incentives to control costs?

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the amended testimony of the witness, except as otherwise noted. Of the eleven witnesses who filed testimony supporting the Application, eight are employed by American Electric Power Service Corporation (AEPSC), one each for AEP Ohio and AEPGR, and one is an outside consultant. The analyses are workproducts of AEPSC, and the proposal is designed to benefit the shareholders of AEP, primarily through its AEPGR subsidiary. I therefore attribute positions and projections to AEP as a whole, without distinguishing among the various subsidiaries of that corporation.

[3] The PPA is effectively a contract for differences, under which AEP Ohio would pay the difference between the cost of service for the units and their market revenues for the energy, capacity and other services. For most purposes in my discussion, this detail is not critical to evaluation of the PPA or the PPA Rider.

- To what extent would the proposed PPA shift economic, financial, performance, and environmental-compliance risk from AEPGR to ratepayers?
- Does the PPA provide an effective price hedge?
    - How could AEP Ohio minimize the cost of a price hedge?
- Are the PPA units likely to be economically viable in the PJM markets without the proposed PPA?
    - If not, has AEP reasonably assessed the impact of potential plant retirements on Ohio reliability?
    - Where is replacement capacity likely to be built, and will it tend to relieve or exacerbate transmission constraints?
    - To what extent can investments in energy efficiency and distributed renewable resources provide alternatives to transmission upgrades, to prevent reliability criteria violations.
    - Has AEP reasonably determined how potential retirement of some or all of the PPA units would affect the need for transmission upgrades?
        - How would PJM allocate the cost of transmission upgrades among AEP Ohio, the remainder of the AEP's transmission zone and other utilities?
    - If the owners of the PPA units were to propose the retirement of some PPA unit that PJM found was needed to address reliability concerns, how would PJM compensate AEPGR and the other owners for delaying retirement of those units?

Q: To which AEP witnesses will you respond?

A: I respond to the following AEP witnesses:

- Kelly Pearce on the net cost of the proposed PPA over the period 2015 to 2024
- Karl Bletzacker on AEP's energy-price forecast

- Steven Fetter on risk and hedging.
- Pablo Vegas on a number of issues, including risk, power-plant development, cost-effectiveness of the PPA to ratepayers, and the cost-effectiveness of the PPA units to the owners without the PPA.
- Robert Bradish on transmission and reliability issues.
- Toby Thomas on the economics of the PPA units without the PPA.
- William Allen on rate stability.

Unless otherwise specified, my citations to the AEP witnesses are from their May 15, 2015 direct testimonies supporting the Amended Application.

Q: What arguments does AEP present to support its proposal?

A: The AEP witnesses offer several reasons for the Public Utility Commission of Ohio (PUCO) to approve the proposed PPA and associated PPA Rider:

- Witnesses Vegas and Pearce assert that the PPA would reduce ratepayer costs.
- Witnesses Fetter, Vegas, and Pearce assert that the PPA would reduce risk and provide a price hedge for AEP Ohio ratepayers.
- Witnesses Vegas, Pearce, and Allen suggest that the ratepayers are exposed to price volatility, including the effects of weather events such as the Polar Vortex, and that the PPA would reduce or eliminate such volatility.
- Witnesses Vegas and Bradish assert that the PPA is necessary to prevent near-term retirement of the PPA units, triggering the need for massive transmission investments.
- Witnesses Wittine and Pearce claim that developers are unlikely to develop capacity to replace any retired PPA units in Ohio.
- Witness Wittine suggests that completion of new generation in PJM is uncertain.

Q: What are your conclusions?

A: I conclude that none of AEP's assertions summarized above are valid. While the PPA is almost certainly valuable to AEPGR (and hence the AEP shareholders), the record does not demonstrate that it has any net benefit to the AEP Ohio ratepayers. From the perspective of the ratepayers, the PPA and associated PPA Rider are solutions in search of a problem. Specifically, I find that:

- The PPA is likely to be very expensive and uneconomic for ratepayers.
- The PPA would do little to reduce price risk and volatility to ratepayers and would introduce new risks to ratepayers.
- The PPA would not provide an effective price hedge.
- Other approaches would reduce price risks and volatility and provide price hedges without the risks and other downsides of the PPA.
- If market prices were to follow AEP's projections, AEPGR and its joint owners would find the PPA units were cost-effective to keep in service, even if they did not cover all of their sunk costs. Thus, the PPA would not be necessary to keep the units operating. If wholesale prices are similar to those currently suggested by the markets, the PPA would be more expensive than alternatives, even if new transmission were required. AEP cannot have it both ways, simultaneously arguing that prices will be high enough to render the PPA economic for ratepayers, but that prices will be low enough to make the PPA units uneconomic to operate.
- PJM has more appropriate pricing alternatives for keeping generators that are needed for reliable service, and the PUCO can enhance PJM's options.
- AEP has exaggerated the potential transmission problems that would result from retirement of the PPA units and thus has also exaggerated the potential costs.

Q: What are your recommendations to the Commission?

A: I recommend that the Commission reject the proposed PPA and the recovery of the PPA and OVEC costs through the PPA rider. If the Commission is concerned about rate stability, it can instruct AEP Ohio to pursue competitive procurement of longer-term SSO contracts, forward energy contracts, and/or contracts for differences with generators or providers of demand-side services. Any of these competitive approaches are likely to be less expensive, less risky, and more consistent with a competitive supply system than is AEP's sole-source proposal.

If the PUCO is concerned about the reliability and cost impacts of retirement of one or more of the PPA units, it should instruct AEP Ohio to hire an independent consultant to review the probability of retirement of each PPA unit, the potential for replacement of retired units with new generation, and the effect of retirement of each unit on reliability needs and costs.

III. AEP's Projection of PPA Economics

A. Claimed PPA Benefits

Q: Describe the PPA summary results.

A: Mr. Pearce presents the simple sums over October 2015 to December 2024 of AEP's projections of the revenues and costs of the units covered by the proposed PPA, for three model runs, which differ only in the forecasts of market energy prices (Pearce Amended Direct, Exhibit KDP-2).[4] The three price cases are described by AEP as being driven by the load level in the area it modeled for its production costing runs, specifically:

[4] The forecasts were developed by yet another AEP subsidiary, the AEP Service Company (AEPSC).

- A forecast of weather-normalized load. To avoid using this confusing title (all the load forecasts are weather-normalized and the important differences in the economic analysis reflect alternative projections of energy price, rather than load), I will refer to this as the AEP Base case.[5]
- Load 5% higher than the base case (the AEP High case).
- Load 5% lower than the base case (the AEP Low case).

In addition, Mr. Pearce presents the average of the High and Low cases. Since that average results in more favorable PPA results than the Base case, AEP tends to discuss the High-low average. The results of the runs are summarized in Table 1. The simple totals are from Pearce's Exhibit KDP-2; I computed the NPVs from the cash flows shown in his workpapers for that exhibit.

Table 1: AEP's Predicted PPA Rider Impacts ($ Million)

	Simple Total			Net Present Value		
AEP Price Case	**Revenues**	**Costs**	**Net**	**Revenues**	**Costs**	**Net**
Base	$11,644	$11,613	$31	$7,019	$7,035	–$16
High	$14,020	$11,946	$2,074	$8,523	$7,232	$1,291
Low	$9,669	$10,697	–$927	$5,815	$6,440	–$625
High-low Average	$11,845	$11,272	$574	$7,169	$6,836	$333

In the base case, AEP predicts minimal total benefits, with a negative net present value (NPV). In the low case, AEP predicts that the PPA would result more than $900 million in total losses to ratepayers over ten years. In the high case, AEP predicts a profit of over $2 billion.

[5] PJM has recently released a new load-forecasting methodology and updates to its economic inputs and other factors, which collectively reduce the summer peak for 2018 by 2.6% compared to the 2014 forecast, and the winter peak by 1.8%, with similar reductions continuing through 2030. If AEPSC relied on the PJM 2014 forecast in its projections of market prices, PJM's forecasts have moved half-way to AEP's low case.

Q: Please describe how the model was constructed.

A: Mr. Pearce describes his spreadsheet model starting on page 11 of his direct. The model seeks to calculate the net PPA rider credit by subtracting the estimated costs of the PPA from an estimate of the resources' PJM energy and capacity revenues. The revenue side is made up of the sale of energy, capacity, and ancillary services in the PJM markets. The PPA costs comprise the following:

- return on rate base and depreciation for current and future investments,
- fixed operation and maintenance (O&M) expenses,
- consumables (which would be the bulk of variable O&M),
- fuel, and
- a carbon dioxide (CO_2) allowance price starting in 2022.

Mr. Pearce relies on AEP forecasts for market energy, capacity, and fuel prices, which are sponsored by Mr. Bletzacker. AEPSC computed the hourly prices for the PJM AEP zone, as well as output (which AEP sometimes calls "load"), energy revenues, and costs (fuel, consumables, and CO_2) for each PPA unit. These hourly results are then aggregated annually to provide energy revenues and variable costs by unit, year, and case.

The difference between the market revenue and the cost for the PPA as a whole would be passed through the PPA Rider to the AEP Ohio ratepayers as a credit (if revenue exceeds costs) or charge (if costs exceed revenue). Mr. Pearce sums these annual benefits over the 10 year study period, even though the Affiliate PPA and the OVEC contracts have no expiration dates.

Q: Please describe how AEP presents its modeling results.

A: Mr. Pearce presents the simple sum calculation of the annual revenue and costs. AEP did these simple-sum calculations for the base case, high case, low case, and average of the high-low case.

Q. **AEP's testimony focuses on the average of the high-low case rather than on any other case; is that the appropriate case to focus on?**

A. No. While analysts sometimes construct probability-weighted averages of high, base and low projections, I cannot recall ever having seen an analysis that included only the high and low cases, ignoring the base case. Forecasters usually define the case so that the base case represents a higher probability than the extremes; that result is expected where many uncertain factors contribute to the outcome. The distribution of price risk is usually asymmetrical, since prices can be 110% higher but not 110% lower than base, so ignoring the large probability contribution of the base case inherently results in an upward bias. Weighting AEP's high and low cases 15% each, and the base case 70%, would result in 10-year benefit about one third of AEP's high-low average.

Q: **What do you mean by the simple sum of costs and benefits over the analysis period?**

A: I refer to Mr. Pearce's calculation, which simply adds up each year's current (or nominal) dollar costs or benefits. A simple-sum calculation ignores the fact that earlier cash flows are more important than later flows, due to inflation (a 2024 dollar will not be worth as much as a 2015 dollar) and the time value of money (almost all ratepayers would rather have a dollar today than the promise of a dollar in 2024).

Q: **Is it appropriate to use simple sums for a long-term investment decision?**

A: No. The summation of nominal cash flows over time is not particularly meaningful, since it ignores both inflation and the time-value of money.

Q: **How do economic analyses account for the time value of money?**

A: Investment decisions that bear costs and benefits over multiple years are typically evaluated using a "discount rate" that represents the value of delaying benefits or costs for each additional year. A dollar of costs in 2015 is generally considered to more than outweigh a dollar of benefits in 2024. The summation of the discounted benefits minus the discounted costs is equal to the "net present value" (NPV). This metric allows for comparison of different options that bear differing benefits and costs over a given time period. Failing to discount implies that the neither AEP nor its ratepayers have a preference for spending (or receiving monies) today or ten years from now.

Q: Is the use of discounted costs common in evaluation of power-supply options?

A: Yes. The presentation of results in NPV terms is nearly universal. For example, Scott Weaver, AEPSC Managing Director for Resource Planning and Operational Analysis, presented the justification for extending the life of the Flint Creek coal plant in present-value terms (Arkansas PSC Docket No. 12-008-U). Even AEP Ohio has expressed the benefits of other ESP provisions in NPV terms.

Q: **Should PUCO rely on Mr. Pearce's simple summation of revenue and costs in current year dollars in evaluating AEP's proposals in this proceeding?**

A: No. The PUCO should rely on the present value of future expected costs and revenues. I know of no utility that makes investment decisions by comparing the summation of undiscounted, nominal dollars over a long period.

Q: Did you convert AEP's predictions of PPA profitability from simple sum to net present value?

A: Yes. Table 2 summarizes the values for the AEP Base energy price case. I present both the simple sum of the annual costs, for consistency with Mr. Pearce, and the net present value (NPV) to 2014 at an 8% discount rate (approximately the initial cost of capital proposed by AEP for the PPA), to reflect the time value of money to consumers.

Table 2: AEP Base Case Net Benefits by Unit ($M)

Unit	Simple Sum	NPV Benefit	Profitable Years
Cardinal 1	[redacted]	[redacted]	[redacted]
Conesville 4	[redacted]	[redacted]	[redacted]
Conesville 5	[redacted]	[redacted]	[redacted]
Conesville 6	[redacted]	[redacted]	[redacted]
Stuart 1	[redacted]	[redacted]	[redacted]
Stuart 2	[redacted]	[redacted]	[redacted]
Stuart 3	[redacted]	[redacted]	[redacted]
Stuart 4	[redacted]	[redacted]	[redacted]
Zimmer	[redacted]	[redacted]	[redacted]
OVEC Combined	[redacted]	[redacted]	[redacted]
PPA Wide	[redacted]	[redacted]	
Excluding Units that AEP Shows as Uneconomic in PPA	[redacted]	[redacted]	

Once adjusted to net present value, AEP's predictions of marginal profitability for the PPA with the base-case inputs disappear entirely. The simple-sum profit of $31 million in AEP's base case becomes a $79 million loss to ratepayers. Looking only at the AEPGR units, the NPV loss is $[redacted] million.

Q: Are certain PPA units more unprofitable than other PPA Units?

A: Yes. Even with AEP's forecasts of PPA revenues and costs, [redacted] units are strikingly unprofitable. AEP forecasts that [redacted] will not provide a benefit to ratepayers in any year in the study period, and that [redacted] would provide a modest benefit in 2016, but run at a loss in the other years.

The AEP projections for the remaining units [redacted] and the OVEC plants—are all modestly profitable, assuming the AEP base market prices. As I discuss below, all of the AEP market prices are unrealistically high.

Q: How would the economics of the PPA change if the plants that AEP expects to cost more than their base-case market revenues were removed?

A: While AEP forecasts that the proposed PPA would have simple net benefits of $31 million, equivalent to an NPV loss of $79 million, excluding [redacted]

[redacted] would increase the PPA's profitability to $[redacted] million in nominal terms, or $[redacted] million in NPV, with AEP's base assumptions.

Q: Are the PPA units, including than the three units that are unprofitable as part of the PPA, "on the economic bubble," as Mr. Thomas suggests?

A: No. Mr. Thomas claims that:

> Yes. The Affiliated PPA units are on the economic "bubble", meaning the market conditions, as described by Company witness Pearce, are not providing the necessary economic signals for incremental investment in these units. The plants have been saddled with increased fixed costs resulting from recent environmental installations. Market volatility and unpredictability only serve to make the situation faced by these generating units, more tenuous. Because of these factors, any major capital spending that might be required in the future, whether for existing equipment repairs or for new environmental requirements, could lead to premature retirements. (Thomas Amended Direct Testimony at 11)

If Mr. Thomas believed that revenues for these units would resemble those in the AEP base case, let alone its preferred average of the low and high cases, he would not believe that the units are anywhere near the "bubble." Under AEP's base-case cost and revenues forecast, most of the units could bear substantial additional costs and remain economic. Those additional costs could be covered with base-case profits through 2024 would be about $[redacted] million for [redacted] million for AEP's share of [redacted] (or over $[redacted] million for the plant) and nearly $[redacted] million for AEP Ohio's share of the OVEC units (about $[redacted] million for the two plants). These are the profits *after* paying for sunk costs and AEP's forecast of future investments, and only include profits through 2024. Under AEP's assumptions, the lifetime benefit of keeping the plants operating would be even greater. Even the units that are not economic for ratepayers as part of the PPA would cover their ongoing costs in the AEP base case, as I show in Section VIII.

The AEP witnesses present two conflicting pictures of the future: one with high market prices, in which some of the PPA units are very valuable (even when burdened with their sunk costs), and a second future, in which low market prices and high operating costs, even ignoring sunk costs, render the units unprofitable for AEPGR and other owners to continue operating.

B. Omitted Capacity Performance Penalties

Q: Does AEP's model, as designed, incorporate all the costs PPA units will incur?

A: No. The AEP analysis omits the penalty costs associated with PJM's new Capacity Performance product. (AEP Response to SC-INT-4-097)

Q: What is PJM's Capacity Performance mechanism?

A: After some years of internal review and regulatory processes, PJM has adopted a system to penalize capacity resources that are unavailable in the hours in which PJM is tight on capacity. PJM can assess these penalties when a resource is out of service or is unable to respond to a capacity emergency due to startup and ramping lead times.[6] To compensate for those penalties, suppliers will require (and PJM will allow) higher prices for the capacity-performance resources to be higher than were allowed prior to these performance penalties.[7]

AEP has stated that the PPA units will be participating in the markets as capacity-performance resources (Vegas Amended Direct at. 17, lines 3-11).

The first capacity-performance resources were acquired in the Base and Residual Auction (BRA) for 2018/19, conducted on August 10, 2015. The market-

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[6] Lead-time constraints will primarily affect steam plants. All the PPA units are steam plants.

[7] Most of the 2018/19 base-capacity resources are apparently renewables, such as wind and solar.

clearing price for capacity-performance resources in the AEP zone and the rest of Ohio was $164.77/MW-day. PJM has conducted auctions to acquire capacity-performance resources during two transition years (delivery years 2016/17 and 2017/18), for which it had already acquired base capacity under the old rules.[8] The ceiling prices for performance capacity were set at $165.27/MW-day in 2016/17 and $210.83/MW-day in 2017/18. Those auctions were designed to acquire performance capacity up to 60% and 70% (respectively) of the total capacity needed in those years, as compared to the 84% of the capacity requirement for 2018/19 that was acquired as performance resources. In addition, the magnitude of nonperformance charges for the 2016/2017 and 2017/2018 Delivery Years will be 50% and 60%, respectively, of the charges that would be computed using the rules in effect for the 2018/19 BRA. Hence, both the demand for performance capacity and the cost of providing performance resources will be lower in the transition years.

Q: How would PJM's Capacity Performance rules affect the economics of the PPA?

A: There are two effects. First, the capacity performance will increase the PJM capacity price compared to the prices that would have occurred without the rules. Second, the PPA units are likely to incur penalties for nonperformance.

[8] These auction results were released August 31, 2015 for 2016/17 and September 9, 2015 for 2017/18. The clearing prices were $134/MW-day for 2016/17 and $151.50/MW-day for 2017/18. These prices were less than the ceiling prices, and higher than the performance capacity prices I used in my analysis, but lower than the 2018/19 price. Given the timing, I have not reflected the results in my analysis.

Q: How did AEP estimate capacity revenues for the PPA resources, including the effects of Capacity Performance?

A: During the transition, AEP assumed that the market will clear at the price ceiling. AEP forecasted that its PPA resources would receive $165.27/MW-day in 2016/17 and $210.83/MW-day in 2017/18. This would increase capacity payments by $196 million. After 2018, AEP assumed that the market would clear at rapidly escalating prices, as I discuss in Section IV.B.

Figure 1: AEP Forecasts of Capacity Prices

[redacted]

Q: What are the costs associated with Capacity Performance?

A: PJM added severe penalties to Capacity Performance to encourage generators to actually provide capacity in times of need. If a unit is not operational in a compliance hour (defined as an hour in which PJM invokes any of nine emergency procedures) without prior authorization, PJM will assess a penalty equal to annual Net CONE divided by 30. PJM will discount the penalties by 50% in 2016/17 and 40% in 2017/18. Given these rules, the penalties will be $2,011/MWh for 2016/17, $2,565/MWh for 2017/18 and $3,657/MWh for 2018/19.

Performance capacity in the AEP zone of PJM cleared at $165/MW-day for 2018/19. A 200 MW unit would receive $165 × 365 × 200 = $12 million in annual capacity payments. If this unit were unavailable during three compliance hours, it would face total penalties of $3,657 × 3 × 200 = $2.2 million, about 18% of its annual capacity revenues.

Q: What might Capacity Performance penalties cost the PPA units?

A: Penalties will cost between $127 and $283 million through 2024, depending on the actual number of compliance hours in a given year. PJM assumes that there will be, on average, 30 such hours each year. Table 3 shows PJM's estimates of the hours that would have triggered the compliance provisions for the AEP region from 2011 to 2014.[9]

Table 3: Historic PJM Compliance Hours

Period	Hours
2011	7
2012	5
2013	16
2014	26
Total	54
Average	13.5

To calculate expected annual penalties for each unit, I made the following assumptions:

- Net CONE (and hence the penalty rate) would increase at 4% annually from 2017/18.[10]

[9] "Performance Assessment Hours for 20112014," PJM, (3232015); http://www.pjm.com/~/media/committeesgroups/committees/elc/postings/performanceassessmenthours20112014xls.ashx

[10] This may be slightly overstated, since net CONE fell from 2017/18 to 2018/19.

- The PPA units would only incur penalties for forced outages, and not due to startup limitations.
- Each unit would operate at its average forced outage rate for 2010–2014.[11]
- The number of annual penalty hours would fall between the historical average of 13.5 and PJM's assumed 30.

The expected penalty equals the product of the penalty rate, the unit forced outage rate, and the compliance hours. Summing these penalties across the 10 year study period, I estimate penalties of $191 million to $425 million, with NPVs of $142–$315 million, depending on the number of annual performance hours.

Q: How will capacity performance change PPA revenues?

A: In its base case, AEP assumes that capacity prices will increase in a relatively linear fashion, exceeding $[redacted]/MW-day in 2024. In this scenario, the PPA would generate $[redacted] billion in capacity revenues between late 2015 and 2024. In the Capacity Performance sensitivity, AEP assumes that in the transition years 2016/17 and 2017/18, that capacity markets would clear at the administratively set price ceiling and then return to the fundamental forecast for 2019–2024. With these maximum performance-capacity prices, capacity revenues would rise by $196 million, to $[redacted] billion. Table 4 compares AEP's maximum estimates of the increased PPA revenues from capacity performance to expected penalties with the expected performance penalties for the PPA plants.

[11] From SC Set 1-INT-001 CONFIDENTIAL Attachment 1.xlsx.

Table 4: AEP Forecast of Capacity Revenues, Corrected for Performance Penalties ($M Total)

		Capacity Performance Case	
	None	**Maximum Price, Low Penalties**	**Maximum Price, High Penalties**
Revenues	$1,922	$2,118	$2,118
Penalties	$0	$191	$425
Net	$1,922	$1,927	$1,693
Change due to Capacity Performance	$0	$5	-$229

Capacity performance penalties will roughly offset AEP's claimed increase in PPA capacity revenue under the new market design.

Q: What is the effect of your corrections to reflect the capacity performance penalties that AEP omitted?

A: Performance penalties for PJM capacity would cost $191 million to $425 million, depending on the number of compliance hours in which penalties are assessed.

With the AEP base-case prices, the performance penalties would render the PPA unprofitable. These corrections would eliminate AEP's projected $31 million benefit, resulting in a total nominal loss to ratepayers of $160 to nearly $400 million. As with the unadjusted AEP case [redacted] impose the greatest costs on the PPA. Similar results occur PPA wide on the other three load cases since performance penalties do not vary with energy prices. Table 5 expresses these results in present value, with the low-end capacity performance penalties and each of AEP's energy-price cases.

Table 5: Summary of Capacity Performance (CP) Corrections to AEP Cases ($M NPV)

Case	AEP Base Case Benefit	AEP Estimate of Incremental CP Benefits	CP Penalties	NPV after Adjustments
Base	($17)	$107	$147	($56)
Higher	$1,264	$107	$147	$1,225
Low	($623)	$107	$147	($662)
High-low Average	$321	$107	$147	$282

IV. More Reasonable Energy and Capacity Forecasts

Q: After accounting for AEP's omission performance penalties and expressing the results in present-value terms, are you satisfied with the AEP model?

A: No. In fact, even minor changes to model inputs radically change the results. In addition to failing to account for capacity-performance penalties that the PPA units would incur on average and computing only the simple sum of costs and benefits, rather than the present value of the cash flows, I have identified the following concerns:

- The AEP energy forecast sponsored by Mr. Bletzacker is substantially overstated, compared to the current forward market prices.
- The AEP capacity forecast sponsored by Mr. Pearce is also substantially overstated, since it assumes that capacity prices in future auctions will be much higher than the prices required by new generic units in PJM.
- AEP's forecasts of net generation (expressed as capacity factor) are very high compared to historical results, probably due to the overstated energy forecast.
- The cost-benefit analysis covers only the period 2015 through 2024, even though the PPA would continue through the commercial operating life of the PPA units, including any post-retirement period necessary to recover

remaining net book costs and asset retirement obligations. AEP currently projects that the various PPA units would retire between 2033 and 2051, but AEP could continue rehabilitating and running the units indefinitely.

A. Market Energy Prices

1. AEP Forecasts

Q: How did AEP forecast market energy prices?

A: AEP Witness Karl Bletzacker discusses AEP's "long-term, weather-normalized power market forecast," starting on page 3 of his direct. This forecast covers essentially all of the United States and parts of Canada. While this breadth of analysis may be useful for other AEP purposes (such as for its southwestern and Texas utilities, and its unregulated activities), only the Eastern Interconnection would have any effect on energy prices in Ohio, and only a part of the Eastern Interconnection would have any material effect. The model is driven by AEP's forecasts of prices for electricity, coal, natural gas, and emissions; hourly loads; power plant heat rates and capacity values; renewable subsidies and inflation factors. The forecast for each of AEP's three cases (base, high, and low) produces forecasts of hourly prices for the PJM AEP hub through 2024.[12] Since hourly dispatch differs among the units, the average annual market energy price also varies. For simplicity, I will focus on the average energy price for the PPA resources.

[12] While not all the PPA resources are in the AEP zone, energy prices for all of them should closely track the AEP price, at least on an annual basis.

The base-case forecast starts just under $40/MWh in 2015 and rises to nearly $70/MWh by 2024. The low forecast closely follows the base forecast but is typically lower by several dollars per MWh. The high case, on the other hand, has wholesale electric energy prices much higher than the base case.

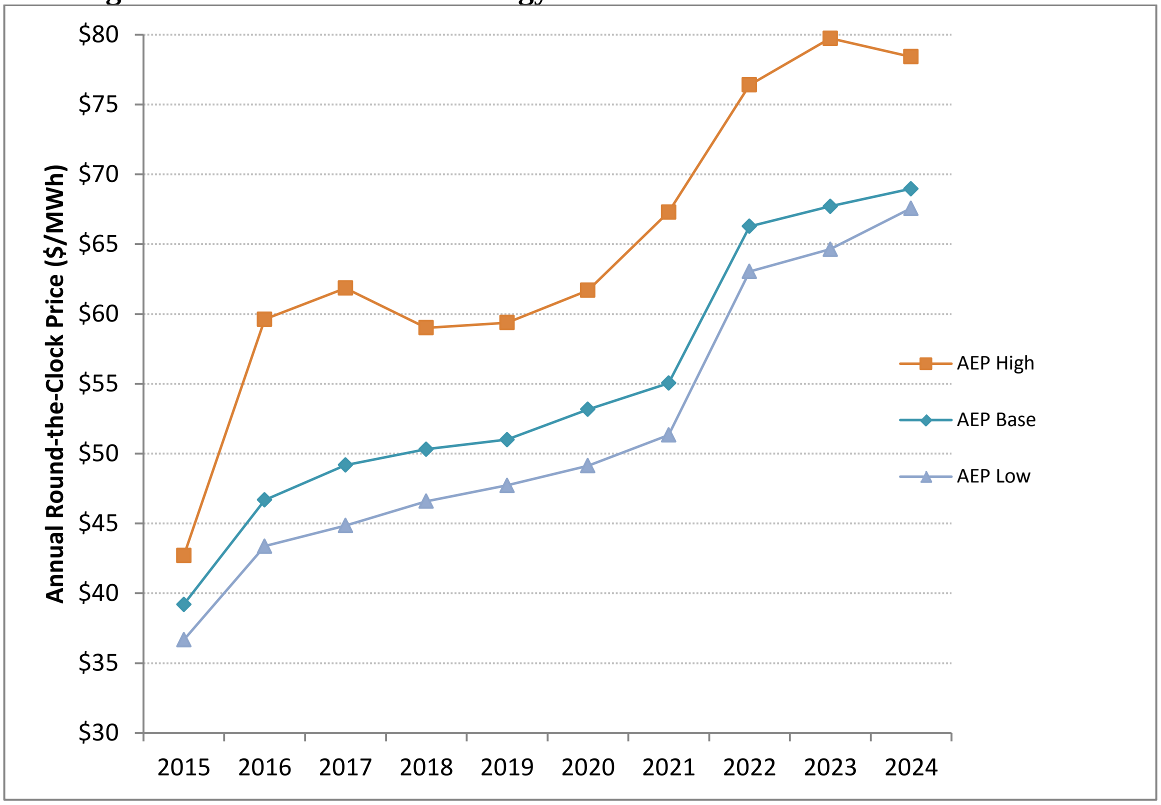
Q: What is AEP's projection of the PPA-wide weighted average price?

A: Mr. Bletzacker presents projections for annual peak and off-peak energy prices at the PJM AEP Hub in Figures 4 and 5 of his testimony. Table 6 and Figure 2 present AEP's forecasts of the PPA-wide average price by year. Prices jump in 2022, when AEP assumes that carbon pricing will start.

Table 6: AEP Energy Price Forecasts (Nominal $/MWh)

Year	Base	High	Low
2015	$39	$43	$37
2016	$47	$60	$43
2017	$49	$62	$45
2018	$50	$59	$47
2019	$51	$59	$48
2020	$53	$62	$49
2021	$55	$67	$51
2022	$66	$76	$63
2023	$68	$80	$65
2024	$69	$78	$68

Figure 2: AEP Forecasts of Energy Prices



2. Forward Prices

Q: How did you forecast energy prices for evaluation of the PPA?

A: I relied on the market energy forwards.

Q: What are market energy forwards?

A: Forwards represent the price against which various market parties (e.g., generators, marketers, financial traders, utilities, large consumers) have agreed to settle the actual price of energy reported at specific times (such as on-peak hours in July 2020) and places. In essence, the seller guarantees that the buyer will pay the contract price, and the buyer guarantees that the seller will receive the contract price, regardless of the actual price. Forward contracts are traded on various exchanges (such as the New York Mercantile Exchange or NYMEX and the

Intercontinental Exchange or ICE) and as bilateral directly between buyers and sellers. The forwards are priced in nominal dollars.

Q: What market energy forwards are relevant for projecting energy revenues from the PPA units?

A: The following four futures trading points appear to be most relevant for the PPA plants:

- PJM's AEP Zone (stretching from Virginia to Michigan, which AEP attempts to model in its forecast), for which day-ahead forward prices (Intercontinental Exchange products PAS on-peak and PAT day-ahead off-peak) are available to December 2018.[13]
- PJM's AEP-Dayton Hub (which closely tracks the AEP Zone price), for which day-ahead forward prices (ICE products ADB and ADD) are available to December 2021.
- PJM's Western Hub (to the east of AEP, in western Pennsylvania), for which day-ahead forward prices (ICE products PJC and PJD) are available to December 2024.
- MISO's Indiana Hub (immediately to the west of AEP), for which day-ahead forward prices (ICE products MCC and MCD) are also available to December 2024.

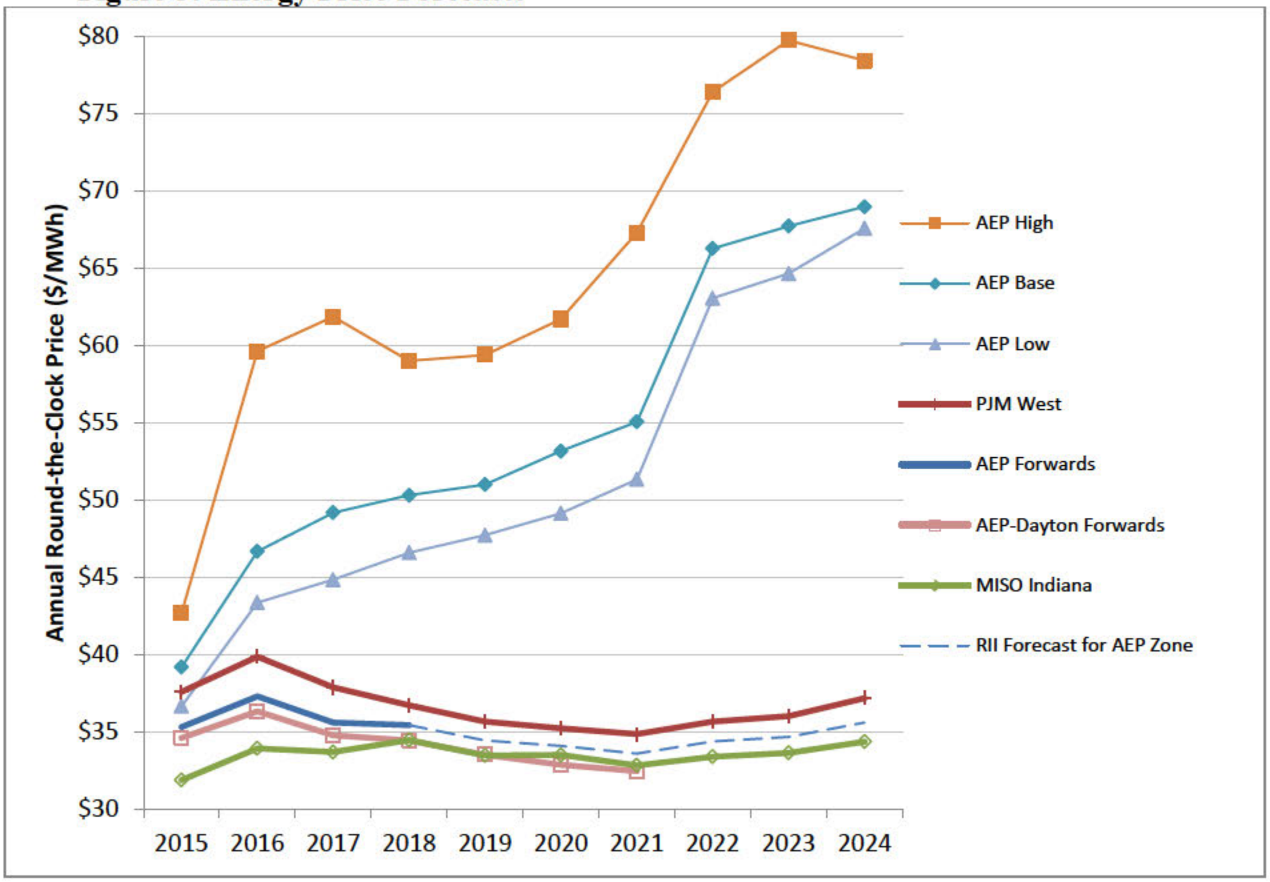
Q: Are AEP's energy price forecasts consistent with forward energy price forecasts?

A: No. Figure 3 and Table 7 compare these annual forward values, as of August 28, 2015, to the AEP forecast. I weighted the monthly peak and off-peak forwards in

[13] Most market energy is priced in the day-ahead market, or through longer-term bilateral contracts based on expectations of the day-ahead prices.

proportion to AEP's base-case forecast of PPA-unit output in each period of each month.

Figure 3: Energy Price Forecasts



AEP's forecasts, even its low forecasts, are inconsistent with the forward prices. The AEP base and low forecasts are roughly 50% higher than the forwards by 2020 and about twice the forwards by 2024. If AEP really believed that future prices would approach those in its forecasts, it would be buying up massive amounts of forward energy for its own account, to be sold into the market at its forecast prices in the future. If a significant share of the market participants believed that the AEP forecasts were realistic, forward prices would be much higher than they actually are.

The power traders whose judgments about the market are embedded in the prices reported by ICE clearly expect market energy prices significantly lower than AEP's base or even its "low" price forecast.

Q: What is the historic relationship among the pricing points you used in your analysis?

A: Figure 4 depicts the average price in three zones between January 2011 and April 2015, from PJM's database of day-ahead energy prices. Over these 52 months, the AEP Generation Hub averaged 10–20% lower than Western Hub and 5% higher than Indiana Hub. The AEP Generation Hub prices have been consistently lower than prices in the AEP Zone or the AEP-Dayton Hub.

Figure 4: Comparison of Market Energy Prices ($/MWh)

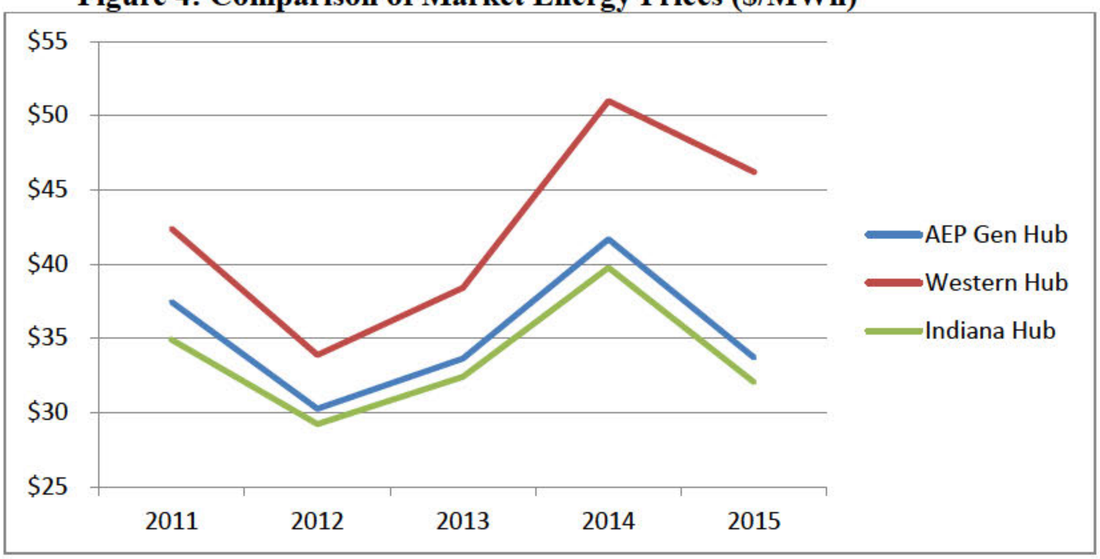


Table 7: Comparison of Forwards with AEP Base Forecast ($/MWh)

	Forwards				
Period	**AEP Zone**	**AEP-Dayton Hub**	**PJM Western Hub**	**MISO Indiana Hub**	**AEP Base Case**
4Q2015	$35.32	$34.62	$37.61	$31.90	$39
2016	$37.31	$36.34	$39.88	$33.94	$47
2017	$35.62	$34.79	$37.88	$33.70	$49
2018	$35.45	$34.46	$36.72	$34.48	$50
2019		$33.53	$35.67	$33.48	$51
2020		$32.89	$35.23	$33.52	$53
2021		$32.46	$34.87	$32.84	$55
2022			$35.67	$33.40	$66
2023			$36.03	$33.65	$68
2024			$37.18	$34.38	$69

Q: How did you construct forecasts of energy prices for the PPA revenue stream from the forward prices?

A: I created an energy-price forecast (which I call the RII energy forecast, for simplicity), using the shaped forwards for

- The AEP Zone for the fourth quarter of 2015 and 2016–2018;
- The average of the PJM Western Hub, the AEP Dayton Hub, and the MISO Indiana Hub, each adjusted by the 2018 average price ratio (the AEP Zone forward divided by the particular hub price) for 2019–2021.
- The average of the PJM Western Hub and the MISO Indiana Hub, adjusted for the ratio of 2018 forwards, for 2022–2024.

The price adjustments are –3.5% for the PJM Western Hub, 2.8% for the Indiana Hub, and 2.9% for the AEP-Dayton Hub. The AEP Ohio zone is located geographically between the Indiana and Western hubs and has historically had prices in between those hubs, as well. I weighted the on and off-peak forwards by the distribution of PPA generation in the base case.

Table 8: Summary of Market-based Forecasts by Year ($/MWh)

Year	AEP Base	RII	% Change
2015	$39	$35.32	–10%
2016	$47	$37.31	–20%
2017	$49	$35.62	–28%
2018	$50	$35.45	–30%
2019	$51	$34.45	–32%
2020	$53	$34.10	–36%
2021	$55	$33.61	–39%
2022	$66	$34.38	–48%
2023	$68	$34.69	–49%
2024	$69	$35.62	–48%

Q: Each AEP energy-price forecast is associated with slightly different generation levels. To which generation levels did you apply your market-based prices?

A: I used the generation energy from AEP's base, high, and low price cases to produce three different cases. I also computed a simple average of the high and low output cases to mirror Mr. Pearce's computations.[14] This is a total of four different load levels.

Q: How much energy generation does AEP forecast for the PPA units?

A: For each case, AEP forecasts that net generation will stay roughly constant over time. In the later years, as the CO_2 price is added in, generation declines somewhat in each case. AEP's forecast of the PPA-wide capacity factor averages [redacted]% in the base case, compared with [redacted]% in the low case, and [redacted]% in the high case. The high case has the plants running in almost all available hours. Figure 5 shows the annual capacity factors for the PPA units, historically and in each of AEP's price cases.

[14] My results may slightly understate the net energy revenues of the PPA resources. Lower market energy prices would result in PJM dispatching the PPA units less, which would somewhat mitigate the losses. Dispatch constraints would require that the units sometimes run when they are not economic or miss out on operating in hours when they would have been profitable.

Figure 5: Comparison of PPA Unit Capacity Factors

[redacted]

Q: What are the historic capacity factors for the PPA units and how do these compare to the AEP forecast?

A: Between 2010 and 2014, the PPA units (including the OVEC units) had an average capacity factor of 59%. In the first half of 2015 (the period for which the EIA has released data), the average dropped to 47%. Specific units' annual capacity factors have ranged from 36% to 82%, as shown in Table 9.

Table 9: Historical Capacity Factors for PPA Units[15]

	2010	2011	2012	2013	2014	5-year average	Jan–June 2015
Cardinal 1	71%	53%	56%	71%	56%	61%	72.3%
Conesville 4	36%	37%	36%	43%	61%	43%	48.6%
Conesville 5	50%	60%	46%	66%	62%	57%	49.3%
Conesville 6	56%	69%	44%	38%	55%	53%	26.8%
Stuart 1	60%	75%	60%	67%	60%	64%	39.5%
Stuart 2	77%	60%	67%	56%	52%	62%	50.5%
Stuart 3	61%	74%	40%	74%	44%	58%	47.1%
Stuart 4	68%	63%	61%	67%	49%	61%	48.6%
Zimmer	82%	57%	41%	80%	62%	64%	67.6%
OVEC Combined	78%	77%	57%	57%	62%	66%	54.9%
Clifty Creek	77%	77%	58%	55%	59%	65%	
Kyger Creek	80%	77%	56%	61%	65%	68%	
Energy-weighted PPA Average	64%	61%	50%	61%	58%	59%	47.3%

In summary, AEP forecasts that the PPA units will produce much more energy during the PPA years than they have in the last five years. This increase in output would require improvements in the dispatch costs (fuel and variable O&M) for the PPA units, compared to market prices, as well as high availability. Since the market indicates that AEP's forecasts of market energy prices are grossly overstated, the high levels of output projected by AEP are unlikely.

Q: What does this imply about the most likely generation scenario?

A: The PPA units are likely to run well below the [redacted] average capacity factors of the AEP low case.

Q: What do the market-based forecasts imply about the benefits of the PPA?

A: If the forward contract prices settled on by market participants are more accurate than AEP's price forecasts, the PPA would impose substantial costs on AEP customers. These costs would be around $3 billion in total, or about $2 billion on an NPV basis between 2015 and 2024, as summarized in Table 10.

15 EIA Form 923 Database.

Table 10: Effect of Energy Forecast, 2015–2024 ($M)

	Simple Net Sum Benefit			Net Present Value Benefit (2014$)		
Output Case	AEP Base	RII Market	Difference	AEP Base	RII Market	Difference
Base	$31	-$3,456	-$3,487	-$8	-$2,008	-$2,000
High	$2,074	-$3,593	-$5,667	$1,291	-$2,082	-$3,373
Low	–$927	-$3,310	-$2,383	-$625	-$1,948	-$1,323
High-Low Average	$574	-$3,451	-$4,025	$333	-$2,015	-$2,348

Table 11 summarizes the change in NPV for each unit, from AEP's base price forecast case to my market-based forecast, using the AEP low-case output. The low-output case is most favorable for the PPA economics with low market energy prices, since at higher output levels, the PPA units more often run when their costs exceed market price.

Table 11: Comparison of Unit Net Benefits, 2015–2024 ($M)

	Simple Net Sum		Net Present Value (2014)	
Unit	AEP Low	RII Market	AEP Base	RII Market
Cardinal 1	[redacted]	-$800	[redacted]	-$453
Conesville 4	[redacted]	-$454	[redacted]	-$276
Conesville 5	[redacted]	-$373	[redacted]	-$218
Conesville 6	[redacted]	-$324	[redacted]	-$187
Stuart 1	[redacted]	-$136	[redacted]	-$77
Stuart 2	[redacted]	-$141	[redacted]	-$79
Stuart 3	[redacted]	-$138	[redacted]	-$78
Stuart 4	[redacted]	-$144	[redacted]	-$82
Zimmer	[redacted]	-$529	[redacted]	-$319
OVEC Combined	[redacted]	-$418	[redacted]	-$240
Total	[redacted]	-$3,456	[redacted]	-$2,008

Q: Would any PPA units be profitable in the market price cases?

A: No. The units that are closest to profitability over the 10 year study period are Conesville 5 and 6. Even for these units to be modestly profitable, the market energy prices would need to transition to something like AEP's Base forecast by about 2019. With prices closer to market forwards, no units are cost-effective.

B. Projections of Market Capacity Prices

Q: What have been the capacity clearing prices for the AEP zone over the past ten PJM auctions?

A: Over the ten BRA auctions, capacity prices outside the constrained zones have ranged from $16.46/MW-day up to $174.39/MW-day averaging out to $93.15/MW-day.[16] The prices for the rest-of-RTO area are shown in Table 12. The AEP zone has always been in the rest-of-RTO area.[17]

[16] The Reliability Pricing Model (RPM) auction allows for different zones to clear at different prices to account for heterogeneous capacity needs.

[17] The constrained areas have generally been in the eastern part of PJM (the MAAC area, or subareas within MAAC), although the ATSI (First Energy) zone was constrained in 2015/16 and 2016/17, due to the retirement of large amounts of First Energy and merchant capacity at short notice, and the ComEd zone was constrained in 2018/19, due in part to reduction of import capacity from outside PJM, driven by technical and contract changes.

Table 12: Actual BRA capacity prices 2007/08–2018/19 ($/MW-day)

Capacity Year	Rest-of-RTO
2007/2008	$40.80
2008/2009	$111.92
2009/2010	$102.04
2010/2011	$174.29
2011/2012	$110.00
2012/2013	$16.46
2013/2014	$27.73
2014/2015	$125.99
2015/2016	$136.00
2016/2017	$59.37
2017/2018	$120.00
2018/2019	$164.77

Although actual PJM capacity prices have varied significantly over the first dozen auctions, prices have not shown any overall trend. The 2018/19 auction price is for performance capacity, which will be subject to penalties for unavailability. The capacity performance prices have recently been set for 2016/17 at $134/MW-day and 2017/18 at $151.50/MW-day.

Q: What is AEP's forecast for PJM capacity prices?

A: In its original October 2014 filing, AEP used the prices already set for May 2015 through May 2018 through the annual PJM RPM capacity auctions. From 2018 through 2024, AEP forecasted a rapid and sustained increase in capacity prices, ending at $[redacted]/MW-day, approaching the administratively calculated net Cost of New Entry (CONE). Since AEP's net benefit computation is aggregated by calendar year, rather than PJM capacity years (June–May), AEP computed the simple average of monthly prices to calculate the annual value. AEP's delivery-year and calendar-year forecast capacity prices are shown in Table 13.

Table 13: AEP Forecast of Base Capacity Prices 2015–2024

Delivery Year	$/MW-day	Calendar Year	Averaged $/MW-day
2015/16	$136	**4Q2015**	[redacted]
2016/17	$59	**2016**	[redacted]
2017/18	$120	**2017**	[redacted]
2018/19		**2018**	[redacted]
2019/20		**2019**	[redacted]
2020/21		**2020**	[redacted]
2021/22		**2021**	[redacted]
2022/23		**2022**	[redacted]
2023/24		**2023**	[redacted]
2024/25		**2024**	[redacted]

In the May 2015 amended testimony, AEP revised its estimates of the 2016/17 and 2017/18 prices to reflect the price caps for performance capacity, as summarized in Table 14.

Table 14: AEP Forecast of Performance Capacity Prices 2015–2024

Delivery Year	$/MW-day	Calendar Year	Averaged $/MW-day
2015/16	$136	**4Q2015**	[redacted]
2016/17	$165	**2016**	[redacted]
2017/18	$211	**2017**	[redacted]
2018/19		**2018**	[redacted]
2019/20		**2019**	[redacted]
2020/21		**2020**	[redacted]
2021/22		**2021**	[redacted]
2022/23		**2022**	[redacted]
2023/24		**2023**	[redacted]
2024/25		**2024**	[redacted]

The actual clearing prices for performance capacity in the transition auctions were $134/MW-day for 2016/17 and $151.50/MW-day for 2017/18. The price increment for 2016/17 was about 70% of the maximum suggested by AEP, while the price increment for 2017/18 was about a third of AEP’s computed up-side.

Q: Why does Mr. Pearce assert that capacity prices will approach net CONE?

A: Mr. Pearce summarizes AEP's rationale for this forecast as "Over the long run, AEP expects that the capacity prices will clear at the Net CONE level." (SC-INT-2-087c). Mr. Pearce asserts that "When PJM first designed the auction they conducted Monte Carlo simulation runs showing that over time, the capacity market would clear at approximately the Net CONE level. Net CONE is Gross CONE less the expected energy & ancillary service net revenues. Therefore, under a long term scenario, it is logical to expect that a sustainable level of payment from PJM's energy and capacity markets roughly equals gross CONE." (SC-INT-2-087)

Q: What is AEP's basis for saying that market capacity prices must rise to "approximately the Net CONE level"?

A: Mr. Pearce asserts that "even the $120 per MW-day that cleared beginning June 1, 2017, are not capacity prices that will tend to encourage new generation or perhaps sustain a large amount of existing generation" (Pearce Amended Direct at 19, lines 5–7).[18]

Q: Is there any indication that prices near Net CONE are needed to "encourage new generation"?

A: No. Over the previous three PJM BRAs (2015/16 through 2017/18), more than 17,600 MWs of new natural gas capacity has cleared, at a rate of nearly 6,000 MW per year.[19] Another 3,385 MW was added in the August 2015 auction for 2018/19. These figures represent only new construction, and omit any uprates at existing

[18] For the 2017/18 RPM auction, Rest-of-RTO net CONE equaled about $351.78/MW-day, nearly three times higher than the actual auction clearing price.

[19] "2018/2019 RPM Base Residual Auction Results," PJM, August 28, 2015, Table 8. http://pjm.com/~/media/marketsops/rpm/rpmauctioninfo/20182019baseresidualauctionreport.ashx.

units.[20] Large numbers of these new gas-fired power plants can be added in PJM, especially in the western portions.

Over these four auctions (2015/16 through 2018/19), zonal prices ranged from \$59/MW-day to \$225/MW-day, but most zones in most years have settled around \$120/MW-day for base capacity, with prices in unconstrained zones below \$165/MW-day. Table 15 summarizes those results, using the data on cleared new capacity by zone and by technology and type from PJM's "RPM Base Residual Auction Results" documents for each of the four auctions (e.g., Tables 3A and 8 in the 2018/19 Auction Results).

[20] While about 1,900 MW of uprates at existing gas-fired units have cleared in the 2015/16 through 2018/19 BRAs, with 580 MW in the 2018/19 BRA, it is not clear how much economic uprate potential remains to be exploited.

Table 15: Summary of New Generation Clearing PJM Auctions

		2015/16	2016/17	2017/18	2018/19
Locations of Generation Added (MW)					
	EMAAC	2,314	59	1,746	1,173
	MAAC	2,991	1,555	4,418	1,569
	Total RTO	4,899	4,282	5,927	5,056
	Rest of MAAC	677	1,496	2,672	396
	Rest of RTO	1,908	2,727	1,510	3,487
Type of New Generation Added (MW)					
	CT/GT	1,383	171	131	1,033
	CC	5,915	4,995	5,010	2,352
	Other	362	149	248	239
	Total	7,659	5,314	5,389	3,625
Minimum Gas (MW) outside high-priced zones in:					
	MAAC[a]	2,629	1,347	2,424	160
	Rest of RTO[b]	~1,500	4,074	3,933	TBD
Max Clearing Price($/MW-day) outside high-priced zones:					
	MAAC	$167	$119	$120	$165
	Rest of RTO	$59	$114	$120	$165

[a] 2016/17, 2017/18 and 2018/19 exclude EMAAC.
[b] 2015/16 excludes about 850 MW Eastlake in ATSI zone, at higher price.

The estimate of minimum new gas installed outside the high-priced zone in each area assumes that (1) all the capacity added in EMAAC was gas-fired, (2) all the EMAAC capacity additions in 2016/17 and 2017/18 were in the high-priced PSEG subarea, and (3) all the "other new" generation (solar, wind, hydro, steam, diesel and fuel cells) was located in the low-priced parts of MAAC or Rest-of-RTO. This computation probably overstates the capacity added in the PSEG zone, and the nets the "other" generation from both MAAC and Rest-of-RTO, so the totals in the low-cost areas are understated.

For 2018/19, PJM has not released information on the amount of new capacity added in the ComEd zone, so I cannot determine the portion of the RTO additions that were at the $165/MW-day price, as opposed to the $215/MW-day at which ComEd cleared.

The auction clearing prices are significantly below the administratively set Net CONE values which started at $321 in 2015/16 for the RTO and escalated to $351 in 2017/18 before falling to $301/MW-day in 2018/19. Other zones have similar net CONE values but differ modestly due to specific differences in the expected costs to build new power plants and the energy revenues expected in each zone.[21]

Q: Can you point to any specific examples of new generation being added in PJM at prices below net CONE?

A: Market participants are willing to bid in new natural gas fired capacity at prices significantly below CONE. Table 16 identifies nearly 12,000 MW of new natural-gas capacity that appears to have participated over the previous four auctions.[22] This represents 68% of the new gas fired capacity added to the PJM market over this period. PJM does not identify the winners of capacity obligations, but the resources in Table 16 (identified through public announcements, analyst reports, proposed in-service dates, and similar information) accounted for most of the new gas fired capacity committed for 2015/16 through 2017/18.

[21] It is clear that PJM's estimate of the net cost of new capacity is overstated. The PJM CONE values are used for a variety of purposes in the capacity market.

[22] The only uprate included in this list is the Tenaska Rolling Hills plant in Ohio. This plant is converting from a combustion turbine to a combined cycle power plant and this will increase capacity by 50%. All other capacity uprates are omitted.

Table 16: PJM New Gas Builds By RPM/Planning Year

Name	Owner	Type	Capacity (ICAP MW)	State	LDA	Clearing Price $/MW-day	First RPM Year	Online Year
Warren	Dominion	Integrated	1,329	VA	RTO	$136.00	15/16	2014
Rolling Hills (Uprate)	Tenaska	IPP	442	OH	RTO	$136.00	16/17	2016
West Deptford Power	LS Power	IPP	650	NJ	EMAAC	$167.46	15/16	2014
Newark Energy Center	Hess	IPP	625	NJ	EMAAC	$167.46	15/16	2015
Garrison Oak	Calpine	IPP	309	DE	EMAAC	$167.46	15/16	2015
St. Charles Energy Center	CPV	IPP	726	MD	MAAC	$167.46	16/17	2017
Woodbridge	CPV	IPP	700	NJ	EMAAC	$167.46	16/17	2016
Nelson	Invenergy	IPP	573	IL	RTO	$59.37	16/17	2015
Brunswick	Dominion	Integrated	1,300	VA	RTO	$59.37	16/17	2016
Liberty	Panda	IPP	936	PA	MAAC	$119.13	16/17	2016
Patriot	Panda	IPP	944	PA	MAAC	$120.00	17/18	2016
Wildcat Point	ODEC	Coop	1,000	MD	MAAC	$120.00	17/18	2017
NAPD Oregon	Multiple Owners	IPP	800	OH	RTO	$120.00	17/18	2017
Keys Energy Center	Genesis	IPP	735	MD	MAAC	$120.00	17/18	2017
Stonewall	Panda	IPP	800	VA	RTO	$120.00	17/18	2017
Middletown	NTE Energy	IPP	525	OH	RTO	$164.77	18/19	2018
Westmoreland	Tenaska	IPP	950	PA	RTO	??	??	2018
Freedom	Moxie	IPP	1,050	PA	MAAC	$164.77	18/19	2018

Q: **Are the decisions to proceed with building new gas generation at capacity prices well below CONE driven by assurance of cost recovery through cost-of-service regulation of integrated utilities or through long-term contracts with independent power producers?**

A: Only in a few cases. Only three of the new capacity additions are projects of integrated utilities. Two plants—the 625 MW Newark Energy Center and the 726 MW St. Charles Energy Center—were offered contracts for differences that would have raised their effective capacity payments. Federal courts voided these contracts sponsored by the states of New Jersey and Maryland. Nevertheless, both plants continued with development—Newark is in service and St. Charles is under construction—even though the developers knew that they would only be paid the PJM clearing price. Merchant generators own the remaining 58% of identified new capacity and are operating without any long-term price support.

Invenergy's Nelson plant in the ComEd zone cleared at a price of $59.37/MW-day, roughly 20% of Net CONE. Overall, 1,873 MW of capacity cleared at less than $60/MW-day in 2015/16 through 2017/18, 5,215 MW cleared between $60 and $120; and the remaining 4,781 MW cleared at a price of $167.46. Merchant generators have apparently found that they can make project economics work within this range of capacity prices and are the parties adding the most new generation into PJM today.

Q: How do the AEP capacity forecasts compare to the actual rest-of-pool capacity prices for the years available and the AEP forecast of capacity between 2018 and 2024.

A: Figure 6 compares the actual capacity prices by calendar year, AEP's capacity-price forecast including its adjustments for the 2016/17 and 2017/18 performance-capacity auctions, and a market-based forecast (RII CP) that I developed and discuss below.

Figure 6: Comparison of Capacity-Price Actuals and Forecasts, AEP Zone

[redacted]

Q: What is your forecast of capacity prices?

A: My RII projection of capacity price with capacity performance (CP) is shown in Table 17, along with actual prices, CONE, and the AEP capacity price projection. I start with the 2018/19 BRA clearing price for performance capacity of $164.77/MW-day and inflate it annually at 5% nominal, to reflect the possibility that the supply of low-cost sites for project development will decline over time.[23]

[23] This is probably a conservatively high-end assumption, since the retirement of older plants will continue to free up sites with transmission and cooling-water access. The Midwest also has many unused industrial sites. Nonetheless, development may become more expensive over time.

Table 17: Summary of PJM Capacity Prices and Forecasts

Capacity Year Ending	Actual RTO Net CONE	AEP Projection	Actual Base Capacity	Performance Increment	RII Projection
2015	$342.23	$136.00	$136.00		$136.00
2016	$326.41	$91.30	$91.30		$91.30
2017	$342.70	$94.74	$94.74	$14.79	$109.53
2018	$321.75	$172.77	$120.00	$14.79	$134.79
2019	$300.57	$215.54	$149.98	$14.79	$164.77
2020		$231.74			$173.01
2021		$248.55			$181.66
2022		$265.99			$190.74
2023		$284.08			$200.28
2024		$302.83			$210.29

Q: Did you adjust any of the prices that have already been set by PJM?

A: Yes. Even though the capacity prices have been set for 2016/17 and 2017/18, PJM has recently held auctions for suppliers that are willing to convert their current contracts for base capacity to higher-priced performance capacity. The performance resources will pay penalties to PJM if they are unavailable at the times the PJM needs them for reliability, so not all resources with existing capacity obligations will want to shift to being performance resources. When I prepared this forecast, it was difficult to estimate the premium that suppliers would demand for this more demanding service, but we did know that performance capacity cleared for $14.79/MW-day more than base capacity in the 2018/19 BRA.

We can also estimate the penalties that generators would expect from the performance mechanism. The expected cost to a generator associated with capacity performance would equal the product of the penalty rate, times the number of penalty hours, times the resource's equivalent forced outage rate (EFOR). For 2017/18, the penalty rate would be $4,275/MWh. As shown in Table 3, PJM's penalty hours over the past five years have averaged 13.5 hours annually. For a 10% forced outage rate, a generator would face an expected penalty of about $4,275 × 13.5 × 10% ÷ 365 = $16/MW-day. With the 30 annual performance hours that PJM assumed in setting the penalty rate, the 2017/18 incremental price for performance capacity would be about $36/MW-day.

Table 18 summarizes the forced outage rates for various types of generation over the past eight years. The forced outage rates have averaged less than 10% for all technologies, except for the smallest coal units (due to the last two years, in which owners may have been allowing plants to deteriorate in anticipation of retirement) and oil-steam units (which represents a very small portion of PJM capacity, and many of which have been retired or are slated to retire in the near future).

Table 18: PJM Forced Outage Rates by Unit Type

	2007	2008	2009	2010	2011	2012	2013	2014	Average
Coal	8.5	8.7	7.8	8.4	9.4	9.9	10.5	12.8	9.5
Coal < 300 MW	9.6	9.1	8.8	9.9	9.9	10.8	13.2	17.8	11.1
Coal 300599 MW	8.8	9.5	8.0	8.2	8.3	9.7	8.8	10.6	9.0
Coal >599 MW	7.4	7.8	6.8	7.4	9.8	9.4	9.8	10.4	8.6
Oil Steam	11.5	22.4	20.7	17.5	23.5	15.3	18.2	12.0	17.6
Gas Steam	4.8	6.4	3.0	5.6	6.4	2.5	7.6	6.3	5.3
Other Steam	7.6	5.6	6.1	6.9	6.4	6.3	8.9	6.7	6.8
Nuclear	1.8	2.1	4.4	2.7	3.0	1.8	1.4	2.4	2.5
Combustion Turbine	9.2	7.4	5.8	5.8	5.3	6.4	9.6	12.9	7.8
Combined Cycle	3.9	3.8	3.8	3.7	3.3	4.1	3.7	3.7	3.8
Hydro	2.8	3.1	3.2	2.7	3.7	3.5	3.5	4.5	3.4
Pumped Hydro	1.4	1.6	2.5	0.8	1.7	3.3	3.7	2.1	2.1
Diesel	10.6	8.5	9.0	5.8	7.3	5.3	6.5	13.7	8.3

The small coal plants were about 3.3% of PJM generation capacity at the end of 2014, and nearly half of that capacity was scheduled for retirement in 2015 and early 2016, before the 2016/17 capacity year. Oil steam capacity was only 2.2% of PJM generation capacity.

Considering the uncertainty, I assumed that the $14.79/MW-day difference between the prices for base and performance capacity in the 2018/19 BRA would also apply in these two earlier years.[24]

Table 18 summarizes my capacity-price forecast by capacity year.[25]

Table 19: RII Capacity-Year Price Forecast ($/MW-day)

Capacity Year Ending	Base Capacity	Performance Increment	Performance Capacity
2016	$136.00		$136.00
2017	$59.37	*$14.79*	*$74.16*
2018	$120.00	*$14.79*	*$134.79*
2019	$149.98	$14.79	$164.77
2020			*$173.01*
2021			*$181.66*
2022			*$190.74*
2023			*$200.28*
2024			*$210.29*
Values in italics are projected.			

Q: How did the 2018/19 BRA results compare to AEP's capacity price projections for that year?

A: AEP's October 2014 forecast of about $[redacted]/MW-day for the 2018/19 auction proved to be greatly overstated when the actual auction cleared at $150/MW-day for base capacity and $165/MW-day for performance capacity. AEP's capacity price forecast for 2018 was 27% higher than the actual BRA result for performance capacity.

24 The actual differentials were higher, at $75/MW-day and $31/MW-day, respectively.

25 My forecasts for 2016/17 and 2017/18 do not reflect the recent transition auctions, which cleared substantially higher than my rough estimate for 2016/17 and slightly higher for 2017/18.

Q: How does your forecast compare to that of AEP?

A: AEP's projections of PJM capacity prices from 2018 on are much higher than the market indicates is necessary to encourage the construction of new gas fired capacity. In 2018, the AEP forecast is [redacted]% higher than the RII market-based forecast; by 2024, it is [redacted]% higher.[26]

Table 20: Comparison of Capacity Price Forecasts

	AEP Forecast		
Calendar Year	**Base (Oct 2014)**	**Performance (May 2015)**	**RII Projection (Performance)**
4Q2015	[redacted]		$136.00
2016	[redacted]	[redacted]	$99.93
2017	[redacted]	[redacted]	$109.53
2018	[redacted]	[redacted]	$152.28
2019	[redacted]	[redacted]	$169.58
2020	[redacted]	[redacted]	$178.05
2021	[redacted]	[redacted]	$186.96
2022	[redacted]	[redacted]	$196.31
2023	[redacted]	[redacted]	$206.12
2024	[redacted]	[redacted]	$216.43

Q: How does this market-based capacity forecast affect PPA profitability?

A: Multiplying the roughly 2,700 MW of UCAP covered by the proposed PPA and the OVEC units by the differences in $/MW-day prices in Table 20 and 365 days per year results in a total revenue reduction of $389 million, with an NPV of $212 million, over the ten year study period, regardless of the energy price or energy output. This change by itself would swamp the modest benefits AEP reports for its base case, and erode most of the reported benefit in the high-low average case.

[26] The AEP values for 2016–2018 represent maximum estimates; AEP does not provide a most-likely case.

Q: Please quantify the overall effects of these changes to energy and capacity forecasts.

A: Table 21 summarizes the benefits by unit with the AEP base-case assumptions and with my market-price price and the output levels of AEP's low case, which minimizes the extent of operating losses.

Table 21: Effect of Market Energy and Capacity Price Forecasts on PPA Net Benefits by Unit ($M)

	Simple Sum		NPV	
	AEP Base	**RII Market**	**AEP Base**	**RII Market**
Cardinal 1	[redacted]	-$800	[redacted]	-$453
Conesville 4	[redacted]	-$454	[redacted]	-$276
Conesville 5	[redacted]	-$373	[redacted]	-$218
Conesville 6	[redacted]	-$324	[redacted]	-$187
Stuart 1	[redacted]	-$136	[redacted]	-$77
Stuart 2	[redacted]	-$141	[redacted]	-$79
Stuart 3	[redacted]	-$138	[redacted]	-$78
Stuart 4	[redacted]	-$144	[redacted]	-$82
Zimmer	[redacted]	-$529	[redacted]	-$319
OVEC Combined	[redacted]	-$418	[redacted]	-$240
Total	[redacted]	-$3,456	[redacted]	-$2,008

V. The Choice of the Ten-year Study Period

Q: Is it appropriate for AEP to have used less than ten years to evaluate a contract to which AEP Ohio ratepayers would be committed for many decades?

A: No. While the PPA has no firm expiration date, it is supposed to run until each unit is retired. AEP projects retirement dates for the various AEPGR units between 2033 and 2051.[27] (Exhibit KDP-1 at 7) The PPA model covers the period October 2015

[27] AEP assumes that the AEPGR entitlements around age 60, except that Cardinal 1 would run to age 66, and that the OVEC units would retire at age 85. Interestingly, the oldest operating utility coal plants are under 70 years old; the OVEC units would be that old by 2025.

through December 2024. This means that the model only covers 25% to 50% of the expected remaining lifespan of these units. Irrespective of the validity of the model in these first ten years, AEP has no basis to claim that its forecasted trends will continue for a quarter century beyond its study period.

Messrs. Pearce and Bletzacker confirm that AEP has not developed any longer-term PPA forecasts but say that "the Company has no reason to believe that the benefits demonstrated over the forecast period would not continue past the forecast period." (SC-INT-02-019(c)(ii)).[28] In fact, there are at least three reasons that the economics of the PPA would deteriorate after 2024:

- Carbon allowance costs are likely to rise as emission constraints tighten, as the 2030 final compliance deadline under the Clean Power Plan approaches.
- The units will continue to age, raising the risks of major failures and rising costs.
- The decline in the claimed remaining life of the units means that depreciation rates and annual cost recovery for capital will need to rise. This effect is obvious in Mr. Pearce's workpapers, which show depreciation expense rising up to 80% from 2016 to 2024.

It is also important to recall that AEP's "demonstration" of benefits include net costs to ratepayers in one of its three modeled cases; on a present-value basis, two of the three cases result in net costs to ratepayers.

[28] I would say that AEP has claimed benefits, rather than demonstrated them, since its projections of market prices are excessive. The response to SC-INT-02-019(c)(ii) also cites a passage in the original Pearce Direct Testimony (page 12, lines 4–5) that mentions volatility, but does not address PPA costs after 2024.

VI. Risk Shifting with the PPA

Q: Has the Commission required that a PPA included in an Energy Security Plan (ESP) appropriately share risks?

A: In approving a PPA mechanism in its ESP III Order, the Commission directed the Company to "include an alternative plan to allocate the rider's financial risk between both the Company and its ratepayers." (13-2385-EL-SSO, Order at 25).

Q: To what extent would the proposed PPA shift economic, financial, performance, and environmental-compliance risk from AEP shareholders to ratepayers?

A: The proposed PPA would shift almost all of those risks to ratepayers.[29]

- If the PPA units are not able to run, the ratepayers pay for their capital and O&M costs anyway.
- If the energy output of the PPA units is too expensive, and the units are rarely dispatched, the ratepayers pay all the units' fixed costs anyway.
- If environmental regulations result in AEPGR installing expensive retrofits on the PPA units, or purchasing expensive emission allowances, or running the plants much less, the ratepayers would still pay all of the fixed costs of the PPA units, plus all of the costs incurred by AEPGR for compliance.

[29] I say "almost" primarily to allow for the possibility that a future Commission would prevail in disallowing some costs of a FERC-regulated tariff on prudence grounds. The magnitude of that disallowance would be limited by AEP Ohio's finances (since it has no generation in rate base to create the equity that would normally absorb disallowances) and the Commission's willingness to push a large distribution utility into financial distress and even bankruptcy.

- If a PPA unit suffers a prolonged outage, AEP Ohio ratepayers will continue paying its fixed costs (including performance penalties) even though they get no PJM revenue for the plant.
- If a PPA unit's heat rate increases, AEP Ohio ratepayers will pay the higher fuel cost per MWh and continue paying the fixed cost.
- If the owners of a PPA unit (AEPGR or a group of joint owners) decide to retire the unit, the ratepayers will pay for all of the remaining net book value in the unit and all the removal costs, including costs that AEPGR has incurred or committed prior to approval of the contract (or even prior to restructuring).
- Even if a PPA unit is retired the day after the PPA becomes effective, AEP Ohio (and hence the ratepayers) still must reimburse AEPGR for the entire net investment and retirement costs.
- Even if the PPA units are no longer cost-effective to keep in service, AEPGR and the joint owners can continue investing in keeping them in service, adding to the investment on which AEP Ohio ratepayers are required to pay a return to AEP shareholders, in addition to paying for depreciation of that investment and the O&M on the plant and any required additions.[30]
- There is little diversity among the PPA units and the OVEC units. They are all coal plants, so any factor that disadvantages coal (such as the implementation of the Clean Power Plan) will affect all of them. Many of the units (especially

[30] Once some of these imprudent costs have flowed into the PPA, and following the PUCO's review of the prudence of the costs, the PUCO can disallow recovery of some costs by AEP Ohio, which may allow AEP Ohio to terminate the PPA and result in ratepayers bearing the entire net plant and retirement cost of all the PPA units, including all the imprudent costs. If AEP appeals the PUCO's authority to disallow AEP Ohio costs due to the imprudence of third parties (since AEP Ohio will have limited ability to control the PPA costs), reflected in a FERC-approved wholesale rate, this process could take years. Many millions of imprudent investments could flow through the PPA before the PUCO could terminate the contract.

the OVEC units) are quite old, and none represent the best of modern steam-plant technology. The management and ultimate fate of six units (Conesville 4, Stuart 1–4, and Zimmer) are all controlled as much (or more) by Dynegy and AES as by any AEP subsidiary.

Q: Does the structure of the PPA create any adverse incentives for AEPGR?

A: Yes. The Agreement provides an extraordinary return on low-risk investments, specifying a return on equity of 650 basis points above Moody's index of Baa bond yield, which is currently about 5.35%, so the current equity return under the PPA would be about 11.85%.[31] Recent allowed equity returns for integrated electric utilities have been in the range of 9.5%–10.95%, with an average of 10%.[32] The Iowa Utilities Board recently approved a 11.35% equity return for the future costs of MidAmerican Energy's next wind farm, with a price cap on construction costs (subject to subsequent prudence review by the IUB) and no upside if bond rates rise in the future (Docket No. RPU-2015-0002, August 21, 2015 Order).[33] The PPA provides AEPGR with a return on sunk costs, as well as future costs, has no price cap, and allows the equity return to rise if bond yields rise.

Since AEPGR is essentially assured recovery of its investment through FERC regulation, it would have little incentive to make decisions that reduce costs to ratepayers at the expense of shareholders. And since the PPA allows recovery of

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31 The current Baa bond yield is the lowest since early 1966, nearly 50 years ago. The minimum yield in Moody's series was about 3% in 1946; it has been as high as 17%, and was over 7.5% for most of the last four decades.

32 Computed from "Risk Holds Sway," Cross P., Fortnightly Magazine, November 2014, excluding utilities without generation.

33 The IUB noted that the 11.35% was based on the consensus of the parties that "the cost of equity should be higher than current capital costs because the ratemaking principle fixes …ROE for the 30-year life of the facilities." (Order at 12)

costs in perpetuity, AEPGR (with approval of the joint owners) could choose to continue adding investments on which it will earn above-market returns and keep uneconomic units running indefinitely or until the PUCO goes through the difficult process of identifying and denying recovery of imprudent costs, triggering termination of the PPA and a balloon payment to AEPGR.

Q: If the Commission were interested in reviewing a revised PPA for recovery through the PPA Rider, how could AEP restructure the PPA to apportion risk more appropriately?

A: The PPA could be revised in a number of ways that would share the risk between AEP and the ratepayers, including the following:

- Fixing the gross contract price in advance, so that AEPGR and its joint owners bear the capital and fixed O&M costs they have some control over.
- Limiting the recoverable removal costs.
- Locking in the units' heat rates, or a range of heat rates, so that AEPGR is at risk if it allows the efficiency of the units to decline.
- Indexing fuel costs to a market index, so that AEPGR bears the risk of inefficient fuel procurement.
- Varying AEPGR's compensation in proportion to the availability of the units and the performance they demonstrate in the capacity models, so that AEPGR is at risk if it allows the reliability of the units to decline.
- Setting a fixed term for the PPA, such as five or ten years.
- Allowing PUCO to order termination of the PPA with some reasonable notice period, such as two years, without the poison pill of requiring AEP Ohio to pay for all net plant and retirement costs.
- Adding AEPGR agreement to credit AEP Ohio for any costs found imprudent by PUCO, so that prudence risks fall on the plant operator.

- Requiring prior PUCO approval for major capital projects.

Q: Does AEP claim that AEP Ohio bears some of the risk of the PPA?

A: Yes. According to Mr. Vegas, the proposed PPA does share the risk between AEP Ohio and ratepayers:

> AEP Ohio is at risk of having recovery of the PPA Rider balance being disallowed in a future ESP proceeding or not having the Affiliated PPA renewed. Either of these actions would impact the Company's credit rating, which would increase the cost of investments in its distribution infrastructure. These financial risks would continue to exist for the Company until the PPA Rider Units are retired. Accordingly, the PPA Rider proposal properly allocates financial risk between the Company and its customers, as contemplated in the ESP III Order. The Commission will have the ability to audit the accuracy of the costs and revenues included in the PPA Rider as well as a prudence review of actions and decisions undertaken by AEP Ohio or its agents. (Vegas Amended Direct at 29)

Q: Do you agree that the possibility of a prudence review of AEP Ohio imposes financial risk on AEP Ohio?

A: Only with regard to bidding into the PJM markets, which I understand would be under the control of AEP Ohio.[34] While PUCO would have the opportunity to inquire into the costs and benefits of AEP Ohio's actions with respect to management of the PPA units, it is unclear what AEP Ohio could do in that regard that could be found imprudent. The decisions about investments and operating expenditures are controlled by a three-member committee, with AEP Ohio having only one vote.[35] To avoid any threat of disallowance, AEP can make any

[34] Unless AEP Ohio hires staff specifically for this purpose, the bidding decisions are likely to be driven by recommendations from AEPSC.

[35] The other members would represent AEPGR and AEPSC, neither of whom is regulated by the PUCO or subject to any disallowance for imprudence. Since AEP Ohio relies on AEPSC for most technical advice, it is not clear how AEP Ohio would make any independent

investment or operating decisions it desires with a two-to-one vote, with AEP Ohio voting in opposition. If PUCO determines that the decision was imprudent, AEP Ohio's behavior would still be prudent (since it voted against the decision); if PUCO determines that the decision was prudent, there would be no imprudently incurred costs to be assessed to AEP Ohio.

AEP Ohio would have control over the daily offers into the PJM energy market (at least where AEP, rather than some other owner, has control of those offers), but would be dependent on its affiliates and co-owners for the information supporting those decisions. Except in the most egregious cases, any regulator would find it difficult to determine whether a bidding strategy is imprudent, since that strategy is so dependent on the physical characteristics of each unit. Assessing damages would also be difficult, since the PUCO would need to know the price bids of all other PJM resources to determine the effect of a different bidding strategy.

Q: Is it possible that the Commission would disallow the PPA Rider balance in future ESP proceedings, as Mr. Vegas claims?

A: That would be very unlikely. Once accepted by the Commission, the PPA would be the basis for a FERC-approved rate. The PUCO would have no ability to reduce AEPGR's billings to AEP Ohio, and it is not clear whether PUCO's disallowance of recovery of charges by AEP Ohio would survive legal challenges on such grounds as federal preemption of wholesale ratesetting. Disallowances would tend to be limited by PUCO's willingness to put AEP Ohio in financial distress and possibly bankruptcy. This problem is exacerbated by the fact that any disallowance would

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judgments. The PUCO could, of course, order AEP Ohio to vote in particular ways in the committee, and find failure to do so imprudent.

come out of AEP Ohio's equity in the distribution system, since the investment in the PPA plants would remain at AEPGR.

In addition, the Agreement includes an Early Termination provision that is essentially a poison pill:

> Buyer can terminate the Agreement upon notice to the Seller if retail cost recovery for Buyer's Agreement costs is discontinued or substantially diminished, including through a onetime significant disallowance for retail rate recovery of costs, provided Buyer must pay Seller an amount equal to the sum of the net book value and retirement-related costs associated with the PPA Units at that time. (Exhibit KDP1 at 5)

Q: Have you been able to confirm Mr. Vegas's statement that AEP Ohio is at risk of "not having the Affiliated PPA renewed?"

A: No. According to the response to OCC-INT-1-13, the Rider mechanism may be reviewed at each ESP proceeding, but the PPA will remain in effect and costs will be fully recovered until all the PPA units are retired or AEP Ohio invokes the Early Termination clause of the Agreement, which would require AEP Ohio to pay immediately for all remaining net investment and the anticipated cost of removal.[36] Either way, all of AEP's investments in the PPA units would be fully recovered from AEP Ohio ratepayers.

[36] AEPGR could continue to operate the plants for the profit of AEP shareholders, even though all the capital costs would have been paid for by AEP Ohio ratepayers (and the retirement costs would have been prepaid, as well).

Q: Would the opportunity to raise issues of AEPGR imprudence before FERC protect AEP Ohio ratepayers?

A: No. I have not identified any instance where FERC found that investments or expenses incurred at an electric generation facility resulted from imprudence.[37] In some cases, state regulators have made such findings, and limited cost recovery for retail rates, but FERC has allowed full recovery for the same costs in wholesale rates.

Q: Would a different PPA reduce risk to ratepayers?

A: Yes. While the cost-plus, life-of-unit form of the proposed PPA was common prior to the emergence of independent power producers in the 1980s, the norm for purchased-power agreements has since shifted to fixed prices (or indexed prices) for fixed periods, with performance incentives or requirements. Those more modern PPAs put more of the operating risks on the plant operator, who is in a better position to manage those risks. In typical PPAs, the generator is paid per kWh delivered, per MW of capacity qualifying in the regional markets, or as a function of availability. Controllable costs are usually collected under a fixed fee schedule, sometimes with allowances for flow-through of specific uncontrollable costs, such as market fuel costs or changes in tax rates.

Another approach that would be superior to the proposed PPA would be a cost-of-service contract rate with preset default prices, tied to performance, and with the state regulator specified as the arbitrator of any deviation from the default price. The Connecticut Public Utility Regulatory Authority established this structure for the purchases by the electric distribution utilities of capacity from new peaking generation.

[37] My search has been extensive, but not exhaustive. If FERC has found such costs to result from imprudence, those cases must be rare and not widely noted.

VII. The PPA and Price Stability

Q: What assertions does AEP make regarding the PPA's effect on the stability of ratepayer bills?

A: Witnesses Bletzaker (Amended Direct at 7), Fetter (Amended Direct at 7), Pearce (Amended Direct at 18 and 24–25) and Vegas (Amended Direct at 8, 13, 15 and 16) suggest that the ratepayers are exposed to price volatility from such sources as the January 2014 Polar Vortex and that the PPA would reduce or eliminate such volatility.

Q: Are ratepayers exposed to price volatility of the sort caused by the Polar Vortex under the current SSO approach?

A: No. Under the approved ESP III, AEP Ohio will be contracting for its customers' SSO power on a full requirements basis, shifting risks of price and load fluctuations on the power suppliers. In this three-year period, the SSO service will be acquired in a mix of one-, two- and three-year contracts, generally procured three to seven months prior to the start of the delivery period.

Mr. Pearce defines the Polar Vortex by reference to the testimony of a PJM Vice President, Michael Kormos, before FERC. Mr. Kormos addresses a three-day period, January 6–8 (Pearce Amended Direct at 24). The outages of gas, coal and other power plants due to the cold weather, combined with the high weather-related loads, caused a number of problems for PJM, power marketers with load obligations and other parties. But customers with power supplied under arrangements similar to ESP III would not experience any price shocks. The prices at which their energy requirements will be met would have been set long before anyone knew what the weather would be.

Tellingly, AEP could not provide any evidence that the Polar Vortex volatility increased bills to customer served under its SSO or through any aggregator or retail supplier (SC- INT-2-024).

Q: Did coal plants provide a good hedge during PJM's Polar Vortex event?

A: No. As Mr. Kormos notes, 13,700 MW of coal capacity (about 7% of total PJM capacity and 17% of PJM coal) was out of service, including some PPA units. Clifty Creek 3, Cardinal 1, Zimmer, and Stuart 3 (totaling 36% of the combined PPA and OVEC capacity) were off-line for all of January 6 through 8, and Stuart 2 was off line (or ramping up at minimal load) for a several hours on January 6 (bringing the off-line percentage of the PPA capacity to about 40%).

Q: Has AEP quantified the volatility to which it claims ratepayers are exposed and the amount of coal capacity that would be needed to achieve specific reductions in that volatility measure?

A: No.

Q: If customers prefer even less exposure to price changes, what can they do?

A: They can contract with a retail supplier offering a fixed price with a term longer than that of the SSO.

Q: How does Mr. Fetter suggest that the proposed PPA would insure ratepayers against market volatility?

A: Fetter promotes the proposed PPA as protection against "the risks of the totally unforeseen and unexpected." He cites as an example the California utility restructuring experience and price manipulation by Enron and others. In support of his contention that the PPA protect Ohio ratepayers, he cites an analysis prepared by the US Congressional Budget Office (CBO) in 2001.[38]

> Having a large reserve of generating capacity could ease the transition from a regulated to a competitive market structure. Indeed, if California had implemented its plan in the early 1990s, when the state's utilities still possessed more capacity than they needed, the market could have better handled the stresses that arose in the summer of 2000. That improved response could in turn have masked some of the faults of the restructuring plan.

Q: What standards did the PUCO establish in the ESP III order for a PPA that purports to be a price hedge under an ESP?

A: In the ESP III order, the Commission stated the requirements for an acceptable PPA as follows:

> Nevertheless, the Commission does believe that a PPA rider proposal, if properly conceived, has the potential to supplement the benefits derived from the staggering and laddering of the SSO auctions, and to protect customers from price volatility in the wholesale market. We recognize that there may be value for consumers in a reasonable PPA rider proposal that provides for a significant financial hedge that truly stabilizes rates, particularly during periods of extreme weather. … As we have consistently emphasized in AEP Ohio's prior ESP proceedings, rate stability is an essential component of the ESP. (132385ELSSO, Order at 25)

In short, in order to be useful for ratepayers, a PPA must "supplement the benefits derived from the staggering and laddering of the SSO auctions," "protect customers from price volatility in the wholesale market" and provide "a significant financial hedge that truly stabilizes rates, particularly during periods of extreme weather." The proposed PPA does not meet these standards.

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[38] US Congressional Budget Office, "Causes and Lessons of the California Electricity Crisis," September 2001.

Q: What is an electric price hedge?

A: From the perspective of a power consumer, a price hedge would provide a contracted amount of power at a preset price, or allow the purchase of power at a preset price (the strike price). The actual market price may turn out to be higher or lower than the hedge or strike price. The goal of price hedging is to provide price stability at a reasonable cost.

Mr. Fetter describes the proposed PPA is just such a hedge, saying that:

> the PPAs…will serve as a hedge against market stresses, albeit with customers bearing a relatively a small payment upfront [that] guards against larger (potentially difficult to pay) costs later. This is the very definition of "insurance," the likes of which virtually every customer in AEP Ohio's service territory already subscribes to in the form of automobile, homeowner, or life insurance. (Fetter Direct at 9–10)

Q: Does the CBO paper support Fetter's arguments supporting the PPA proposal?

A: No. The California experience as discussed in the CBO paper is irrelevant for three reasons:

First, as acknowledged by Fetter, the CBO analysis concerns a time of "transition from a regulated to a competitive market structure." Unlike California in 2000, the PJM market has been in place for 18 years. While it is not perfect, it has been operating for some time without abuses and price manipulation on the order of California's experience.

Second, the CBO paper does not actually recommend a large reserve of capacity as an economic solution to price instability. Directly following the paragraph cited by Fetter, the report states that:

> Creating such a reserve as a matter of policy, however, is an expensive way to ensure price stability. One of the reasons that the state moved to a competitive market structure was to help reduce electricity prices by lowering the costs of the utilities' reserve capacity. In a competitive market, producers' investment in reserve capacity should be consistent with the amount of price stability (or, equivalently, supply security) that consumers are willing to pay for in the form of long-term supply contracts.

Third, the CBO paper was prepared before Enron's manipulation of the market was widely known. In fact, the CBO paper does not even mention Enron. Therefore, the CBO paper does not provide an analysis of mechanisms to defend consumers against illegal manipulation of price and supply.

In short, the CBO paper cannot be interpreted as saying that excess capacity could have protected against manipulation of market prices, or that maintaining excess capacity would be an appropriate substitute for competitive market rules.

Q: What did the CBO paper recommend as a solution to market stresses?

A: It recommends long-term fixed contracts and hedging through the futures market:

> …Letting utilities both enter into long-term contracts with suppliers at fixed prices and hedge through the futures market would help protect them from the financial difficulties that have plagued California's power distributors. It would also enable the utilities to offer greater price certainty to their customers ... (CBO paper, p. 32)

Q: Is the proposed PPA a price hedge, in the normal sense to the term?

A: No. The proposed PPA provides no guarantee that the hedge will be effective, and the price of the hedge is not known and not under the control of the PUCO or any regulated entity. The only "insurance" the PPA provides is a guarantee of cost recovery for AEPGR, and of a return on equity for shareholders, at the expense of the Ohio ratepayers, by way of the PPA Rider.

Q: Why does the PPA provide no guarantee that the hedge will be effective?

A: In a normal hedge, the buyer pays for price certainty for a specified amount of commodity, agreeing to pay $40/MWh for 500 MWh at a specified time, or paying $10/MWh today for the right to buy up to 500 MWh at $35/MWh at a future time. Under the PPA, the ratepayers of AEP Ohio would be committed to paying an unknown amount for an unknown quantity of energy, since the price of the hedge depends on how AEPGR manages the units (and other factors, including market prices for coal and allowances) and the amount of energy hedged depends on the availability, efficiency variable costs of each unit.[39]

Q: Does the PPA constitute the type of contract that the CBO advocated for price certainty to customers?

A: No. The PPA is not a long-term contract at fixed prices nor is it a hedge through the futures market.

Q: How could AEP Ohio obtain a price hedge that would meet the Commission's standards?

A: As a threshold matter, it is not clear that the SSO requires an additional price hedge. As the Commission has determined:

> there are already existing means, such as the laddering and staggering of SSO auction products and the availability of fixed price contracts in the market, that provide a significant hedge against price volatility (Opinion and Order in 132385ELSSO and 132386ELAAM, February 25, 2015, at 24)

If the Commission wants to test out mechanisms for even greater price stability, it could instruct or encourage AEP Ohio to initiate a competitive procurement for such products as the following:

[39] Similarly, the capacity value hedged depends on the availability of the PPA units.

- Forward contracts for on or off-peak power, for one or more years following the term of the SSO contracts.
- Contracts for differences to be settled against fixed contract prices, with new or existing generators, which may include coal plants, nuclear plants, distributed and utility-scale renewable resources, demand response, energy-efficiency installations, or gas fired generation with long-term fuel contracts. Unlike the proposed PPA, these contracts should only pay the supplier for energy generated and capacity supplied.

Any of these options is likely to be less expensive than the PPA, while providing more price stability. Buying forward energy contracts at $40/MWh would be less expensive and more predictable than buying PPA power at $70/MWh, or whatever the PPA energy would actually cost. If any AEP affiliates participate in the procurements, a third party selected by the PUCO should be responsible for soliciting bids and selecting the winning bidders for PUCO approval.

Q: Do the AEP witnesses address the availability of long-term contracts from the competitive market?

A: Only in a very limited way. Mr. Allen dismisses the idea of long-term contracts from competitive retail suppliers, as follows:

> While it is theoretically possible that a competitive supplier could offer long-term stable offers, the fact is that they do not currently do so. …June 2013 and June 2014 data … demonstrated that CRES providers are not offering long term stable offers. (Allen Amended Direct at 6)

The contracts offered by CRES providers are fundamentally different from the long-term contracts that AEP Ohio could enter with generators or marketers. In particular, while CRES contracts are for whatever energy the customer uses, in whatever time pattern the customer uses energy, AEP Ohio can purchase fixed quantities of energy as a cost hedge, greatly reducing the supplier's risk.

VIII. Market Economics of the PPA Units

Q: How do the market economics of the PPA units differ from the question of whether the PPA would reduce prices for AEP Ohio customers?

A: The PPA includes the unavoidable costs of the units, including both the remaining net plant and the future cost of retirement and removal. The market economics, which drive such decisions as whether to retire a unit, exclude those sunk costs.

Sunk costs (e.g., prepaid pension liabilities, environmental compliance measures such as closure of combustion residual disposal sites, return and income taxes on existing plant) will have no bearing on decisions to retire a plant. Only new or ongoing costs will inform retirement decisions. Forward going costs, by contrast, are only those new costs starting in 2015. These forward-going costs are indicative of what PJM might offer the owners if they propose to retire the units and PJM determines that the plants are required for reliability.

Table 22 shows the sunk costs by AEPGR unit and year. AEP did not provide detail of the sunk costs of the OVEC units. I estimated the sunk cost recovery by rerunning Mr. Pearce's computations with all capital additions, O&M and fuel zeroed out. The difference should represent depreciation, return and taxes on the sunk investment.

Table 22: Sunk Cost Recovery by Unit ($M)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total	NPV
Cardinal 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Conesville 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Conesville 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Conesville 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Stuart 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Stuart 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Stuart 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Stuart 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Zimmer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q: Are the PPA units cost-effective to continue running, omitting these sunk costs?

A: In AEP's base case, AEPGR could profitably continue running all the PPA units as merchant generators, since even the units that are not cost-effective for ratepayers as part of the PPA, including their sunk costs, would be worth running on a going-forward basis.

With my lower market prices, continued operation of the plants would be uneconomic and they would be retired, but the ratepayers would save about $2.5 billion compared to the PPA; those savings should more than cover the costs of any measures necessary to accommodate the retirements.

IX. Reliability Implications

Q: What reliability issues has AEP raised in this proceeding?

A: AEP has posited three problems:

1. that rejection of the PPA could lead to the prompt retirement of all the PPA units,
2. that new generation would not be built in Ohio, and thus

3. that large amounts of transmission would need to be built, much of which would be charged to AEP Ohio customers.

Q: What is AEP's basis for claiming that rejection of the PPA would lead to the prompt retirement of all the PPA units?

A: Actually, AEP does not predict the retirement of any of the PPA units if the PPA is rejected.

> Without the PPA, the PPA Units will be at greater risk of premature retirement, and these units are likely to be sold by AEP, which is evaluating strategic alternatives for [its] merchant generation fleet. A sale could be to an out-of-state entity that does not have the same long-term commitment as AEP to Ohio and the communities where the PPA Units are located. Even if the units are sold, the premature retirement risk and the resulting economic impact to Ohio may not be lessened – the units will still face the same uncertain market economics that they do now. (Vegas Amended Direct Testimony at 14)

Q: Is rejection of the PPA likely to lead to the prompt retirement of all the PPA units?

A: Not if market prices approximate those assumed by AEP. As I show in Section VIII, with the AEP base projection of energy prices and AEP's projection of capacity prices, only three PPA units would be uneconomic to operate going forward.[40]

In addition, AEPGR is a minority owner of the OVEC units, Conesville 4, Stuart, and Zimmer. The OVEC plants are split among ten investor-owned utilities and two generation cooperatives, while the other units are co-owned by Dayton Power and Light (a subsidiary of AES Corporation, which is primarily a developer and owner of merchant generation) and the merchant generator Dynegy. The fate of the OVEC and jointly-owned units will be determined by the decisions of the

[40] If market prices are as suggested by the forward energy markets and by past responses to the PJM capacity auctions, the PPA would be extraordinarily expensive, so even a major transmission build-out would be less expensive.

majority of owners (or other governance terms established by the joint ownership agreements), which may have nothing to do with the fate of the proposed PPA.

Q: What is AEP's basis for suggesting that generation would not be built in Ohio?

A: Mr. Vegas expresses his belief that replacement capacity is not being built in Ohio, and in the event of retirement of the PPA units, they would not be replaced by generation in Ohio.

> Q. IS THE RETIRED CAPACITY BEING REPLACED IN OHIO?
>
> A. Not fully or promptly. Ohio should be a prime location for new gas fired generation investment as it is fortunate to sit on vast reserves of shale gas. Unfortunately, for reasons I will describe below, significant new capacity is not being built in Ohio.
>
> Q. WHY ARE SO FEW NEW CAPACITY PROJECTS BEING BUILT IN OHIO?
>
> A. Ohio has distinct disadvantages to attracting generation investment. Because Ohio has moved to SSO procurement through short-term auctions, investors can only rely on projected market revenues to support long-term investment decisions. Based strictly on market economics, new generation is more likely to be built in eastern PJM, where PJM's capacity market has traditionally identified constrained delivery areas supporting greater capacity clearing prices.
>
> Ohio's neighbors – Indiana, Michigan, Virginia, West Virginia, and Kentucky all provide regulated recovery of generation investments providing investors more clarity regarding the return on such large investments.…These regulated states, however, are not going to build new generation to serve Ohio. (Vegas Amended Direct Testimony at 24)

Mr. Fetter also channels "AEP Ohio's worry that there will not exist an easy path ahead for generation construction, whether by itself or by third-party merchant plant developers." (Fetter Amended Direct Testimony at 6) He also suggests that "The traditional cost-based regulatory frameworks in four of Ohio's neighboring states go far toward affording the certainty that investors require before providing their funds for infrastructure enhancement," in contrast to Ohio's restructured market. (Fetter Amended Direct Testimony at 9)

I respond to these concerns in Section IX.A, below.

Q: Has AEP reasonably assessed the impact of PPA retirements on Ohio reliability and transmission requirements?

A: No. The transmission requirements and costs that AEP presents in the testimony of Mr. Bradish are overstated for several reasons:

- If market prices are comparable to those predicted by AEP, the PPA units would be cost-effective to keep running and any replacement decisions would arise well in the future.
- Generation can be and is being built in Ohio, and more would be built if market prices rose to the levels that AEP forecasts.
- The surge of generation being built in Pennsylvania will tend to reduce power flows and transmission requirements.
- System operators respond to changes in capacity configurations by changing dispatch patterns.
- Given Mr. Bradish's description of the nature of the potential transmission problems, a large portion of any additional transmission costs appear to be driven by and allocable to other PJM zones.

A. Locations of Replacement Capacity

Q: Is Ohio a competitive location to build new capacity?

A: Yes. While Messrs. Vegas and Wittine fret that Ohio's competitive environment will not encourage new construction, compared to construction in neighboring states that still have vertically-integrated utilities, the record does not support this conclusion. Within PJM, only Virginia, West Virginia and the small PJM portions of

Michigan, Indiana and Kentucky are vertically integrated.[41] In Virginia, Dominion is committed to building a number of new gas plants, but merchant generators are building or planning more generation in Pennsylvania, Ohio, Maryland and New Jersey, as shown in Table 23.[42] Much of this merchant generation is in areas that have been clearing primarily or entirely at the same capacity price as AEP's service territory. Neither the lower energy and capacity prices in western PJM nor the lack of vertically-integrated utilities in Ohio, Maryland, New Jersey and Pennsylvania has precluded development of new gas-fired generation.[43]

Table 23: Planned Gas-fired Capacity Additions by State by Capacity Year

Year Ending	**DE**	**IL**	**MD**	**NJ**	**OH**	**PA**	**VA**	**KY**	**MI**	**IN**	**WV**	**Total**
2015		575		669								1,244
2016	309		110	1,473		1,530	1,423	640	408			5,893
2017			1,840				774		127	1,286		4,027
2018			1,008	443	1,530	1,854	653					5,488
2019				828	595	1,290	1,585				578	4,876
Total	309	575	2,957	3,413	2,125	4,674	4,435	640	536	1,286	578	21,527
		EIA860 2014 Early Release Database, August 2015										

Kentucky, Michigan, and Indiana are split between PJM and MISO, and none of the three have restructured. As shown in Table 23, gas-fired additions in these three states in this period barely exceed those of Ohio alone, and 640 MW of the Indiana capacity (about half) is being developed by a merchant generator.[44] Again, vertically-integrated utilities do not appear to be pursuing new generation with more zeal than merchant developers. In fact, the New Covert merchant combined-

41 Small parts of Illinois are still vertically integrated, as are some public utilities in Maryland.

42 About 1,100 MW of the Maryland additions are owned by a generation cooperative.

43 Low gas prices have been encouraging development of generation in western Pennsylvania and Eastern Ohio.

44 The West Virginia power plant is also being developed by a merchant generator.

cycle plant, located in the MISO portion of Michigan, is paying for transmission upgrades to be able to operate as a PJM resource, due to the low market prices in MISO.

I see no reason to believe that merchant generators would avoid Ohio in favor of neighboring states.

Q: Does Mr. Wittine demonstrate that generation will not or cannot be built in Ohio?

A: No. Mr. Wittine's analysis looks at the PJM queue over the past 15 years and computes the fraction of interconnection requests that proceed to specific milestones, including going into service. His analysis is deeply flawed in a couple significant ways.

First, his analysis of the period from 2000 to 2014 is dominated by periods with large excesses in most of PJM and variable but generally low capacity prices. It is hardly surprising that many projects proposed in brief periods of bullish outlook (such as 2007 and 2008, when the 2009/10 and 2010/11 RTO capacity markets cleared at $191/MW-day and $174/MW-day) were suspended or canceled when prices fell (as they did in 2009, when the RTO market cleared at $16/MW-day for 2012/13). Even though my projection of capacity prices is far below AEP's, it is still comparable to the highest prices ever seen in the RTO. If capacity prices collapse to under $50/MW-day, new power plants would not be needed and would be delayed, and the proposed PPA would be massively unprofitable.

Second, gas-fired plants that looked economic in the late 1990s and early 2000s became less attractive in the run-up of natural-gas prices starting in 2003.

Third, the effects of the great recession, both on prospects for power demand and prices and on the difficulty of financing new generation, probably accounted for the delays and cancelations that Mr. Wittine identifies.

Fourth, Mr. Wittine computes the percentage of projects proposed in 2000 through 2014 that were completed (or achieved other milestones) by the end of 2014. This analysis is biased, since a plant proposed in 2010 is not likely to have been completed in 2014, even if all goes well, and a plant proposed in 2012 certainly would not be completed in 2014.[45]

Mr. Wittine calls out the Dresden plant as an example of the supposed difficulty in building power plants:[46]

> For example in 2000, a merchant generator proposed the 580 MW natural gas fired Dresden Plant, and the plant was certificated by the OPSB in 2001. Construction was suspended when the plant was approximately 50% complete, and in 2007 it was sold to an affiliate of AEP Ohio. Construction was finished and the plant was placed into service in 2012....The suspension of this project after being 50% completed is a prime example of how new merchant generation can be abandoned – even at an advanced development stage. (Wittine Amended Direct at 6–7)

Mr. Witttine's interpretation of the history of Dresden, and of capacity development in PJM more generally, is belied by AEP's own documents. Specifically, the Appalachian Power Company (APCo, a subsidiary of AEP) Report on Capacity Matters, provided as an attachment to SC-RPD-2-080, states as follows:

[45] By the same reasoning, one could conclude that it is difficult to graduate from the Columbus public schools, since only a small portion of the children who registered for kindergarten in 2000 through 2014 had graduated by the end of 2014.

[46] Mr. Wittine makes a similar point about the Fremont Energy Center.

> In the late 1990s, through the early part of the last decade, many new, nonregulated, natural gas merchant plants had been built by Independent Power Producers ("IPPs") when natural gas prices were in the $2-$3/MMBTU range. These prices created "spark spreads," the difference between gas prices and electricity prices, which appeared to favor gas generation as a low-cost form of generation. Once gas prices began rising, many of these gas plants became "distressed' in the sense that they were rarely dispatched as economic resources. (APCo report at 18)
>
> … in the fall of 2004, AEP launched an initiative to identify and evaluate existing "distressed" marketplace assets to determine if these assets could be acquired at a discount (when compared to newly-built generation)…(ibid)
>
> …AEP continued to pursue additional "distressed" generation opportunities with the expectation that the next assignment would likely go to APCo given its projected capacity deficit. In September 2007, AEGCo purchased the partially completed, nominal 580 MW Dresden Natural Gas CC plant located in Dresden, Ohio.… At the time of purchase, Dresden was approximately 45% complete. Shortly after Dresden's purchase, work began to complete construction of the plant. (ibid at 24)
>
> In this same time frame, the 2007–2009 recession reduced AEP-East System loads and the need for capacity. This in turn led to construction being halted on the Dresden Plant. (ibid at 25)

The story told by this history is very different from Mr. Wittine's description. Dresden was not troubled by construction or licensing problems; it simply became uneconomic due to changing gas and electric prices. The developer (a subsidiary of Dominion) suspended construction when that was appropriate, AEP purchased the unit when that looked appropriate, AEP suspended construction when loads fell, and completed the plant when it made sense. Nothing about Dresden's history suggests that power plants that are needed and cost-effective cannot get built in Ohio or PJM generally.

B. Alternatives to Transmission Upgrades

Q: Are there other actions that the PUCO can undertake if some of the PPA units are retired, to reduce the need for transmission upgrades?

A: Yes. The PUCO can encourage investments in energy efficiency and distributed resources, including solar photovoltaics, small hydro, biogas plants and efficient gas-fired combined heat and power. Reduced power flows into Ohio Power's load centers will reduce the need for transmission upgrades.

A large amount of load reduction would be cost-effective, even without consideration of the value of avoiding the high-cost PPA and the potential need for new transmission. Additional resources would almost certainly be justified, including that additional benefit.

Q: What should the PUCO do in this proceeding to promote those alternatives?

A: Considering the nature of this proceeding, and the uncertainty as to which retirements might occur, which retirements would be replaced by new central generation, and which transmission resources may be required, it would not be appropriate for the PUCO to address any specific potential resource needs. However, I suggest that PUCO require that AEP Ohio start the process of identifying potential power plant retirements that would require major transmission upgrades, the areas in which load reductions would delay or avoid the upgrades, and methods for promoting those load reductions as potential needs become more likely.

C. PJM Response to Potential Deficiencies

Q: How does PJM respond when the owner of a power plant determines that it is not cost-effective to operate and requests permission to retire it?

A: PJM reviews the reliability effect of the retirement and, if necessary, offer the owner a reliability-must-run (RMR) contract to keep the unit on line until other generation or transmission resources are added. The PJM process allows for the payment of the forward-going costs of the plant, specifically the portion of the following costs that would be avoidable through shutdown:

- Operations and maintenance labor.
- Administrative expenses, including costs directly related to employees at the generating unit (such as pensions and human resources), fees, training, office supplies, and administrative support labor.
- Maintenance expenses.
- Variable expenses, such as water treatment and utility bills for plant operation.
- Property taxes and insurance.
- Carrying Charges on fuel stocks, materials and supplies, but not the existing plant investment.
- Corporate Level Expenses.
- Investment recovery for capital projects that would be required to keep the plant operating.

To encourage plant operators to cooperate, PJM adds a percentage adder to these avoidable costs.

Q: How are these RMR rates set?

A: The PJM internal market monitor and the plant operator typically reach agreement on each cost item, which includes determining which costs are avoidable.

Q: How long are the terms of these PJM contracts?

A: Generally only a few years, until new generation or transmission eliminates the need for the generators. PJM retains the right to cancel the contract earlier than expected, if the generator is not needed.

Q: How does the PJM mechanism for keeping uneconomic units on line compare to the proposed PPA?

A: The PJM mechanism is superior to the proposed PPA in several ways, as follows:

- PJM pays only for specific facilities that have been shown to be necessary, while the proposed PPA would burden ratepayers with the units and entitlements for which AEPGR desires subsidies.
- PJM pays only for specific facilities that would otherwise face retirement, generally because they have failed to clear in a capacity auction, while the proposed PPA includes units that have been clearing in capacity auctions and are not proposed for retirement.
- PJM pays only for entire generating units, to keep them operating, while the proposed PPA would include minority ownership shares in facilities, without any clear nexus to whether the units remain in service.
- PJM pays only for future fixed costs, plus an adder, while the proposed PPA would charge customers for sunk costs.
- PJM pays to keep the units on line only as long as they are needed, while the proposed PPA would require ratepayers to underwrite the units as long as AEPGR and co-owners choose to keep them on line.

Q: What effect would the buildup of generation capacity in Pennsylvania that you report in Table 23 have on the need for transmission?

A: As Mr. Bradish points out that:

> power flows change significantly in magnitude and direction, depending on the conditions modeled. For example, under peak conditions, the AEP transmission system is typically utilized to transport power from areas in the west to areas north and east of the AEP system. Under light load conditions, power flows primarily from west to east and south of the AEP system as a result of increased wind generation, pump loads at hydro storage facilities, and reduced natural gas generation during off-peak hours. (Bradish Amended Direct Testimony at 7–8)

The construction of new gas-fired combined-cycle capacity in western Pennsylvania and eastern Ohio will tend to reduce the peak-period west-to-east flows that Mr. Bradish points to as burdening the AEP transmission system. Also, to the extent that AEP Ohio has sufficient transmission capacity to import economy off-peak energy from the west, but not enough to serve loads further east and south, PJM will dispatch additional generation in the eastern and southern zones, reducing the flows. The load flows and generation dispatch patterns of the past decade are very likely to change as a result of retirements and new generation construction.

Q: Are any changes in transmission likely regardless of the fate of the PPA units?

A: Yes. The low cost of wind generation to the west of Ohio and demand for renewable energy to the east is likely to result in additional transmission being constructed through Ohio. This issue is discussed in detail in the Eastern Interconnection Planning Collaborative Phase II reports.[47]

Q: Would all the costs of any transmission that would be built as a result of PPA unit retirements be allocated entirely to Ohio consumers?

A: While Mr. Vegas suggests this would be the case (Vegas Amended Direct at 14 and 15), AEP's explanation of the justification for the additional testimony relies on the needs of other areas, to the north, south and east. As Mr. Bradish notes, "the AEP transmission system serves as a thoroughfare for PJM… under peak conditions, the

[47] http://www.eipconline.com/Phase_II_Documents.html.

AEP transmission system is typically utilized to transport power from areas in the west to areas north and east of the AEP system. Under light load conditions, power flows primarily from west to east and south of the AEP system" (Bradish Amended Direct at 7–8).

AEP also suggests that the "Based on PJM's cost allocation methodology, it is reasonable to assume 50% of the 765kV facilities would be allocated across all PJM zones (including AEP)" and that the 765kV facilities would cost $750 million, out of a total of $1,600 million for the upgrades that AEP believes would be needed if all the PPA generation were retired and no new generation was built in Ohio (SC-INT-2-072). That allocation would result in the AEP zone paying for 77% of the additions. Ohio is less than half of the AEP zone; even in AEP's view, AEP Ohio would pay for about $543 million in transmission upgrades.

The projects flagged as 765 kV in SC-INT-2-072 total $900 million, and another $200 million substation may be a "Necessary Lower Voltage Facility" as defined by Schedule 12, Section b(i) of the PJM OATT. So perhaps the portion of the cost that is allocated to all of PJM based 50% on load and 50% on usage of the facilities should be $900 million or $1,100 million, of which $450 million or $550 million would be allocated to all of PJM on load.

Perhaps more importantly, the OATT provides that the 50% of the Required Transmission Enhancements that is allocated on usage will be assigned on the basis of "distribution factors…which express the portions of a transfer of energy from a defined source to a defined sink that will flow across a…group of transmission facilities. These distribution factors represent a measure of the use by the load of each Zone…of the Required Transmission Enhancement." (Schedule 12, Section b(iii)) If Mr. Bradish is correct that the transmission facilities would be required to allow transfer of energy from the west to points north, east and south of Ohio (and of the AEP zone), a large share of the distribution factors would be borne by those zones, such as FirstEnergy, Duquesne, PennElec, Allegheny, and Dominion.

In short, it is not clear what PPA units would retire if the PPA is rejected, which transmission facilities would actually be needed with new generation in Ohio and elsewhere, what those facilities would cost, or how those costs would be allocated.

Q: Does this conclude your direct testimony?

A: Yes.