BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan.	)))))	Case No. 13-2385-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority.	)))	Case No. 13-2386-EL-AAM

OHIO POWER COMPANY'S INITIAL POST-HEARING BRIEF

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CERTIFICATE OF SERVICE

OHIO POWER COMPANY'S INITIAL POST-HEARING BRIEF

I. INTRODUCTION

SSO generation service rates

Ohio Power Company's ("AEP Ohio" or the "Company") proposal for a Competitive Bid Process (CBP) and procurement of wholesale generation supplies for standard service offer (SSO) load will utilize full auction-based pricing for the Company's SSO customers beginning in June 2015 through the full term of the proposed electric security plan (ESP). This feature of the proposed ESP, along with the corporate separation completed earlier this year, fulfils the end goal of the *ESP II*[1] decision's path to a fully competitive SSO procurement. The proposed ESP also completes the restructuring of the SSO rate design to better align the structure to competitive market rates for generation. More specifically, transparency in AEP Ohio's generation pricing through separate generation riders for capacity, energy and SSO auction costs (GENE, GENC, and the ACRR, respectively) give consumers a price-to-compare that they can use to effectively compare competitive retail electric supplier (CRES) provider information when determining whether to select an alternative supplier. The Company also proposes to continue the Alternative Energy Rider (AER) to recover renewable mandate compliance costs and to restructure and discontinue some of the other generation tariff schedules.

The final generation rate proposed by the Company is the nonbypassable Power Purchase Agreement (PPA) Rider. Despite being met with opposition, the Company continues to believe that the PPA Rider will be highly beneficial to customers and urges the Public Utilities

[1] Case Nos. 11-346-EL-SSO, *et al.*

Commission of Ohio ("Commission") to adopt it – initially to only reflect the Ohio Valley Electric Corporation (OVEC) contractual entitlement and subsequently to reflect (if the Commission separately approves the expansion) an additional PPA involving Ohio legacy plants formerly owned by AEP Ohio.

The PPA Rider would reflect the net benefit of all revenues accruing to AEP Ohio from the sale of its OVEC contractual entitlement into the PJM market (including energy, capacity, ancillaries, etc.) less all costs associated with the Company's OVEC entitlement. None of the energy or capacity associated with the Company's OVEC entitlement would be bid into the auctions conducted to procure generation services for or used to offset any of the SSO load included in the auction. The energy and capacity associated with the Company's OVEC entitlement will simply be sold into the PJM market, consistent with the Commission's recent decision in Case No. 12-1126-EL-UNC.[2] Coupled with the nonbypassable nature of the rider, this will ensure that this provision of the Company's proposed ESP will have no adverse impact on the SSO auction or the ability of CRES providers to compete for customers on a level playing field.

As AEP Ohio President Pablo A. Vegas testified, the PPA Rider will stabilize customer rates by providing a hedge against future market volatility. Due to the relative stability of OVEC's costs as compared to market based costs, this rider will smooth out market fluctuations and rise and fall in a manner that is counter to the market – increasing rate stability for all customers. OEG witness Alan S. Taylor acknowledged in his testimony that the Company is trying to provide stable pricing so that its customers are not exposed to a 100 percent marginal cost pricing where prices may rise very dramatically and disadvantage the customers.

[2] *See* Case No. 12-1126-EL-UNC, Finding and Order at ¶20 (Dec. 4, 2013).

As the evidence in this case shows, PJM markets are in the process of being reformed – the market prices are unequivocally volatile and largely expected to increase as the reforms are successful. It is unwise to rely exclusively on PJM market prices. By contrast, OVEC costs are largely fixed and relatively stable – so the PPA construct will serve to stabilize retail customer rates. It can be tempting to partake in abstract ideological debates about competitive market theory, but AEP Ohio is responsible for the prudent management of the Company and is interested in presenting a practical and well-examined real-world solution for its customers who are facing volatile market prices.

AEP Ohio has a long history of a cooperating with the Commission in its efforts to oversee and regulate the industry in times of volatility and change. The PPA Rider is another chapter in that long history, in the same spirit as AEP's 2005 purchase of Monongahela Power, which the Commission requested in order to avoid rate shock for customers in Southeast Ohio; the *ESP I*[3] rate plan (which the Commission found saved customers $1.5 billion); and the *ESP II* rate plan (which the Commission found provided essential rate stability and was extremely beneficial). AEP Ohio witness Vegas testified that the Company's intention in establishing the PPA mechanism is to have a long-term contractual relationship with its customers where they get the opportunity to benefit from that long-term hedge over an extended period of time. Approval of the PPA Rider now for OVEC keeps that prospect alive for an even more meaningful hedge to the benefit of customers – without prejudice to a subsequent decision on the additional PPA. In short, the PPA Rider is permissible under Ohio law, and the Company urges the Commission to seriously consider the PPA Rider proposal and its expected benefits in the context of a robust policy debate.

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[3] Case Nos. 08-917-EL-SSO, *et al.*

Distribution service rate matters

The Company is proposing the continuation and addition of some important distribution riders to ensure customer reliability and maintain a high quality of service. The General Assembly in its foresight included the ability for utilities to seek these types of riders in the update to R.C. 4928.143. That ability to propose proactive plans and seek cost recovery on a more timely basis addresses the regulatory lag issue that precluded aggressive investment in the past. Company witness Dias referred to the traditional rate case model as the "slow turtle dinosaur." The Commission has the opportunity to continue its past approval of these riders, while modifying and adding others to implement the regulatory model encouraged by the General Assembly to ensure investment in Ohio and timely recovery by the utility to meet customer needs.

The distribution riders sought in this case like the Distribution Investment Rider (DIR), Enhanced Service Reliability Rider (ESRR), gridSMART® Phase 2 Rider, Storm Damage Recovery Rider (SDR) and the Sustained and Skilled Workforce Rider (SSWR) ensure a more rapid and proactive investment in the distribution system. The DIR continues a successful effort by the Company to act proactively and avoid outages from aging infrastructure by replacing items before they fail, in line with the Company's comprehensive reliability plan. The updates to the DIR will ensure that a communications system, crucial for service restoration and system planning, will be replaced under the review of Staff and that investment already made (*e.g.,* gridSMART® Phase 1) have a place for recovery. The ESRR will provide the incremental dollars above and beyond those included in base rates to sustain the four year trim cycle that the Commission previously established. The gridSMART® Phase 2 Rider will ensure that a mechanism is available to implement any future gridSMART® phase and that the costs and benefits can be clearly aligned. The SDR will ensure that AEP Ohio stands ready to act quickly and efficiently to restore service when acts of God damage the system and impact customer service. The SSWR will allow the Company to begin the training of the next generation of skilled laborers to ensure the Company stands ready to maintain the dangerous and integral distribution system. These issues rise above and beyond the normal changes in O&M that are appropriately considered in a base rate case and allow the Company and the Commission to ensure that customer reliability and system safety is not stuck waiting for that slow moving dinosaur to benefit customers.

The Commission also should approve the Company's proposed NERC Compliance and Cybersecurity Rider (NCCR), which would serve as a placeholder for significant future increases in AEP Ohio's cost of complying with the North American Electric Reliability Corporation (NERC) compliance and cybersecurity requirements. The Company intends to track and defer both the capital and operational and maintenance (O&M) costs associated with new requirements or new interpretations of existing requirements, with a carrying cost, starting on the date of the decision in this case and going forward through the entire term of the proposed ESP. The NCCR would be a placeholder rider established at a level of zero until the Company incurs such costs and files for Commission review and approval of recovery through the NCCR.

The Company also is requesting approval to continue its Pilot Throughput Balancing Adjustment Rider (PTBAR), a revenue decoupling mechanism, and Residential Distribution Credit Rider (RDCR). The Commission initially approved both riders in its December 14, 2011 Opinion and Order in Case Nos. 11-351-EL-AIR, *et al*. The Company proposes to continue the PTBAR revenue decoupling pilot program for residential and GS-1 tariff schedules, as currently implemented, throughout the ESP III term. No party appears to oppose the Company's substantive proposal to continue the RDCR for all residential tariff schedules, as currently implemented, through ESP III's term.

Transmission service rate matters

AEP Ohio proposes to establish a new, nonbypassable Basic Transmission Cost Rider (BTCR) to recover non-market based transmission charges from all customers. As Company witness Vegas explained, AEP Ohio currently recovers all of its PJM-assessed transmission costs for SSO customers through the previously-approved bypassable Transmission Cost Recovery Rider, while CRES providers currently include their PJM-assessed transmission costs in their rates to Shopping customers. Under the proposed BTCR, AEP Ohio would recover non-market based transmission charges from all customers, while market based transmission charges would be included in the auction product offering for SSO customers and continue to be assessed by CRES providers for shopping customers. The proposed change has the additional benefits of aligning the Company's transmission cost recovery mechanism with other Ohio electric distribution utilities, which provides clarity for customers about non-market based transmission charges, and enabling CRES providers and SSO suppliers to operate throughout the state using similar price rate offerings.

Other nonbypassable "wires" charges

The Company committed to review the offering of a Purchase of Receivables (POR) Program in its prior ESP and has proposed a specific plan in this filing that works for the AEP Ohio territory. The Company ensured consistency with the other POR programs in Ohio and paired its proposal with a discount rate of zero dollars and a bad debt rider. This consistency is important, as discussed in the Commission's recent market study, to assist the competitive suppliers seeking to enter the Ohio market. As discussed throughout the record and as encouraged by the Commission, an increase in competition should result in lower prices for customers. The usage of the bad debt rider will ensure that all customers are marketed to by the CRES providers and will provide an advantage to Ohio's at-risk populations that have traditionally not received the benefit of aggressive CRES offerings. The Company also is requesting the establishment of a late payment charge, the collection of which will be a credit toward s the bad debt rider. The Company voluntarily offered its POR plan even prior to the Commission's encouragement in the statewide market study. The Commission should approve the Company's POR plan to ensure that the Company is not harmed in the provision of this voluntary benefit for customers and the competitive suppliers.

The Company proposes to continue the Energy Efficiency/Peak Demand Reduction Rider (EE/PDR Rider) as approved in *ESP II*. The Company also proposes the continuation of its Economic Development Rider (EDR) for reasonable arrangements with mercantile customers, approved by the Commission. Finally in this regard, the Company plans to continue implementing other existing riders during the term of the ESP III.

MRO Test

The proposed ESP is more favorable for customers in the aggregate than the results that would occur under a market rate offer (MRO) alternative, especially given the rate stability hedge against volatile market prices being provided through the PPA Rider.

II. STANDARD OF REVIEW

Two key statutory standards apply to the Commission's consideration of AEP Ohio's ESP III proposal. First, the Commission must determine whether the provisions of the ESP III, including pricing and all other terms and conditions, are more favorable in the aggregate as compared to the expected results that would otherwise apply under an MRO. R.C.

4928.143(C)(1). While the details associated with this so-called “MRO test” will be discussed more extensively in this brief, it is sufficient at this point to say that the Commission needs to consider not only the quantitative costs and benefits of the ESP III as part of the price test component of the MRO test, but also the non-quantitative components over the term of the plan in order to fully examine whether the proposed ESP III is more favorable in the aggregate than the expected results under an MRO. As demonstrated below, the ESP III passes under the aggregate MRO test. Second, if the Commission does not approve the ESP III as proposed and instead adopts changes or modifications to the proposed ESP III, AEP Ohio has the right to withdraw the ESP III and file a new SSO either under the ESP statute or the MRO statute. R.C. 4928.143(C)(2). This “consent” requirement is particularly important to bear in mind as the Commission examines the ESP III’s terms because many of the significant provisions presented in the ESP III may not even be possible in another context.

III. THE TERMS OF THE PROPOSED ESP III ARE LAWFUL, REASONABLE, AND ADVANCE STATE ENERGY POLICIES.

A. The Proposed Generation Rates Are Reasonable And Promote Rate Stability And Certainty.

1. The Company’s Proposed CBP And Procurement Of Generation Services For Its SSO Load Are Reasonable And Should Be Approved.

The Company’s proposal for a CBP and procurement of wholesale generation supplies for SSO load will utilize full auction-based pricing for the Company’s SSO customers beginning in June 2015 and throughout the term of the proposed ESP. As explained in greater detail below, the procurement plan increases diversity of supplies and suppliers, which supports reasonably priced retail electric service.

a. The Commission should adopt the Company's proposals for the CBP, including for staggering the timing of auctions and laddering of auction products.

The Company retained NERA Economic Consulting (NERA), and Dr. Chantale LaCasse, Sr. Vice President of NERA, to assist in the design of the Company's CBP used to procure generation supply for non-shopping customers who take service from the Company's SSO.

Dr. LaCasse looked specifically to, and modeled AEP Ohio's proposed CBP based on, Duke Energy Ohio's recent successful CBP. Notably, in its Opinion and Order approving AEP Ohio's current ESP, the Commission specifically encouraged the Company to formulate its CBP in a manner consistent with the CBP processes that Duke Energy Ohio used.[4] Furthermore, Dr. LaCasse has direct experience designing and managing a number of competitive bidding processes, including the New Jersey BGS Auction Process. She observed that the New Jersey auction process was the first to use a descending clock auction format for procuring supply for SSO-type customers and it shares many features with the Duke Energy Ohio and, now, the AEP Ohio, CBP. Accordingly, Dr. LaCasse confirmed that the design of AEP Ohio's CBP aligns with the Duke Energy Ohio's most recent CBP processes. In addition, she explained that the approach favored by the Commission finds support from auctions that have been implemented successfully elsewhere. (AEP Ohio Ex. 15 at 5.)

In order to guide the design of AEP Ohio's CBP, Dr. LaCasse relied upon the standards for CBPs described in R.C. 4928.142, which apply to a Market Rate Offer. Those standards are that a CBP: (1) must provide for an open, fair, and transparent competitive solicitation; (2) must provide for clear product definition; (3) must provide for an independent third party to design the solicitation and administer the bidding; (4) must provide for standardized bid evaluation criteria

[4] *ESP II*, Opinion and Order at 40 (Aug. 8, 2012).

and evaluation of the submitted bids prior to the selection of the least-cost bid winner or winners; and (5) must not prohibit the participation of any one generation supplier. (*Id*. at 6.) Dr. LaCasse used these standards for designing the various aspects of the CBP. She also considered that, as for any bidding process, the CBP should aim to maximize participation as well as aim to establish efficient, market-reflective prices, which will generally contribute to efficient retail markets. (*Id.*) Accordingly, Dr. LaCasse designed AEP Ohio's competitive bidding process so that it includes a number of key elements that work together to ensure its success in meeting its objectives. Those elements are discussed at length in her direct testimony (*see* AEP Ohio Ex. 15 at Exhibits CL-2 - CL-10.)

The Company's CBP proposals are consistent with the standards established by the Commission and its precedent. Full auction-based pricing for the Company's SSO customers beginning in June 2015 and continuing through the term of the proposed ESP increases diversity of electricity supplies and suppliers and ensured effective competition among CRES providers for electricity pricing to shopping customers. (AEP Ohio Ex. 3 at 3.) It thus advances the state policy objectives set forth in R.C. 4928.02, specifically, R.C. 4928.02(A), (B), (C), and (G). As such, the proposed CBP is reasonable and should be adopted.

b. Staff witness Strom's and OCC witness Kahal's criticisms of the Company's proposal for laddering the terms of auction products are overstated. In any event, Staff witness Strom's proposal to adopt a five-year term for the ESP in order to implement his laddering proposals is both unnecessary and ill-considered, and it should be rejected.

In general, Staff and Intervenors recognize that the Company's proposed CBP, which Dr. LaCasse comprehensively explained and supported, is reasonable and consistent with the CBP methods previously approved by the Commission for use by other Ohio electric distribution utilities (EDU). Thus, Staff witness Strom states that, "in general, the procedures that the

Company is recommending appear to be appropriate and consistent with other competitive bidding processes that are conducted by other Ohio EDUs." (Staff Ex. 16 at 2.) Similarly, OCC witness Kahal testified that the CBP that Dr. LaCasse described "is typical of those used by [EDUs] to provide SSO generation service," and he has no disagreement with the proposition that the Company's CBP framework meets the statutory requirements for a CBP that would be used to implement an MRO under R.C. 4928.142. (OCC Ex. 13 at 44 and 48.)

However, Staff witness Strom and OCC witness Kahal object to the Company's proposal to procure SSO supply auction products that terminate at or before May 31, 2017, and then, again, at May 31, 2018. Both Mr. Strom and Mr. Kahal are concerned that the Company's proposed laddering introduces excessive uncertainty and potential rate volatility. Mr. Kahal recommends that the Company's proposed laddering be modified by changing the terms of the products procured in the fifth and sixth auctions (which will take place in September and March before the beginning of the June 1, 2017 delivery year (year three of the ESP)). Specifically, Mr. Kahal proposes that, instead of procuring 100 percent twelve-month term contracts in those two auctions (for supply during year three of the ESP), those two auctions would procure a 50/50 mix of twelve-month and twenty-four month contracts. (*Id.* at 49-52.)

Mr. Strom recommends that the mix of auction products be revised so that there would be an overlap of product terms, instead of a 100 percent termination, at June 1, 2017. In order to address his concern regarding the 100 percent termination of auction products at June 1, 2018, Mr. Strom makes a much more fundamental, and ill-considered, change. Instead of simply recommending that auction product terms in the last two auctions include some proportion of products with terms greater than twelve months, Mr. Strom recommends that the term of the Company's ESP be extended to five years (thus avoiding, at least temporarily in his view, the

100 percent termination of auction products at the end of year three of the ESP). Essentially, in order to address the problem that Mr. Strom sees with auction products terminating, *i.e.*, with laddering ending, at the end of a three-year ESP, he recommends that the Commission force EDUs to adopt five-year ESPs. (Staff Ex. 16 at 2-3.)

First of all, with regard to both Mr. Kahal's and Mr. Strom's concern about uncertainty and rate volatility as a result of 100 percent of the auction products ending at June 1, 2017, and June 1, 2018, there is no evidence, beyond each witness's conjecture, that rate volatility will be increased materially by the Company's laddering proposal. Moreover, it is reasonable for the Company to provide for the termination of the auction products' terms at the end of its ESP, and that is what the Company's proposed laddering accomplishes, both with regard to the potential early termination of the ESP by June 1, 2017, and the termination in the normal course by June 1, 2018. In short, their concerns are overstated.

Second, Mr. Strom's proposal to address concerns about rate volatility that might occur as a result of 100 percent of the auction products' terms ending at June 1, 2018, by extending the ESP term by two years beyond the Company's proposed three-year term is ill-advised and, in any event, by his own admission unnecessary. It is ill-advised because Mr. Strom gave no consideration to the impacts his proposal would have on significant aspects of the proposed ESP outside of the CBP subject matter area. For example, Mr. Strom did not consider what impact his proposed five-year ESP term would have on the proposed continuation of the Distribution Investment Rider. (Tr. IX at 2257.) Under the Company's proposed ESP, the DIR is proposed to be expanded and extended for three more years. Mr. Strom did not consider whether, by extending the term of the ESP to five years, Staff was recommending that the DIR also be further expanded and extended beyond three years. (*Id.*) He made no analysis, and made no recommendation, regarding whether or in what form the DIR would exist during the fourth and fifth years of his proposed five-year ESP. Nor did he consider what impact his five-year ESP term proposal would have on Staff witness McCarter's recommendation that the DIR recovery mechanism sunset with the end of the ESP, which Ms. McCarter assumed would be May 31, 2018, unless the Commission had authorized the Company, in a subsequent ESP proceeding, to further extend the DIR. (Staff Ex. 17 at 9.) Indeed, Ms. McCarter did not even incorporate in her analysis Mr. Strom's recommendation of a five-year ESP. (Tr. IX at 2278.)

Nor did Mr. Strom consider that by imposing upon the Company a five-year ESP, his proposal would also impose upon the Company, in addition to the annual retrospective SEET review of R.C. 4928.143(F) that applies to ESPs of any term, another prospective SEET review pursuant to Section 4928.143(E) during the fourth year of the plan. (*Id.* at 2262-2263.)

Notably, Mr. Strom appears to believe that there are other mechanisms available to accomplish the same auction blending and laddering process that is the goal of his five-year ESP term recommendation. Thus, in connection with his discussion of the Company's proposal to reserve the right to terminate the ESP after two years, Mr. Strom states that, if the Commission were inclined to approve that aspect of the Company's proposed ESP, "it should only do so with the concomitant requirements that any subsequent ESP would include the same [CBP] for procurement of its SSO supply, and that the auction blending process would continue unabated." (Staff Ex. 16 at 4.) And, even with his five-year ESP term, Mr. Strom recommends that "it should be possible to lessen the potential for rate volatility [at the end of the fifth year] if the Commission were to require, as part of this ESP, that the Company propose its next SSO, whether ESP or MRO, sufficiently far in advance that the last procurements of this ESP could be blended with the initial procurements of the subsequent SSO." (*Id.*) Accordingly, Mr. Strom believes that there are other means of achieving his goal of a continuous auction blending process that do not require a five-year ESP term.

Staff witness Strom's proposal to adopt a five-year term for the ESP in order to implement his laddering proposals is both unnecessary and ill-considered, and it should be rejected.

c. IGS's proposals to implement retail auctions or, in the alternative, retail price adjustments, must be rejected, as they have been in the past, because they conflict with Ohio law and are unreasonable.

IGS witness White has a more fundamental criticism of the Company's proposed CBP and wholesale auction to procure a full requirements supply for its SSO customers. IGS recommends that the Commission reject the use of a wholesale auction procurement and, instead, adopt a retail auction to procure SSO service. As a result, CRES suppliers would establish a retail relationship with the customer and supply the SSO produce directly to the customer. AEP Ohio would no longer be the SSO supplier to non-shopping customers. (IGS Ex. 2 at 14-18.) In the alternative, if the Commission declines to adopt a retail auction to procure generation supplies for non-shopping customers and to assign their SSO service to CRES providers, IGS recommends that a "retail price adjustment" should be imposed on SSO service. IGS contends that a retail price adjustment is necessary, if wholesale procurement of the SSO supply is used, in order to eliminate structural cost disadvantages that CRES providers face when competing with SSO service that is sourced through wholesale procurements. (IGS Ex. 2 at 18-22.)

The Commission should not accept either of these recommendations. First, IGS's proposals have no legal basis. Specifically, the recommendation to substitute a retail auction for the wholesale SSO auction and to replace the EDU as the SSO provider with third party default service providers conflicts with R.C. 4928.141(B), which specifically requires the EDU to provide an SSO, available to all consumers, of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of generation service. IGS's retail auction proposal could not be implemented without fundamental changes made by the General Assembly to, at a minimum, R.C. 4928.141. Similarly, there is no statutory basis for artificially increasing either the wholesale cost of procuring SSO supply or the retail price charged to non-shopping customers for SSO service by imposition of a "retail price adjustment."

Second, IGS made the same recommendations both in the Company's *ESP II* proceeding and through comments it submitted in the Commission's recently concluded investigation of Ohio's retail electric services market, Case No. 12-3151-EL-COI. (*See, e.g., ESP II*, IGS Ex. 101 at 21-24; *ESP II*, IGS Initial Br. at 11 (June 29, 2012); Case No. 12-3151-EL-COIm, IGS Comments (Mar. 1, 2013).) The Commission ignored IGS's suggestion in its *ESP II* decision. Moreover, in Case No. 12-3151-EL-COI, the Commission again declined to accept IGS's recommendations. Rather, it concluded that the EDU-provided SSO is, and should remain, the default service for non-shopping customers.[5] Nothing has changed legally or factually since the Commission rejected IGS's recommendations in *ESP II* or four months ago in Case No. 12-3151-EL-COI. Accordingly, the Commission should decline to accept IGS's recommendation in this proceeding.

d. Establishing a new pricing point to settle AEP Ohio load

AEP Ohio's proposed CBP specifies the delivery point for the auction as the AEP Load Zone established in PJM. This is currently the point at which all load in AEP Ohio's service territory is priced. In its Application, the Company noted that at some point in the future it may be appropriate to request that PJM establish an AEP Ohio Aggregate pricing point that would be

[5] Case No. 12-3151-EL-COI, Finding and Order at 19 (Mar. 26,2014).

used to settle AEP Ohio load. (AEP Ohio Ex. 1 at 7.) Staff witness Benedict testified that the creation of a new pricing point that better reflects the auction product being procured would be an improvement to the auction procurement process, and he encourages AEP to petition PJM to establish an AEP Ohio settlement zone for this purpose as soon as is practicable. (Staff Ex. 9 at 2-3.) However, he did agree that it would be appropriate to comprehensively evaluate the benefits and costs of establishing an AEP Ohio-specific delivery point before committing to making the change. (Tr. V at 1319-22.)

AEP Ohio is not averse to establishing an AEP Ohio delivery point for its auctions, but believes that a thorough analysis of the benefits and costs should precede the decision to petition PJM for a change to the delivery point. Accordingly, AEP Ohio commits to conducting the necessary analysis and reporting back to Staff with the results of the analysis in a timely manner.

2. The Company's Proposals To Establish SSO Generation Service Riders Are Reasonable.

The Company's proposed ESP will provide transparency in its SSO pricing, through the introduction of a Generation Capacity (GENC) rider, a Generation Energy (GENE) rider, and an Auction Cost Reconciliation Rider (ACRR), which will give consumers a comparable price that they can use to compare information when determining whether to select an alternative supplier. Transparency in AEP Ohio's generation pricing through riders GENE, GENC, and the ACRR give consumers a price-to-compare that they can use to effectively compare CRES provider information when determining whether to select an alternative supplier. (AEP Ohio Ex. 3 at 3.) Thus, the Company's generation service rider proposals advance numerous state policies, including those set forth in R.C. 4928.02(A), (B), (H), and (I).

a. The Company's proposal for recovering the costs of procuring power for SSO customers for each class of customers through Rider GENC, Rider GENE, and the ACRR is reasonable.

For non-shopping customers, the SSO rates will be determined based on a competitive bid auction, described above in the previous section of this brief, which will result in a bundled price for capacity, energy, and market-based transmission services stated as a price in $/MWh. Company witness Roush illustrated how, since there will be multiple auctions for a particular June through May delivery year, the tranche-weighted average auction price will be determined for each particular delivery year. (AEP Ohio Ex. 12 at Exhibit DMR-2, page 1.) Once that tranche-weighted average price is determined for a delivery year, that price will be subdivided into a capacity price and an energy price. Mr. Roush also illustrated how the capacity price will be determined using the PJM final zonal capacity price for the delivery year. (*Id.* at Exhibit DMR-2, page 2.) The energy price will be the remainder after deducting the capacity price from the tranche-weighted average auction price. (AEP Ohio Ex. 12 at 4.) Unique rates will then be determined for each of the following classes: Residential; General Service – demand-metered secondary, primary, and subtransmission/transmission voltages; General Service non-demand metered secondary; and lighting. (*Id.* at 4-5.)

Mr. Roush explained that capacity prices for each class of customers, including a gross-up for taxes, will be computed as shown. (*Id*. at Exhibit DMR-2, page 3.) He noted that the capacity prices will be determined based upon each customer class's contribution to the PJM 5 Coincident Peaks (CP), and computed as a rate per kWh. Those prices will be the Rider GENC rates, which will be updated annually to reflect the PJM final zonal capacity price for the delivery year. (AEP Ohio Ex. 12 at 5.)

Mr. Roush next explained that the energy prices for each class of customers will be computed in the manner depicted at page 4 of Exhibit DMR-2 to his testimony. These energy prices are the Rider GENE rates and will be computed using the seasonal factors set forth in the CBP auction rules, loss factors, and will include a gross-up for taxes. The Rider GENE rates will also be updated annually to reflect the results of the competitive bid auctions for the delivery year. (*Id.*) Mr. Roush confirmed that this calculation methodology is consistent with the manner in which the Commission has approved the conversion of auction prices into customer rates for other Ohio electric distribution utilities. (*Id.*)

Company witness Moore explained AEP Ohio's proposal to reconcile any over- or-under-recoveries related to Rider GENE and Rider GENC through the ACRR. (AEP Ohio Ex. 13 at 11.) The ACRR will allow the Company to return any over-recovery or collect any under-recovery based on what was billed to SSO customers versus what was paid to auction winners for the procurement of power. In addition, Ms. Moore explained, the Company will recover through the ACRR all other costs associated with the competitive bid process such as auction manager fees, incremental auction costs, and the costs of the contingency plan (*i.e.*, the costs of acquiring SSO supplies in the event that there are unfilled tranches in an auction or that there is a supplier default), as further discussed by Company witness LaCasse (AEP Ohio Ex. 15 at 32-34.) The Company is proposing this rider to be collected on a per kWh basis and will update the rider quarterly. (AEP Ohio Ex. 13 at 11.) Ms. Moore provided an example of how the ACRR would be implemented at Exhibit AEM-4 to her testimony.

b. Staff's recommendations regarding the ACRR are acceptable.

Staff has indicated no objection or concern with regard to the Company's proposals for Riders GENC and GENE.[6] With regard to the ACRR, Staff witness Snider stated that, in general, Staff agrees with the Company's proposal. (Staff Ex. 7 at 2.) However, he recommended that the Commission confirm that the Company should be allowed to collect only the prudently incurred costs associated with the competitive bid process. Furthermore, while amenable to quarterly updates to the ACRR, as the Company has proposed making, Staff recommends that the ACRR be subject to an audit by Staff on an annual basis and that the Commission direct the Company to work with Staff regarding details of such an audit. Staff also requested that the Commission instruct Staff to ensure that there is no "overlap" of costs recovered through the ACRR and the existing Auction Phase-In Rider (APIR) that the ACRR will replace. (*Id.* at 2-3.) The Company has no objection to any of Mr. Snider's recommendations.

c. Staff witness Turkenton's recommendation regarding the proposed generation capacity rider for CSP Residential customers is acceptable.

Staff witness Turkenton made a recommendation regarding the proposed generation capacity rider (Rider GENC) for residential customers in the Company's CSP rate zone. (Staff Ex. 15 at 6.) Ms. Turkenton noted that in Case 13-1530-EL-UNC, the Commission approved the Company's proposed rate mitigation plan for CSP Residential customers, which phases out (increases) winter tail block rates for Rider GENC during the Energy-Only Auction Phase In Period that ends May 31, 2015. (*Id.*) Pursuant to the proposed ESP, the tail block rates will be

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[6] Staff witness Turkenton explains that "[i]t is Staff's intent to provide testimony only for the issues in the Company's application which Staff either does not support or is proposing to modify." (Staff Ex. 15 at 2.)

completely phased out by June 1, 2015. Because capacity costs are expected to decrease beginning June 1, 2015, Ms. Turkenton noted that it appeared that the impacts from completely phasing out the tail block on June 1, 2015, would result in moderate increases for CSP Residential customers. (*Id.*) She also noted that other rates and riders may impact those customers' typical bills. (*Id.*) Thus, she proposed that AEP Ohio provide a typical bill impact for CSP Residential customer within 30 days following the Commission's *ESP III* decision, once other June 1, 2015 rates and rider impacts are known, to determine if the complete phase out of the tail block is appropriate. (*Id.*) AEP Ohio has no objection to this recommendation.

d. OCC's proposal to eliminate pricing differentials among customer classes that are based on differences in customer class load factors, as well as its alternative proposal to conduct separate SSO auctions for each customer class, should be rejected.

As explained above, Mr. Roush identified the portion of total SSO supply costs attributed to capacity and then allocated responsibility for capacity costs to the various customer classes based on each class's load factor. The residential class has a relatively low load factor. This means that it utilizes capacity in a relatively less efficient manner than other customer classes, requiring more fixed generation costs per unit of energy consumed. Accordingly, it is appropriate to allocate a relatively greater proportion of capacity costs to the residential class than is allocated to other classes, as Mr. Roush's approach does.

OCC witness Kahal agrees that the relatively low load factor for the residential customer class may support assigning a relatively greater proportion of capacity costs to the class, compared to the amount allocated to the higher load factor customer classes, assuming that all else is equal. (OCC Ex. 13 at 56.) However, Mr. Kahal believes that all else is not equal. He contends that because the residential class comprises the majority of the SSO load currently, and because a lower proportion of residential customers have switched to CRES providers at this point, residential customers have less migration risk. Mr. Kahal believes that the alleged lower migration risk completely offsets the relatively greater capacity costs incurred by SSO suppliers to provide generation services for the residential class. Consequently, Mr. Kahal recommends that capacity costs should not be allocated to the residential customer class based upon its relatively low load factor and, instead, the residential class should be allocated only an average share of capacity cots. Alternatively, Mr. Kahal recommends that the CBP should be conducted in a manner that procures generation services for the residential class separately from the other classes. (*Id.* at 56-59.)[7]

Mr. Kahal's recommendations should not be accepted. First of all, the calculation methodology that Mr. Roush used for rider GENC, including the allocation of capacity costs based on class load factors, is the same approach that the Commission has approved for the conversion of auction prices into customer rates for the other Ohio EDUs. (AEP Ohio Ex. 12 at 5.) Accordingly, the Commission has already determined that it is appropriate to allocate responsibility for capacity costs to the various customer classes based upon their relative load factors. Second, Mr. Kahal's contention that the residential class presents lower migration risk is both overstated and selective. It is overstated because it fails to take into account the heightened risk that the residential class presents, in comparison to other customer classes, as the result of the possibility of abrupt migration of significant amounts of residential SSO load to CRES providers through local governmental aggregation. Although Mr. Kahal is aware that

[7] Mr. Kahal also contends, in passing, that the size of the residential class provides a scale benefit to SSO suppliers, but his primary rationale for contending that the residential class should be excused from an allocation of capacity costs based on a relatively low load factor is his claim that alleged lower migration risk completely offsets the cost impact of the residential class's lower capacity factor.

aggregation exists in Ohio, he is not familiar with its details or how it is implemented in Ohio. (Tr. IX at 2101-08.) Accordingly, he did not incorporate its potential impact into his analysis. In addition he did not conduct any analysis to demonstrate that the impact the alleged lower migration of the residential customer class actually would have on SSO CBP auction participants is material, let alone that it would substantially offset the increased costs due to the residential class's lower capacity factor. Mr. Kahal's analysis is selective because it does not take into account other risks that would be factored into supplier's bids in the CBP auction, such as the weather-sensitive nature of residential usage.

With respect to Mr. Kahal's alternative recommendation, which is to conduct a separate procurement for the residential class, he provides the answer himself. It would introduce an undue and unnecessary complexity, and thus cost, into the CBP. (OCC Ex. 13 at 58.) Smaller auctions also could have the risk of lower participation and ultimately higher clearing prices. Mr. Kahal's proposal should also be rejected.

3. The Proposed Power Purchase Agreement Rider Is Beneficial And Should Be Adopted.

a. Overview of PPA Rider proposal

As detailed in AEP Ohio's Application, the Company is seeking to stabilize customer rates by providing a hedge against market volatility through the Power Purchase Agreement Rider. Under the PPA Rider mechanism, the Company would have the ability to petition the Commission to allow the inclusion of additional PPAs (or similar products subsequently approved by the Commission) in the PPA Rider throughout the ESP term. The Company is proposing that this new rider would initially flow through to customers, on a nonbypassable basis, initially only encompassing the Ohio Valley Electric Corporation (OVEC) contractual entitlement. The PPA Rider would reflect the net benefit of all revenues accruing to AEP Ohio from the sale of its OVEC contractual entitlement into the PJM market (including energy, capacity, ancillaries, etc.) less all costs associated with the Company's OVEC entitlement. None of the energy or capacity associated with the Company's OVEC entitlement would be bid into the auctions conducted to procure generation services for or used to offset any of the SSO load included in the auction. The energy and capacity associated with the Company's OVEC entitlement will simply be sold into the PJM market, consistent with the Commission's recent decision in Case No. 12-1126-EL-UNC.[8] Coupled with the nonbypassable nature of the rider, this will ensure that this provision of the Company's proposed ESP will have no adverse impact on the SSO auction or the ability of CRES providers to compete for customers on a level playing field. In sum, the proposed PPA Rider allows customers to take advantage of market opportunities while providing added price stability. (AEP Ohio Ex. 1 at 8.)

As AEP Ohio witness William A. Allen testified, OVEC was organized on October 1, 1952. OVEC was formed by investor-owned utilities furnishing electric service in the Ohio River Valley area and their parent holding companies for the purpose of providing the large electric power requirements projected for the uranium enrichment facilities then under construction by the Atomic Energy Commission (AEC) near Portsmouth, Ohio. The contract to provide OVEC-generated power to the federal government was terminated in 2003. OVEC and the Sponsoring Companies signed an Inter-Company Power Agreement (ICPA) on July 10, 1953, to support the DOE Power Agreement and provide for excess energy sales to the Sponsoring Companies of power not utilized by the DOE or its predecessors. Since the termination of the DOE Power Agreement on April 30, 2003, OVEC's entire generating capacity has been available to the Sponsoring Companies under the terms of the ICPA. The Sponsoring

[8] Case No. 12-1126-EL-UNC, Finding and Order at ¶ 20 (Dec. 4, 2013).

Companies and OVEC entered into an Amended and Restated ICPA, effective as of August 11, 2011, which extends its term to June 30, 2040. The Federal Energy Regulatory Commission (FERC) accepted the Amended and Restated ICPA on May 23, 2011. Ohio Power Company has a 19.93% share of the OVEC power participation benefits and requirements. Annually, OVEC provides over $40 million of economic benefit in its six county region[9] and over $100 million of economic benefit in Ohio. (AEP Ohio Ex. 7 at 8-9.)

Mr. Allen generally explained in his direct testimony why AEP Ohio retained the OVEC contractual entitlement after completing corporate separation earlier this year. As part of the Company's corporate separation plan approved by the Commission in Case No. 12-1126-EL-UNC, the Company had planned to transfer its OVEC power participation benefits and costs to AEP Generation. Under the ICPA, AEP Ohio must obtain consent from all of the other Sponsoring Companies before AEP Ohio can transfer the contractual entitlements to AEP Generation. The OVEC Sponsoring Companies, however, have withheld that required consent. On October 4, 2013, AEP Ohio filed a request with the PUCO to amend its corporate separation plan to allow the OVEC contractual entitlements to remain with AEP Ohio. The Commission approved that request on December 4, 2013. (AEP Ohio Ex. 7 at 9-10.)

Contrary to IEU witness Murray's contention that the Commission's decision in Case No. 12-1126-EL-UNC only provided "temporary" authorization for AEP Ohio to retain OVEC (IEU Ex. 1A at 8-9), Company witness Vegas maintained during cross-examination his understanding that the Commission's exemption for OVEC from corporate separation was not temporary and that there was no expectation of the Company continuing to try to transfer the asset – especially since the Commission indicated that it would entertain the rate issues associated with OVEC in

[9] The six county region is made up of Meigs, Vinton, Gallia, Jackson, Scioto and Pike counties.

this ESP proceeding. (Tr. I at 25.)[10] Moreover, AEP Ohio witness Vegas explained that there is no reason to try to transfer the OVEC contractual entitlement again because the same conditions that led the OVEC owners to withhold their consent for transferring AEP Ohio's share – the AEP Genco's credit rating being lower than AEP Ohio's – continue to exist. (*Id.* at 23-24.)

Company witness Vegas further testified that AEP reasonably offered a parental guaranty of nearly $700 million to OVEC owners in an attempt to gain their consent for transferring OVEC to the AEP Genco. (*Id.* at 113.) But as Mr. Vegas explained, the reason OVEC owners ultimately withheld their consent for the transfer was that the credit rating of AEP Genco was lower than that of AEP Ohio and, as counterparties that can incur liability if their partners are not creditworthy, the owners had no real reason to agree to the proposed transfer. (*Id.* at 23-24.) Because those circumstances have not changed, there is no reason for AEP Ohio to try again – because the same result would be expected. (*Id.*) In short, the Commission has already decided to exempt OVEC from corporate separation and to consider the Company's rate proposal as part of this case. Consequently, the Company included its PPA Rider proposal as part of the ESP III Application.

Moreover, as Mr. Vegas testified, the PPA Rider will stabilize customer rates by providing a hedge against future market volatility. (AEP Ohio Ex. 2 at 13.) Due to the relative stability of OVEC's costs as compared to market based costs, this rider will smooth out market fluctuations and rise and fall in a manner that is counter to the market – increasing rate stability for all customers. (*Id.*) These aspects of the PPA Rider are discussed in greater detail below.

Company witness Allen also confirmed that the proposed PPA Rider would not affect retail or wholesale competition in Ohio. AEP Ohio would bid each of these generation related

[10] *See also* Case No. 12-1126-EL-UNC, Finding and Order at 9 (Dec. 4, 2013).

items – capacity, energy, and ancillaries etc. – into the PJM market. All of the revenues that the Company obtains from the sale of these generation related elements would be used to offset the costs billed to the Company by OVEC under the ICPA. None of the energy or capacity associated with the Company's OVEC entitlement would be bid into the auction or used to offset any of the SSO load included in the auction. The energy and capacity associated with the Company's OVEC entitlement will simply be sold into the PJM market. This along with the nonbypassable nature of the PPA rider will ensure that this element of the Company's proposed ESP will have no adverse impact on the SSO auction or the ability of CRES providers to compete for customers on a level playing field. This proposal allows customers to take advantage of market opportunities while providing added price stability. (*Id*. at 12.)

AEP Ohio witness Vegas summarized the Company's proposal to initially include the OVEC asset in the PPA Rider as follows:

> What we're proposing is to utilize that asset and the contract that AEP Ohio has had to own as a result of its inability to transfer it to the generating company. What we're proposing to do is to utilize it as a hedge for customers. We think there's a value in doing that given the volatility in market prices that we expect to see in the coming years during the ESP period so we felt that a very good use of that asset and to give benefit to customers would be to offer this PPA and to allow customers to get a hedge through that PPA.

(Tr. I at 173.) OEG witness Alan S. Taylor described his understanding of the PPA Rider proposal by AEP Ohio as follows: "on behalf of its customer base [AEP Ohio] is trying to provide stable pricing, stable rates, so that its customers are not exposed to a 100 percent marginal cost pricing where prices may rise very dramatically and disadvantage the customers." (Tr. XI at 2573.) In proposing the PPA Rider, AEP Ohio is not interested in abstract ideological debates about competitive market theory, but it *is* vitally interested in presenting a practical real-world solution for its customers who are facing volatile market prices. The Company hopes the Commission will seriously consider the PPA Rider proposal in that context.

b. The Commission has ample authority to include the nonbypassable PPA Rider as part of this ESP, and there are no legal barriers to doing so in this case.

i. The ESP statute enables the Commission to adopt the PPA Rider in this case.

There are multiple bases for justifying the PPA Rider from a legal standpoint. Division (B)(2)(d) of the ESP statute, R.C. 4928.143, most explicitly supports approval of the PPA Rider, as that provision permits charges relating to default service that have the effect of stabilizing or providing certainty regarding retail electric service. This provision within the ESP statute provides that the Commission can adopt as part of an ESP:

> *Terms, conditions, or charges* relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, *as would have the effect of stabilizing or providing certainty regarding retail electric service*

(R.C. 4928.143(B)(2)(d) (emphasis added).) Based on this statutory language, there are three conditions that must be fulfilled in order for a proposed electric security plan provision to qualify: (1) the proposal involves a term, condition or charge, (2) the term, condition or charge must relate to one of the several categories listed in the middle of the provision, and (3) the proposal must have the effect of stabilizing or providing certainty regarding retail electric service.[11]

Obviously, the PPA Rider involves a term, condition or charge. Regarding the second criterion, the PPA Rider can be considered as "relating to" multiple categories in the list. Most

[11] *See ESP II*, Entry on Rehearing at 14-16 (Jan. 30, 2013).

clearly, the PPA Rider relates to a default service and addresses (non) bypassability. The PPA Rider could also be considered a limitation on customer shopping to the extent it is viewed as selling a generation hedging service to shopping customers even though they are purchasing generation service from a CRES provider.[12] Consequently, it would seem evident that the only real debate surrounding the PPA Rider relates to the third criterion and specifically to the fact-intensive question of whether the proposal would have the effect of stabilizing or providing certainty regarding retail electric service.

As further discussed below, AEP Ohio submits that the PPA Rider clearly provides rate stability and certainty to all customers – shopping and non-shopping customers alike. As the Company has shown in its testimony (further discussed below), the PPA Rider provides all customers a hedge against volatile market prices and works in the opposite direction of market prices. Presumably, the Commission will not adopt the PPA Rider unless it determines that the proposal will have the effect of stabilizing or providing certainty regarding retail electric service.[13] In this context, it is also noteworthy that the division (B)(2)(d) language about providing rate stability and certainty does not limit the scope to non-shopping customers. Of course, the PPA Rider has the effect of stabilizing and providing certainty for the provision of retail electric service to all customers.

[12] For example, OEG witness Taylor described the nonbypassable hedge effect of the PPA Rider as being a "financial imitation on shopping that translates into more stabilized rates." (Tr. XI at 2559.)

[13] For example, in AEP Ohio's *ESP II* proceeding where the Commission invoked division (B)(2)(d) to adopt another rate stability rider, the Commission found repeatedly that the nonbypassable rider in that case provided stabilizing benefits to all customers, shopping and non-shopping alike. *ESP II*, Opinion and Order at 31, 32, 36 (Aug. 8, 2012); *ESP II*, Entry on Rehearing at 19-20, 25 (Jan. 30, 2013).

Division (B)(2)(a) of the ESP statute also provides authority to the Commission to adopt the PPA Rider. That provision explicitly permits affiliate purchase power agreements.[14] Nothing in that provision requires the affiliate PPA to be delivered directly to the retail customers of the EDU. In fact, in the current PJM market, a PPA only relates to the price paid for power, the physical procurement of power is based upon dispatch determined by PJM and operation of the PJM real-time energy market. Similarly, the PPA Rider as proposed by the Company relates to the price ultimately paid for the power delivered through the grid.

Moreover, under a typical regulatory treatment of purchased power contracts, revenues associated with such contracts also have to be passed through to customers. Thus, when taking into account that the FERC-authorized costs associated with the OVEC contract need to be recovered at the retail level and given AEP Ohio's existing authority to exclude OVEC from corporate separation and its obligation (under the Case No. 12-1126 decision) to liquidate OVEC power into the PJM markets, the net cost (or credit) associated with OVEC is precisely what would be passed through the customers under the PPA Rider. Indeed, the Commission's rule implementing division (B)(2)(a) of the ESP statute contemplates netting revenues against fuel and purchased power costs in the context of an ESP proposal.[15] Further, nothing in division (B)(2)(a) limits the recovery of costs associated with an affiliate PPA to non-shopping customers. Similarly, the Commission's rule implementing division (B)(2)(a) of the ESP statute contemplates that fuel or purchased power costs could be recovered from all customers as opposed to being strictly bypassable.[16] Regardless, division (B)(2)(d) could be invoked if

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[14] In this context, AEP Ohio submits that OVEC – the counterparty to the PPA – would be an affiliate, since AEP Ohio has a minor ownership share of OVEC and the two parties share AEP resources.

[15] O.A.C. 4901:1-35-03(C)(9)(a)(ii).

[16] O.A.C. 4901:1-35-03(C)(9)(a)(iii).

necessary – in conjunction with division (B)(2)(a) – to provide for nonbypassability of the PPA Rider charge/credit. Thus, the PPA Rider (especially as it relates to the legacy OVEC contract) can also be adopted under R.C. 4928.143(B)(2)(a).

Separately, division (B)(2)(e) of the ESP statute also permits automatic increases or decreases and encompasses a mechanism relating to SSO service such as the PPA Rider. This automatic pass through of increases or decreases accurately describes operation of the PPA Rider. As with the discussion under division (B)(2)(a) above, when taking into account that the FERC-authorized costs associated with the OVEC contract need to be recovered at the retail level and given AEP Ohio's existing authority to exclude OVEC from corporate separation and its obligation (under the 12-1126 decision) to liquidate OVEC power into the PJM markets, the net cost (or credit) associated with OVEC is precisely what would automatically be passed through the customers under the PPA Rider. Thus, division (B)(2)(e) also provides a source of authority to adopt the PPA Rider. Further, to the extent that an expanded PPA Rider would also promote economic development and job retention, as discussed above, division (B)(2)(i) also provide an additional source of authority for the PPA Rider. In sum, there are multiple provisions within the ESP statute that support adoption of the PPA Rider in this case.

In addition, there is a distinct set of legal issues concerning the Commission's authority to adopt the PPA Rider related to the long-term nature of the proposal as compared to the three-year ESP term. While the Company is explicitly requesting approval of the PPA Rider for the three-year term of the ESP as part of the current case, the over-arching issues with the PPA Rider involve a long-term decision. In this initial version of the PPA Rider, the Company is only requesting inclusion of the OVEC contract – which is an existing contract that does not expire until 2040. (Tr. I at 98.) Because OVEC is a legacy contract and the Commission has routinely permitted recovery of OVEC costs as being prudent, there is no need to review the prudence of entering into the OVEC contract or the terms and conditions of the OVEC contract.[17]

By contrast, if the Company subsequently files for Commission approval of an additional affiliate PPA to be included in the PPA Rider (*i.e.*, the expanded PPA Rider), there will be an additional request for a one-time, up front prudence review of the proposed expanded PPA. In the expanded PPA case – which can ultimately only proceed if the Commission adopts the PPA Rider in this case starting with OVEC – the Company will be seeking a determination from the Commission that it is prudent for AEP Ohio to enter into the additional PPA. The Company expects and would request that a one-time determination be made and that the Commission would be bound by that up-front prudence determination for the full term of the additional PPA. This situation is similar to the Commission's approval of AEP Ohio's decision to enter into a 20-year renewable energy purchase agreement in *ESP II*, where the Commission approved as prudent the Company's decision to enter into the Timber Road renewable energy purchase agreement (REPA); the costs recovered through retail rates are still subject to ongoing financial audits but not subsequent prudence audits.[18]

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[17] Indeed, the Commission previously decided to affirmatively and explicitly permit recovery of OVEC/Lawrenceburg demand charges separately from base generation rates and through the FAC for the period of 2009-2011 as part of its *ESP I* decision, which has long since been final and nonappealable. *ESP I*, Opinion and Order at 14-15, 51-52 (Mar. 18, 2009).

[18] *ESP II*, Opinion and Order at 19 (Mar. 18, 2009). Recently, that Commission decision regarding REPAs has effectively been codified by the General Assembly in SB 310 through the enactment of R.C. 4928.641. Traditionally, the same process applies to long-term fuel contracts, the costs of which are recovered through a fuel adjustment clause. Specifically, when a new long-term fuel contract is formed during an audit period, there is a one-time prudence review; after that, only the administration of the contract terms are subject to ongoing prudence review (in addition to the costs being subject to ongoing financial audits). In any case, the prudence determination regarding the expanded PPA is not a decision that needs to be made presently, but it is important to a full understanding of the PPA Rider construct.

When asked about the REPA example, Staff witness Dr. Hisham M. Choueiki[19] admitted that AEP Ohio will continue to have REPAs on a going-forward basis (and consistent with the Commission's corporate separation approvals for AEP Ohio), but he dismissed the example as being irrelevant due to the statutory renewable mandate. (Tr. XII at 2889-90.) Upon further probing, he admitted that there is not actually a mandate for REPAs – only to buy renewable energy credits (RECs) for compliance. (*Id*.) The reality with REPAs is that the Commission agreed it would be in the customers' best interests in the long term for AEP Ohio to enter into long-term REPAs. Specifically, the Commission in AEP Ohio's *ESP II* proceeding approved a 20-year REPA (Timber Road) as part of a 3-year ESP – based on the determination that the long-term PPA was likely to be a lower cost option in the long run for customers.[20] What Dr. Choueiki misses in summarily dismissing the REPA example is that long-term price consideration is the same basic choice being proposed under the PPA Rider: while there is no mandate for PPAs, they are permissible as part of an ESP and could provide substantial customer benefits as compared to relying exclusively on volatile market prices.

The other long-term issue that goes beyond the ESP term is the question of the Company's commitment to continue proposing the PPA Rider in subsequent ESP filings, such that the customer is guaranteed to receive the longer-term benefits of the PPA Rider after being obligated to potentially pay a charge during some earlier portion of the ESP term. OEG witness Taylor raised this concern in its testimony and recommended that "AEP Ohio's customers should be assured of the longer-term net benefits of the rider by locking it in" through 2024. (OEG Ex.

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[19] AEP Ohio will refer to Staff witness Choueiki as "Dr. Choueiki" in this brief, even though he is not an economist and his Ph.D. qualifications have nothing to do with the subjects addressed in his testimony. (Tr. XII at 2875.)

[20] *ESP II*, Opinion and Order at 19 (Aug. 8, 2012).

3 at 5.) When asked by OEG counsel about the prospect of an obligation longer than the three-year ESP term in connection with the PPA Rider, AEP Ohio witness Vegas readily agreed that the long-term commitment dovetails into the Company's proposal quite well:

> Our intention in establishing the PPA mechanism is to have a long-term contractual relationship with our customers where they get the opportunity to get the benefit of that long-term hedge over an extended period of time.

(Tr. I at 121.) Similarly, when discussing the PPA Rider with OMA counsel, Mr. Vegas also confirmed the Company's intention to enter into a long-term commitment to retail customers:

> This OVEC rider is a concept that is intended to extend beyond this ESP, so we see the benefits of it in the long term so we would want to remain committed to that, to that arrangement.

(*Id.* at 264.) Accordingly, the Company requests that the Commission reiterate and confirm in its ESP III order that it was prudent for the Company to enter into the OVEC contract, and that the Commission will be bound by that prudence determination for the full term of that contract (through 2040). For its part, the Company's intention would then be to continue to include the OVEC contract in the PPA Rider beyond the term of this ESP III, to the same extent that the Commission is committed, up front, to this proposed hedging arrangement.

ii. The Staff's attempt to bypass the ESP statutory framework is misguided and inappropriately attempts to limit the Commission's available tools on the important matter of rate stability.

Staff witness Choueiki recommends denial of the PPA Rider based on his conceptual disagreement with its premise that a lawful, carefully crafted regulatory tool should be made available to mitigate the impacts of an imperfect competitive construct. His disagreement is too narrowly focused. As a result, he did not provide the Commission with a comprehensive analysis of the complete rider concept. Dr. Choueiki stated, "[i]t took over a decade for the Commission to transition the four Ohio EDUs to a fully competitive retail electricity market" and "[g]ranting a PPA rider is a move in the opposite direction." (Staff Ex. 18 at 9.) Similarly during his cross-examination, Dr. Choueiki repeatedly maintained that he was "ideologically" opposed to the PPA Rider since AEP Ohio is an electric distribution utility and should not be selling what he considers to be a form of insurance. (Tr. XII at 2839, 2897-98, and 2902-03.) Dr. Choueiki's view is that "Ohio has already went [down] the retail choice path so we are there. We have it. The choice is we have to buy in the market." (*Id.* at 2998.) Moreover, he stated that it did not matter in making his recommendation whether a PPA Rider is permitted under the ESP statute. (*Id.* at 2900-01.) Further, he did not seek legal counsel on whether the PPA Rider was permitted under the ESP statute. (*Id.* at 2903.)

Dr. Choueiki also acknowledged that he did not look at the PPA Rider rate impacts "at all." (*Id.* at 2907.) In fact, he agreed that Staff did not do any analysis of the market price side of the PPA Rider debate; in other words, Staff did not attempt to examine the price tag resulting from its recommended approach of relying exclusively on the market prices – due to a conceptual disagreement. (*Id.* at 2947.) He further stated that even if the PPA Rider was a benefit, he would oppose it. (*Id.* at 2852.)

Dr. Choueiki's opinion does not appear to line up with the Commission's obligation to provide practical oversight of the industry or the Commission's previous public comments concerning future risks and the use of hedges. In comments filed very recently before FERC, the Commission has advocated – based on Dr. Choueiki's input and advice – that fuel diversity is "extremely important" and asserted that "we cannot afford to forget about protecting our coal units that help in hedging against any unforeseen natural gas curtailments." (*Id.* at 2980, 2984; AEP Ohio Ex. 27 at 7.) Incredibly, these comments were filed *within one week of Dr. Choueiki filing his testimony in this ESP III case* – yet he proposes here to categorically eliminate the PPA

Rider option even though it would help provide the very type of hedge the Commission (based on Dr. Choueiki's input) recommended.

Respectfully, AEP Ohio submits that the Commission should take into account the controlling statutory framework and the proposal's inherent flexibility rather than take permissible options "off the table" without a complete and thorough analysis.[21] AEP Ohio understands and respects Staff's right to formulate independent recommendations and advance opposing viewpoints as part of the Commission decision-making process. But the adoption of the PPA Rider is a permissible and well-intentioned proposal – and it deserves full consideration and a legitimate policy debate. The Company developed a record to show that the proposal is being advanced to promote rate stability for retail customers, which is another important factor that the Staff knowingly avoided. Further, Dr. Choueiki acknowledges that "market prices don't have to be fair" and that sometimes market rates are unreasonable and unfair. (Tr. XII at 2890-91.) The Company seeks to give customers and the Commission a hedging tool that may be appreciated when, as Dr. Choueiki indicates, things become unfair when market prices spike. But those kinds of practical considerations do not affect his conceptual position. Staff's approach to "just say no" does not provide an evaluation of the legal or policy support for the PPA Rider. For those reasons, Staff's recommendations should not be accepted.

Staff's approach is disconnected both from the present and historical controlling regulatory regime. The controlling regulatory regime was discussed above to demonstrate that the PPA Rider is permissible under the ESP Statute. The Company submits that it would be unwise to blindly pursue competition for competition's sake and without regard for customer rate

[21] Dr. Choueiki acknowledged that his recommended approach assumes the PPA Rider is "off the table" for the Commission in this case. (Tr. XII at 2916-17.)

impacts. While it was not surprising that CRES witnesses such as Exelon witness Campbell maintained that the PPA Rider should not be considered even if it saves customers money,[22] it is surprising that Staff took such an extreme position. Even OCC's witness Wilson admitted that unconstrained competition is not necessarily a good thing if it results in increased prices. (Tr. X at 2489.)

Dr. Choueiki thematically laments that is has taken over a decade to get to a fully competitive SSO (Staff Ex. 18 at 7, 9, 15) – but that perspective ignores the actual regulatory history in Ohio and the Commission's own emphasis on rate stability as opposed to a blind ideological pursuit of competition. Accordingly, a brief digression is needed to demonstrate why Staff's position is so disconnected from recent events and Ohio regulatory history.

Following SB 3's market development period (MDP), when generation rates were supposed to be market-based, the Commission encouraged EDUs to avoid market-based rates and to provide rate stabilization plans (RSP).[23] The RSPs were to promote rate certainty, financial stability, and allow for competitive market development prior to charging customers market-based rates.[24] In AEP Ohio's RSP case, the Commission acknowledged this important context: "At the outset, we will note that AEP proposed a rate stabilization plan because we requested it."[25] The Commission found that competitive market rates would not be effective and

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[22] (Tr. VII at 1637.) Mr. Campbell testified that competitive markets are always superior to regulatory solutions and that, even though retail customers faced higher prices for electricity in 2005 when the Commission pursued the Rate Stabilization Plans, the RSPs were harmful to competition and artificially suppressed market prices. (Exelon Ex. 1 at 13; Tr. VII at 1625.) Exelon witness Campbell testified that, even if the PPA Rider helps customers achieve rate stability and reduces the overall cost of electricity, the cost savings should be ignored as irrelevant and the PPA Rider should be rejected as a threat to competitive markets. (Tr. VII at 1636-37.)

[23] *See in re DP&L*, Case No. 02-2779-EL-ATA, Opinion and Order at 29 (Sept. 2, 2003).

[24] *In re Ohio Edison*, Case No. 03-1461-EL-UNC, Entry at 4-5 (Sept. 23, 2003).

[25] *In re AEP Ohio*, Case No. 04-169-EL-UNC, Opinion and Order at 13 (Jan. 26, 2005).

that the Company's proposed rates were more favorable to customers than the market-based rates would be because competitive markets had not adequately developed.[26]

At the same time, customers of Monongahela Power Company (Mon Power) in southeast Ohio were faced with big increases if that company went to market under the 1999 law. Thus, the Commission ordered AEP Ohio to pursue the purchase of Mon Power (which had refused to submit an RSP), and AEP Ohio obliged.[27] In approving the purchase, the Commission determined that Mon Power customers would be "far better off under the rates established under the Companies' proposal" than by being served at a market rate.[28] The Mon Power crisis is another undisputed example of regulatory history in Ohio where AEP Ohio came through for the Commission and bailed out customers that were not even its own at that time. Thus, AEP Ohio's experience during the SB 3 restructuring era was that the Commission would not move toward competition (in an apparent effort to protect customers from higher market rates) and acted to prevent utilities from collecting the higher market rates, instead pushing the utilities toward a regulated structure.

In 2008, competitive markets had still not developed as contemplated in the 1999 law.[29] The General Assembly passed SB 221 to change Ohio's regulatory framework once again. And the General Assembly turned a sharp corner when it passed SB 221; most notably, the singular provision in RC 4928.14 requiring market-based SSO rates was repealed and was replaced with the choice for a utility to pursue an MRO or an ESP. Under the MRO option, there was a new and extended period of transition created to reach fully market-based rates. Unlike the prevailing

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[26] *See id.* at 14.

[27] *In re Monongahela Power*, Case No. 05-765-EL-UNC, Entry (June 14, 2005).

[28] *In re Monongahela Power*, Case No. 05-765-EL-UNC, Opinion and Order at 10 (Nov. 9, 2005).

[29] *Consumers' Counsel v. Pub. Util. Comm.*, 128 Ohio St.3d 512, 513 (2011).

assumption during passage of SB 3 that market rates would be lower than regulated rates, the passage of SB 221 was premised upon market rates being higher than existing rates; thus, it established a new and extended transition period to very gradually subject customers to market rates over a period of 6-10 years. The General Assembly could not have envisioned the lower prices driven by shale gas or the major economic recession, both of which are significant events that developed after passage of SB 221. More to the point, SB 221 does not require unconstrained market rates without regard to customer rate impacts. On the contrary, as further discussed below, SB 221 supports continued emphasis on rate stability. And the Commission – unlike its Staff – has kept rate stability high among its priorities.

The cooperative partnership between AEP Ohio and the Commission continued after passage of SB 221, accruing substantial benefits to customers and the State of Ohio. In its first ESP under SB 221 (*ESP I*), AEP Ohio followed the Commission's direction and entered into an ESP that provided below-market generation rates for its customers. The Commission ultimately modified and approved AEP Ohio's ESP, finding that, in order to take advantage of AEP Ohio's low-cost generation, "it is essential that the plan we approve be one that ... provides future revenue certainty for the Companies, and affords rate predictability for the customers."[30] More specifically, the Commission's *ESP I* decision found that the cost of the proposed ESP ($1.4 billion) was less than half of the expected cost of an MRO ($2.9 billion).[31] Due to the dilution of the benchmark market price used to develop the projected MRO cost (through the 10%, 20%, 30% price blending with adjusted SSO prices during the 3-year term), this finding confirms that market rates were much higher than SSO rates at the time of the *ESP I* decision.

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[30] *ESP I*, Opinion and Order at 72 (Mar. 18, 2009).

[31] *Id*.

In the *ESP II* case, the cooperative partnership between the Commission and AEP Ohio continued and the result was generation divestiture and a rapid transition to a fully competitive SSO procurement status as of the end of the *ESP II* term (May 30, 2015). Significantly as it relates to the present debate, the Commission was concerned with the prospect that an "unexpected, intervening event occurs during the term of the ESP, which could have the effect of increasing market prices for electricity."[32] In this context, the Commission deemed AEP Ohio's ability to maintain a stable SSO rate "extremely beneficial" and approved a rate stability charge which the Commission concluded was "undoubtedly consistent with legislative intent in providing that electric security plans may include retail electric service terms, conditions, and charges that relate to customer stability and certainty."[33] The Commission – as contrasted with the position of its Staff in this *ESP III* case – should again promote rate stability and certainty by approving the PPA Rider.

In sum, while Dr. Choueiki laments the fact that it has taken over a decade to get to fully competitive SSO, this perspective ignores the factual history of the 15 years since passage of SB 3 in Ohio. The market development period was five years, starting in 2001and lasting through 2005. The Rate Stabilization Plans lasted three years, from 2006 through 2008, avoiding substantial rate increases. SB 221 was enacted to pull back from the market-based rates cliff. AEP Ohio's first ESP under SB 221 was from 2009-2011 and saved customers $1.5 billion. The Commission also found that the Company's second ESP was more favorable than the market rate option while accelerating the path toward a fully-competitive SSO procurement process and providing for a retail stabilization rider as a primary feature of that rate plan. Here, rather than

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[32] *ESP II*, Opinion and Order at 32 (Aug. 8, 2012).

[33] *Id.*

following Staff's recommendation to refuse to consider potential benefits that are both lawful and based on sound regulatory policy, the Commission should continue to do the right thing and incorporate customer rate impacts and take advantage of the flexible regulatory regime provided for in the ESP statute. This is not a "step backward" regarding competitive issues but merely builds on the same tradition and regulatory history of protecting rate stability while advancing competition – it is actually Staff's purely academic position that is a "step backward" from that well-established regulatory context and long history of rate impact sensitivity and real-world pragmatism by the Commission. Here, the Commission should continue its trajectory of moving toward competition while being mindful of – and addressing – customer rate impacts and market price volatility through adoption of the PPA Rider.

Dr. Choueiki also relies on an incorrect assumption that AEP Ohio will stop selling electricity to its retail SSO customers starting next year – something he repeated several times in his written testimony and affirmed on cross-examination. (Staff Ex. 18 at 9, 15; Tr. XII at 2813-14, 2882-83, 2886, 2903.) Moreover, Dr. Choueiki refers to the EDU as a "middleman" and a selling "agent," relegating the EDU's responsibility and downplaying its SSO duty as merely "an obligation to distribute electricity." (Tr. XII at 2883-85.) In reality, AEP Ohio is legally obligated to sell electricity to any customer that does not shop for generation service and is the provider of last resort should competitive providers default. R.C. 4928.141 clearly imposes a duty on electric distribution utilities such as AEP Ohio to provide retail electric service to non-shopping customers – as the Supreme Court of Ohio has explicitly acknowledged.[34] Even where the supply is competitively procured through a CBP auction process, the EDU remains the retail

[34] *Consumers' Counsel v. Pub. Util. Comm.*, 128 Ohio St.3d 512, 513 (2011).

supplier and merely enters into wholesale power agreements with the winning auction suppliers. (AEP Ohio Ex. 16 at Exhibit CL-2.)

Legally, the conclusion that EDUs remain responsible for provision of the SSO and will continue to be the retail provider of service to SSO customers simply cannot be debated. Yet, again, Dr. Choueiki's incomplete analysis provides incorrect information to the Commission by suggesting that the current legal and regulatory construct requires full reliance on volatile market prices – a position that not only betrays regulatory history in Ohio but is also wholly unsupported by current law. Through this incorrect assumption that EDUs no longer provide generation service to SSO customers, Dr. Choueiki implicitly harkens back to SB 3 structure where the plan was to throw customers to the market volatility "wolves." This perspective ignores that the basic purpose of SB 3 (to complete the transition to market pricing by 2006) failed and that SB 3 was eventually replaced by a hybrid re-regulatory approach adopted under SB 221, which substantially changed the SSO pricing regime in 2009. That hybrid regulatory regime is effective today and SB 3's requirement for "market-based" SSO pricing was repealed in 2008 as part of the enactment of SB 221. As stated earlier, AEP Ohio is interested in presenting a practical real-world solution for its customers who are facing volatile market prices. AEP Ohio has the default SSO obligation under Ohio law and is proposing the PPA Rider under that obligation to try and help address the market rate volatility problem faced by the Company's customers.

Dr. Choueiki admits that he has taken similar positions on major policy questions in the recent past. In AEP Ohio's *ESP II* proceeding, Dr. Choueiki forcefully advocated that the RPM market price for capacity be imposed on AEP Ohio. (Tr. XII at 2891.) A short two years later, Dr. Choueiki now admits that the $16/MW-day or $27/MW-day rates he recommended at that time did “not provide enough coverage, fixed annual costs, or the energy costs.” (*Id.* at 2834.) And Dr. Choueiki even candidly admits that the $16/MW-day RPM price he recommended was actually “not reasonable,” “unfair,” and was “not an appropriate charge” for capacity. (*Id.* at 2842, 2891.) Fortunately for AEP Ohio and its customers, the Commission rejected Dr. Choueiki’s position in 2012 and adopted a fair cost-based capacity charge in AEP Ohio’s *ESP II* and *Capacity Charge* cases.

Dr. Choueiki’s other major objection to the PPA construct is that it would involve federally-regulated charges that the Commission could not fully review or disallow based on a traditional prudence review. (*Id.* at 2806, 2855.) But in this regard, the PPA Rider proposal is no different from the Company’s existing recovery of transmission charges. During cross-examination, Dr. Choueiki agreed that AEP Ohio recovers its transmission costs by passing FERC-regulated charges through to retail rates and that the PUCO merely engages in financial audits to ensure proper accounting but does not attempt to disallow any of the costs. (*Id.* at 3043.) It is also ironic that Staff’s entire premise is to rely exclusively on PJM market prices – which are also federally-regulated and beyond the Commission’s direct control.[35] There is a good track record of relatively smooth and uneventful recovery of federally-regulated transmission charges in Ohio retail rates and the Commission should not be reject the PPA Rider based on such concerns.

Interestingly, Governor Kasich has publicly stated his own concerns regarding over-

[35] Dr. Choueiki’s solution of being a price taker in the PJM capacity and energy markets involves a hybrid regulatory market construct. As discussed in greater detail below, the PJM markets are managed and quasi-regulatory (as opposed to being the product of unconstrained market forces). Moreover, the PJM markets – especially the RPM capacity market – are flawed and cannot be relied upon to produce reasonable rates. At this juncture, it is sufficient to say that Dr. Choueiki’s ideological position breaks down because his desire to rely exclusively on market forces is not fulfilled by being a price taker from a regulatory-managed and flawed “market” construct.

reliance on short-term markets and said that, while we are presently moving onward in a deregulatory environment, "we've got to figure it out." (AEP Ohio Ex. 25.) In April 2014 remarks, Governor Kasich went on to say he "wasn't sure if it was the smartest thing" to pursue an "ideological definition of deregulation." (*Id.*) It is particularly poignant that Governor Kasich used the very same terminology in his April 2014 critique of deregulation that Staff witness Dr. Choueiki used in describing his own recommendation here of being "ideologically" opposed to the PPA Rider and in favor of competition regardless of price impacts. (Tr. XII at 2839, 2898.) The Company's proposal is a creative and practical solution to real-world rate volatility problem facing customers. It is a valid and helpful solution within the current statutory paradigm to mitigate over-reliance on short-term market prices and "figure it out" – just as the Governor implored those responsible and interested to do.

c. Regardless of whether the PPA Rider is a credit or a charge during the ESP term, it cannot be disputed that the PPA Rider will promote rate stability, especially over the long term.

Virtually all of the witnesses that testified regarding the PPA Rider acknowledged that PJM market rates are volatile.[36] AEP Ohio witness Dr. Karl A. McDermott (former Illinois Commissioner, Director of the Center for Business and Regulation and Ameren Distinguished Professor of Business and Government at the University of Illinois Springfield, and Special Consultant to NERA) demonstrated unequivocally that electric prices exhibit a high degree of volatility. As a prefatory matter for policy issues he addressed in his rebuttal testimony (discussed further below), Dr. McDermott explained the reasons for electricity pricing volatility:

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[36] In addition to AEP Ohio witnesses Vegas and Allen, Staff witness Dr. Choueiki testified that market prices have been "quite volatile." (Staff Ex. 18 at 10.) OCC witness Wilson also agreed that recent market prices were volatile. (Tr. X at 2490.)

> Short-term commodity markets, such as PJM's spot and forwards electricity markets, tend to be volatile due to the rapid incorporation of the factors affecting supply and demand into the commodity's price. For example, short-term electricity demand tends to be very sensitive to short-term factors such as weather. Further, the supply of electricity, in the short-run, tends to be highly inelastic (*i.e.*, not sensitive to price changes) since building new power plants often takes years. In any given hour limits on the available supply can cause dramatic changes in prices as demand shifts with changing weather patterns. Moreover, even futures markets for electricity tend to be inherently volatile because electricity is difficult to store.

(AEP Ohio Ex. 32 at 6.) His rebuttal testimony demonstrated in detail how electricity prices – especially the auction clearing capacity prices – are highly volatile. (*Id*. at Table 1.)

It is self-evident that reasonable rates are not achieved by unmitigated exposure to volatile market rates. As discussed above, the Commission has a long tradition of pursuing rate stability. Most notably, in the Company's first ESP proceeding, the Commission held that "it is essential that the plan we approve be one that ... provides future revenue certainty for the Companies, and affords rate predictability for the customers."[37] Both before and after the enactment of SB 221, the Commission has considered rate stability as a primary feature of the Company's rate plans over the past decade.[38] Company witness Vegas explained his basis for asserting that customers continue to place value on rate stability:

> If you look at the costs on the Apples to Apples website that the Commission sponsors, supply costs from various competitive suppliers, I can read that the rates for longer-term fixed price supply options cost more than shorter-term variable price options. So to me that implies that customers are willing to pay more for stability.

[37] *ESP I*, Opinion and Order at 72 (Mar. 18, 2009).

[38] In addition to the Rate Stabilization cases, the Mon Power case, and the *ESP II* Rate Stabilization Charge examples discussed above, AEP Ohio also points out that rate stabilization was codified in RC 4928.144 – the phase-in statute. That statute authorizes the Commission to implement a phase-in where customers are otherwise facing significant rate impacts; in both AEP Ohio's *ESP I* and *ESP II* cases, the Commission invoked the phase-in statute to formulate rate caps and navigate around adverse customer rate impacts.

> Or, in another similar vein, customers will pay higher rates for a loan on their mortgage if it has a longer-term stable fixed component to it versus a shorter-term variable component. So I believe that customers do pay more for stability in prices.

(Tr. I at 43-44.)

OEG witness Taylor described the desire for rate stability as follows:

> I think most households like to have some degree of certainty in their budgeting about what their utility bill is going to be and being entirely open to marginal cost pricing may result in utility bills that are a great surprise and a burden for a household.

(Tr. XI at 2575.) OEG witness Taylor also offered his expert opinion on the inextricably intertwined market of rate volatility faced by customers during this future period:

> My professional opinion is that there has been a period of tame market pricing both in the capacity and energy pricing area that has been enjoyed for the last five to ten years and that PJM is likely to experience some tight capacity markets that will drive prices up, and certainly the hundreds of contracts that I've overseen the negotiation and execution of in other parts of the country are at prices for new generation that are much higher than what PJM has been experiencing as far as its market pricing and that, therefore, it's highly likely that this hedge will be economically beneficial.

(Tr. XI at 2563.) The rate stabilizing effect of the PPA Rider will only be enhanced by market rate volatility that has not only been experienced recently but is expected to continue increasing.

Given that the Commission and customers place value on rate stability, the next question is whether the PPA Rider, in fact, will provide rate stability. As will be demonstrated, that answer is affirmative. Company witness Vegas explained that the proposed PPA Rider enables AEP Ohio's customers to benefit from the OVEC contract by having a financial hedge that would move in the opposite direction of market prices and provide a financial stabilizing component to customer rates. (Tr. I at 28.) Intervenor witnesses that addressed the PPA Rider also acknowledged the hedge value of the proposal. (*See e.g.* Tr. X at 2495 (OCC witness Wilson acknowledged that the PPA Rider would be more valuable to customers as a hedge during periods of high market prices, such as a period of extreme weather); Tr. XI at 2558 (OEG witness Taylor agrees that the PPA Rider is a price-stabilizing hedge). *See also* Tr. VII at 1518-19 (Exelon witness Campbell agreed that a financial hedge can provide rate stability, though he opposes the PPA Rider).) OEG witness Alan S. Taylor testified that he expects the PPA Rider to have a stabilizing effect on rates because OVEC costs are largely fixed and stable, given that the underlying coal-fired generation plants involve very capital-intensive technology of a fixed nature. (Tr. XI at 2451-52.) OCC witness Wilson also agreed that a hedge can provide rate stability for retail customers. (Tr. X at 2491.)

While some of the intervenors are critical of the Company's statement that the PPA Rider would move in the opposite direction of market prices, those criticisms are non-substantive and based on a potential lag issue relating to the rider's true-up mechanics – they do not challenge the premise that the PPA Rider credit/charge would mitigate the effects of volatile market prices. In this regard, for example, OCC witness James F. Wilson claims that the PPA Rider may be about as likely to move in the same direction as the opposite direction. (OCC Ex. 15 at 30-31.) Setting aside the relative likelihood of the PPA Rider moving in the opposite direction in comparison to a then-current realtime market price, the Company acknowledges the effect that reconciliation component of the rider (operating on a one-year lag) could create. But that does not change the basic effect of the PPA Rider moving in the opposite direction of market prices and causing a rate stabilization effect.

As discussed above, the PPA Rider will produce a credit when OVEC's largely fixed and stable costs (at the time the costs are incurred) are below market prices (defined by the revenues produced at the time the capacity, energy, and ancillary services are sold). Conversely, if OVEC costs are above market prices, the PPA Rider will produce a charge. That is what the Company meant in saying the PPA Rider moves in the opposite direction as market prices. The reconciliation component of the rider is what could create the variance from this effect – due to the fact that it involves a regulatory lag and relates back to a historical period but is charged (or credited) prospectively. Regardless of synchronization, however, the customers receive the same benefits over time, and the net effect of the PPA Rider works in the opposite direction of market prices.

AEP Ohio witness Allen acknowledged that the reconciliation component of the rider – involving a true-up to actual historical costs and revenues – would not always operate in the opposite direction of the market prices prevailing at the time of the true-up. (Tr. II at 517-518.) But Mr. Allen indicated that he expects the PPA Rider will be a credit more often than a charge and so the PPA Rider overall would operate to mitigate higher market prices. (*Id.*) In any case, Mr. Allen indicated that the lag issue with the reconciliation feature of the rider could be addressed with more frequent updates – and that the Company is not opposed to that if it is important. (*Id.* at 514.) More importantly, it is undisputed that customers will receive a credit or charge that moves in the opposite direction of market prices under the PPA Rider – regardless of the timing of the credit and whether the credit is perfectly aligned with real time market prices. That is the substantive and financial effect of the PPA Rider and that is what provides the basic hedging effect of the PPA Rider.

The Company's PPA Rider net impact projection (discussed in the next section below) incorporates normal weather. (*Id.* at 529, 571.) But if extreme weather occurs during the ESP term, the PPA Rider benefit is highly likely to increase. As Mr. Allen testified (based on data analysis provided to the parties as part of the discovery process), *extreme weather* – a hotter-than-normal Summer or colder-than-normal Winter – *has an upside market price impact of ten* *times as much as mild weather would decrease market prices*. (AEP Ohio Ex. 9; Tr. III at 745-46.) OCC witness Wilson also agreed that weather variations not forecasted drive price volatility and that extreme weather drives volatility more so than mild weather. (Tr. X at 2491, 2494.) Further, Mr. Wilson admitted that the hedge being offered through the PPA Rider would be more valuable to customers during period of extreme weather. (*Id.* at 2495.)

Mr. Allen explained why this weather-price relationship makes sense based on how the generation stack works:

> When weather's mild, demand goes down, and when demand goes down, you move down in the stack. And so you move from CTs [combustion turbine units] and CCs [combined cycle units] producing some of the power to baseload coal units producing some of the power.
>
> What you don't do – so for coal plants you may see a variable cost of about $30 that would set the market price. The next step down in the stack is to move down to nuclear units which are going to be in the 8 to 10 dollar a megawatt-hour variable price range. I don't move down that next step, demand never falls so low that you have to reach into the nuclear units to set the marginal price.
>
> On the upside, though, when weather is extreme, demand goes up, you quickly start moving up the stack from the coal units that are setting the price, the CCs setting the price, you move into CTs setting the price at a much higher cost and you start moving into oil-fired units and the like that have much, much higher costs and you start to see $1,800 a megawatt-hour. Structurally the floor on the prices is somewhere in the $30 a megawatt-hour range. On the upside it's much, much higher.

(Tr. II at 518-19.) This relationship means that all of the PPA Rider impact projections in the record fail to incorporate a potentially significant hedge benefit if extreme weather occurs during the ESP term.

AEP Ohio witness Vegas explained that, because the existing PPA Rider cost estimates are based on normalized weather projections, they do not incorporate the significant volatility that would create significant benefits to customers. (Tr. I at 48, 55.) In rejecting a flawed example put forth by counsel for OCC during cross-examination, Mr. Vegas further explained how Company data and analysis made available to the parties through discovery demonstrates the potential but unquantified value of the PPA Rider:

> I think there's an important element to the way the PPA rider works that's missed from that example or from your hypothetical and that is the way that the PPA rider performs on a day-to-day basis.
>
> So thinking about market prices in general over a year, *volatility is a key driver of whether the PPA rider will generate a cost or a credit.*
>
> In the case of volatility occurring, volatility on the high side of pricing tends to be much greater than volatility on the low side of pricing. *So you could have ten periods over the course of a year with abnormally low pricing in the daily market and one period of abnormally high pricing during that same period but yet have the net effect be a significant benefit or credit because the deviation of volatility on the high side of pricing averages ten times the deviation on the low side of pricing.*
>
> So in your scenario you're trying to describe a homogenous year of pricing, that's not the reality of how the PPA will work. *It will essentially capitalize on those periods of high price volatility which tend to be ten times higher than low volatility, capture that benefit as a credit to customers over the course of the year.* So the scenario you're describing is not realistic in how I believe the PPA rider will actually create value for customers.

(Tr. I at 55-56 (emphasis added); see also AEP Ohio Ex. 9.)

Mr. Allen explained conceptually that a probabilistic model – such as Monte Carlo – could be used to do a more sophisticated simulation that would reflect the added value of the PPA Rider using the probability of extreme weather during the ESP term. (Tr. II at 529-30.) But AEP Ohio did not perform the analysis and neither did any other party in this case. Regardless, because none of the parties' estimates incorporate the probability of extreme weather, they all *significantly understate the hedge value of the PPA Rider* should any extreme weather occur during the three-year ESP term and even more so over the longer term. The Commission should bear this in mind and recognize that the Company's projected PPA Rider credit is very conservative and provides yet an additional basis to reject the flawed PPA Rider impact projections submitted by OCC witness Wilson and IEU witness Murray.

In addition to having an exponential financial benefit during periods of extreme weather, Mr. Allen further explained that the PPA Rider hedge would have a highly beneficial compounding effect when energy prices are higher (for whatever reason) and the OVEC units are dispatched more continuously. Under those circumstances, ramp-up and ramp-down periods are minimized, heat rates are more efficient and costs are spread over a larger base of megawatt hours – causing the OVEC energy margin to be higher and the net credit to customers to be ever larger. (Tr. II at 478-79.) In other words, as energy prices increase for whatever reason and OVEC dispatch goes up, it would cause the PPA Rider credit to be commensurately increased. Thus, the PPA Rider not only serves to insulate customers from the effects of high energy prices, it actually yields progressive benefits in the face of high and volatile market prices.

Separate and apart from the competing estimates of how the PPA Rider will impact rates during the ESP term, AEP Ohio witness Allen addressed the longer-term benefits of OVEC through the PPA Rider:

> I think it's important, though, to recognize that this PPA mechanism may be in place for a number of years and forward prices do change, and in looking at Attachment 3 [OMA Ex. 3 (IEU INT 2-001), Attachment 3] I saw that the cost or benefit of OVEC over the period of the ESP was nearly neutral and in the longer term it was a significant benefit to customers.
>
> So what that gave me some comfort is that, as fundamental market prices may change over time, that the OVEC units still looked like a very valuable hedge for customers.

(Tr. II at 506-07.) After all, AEP Ohio's intention with the PPA Rider proposal is to create a long-term rate stability mechanism for customers.

Of course, the *raison d'etre* of the PPA Rider will be long-term rate stability – for example, the Company believes that long-term rate stability is the basis for OEG's interest and support for the PPA Rider, not for the benefits that can be received by customers strictly within the ESP term. And AEP Ohio President Pablo Vegas agreed that AEP Ohio is willing to consider a PPA Rider longer than the term of the proposed ESP. As he explained, the Company's intention in establishing the PPA mechanism "is to have a long-term contractual relationship with our customers where they get the opportunity to get the benefit of that long-term hedge over an extended period of time." (Tr. I at 121. *See also id.* at 150-51.) Thus, the potential for a long-term solution for market rate volatility is a real possibility.

Finally in this regard, it is important to understand that the potential for an expanded PPA to flow through the PPA Rider would significantly increase the significance of the potential upside benefit for customers. AEP Ohio witness Allen demonstrated this in his rebuttal testimony. (AEP Ohio Ex. 33 at Exhibit WAA-R2.) Mr. Allen explained that a $5/MWh increase in market prices would yield an offset of $2.39/MWh under the expanded PPA Rider – assuming in the illustration that 3,000 MW of capacity would be included in the expanded PPA. (AEP Ohio Ex. 33 at 3-4.) This equates to a very significant 48% mitigation of the price increase. While the OVEC illustration provided a lower rate mitigation effect of 7%, that is not insignificant either – and the larger potential for the expanded PPA is preserved only if the Commission approved the initial step of including OVEC. And, unlike Staff who maintains that only two specific SSO auction design measures should be used to mitigate rate volatility (and only for non-shopping customers), the Company submits that the Commission should retain and utilize as many volatility mitigation tools that it can, in order to better manage rate volatility and ensure rate stability for all customers – including governmental aggregation and shopping customers.

d. The expected net rate impact of the PPA Rider is neutral-to-positive during the ESP term and clearly beneficial in the longer term.

As discussed above, the PPA Rider will provide rate stability to AEP Ohio customers, regardless of whether it happens to be a credit or a charge over the three-year ESP III term. As reflected in OMA Ex. 3, there were three sets of analysis based on differing assumptions/data that were provided to parties through the discovery process projecting the potential rate impact of the PPA Rider. OMA Ex. 3 is just a copy of the Company's response to the first interrogatory in IEU's second set of questions (*i.e.*, IEU INT 2-001), which appended the three sets of projections – referred to by the parties during the hearing simply as Attachment 1, Attachment 2 and Attachment 3.[39] As will be discussed in detail, AEP Ohio witness Allen updated the projections in Attachment 2 (the most current of the three projections) to incorporate the most recent data available at the time of the hearing. Mr. Allen's estimate is that the PPA Rider will result in an $8.4 million net credit over the ESP term.

OCC witness Wilson made an attempt to estimate the PPA Rider impacts during the ESP term – but his analysis is flawed as will be demonstrated. Exelon witness Campbell did not attempt to quantify the PPA Rider rate impact and testified that, even if the PPA Rider helps customers achieve rate stability and reduces the overall cost of electricity, the cost savings should be ignored as irrelevant and the PPA Rider should be rejected as a threat to competitive

[39] The Company notes that it provided the three Attachments in response to IEU's discovery request (INT 2-001) asking for each of the estimates possessed by the Company. (OMA Ex. 3.) So, the Company was not advancing all three of the estimates as being the most accurate. Mr. Allen sponsored through his testimony a single estimate of the PPA Rider impact – based on the most updated and accurate information – during the ESP term in AEP Ohio Ex. 8.

markets. (Tr. VII at 1636-37.) IEU witness Murray was the only witness to use Attachment 3 (the oldest vintage of the three projections) and applied only a single adjustment to back out the LEAN savings projected by the Company. Moreover, as mentioned above, Staff did not even consider the PPA's cost-stabilizing impact. Yet, the rate stability impact is critical to the purpose and value associated with the PPA Rider, and Staff's decision to ignore this super-important issue severely undermines the relevance and validity of Staff's position. Thus, after discussing AEP Ohio witness Allen's and OEG witness Taylor's projections for the PPA Rider impact, the following discussion will focus on the four primary and most fundamental flaws in Mr. Wilson's PPA Rider projection (which also addresses the flaw in IEU witness Murray's testimony).

i. AEP Ohio witness Allen's estimate of a net credit of $8.4 million is the best evidence in the record of the rate impact during the ESP term, and both Mr. Allen and OEG witness Taylor conducted the only long-term evaluation of the PPA Rider.

Based on the latest information available at the time of the hearing and presuming for present purposes that the OVEC contract is the only PPA reflected in the PPA Rider, AEP Ohio witness Allen testified that "the most accurate representation of what the value of the PPA rider would be" is an $8.4 million net credit to be given to customers over the ESP term. (AEP Ohio Ex. 8A (CONFIDENTIAL); Tr. II at 484-86, 506.) The data supporting this calculation was provided to the parties through the discovery process. (Tr. II at 533.) Mr. Allen explained in detail how the $8.4 million projected credit was calculated using the original modeling from Attachment 2 and updating it with the information from another discovery response (OEG INT 2-004) to calculate the most accurate projection for the PPA Rider impact during the ESP term. (*Id.* at 485-87, 489.) As Mr. Allen explained, the primary difference between the three attachments was the vintage of the data used and Attachment 2 was the most recent forecast. (*Id.* at 498.) Because Attachment 2 was the most recent vintage, it used the most updated market data and forced outage rates, the most recent operational forecast of OVEC costs, etc. (*Id.* at 500-01.) Moreover, as further discussed in the sections below, which critique OCC witness Wilson's modeling flaws, the Company's major assumptions incorporated into Mr. Allen's estimate were the best evidence in the record.

It is also significant that the Company's analysis – reflected in Attachment 2 – provided a reliable long-term evaluation of the PPA Rider well beyond the ESP term. Specifically, Attachment 2 shows that the net benefit of the PPA Rider through 2032 is $400 million. (OMA Ex. 3 at Attachment 2.) For his long-term evaluation, OEG witness Tylor estimates the rate impact of the PPA Rider over his recommended 9 ½ year term to be a net credit of $49 million – which he further updated at the time of the hearing to be closer to a $70 million credit over the longer-term. (Tr. XI at 2557, 2604.) The Commission should evaluate the long-term benefits of the PPA Rider when considering whether to adopt the proposal. The only evidence in the record on this subject shows that the PPA Rider – even just with the OVEC contract – will provide substantial benefits to retail customers over the long term.

ii. OCC witness Wilson's PPA Rider impact analysis (and, by extension, that of IEU witness Murray) are critically flawed and should not be relied upon by the Commission. The input adjustments made by OCC witness Wilson without re-running the model produced flawed results.

The over-arching and most extensive flaw to OCC witness Wilson's PPA Rider impact estimate is that OCC did not do any modeling in this case but just made changes to AEP Ohio's model assumptions – including changing the market prices embedded in the Company's modeling. (Tr. X at 2451.) Mr. Wilson acknowledged that re-running the model would be required if changes are made to the input assumptions in order to get results that are fully consistent with the original model. (*Id.*) Yet, Mr. Wilson made major changes to the inputs and did not re-run the model. He maintains that his adjustments to the inputs and related recalculations of the output produced results that are "sufficiently consistent" with the results of the original modeling – but he admitted that the consistency of the adjusted modeling can only be verified by re-running the model. (*Id.* at 2453.) He also asserted that he used the most recent information available through discovery (*id.* at 2460), but that was also demonstrated to be false. These fundamental errors could result in the criticism that Mr. Wilson did sloppy modeling – but he would have had to do modeling to receive that appraisal. Due to his major adjustments without re-running the model, Mr. Wilson really had no basis to conclude that the results of his adjustments are valid as compared to the original modeling done by AEP Ohio.

The data OCC used to estimate the PPA Rider rate, as examined during cross-examination of witness Wilson's detailed workpapers (a sample of which is reflected in AEP Ohio Ex. 22), do not reflect accurate modeling of dispatch or revenues. AEP Ohio Ex. 22 shows, for example, on just one day that he did not dispatch OVEC (for that entire day), OVEC's cost was below his market price in hours 1-7 and hour 24 (and, thus, OVEC would have dispatched during those hours and produced margins). Thus, just for that one day, his modeling produced mismatched and illogical results for 1/3 of the hours displayed.

In his rebuttal testimony, AEP Ohio witness Allen partially quantified the impacts of Mr. Wilson's error in this regard:

> Based on a margin of $15/MWh and a maximum output of 437MW, for every hour that his model fails to reflect appropriate dispatch revenues are understated by over $6,500. In the first month of his forecast this occurred 61 times which understated revenues by approximately $400,000. Similarly, in the second month of his forecast there are 37 hours where the market price in his forecast exceeds the variable cost of production for the OVEC units by approximately $28/MWh and yet his model recognizes no revenue for that hour resulting in an understatement of revenues of over $450,000. In January of 2016, his analysis has a similar problem but in this case both the on and off-peak prices exceed the variable cost of the OVEC units by a considerable amount and there are 102 of 744 hours in the month where the units should be economically dispatched and his model fails to do so.

(AEP Ohio Ex. 33 at 7-8.) Mr. Allen went on to observe that "[t]hese same errors persist throughout his analysis, over 10% of the total hours in the three year forecast period, to such a degree as to make the analysis unreliable and unusable." (*Id.*)

Ultimately on cross-examination, even Mr. Wilson retreated to saying that his analysis is "not an attempt to re-create the hourly results" and "is not meant to be a simulation of what would happen if the model were rerun." (Tr. X at 2489.) Yet, AEP Ohio Ex. 22 (the sample from his workpapers) clearly shows hourly dispatch results, and he used those results to project the market revenues for the OVEC plants – and those form the sole basis for his PPA Rider impact estimate. (*Id.*) Obviously, if the author of the revenue simulation admits that it does not portray what would happen in the real world, there is certainly no reason for the Commission to rely upon it.

1) OCC's failure to shape hourly prices produced inaccurate results.

Second, OCC witness Wilson did not shape hourly market prices in his adjustments to AEP Ohio modeling, which did use shaped hourly prices to estimate dispatch of the OVEC plants. (*Id.* at 2485-86.) He also admitted that he would have used shaped hourly prices if he had done his own modeling – which of course he did not. (*Id.* at 2486.) This is a significant flaw because in the real world plants actually get dispatched based on the prices that change hourly.

In his rebuttal testimony, AEP Ohio witness Allen also evaluated this flaw in Mr. Wilson's analysis:

> To the extent that his forecast shows the OVEC units not dispatching at the beginning of a peak period in a given day, his analysis understates the revenues associated with the generation during the higher priced peak hours that a shaped price would produce. An example of this flaw in his analysis shows up in the

> 0700, 0800 and 2200 hours of June 1, 2015 – the first day in his analysis – and persists throughout.

(AEP Ohio Ex. 33 at 8.)

2) OCC's crude downward allocation of OVEC production (by one third overall) was unjustified.

The third critical flaw in Mr. Wilson's projection relates to the OVEC hours of production, where he took the Company's model results and manually slashed the hours of production without justification. Specifically, Mr. Wilson applied major downward adjustments to OVEC hours of production – 20% across-the-board for all peak hours and a whopping 40% reduction to all non-peak hours. (Tr. X at 2480; AEP Ohio Ex. 22.) While he claimed this adjustment was justified by recent production results for OVEC, he ignored the unique and temporary circumstances that caused those historical limits on production – factors that proper modeling should incorporate.

During his cross-examination, AEP Ohio witness Allen addressed the temporary increase in OVEC's cost per megawatt-hour during 2011-13, indicating that there were four separate, unique causes of the temporary increase in OVEC costs per megawatt hour: (1) mild weather meant lower sales, (2) a soft energy market based in part on lower demand due to the economy, (3) , outages at the OVEC plants relating to installation of environmental equipment, and (4) lower natural gas prices which gave gas-fired generation assets the advantage during that period. (Tr. II at 477-79, 547-49; Tr. III at 717.) These factors ultimately meant temporarily-reduced dispatch and lower sales for the OVEC units, which translates into the costs being spread out over fewer megawatt hours and resulted in a higher cost per megawatt hour for that period. (Tr. II at 479.) But overall, as reflected in IEU Ex. 6 (2012 OVEC Annual Report), the OVEC costs were stable over the several recent years – before and after 2011-13 period – including the most recent 2014 cost data. (*Id.* at 476-478.) Specifically, the OVEC costs were in the range of $40/MWh to $48/MWh during 2008-2010 and again starting in 2014. (*Id.*)

Mr. Allen also addressed this deficiency in OCC witness Wilson's analysis, as part of the Company's rebuttal testimony:

> His reduction in the output of the units by approximately 25% relies on only two years' worth of data - 2012 and 2013. His analysis assumes a projected capacity factor of approximately 50%. Other than in 2012 and 2013 when the OVEC units had environmental tie in outages and dispatched in a more limited fashion due to extremely low market prices the OVEC units have historically had capacity factors of approximately 75%. The use of capacity factors that are well below those that would be expected for these units based upon projected market prices results in a significantly overstated cost of the PPA rider.

(AEP Ohio Ex. 33 at 9.) Thus, OCC witness Wilson's capacity factor reduction is unjustified and should not be used.

In sum, Mr. Wilson's extensive adjustments to the OVEC hours of production inaccurately perpetuated aberrant conditions from 2012-13 (low energy prices and tie-in outages at OVEC plants) into his forward projections of revenue – significantly understating the revenues and increasing the level of his claimed net cost of OVEC during the ESP term. (OCC Ex. 15 at 21-25; Tr. X at 2482-84, 2489.) This additional and pervasive flaw is yet another reason to discount any reliance on his projection.

3) OCC's (and IEU's) selective adjustment reversing the expected LEAN savings embedded in the current budget results in over-stated OVEC costs.

The fourth material inaccuracy reflected in OCC witness Wilson's quantitative analysis (and that of IEU witness Murray) is the unwarranted increase of the OVEC demand charge based on a belief that projected savings reflected in the OVEC budget are not fully guaranteed to occur. Specifically, Mr. Wilson added $10 million back in to the OVEC demand charge estimate because he did not feel that the LEAN-related cost savings program being implemented by

OVEC (and with a severance program already being implemented) were sufficiently certain to occur. (OCC Ex. 15 at 12; Tr. X at 2468-69.) IEU witness Murray also made the same adjustment. (IEU Ex. 1A at 12.) As AEP Ohio witness Allen demonstrated, the cost savings reflected in the Company's PPA Rider rate impact analysis are sufficiently certain to be used in the rider estimate.

The OVEC demand charge estimate used to develop Company witness Allen's PPA Rider estimate during the ESP term of an $8.4 million credit (AEP Ohio Ex. 8A) reflects a prospective savings of approximately $12 million annually, based on OEG INT 2-004. (Tr. II at 501, 649.) A conservative value of $10 million was reflected in the Attachment 1 rider estimate provided to the parties in discovery and in Mr. Allen's updated estimate of an $8.4 million customer credit over the ESP term that was derived from Attachment 2. (*Id.* at 501-02.)

The projected OVEC cost savings relate in part to a cost-savings initiative known as "LEAN" and for other reasons such as a severance program. (*Id.* at 648.) The overall premise of the LEAN program, being undertaken by AEP affiliates and OVEC, is essentially to improve productivity by eliminating waste in the work of the business. (Tr. I at 88.) The expected cost reductions at OVEC units are based upon their current budget that they provide to the sponsoring companies/owners, who need to be able to rely on the budget; so Mr. Allen is confident that what OVEC has provided to AEP Ohio at this point in time is a reasonable estimate of where their expenses will be in the future. (Tr. II at 486, 502.) Mr. Allen also maintained and defended this position as part of his rebuttal testimony. (AEP Ohio Ex. 33 at 6-7.)

If anything, Mr. Allen explained that his experience in this area tells him that the budget amounts will end up being higher than actual costs. "In the past my role was director of Financial Forecasting for AEPSC and individuals that reported to me would have reviewed those

OVEC costs, and I've had discussions with those individuals very recently and their understanding or their experience is that the longer-term forecasted costs from OVEC are typically greater than the actual costs seen by OVEC." (Tr. II at 510.) While not a firm commitment, Mr. Allen – based on his extensive experience with corporate planning and budgeting – treats the budgeted cost savings as "an expectation that OVEC will be working to make those changes and they will be working to make that successful." (*Id.* at 550-551.) And he further bolstered this conclusion by referencing OVEC's 2012-2013 financial statements to show that OVEC has already taken steps toward achieving the projected cost savings. (*Id.* at 551.)

e. Staff is mistaken in claiming that SSO auction design alone can effectively mitigate market rate volatility, and OCC/CRES intervenors are similarly wrong in relying exclusively on short-term fixed rate offers in the market.

Staff witness Dr. Choueiki contends in his direct testimony that using staggered auction procurement and laddering multiple products (a combination of 12-, 24- or 36-month products) is a more effective approach for mitigating rate volatility than the PPA Rider. (Staff Ex. 18 at 10-11.) During cross-examination, however, Dr. Choueiki admitted that, even with the SSO auction design tools of laddering and staggering, the auction clearing prices still follow market price changes up and down. (Tr. XII at 2810.) Nonetheless, he continued to unreasonably defend the position on the stand that those two SSO auction design tools should be used to the exclusion of other tools such as a hedge. (*Id.* at 2924, 2933-34, 2936.) Staff's position advocating that an additional tool for rate mitigation should be categorically excluded is also suspect. More importantly, Dr. Choueiki is empirically wrong in making this claim.

Mr. Allen demonstrated in his rebuttal testimony that the laddering/staggering approach only partially mitigates rate volatility and does not mitigate fundamental changes in market rates. (AEP Ohio Ex. 33 at 2-3, Ex. WAA-R1.) Mr. Allen also pointed out another obvious limitation to the auction design solution: it can only help for non-shopping customers and does not mitigate rates for shopping customers or those participating in governmental aggregation programs. (*Id*.) Aside from these significant limitations, it is simply unreasonable to suggest – as Dr. Choueiki does – that the Commission should not employ any other solutions.

AEP Ohio witness McDermott rebutted Dr. Choueiki's claim that auction design should be used exclusively to mitigate rate volatility:

> I agree that the SSO auction is an effective method of mitigating price volatility in the shorter term electricity markets and the SSO auction design can benefit customers by mitigating those shorter term price fluctuations. *There is, however, no basis to conclude that the SSO auction mitigates longer term market changes. The SSO auctions are not designed to provide price protection from longer-term market trends like the physical hedge found in the PPA.* Moreover, the SSO auctions apply only to non-shopping customers. Even the limited protection from short-term volatility achieved by the auction design is not applicable to shopping customers or those being served by governmental aggregation.

(AEP Ohio Ex. 32 at 11 (emphasis added).) Dr. McDermott reasonably drew the obvious and compelling conclusion (though one disputed by Staff) that, in light of these limitations of auction design, the Commission "should evaluate the PPA Rider's potential effect on volatility based on its own merits quite apart from the SSO auction design questions." (*Id*.)

Another similarly flawed argument advanced by CRES intervenors is that fixed generation price offers in the market adequately manage rate volatility such that the PPA Rider is simply not needed. For example, Exelon witness Campbell maintains that there is no need for AEP Ohio to provide a hedge because CRES providers have a number of competitive offerings geared toward customer goals and objectives, including their risk tolerance or desire for a market hedge. (Exelon Ex. 1 at 15.) He also maintained that CRES providers "can offer a stable, long term, fixed price at a much lower rate that is reflective of market prices." (*Id*. at 16.)

As a threshold matter, as Exelon witness Campbell himself admitted, any CRES offer for a fixed price reflects a risk premium to account for the risk of having to honor the price when market prices are higher. (Tr. VII at 1604-06.) Dr. Choueiki also agreed that a CRES fixed price offer reflects a price premium. (Tr. XII at 3017.) By contrast, the PPA Rider involves a differential between cost and market without an additional premium. In any case, Mr. Campbell's assertion is not factually supported as refuted by AEP Ohio witness Allen in his rebuttal testimony and was dismantled from a policy basis by AEP Ohio witness Dr. McDermott through his rebuttal testimony.

Factually, Mr. Allen demonstrated that CRES providers are not offering long term stable offers to residential customers – using data from the Commission's Apples-to-Apples website. (AEP Ohio Ex. 33, Exhibit WAA-R3.) In reality, the vast majority of offers (72.4%) are for terms of 12 months or less and there are no offers in the AEP Ohio service territory exceeding 36 months. The short-term nature of these contracts results in customers needing to sign new contracts on a regular basis which creates volatility for customers as they transition from one contract to another. Based upon a review of CRES offerings of comparable terms, Mr. Allen showed that this transition can result in significant volatility in the form of generation rate changes of at least 9.7% and up to 48.4% over the most recent 12-month period. (*Id*. at Exhibit WAA-R4.) Mr. Allen also demonstrated that the same phenomenon can occur for customers served by CRES providers through governmental aggregation. As shown in Mr. Allen's Exhibit WAA-R5, the CRES pricing for customers served under the Upper Arlington governmental aggregation program will see their price increase this year from 5.545 ¢/kWh to 7.84 ¢/kWh, or just over 41%. Finally in this regard, Mr. Allen observed that the risk of shopping customers seeing significant price volatility is exacerbated by the fact that many CRES contracts for residential customers include a rollover provision that automatically enrolls the customer in a new market based variable rate plan or a fixed rate plan unless the customer takes action. In that common scenario, unless the customer takes proactive action, a new and potentially higher rate unilaterally charged by the CRES provider will automatically apply. (*Id.* at 5.)

From a policy perspective, similar to Staff's recommendation to rely exclusively on SSO auction design solutions, Exelon's recommendation to rely exclusively on CRES offers is suspect. Moreover, Mr. Campbell admitted on cross-examination that its CRES affiliate does not offer longer term hedged products for residential customers. (Tr. VII at 1590.) Dr. McDermott also refuted the notion that fixed rate offers from CRES providers should be relied upon exclusively to mitigate volatile market rates:

> Whether Exelon wishes to have longer term hedged products is beside the point, if the Commission wishes to provide longer term hedges for all customers it appears that the PPA is the only method currently proposed in AEP Ohio's service territory to do so. Further, as I explain below, some regulators have determined that longer term hedges do serve the public interest and all customers, including those that have chosen to hedge their short-term risk using contracts from competitive suppliers, should benefit, and pay for, those longer term hedges. Mr. Campbell's argument that the PPA, almost by definition, is anti-competitive seems to fly in the face of decisions these regulators have made that longer term hedges serve the public interest.

(AEP Ohio Ex. 32 at 15.) Dr. McDermott went on the show that several restructured states (Connecticut, Maine, Massachusetts and Delaware) have created nonbypassable charges to reflect long-term hedges on behalf of all customers, independently from their default standard service procurement process. (*Id*. at 16.)

In sum, Dr. Choueiki's recommendation that SSO auction design tool be used to the exclusion of a hedge like the PPA Rider is unjustified. Exelon's similar recommendation to rely exclusively on CRES offers for fixed rates is unreasonable and should not be adopted.

f. Staff's and opposing intervenors' position that the PJM market prices for capacity and energy should be exclusively relied upon is misguided and unwise.

Although one of the main objections to the PPA Rider construct advanced by Staff and some intervenors is that market forces should be relied upon instead of regulatory solutions, the PJM markets relied upon by Staff and some intervenors are actually "regulated markets" that are far from fully functioning, transparent and effective. The list of reforms to the PJM markets – for which the Commission itself has advocated – is lengthy, and many concerns are far from being resolved. The PJM market reforms will cause the market prices to increase over time, as compared to the largely fixed and stable OVEC costs being included in the PPA Rider proposal. And the cost of maintaining reliability under the PJM construct (usually transmission fixes) is also significant and should be considered – rather than ignored – in this process. In short, it would be unwise to summarily exclude viable options for rate stability and rely exclusively on the PJM markets, as recommended by Staff and some intervenors.

First, it is evident that the PJM markets are regulated markets that are managed and administered by FERC, PJM, and the market monitor. While Dr. Choueiki quibbled with referring to the PJM markets as "regulated" or "administered," he readily acknowledged a number of prominent regulatory features that apply. And he stated that it is "very true" regarding the capacity market that "the so-called competitive market has a fair degree of administrative oversight." (Tr. XII at 2840, 2967-68.) More specifically, during cross-examination, Dr. Choueiki agreed that the following regulatory/administrative features of the PJM markets exist:

- PJM dictates whether demand response resources can qualify (Tr. XII at 2831.)

- PJM decides constraints on what suppliers are allowed to bid into the capacity auction, based on the market monitor approving a price cap for each generation unit. (*Id.* at 2831, 2967.)

- PJM restricts the auction clearing price as being 1.5 times net CONE (cost of new entry). (*Id.* at 2968.)

- PJM administratively establishes the demand curve (also referred to as the Variable Resource Requirement or VRR curve) which ultimately determines the auction clearing price based on where the supply curve intersects with the VRR. (*Id.* at 2839, 2968.)

- There is a regulatory backstop if the capacity auction fails – whereby generation owners can be forced to sell at a cost-based rate. (*Id.* at 2968-69.)

- There is the reliability must run (RMR) regulatory construct where a generation owner is paid a cost-based price in lieu of retiring an uneconomic unit; this can affect the auction clearing price as well. (*Id.* at 2969, 2972.)

- PJM and the Market Monitor have to review and approve unit retirement plans of generation owners. (*Id.* at 2971-72.)

Again, AEP Ohio does not bring up all of these regulatory features to be critical of PJM or FERC, but to expose the reality that the recommendation of Staff and some intervenors to rely exclusively on market forces is a misnomer and a red herring. The Company would simply like for the Commission to consider the PPA Rider based on the rate stability and hedging benefits as a permissible proposal under the ESP statute.

Second, another reality is that the PJM markets are, indeed, flawed and are in the ongoing process of being reformed. Dr. Choueiki acknowledged that he and the Commission have an ongoing list of reforms that are still needed regarding the PJM markets – most if not all of these will result in increasing market prices:

- Impose more restrictions on demand response resources so that all generation resources are on equal footing. (*Id.* at 2834, 2964, 2977.)

- Performance incentives are needed for generation resources. (*Id.* at 2963.)

- PJM needs to restrict the market construct where bidders are permitted to engage in speculative participation in the Base Residual Auction only to cover the underlying obligation through participation in the incremental auction. (*Id.* at 2965-66.)

- Restrict generation resource imports into PJM to ensure that firm transmission is committed. (*Id.* at 2979.)

- Pursue fuel diversity as a top priority as FERC/PJM considers the Polar Vortex lessons learned. (*Id.* at 2980.)

- Reform artificial price suppression that may lead to uneconomic unit retirements. (*Id.* at 2983.) In the history of the RPM capacity market, none of the eleven Base Residual Auctions as applicable to Ohio have reached the PJM-designed goal of net CONE; currently, net CONE is $382/MW-day as applicable to Ohio. (*Id.* at 3025, 3032-34; AEP Ohio Ex. 27; AEP Ohio Ex. 31.)

All of these reforms will likely take a significant amount of time and either come with a price tag or increase PJM market prices if successful.

OCC witness Wilson displayed incredible optimism by stating that, if there is another polar vortex in January 2015, it will not produce high prices like it did this year because all of the needed PJM reforms are going to happen in the next few months (before January 2015). (Tr. X at 2496-98.) When the basis for Mr. Wilson's naïve optimism was probed, the only two areas of expected reform he could name were performance incentives and better communication – and when asked for details of the two expected reforms he vaguely stated he was "not sure what exactly would be done" to improve performance incentives and that PJM would "put some changes in place" to improve communication. (*Id.* at 2499, 2503.) When asked whether he agrees with Mr. Wilson's unbridled optimism about what PJM will accomplish in the next six months, Dr. Choueiki indicated: "I hope they do. I mean, we have lots of recommendations before PJM right now and they're starting – PJM is starting to even listen to the states now on some of these recommendations. (Tr. XII at 2976.) So even though Dr. Choueiki himself – the biggest supporter of the PJM markets in this case – says he has lots of reforms for PJM to take up and even though PJM has "just starting to listen" to State commissions regarding the needed reforms, Dr. Choueiki nonetheless simply "hopes" things get resolved in the next few months.

Again, AEP Ohio is not being unduly critical of the reforms needed in the PJM markets – the Company is working to achieve many of the same objectives. But the point in this context is to realize that many reforms are needed and that most – especially the capacity market reforms – will take considerable time and ultimately tend to increase PJM market prices if successful. OCC witness Wilson agreed there would be a price tag for transmission fixes associated with plant retirements that may occur, but acknowledged that he did not evaluate the impact of his recommended approach or compare that price tag to the expected cost of the PPA Rider. (Tr. X at 2516.) Exelon witness Campbell also recommends exclusive reliance on PJM markets and, if there are reliability issues, to build out transmission facilities to address the situation. (Tr. VII at 1630-32.) While he acknowledges it would be fair to consider the costs associated with such solutions, he has not done so and does not recommend considering the cost of transmission fixes in deciding whether to adopt the PPA Rider. (*Id.* at 1635-37.) Dr. Choueiki also testified that there are always reliability issues when coal plants retire and transmission fixes have definite price tags – sometimes hundreds of millions of dollars. (*Id.* at 3000.) Yet, neither the Staff nor the opposing intervenors examined the cost of their market alternative recommendation.

g. For purposes of deciding this case, granting the PPA Rider only serves to approve inclusion of the OVEC contractual entitlement such that the Commission and all parties reserve their right to disapprove or oppose, respectively, expansion of the PPA Rider during the ESP III term.

The Company is only requesting approval of the inclusion of OVEC in the PPA Rider as part of this case. Doing so would preserve the parties' and the Commission's right to decide whether to accept or reject an additional PPA in a subsequent case. But denial of the PPA Rider now for OVEC would preclude the potential for an additional PPA for Ohio legacy plants. (Tr. XII at 2881.) AEP Ohio witness Dr. McDermott – a former Commissioner – summed up this choice as follows:

> Of course, the proper amount of hedging is related to the risk tolerance of the entity purchasing the hedge. In this case, the Commission would have to decide how important rate stability is for retail customers and whether to keep the option open to buy additional price certainty for consumers. (That is, the expansion of the PPA Rider to include other PPAs is not a foregone conclusion, the Commission would have complete control over the potential future expansion.) Yet if the Commission were to deny the PPA rider now, it could be precluding that potential flexibility in the future.

(AEP Ohio Ex. 32 at 10.) Even Staff witness Dr. Choueiki acknowledged that the OVEC contractual entitlement was unique and could be approved as a legacy contract. (Tr. XII at 3037.)

Regarding the potential for a subsequently expanding the PPA Rider, AEP Ohio witness Vegas testified that the Ohio legacy generation units (those formerly owned by AEP Ohio and previously used to support retail service in Ohio) are the assets that would be considered for the expanded PPA Rider. (Tr. I at 111.) Mr. Vegas also testified that AEP recently made a determination that "those assets could continue to be operated profitably over a long period of time." (*Id.* at 122-23.) Again, the details and the ultimate choice of whether to pursue the additional PPA would be made by the Commission later in a separate case.

Another aspect of the "free option" relates to the potential usefulness of Ohio coal plants in formulating a viable state compliance strategy for the carbon regulations being proposed by the USEPA. When Company witness Vegas was asked about how the PPA Rider relates to the carbon regulations recently-proposed by the USEPA, he explained that the PPA Rider would give the Commission and the State of Ohio significant flexibility in formulating a compliance strategy:

> I think the PPA could represent a very valuable tool in the state's portfolio of options to consider how to meet compliance requirements and how to balance out the approach that the state would take in an all-of-the-above strategy. It would allow the introduction of a more regulated type cost basis for certain aspects of generation that, when coupled with the other all-of-the-above options that the state would have, could give a more balanced and customer benefiting method for complying with the greenhouse gas guidelines.

(*Id.* at 127.) OEG witness Taylor also testified that the PPA Rider could provide reliability benefits and potential flexibility for carbon regulation compliance. (Tr. XI at 2637.) The Commission should preserve flexibility and keep the "free option" of an expanded PPA Rider alive by initially approving the PPA Rider to reflect the OVEC contract.

4. Continuation Of The Alternative Energy Rider Is Reasonable.

The Company proposes to continue to recover REC expenses through the bypassable Alternative Energy Rider (AER) that the Commission previously approved in *ESP II*. (AEP Ohio Ex. 1 at 9.)[40] Company witness Spitznogle explained that continuation of the AER as approved in *ESP II* advances state energy policies by "[e]nsur[ing] the availability of unbundled and comparable retail, electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs," R.C. 4928.02(B), and "[f]acilitat[ing] the state's effectiveness in the global economy." R.C. 4928.02(N); (AEP Ohio Ex. 3 at 6.) No other party offered testimony in opposition to or cross-examined Mr. Spitznogle or any other Company witness regarding the AER's continuation. Thus, the continuation of the AER for recovery of REC expenses during the term of ESP III is uncontested, reasonable, and should be approved.

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[40] *See also ESP II*, Opinion and Order at 18 (Aug. 8, 2012).

5. The Company's Proposals To Discontinue Variable Price Tariffs Are Reasonable.

a. The Company's proposal to eliminate Standby Service and Time of Use rates should be approved.

The Commission also should approve AEP Ohio's proposals to eliminate Schedule Standby Service (SBS) and the generation component of its Standard Time of Use (TOU) tariffs not related to the pilot gridSMART® project tariffs at issue in Case No. 13-1393-EL-RDR. (AEP Ohio Ex. 1 at 12.) As Company witness Spitznogle explained, both SBS and the generation component of AEP Ohio's TOU tariff are legacy rates from the Company's historical cost of service model. (AEP Ohio Ex. 3 at 12-13.) Few customers take service under either tariff (*id.* at 13), and those that do can more appropriately obtain comparable services in the market from CRES providers who are better positioned to offer them under the current market construct. (*Id.* at 12-13.)

SBS should be eliminated and certain elements relocated to the Company's tariffs and terms and conditions of service for the additional reasons that the Company cannot monitor when SBS will be used and AEP Ohio's distribution charges will be the same for the general service schedule and the Schedule Standby Service. (*Id.* at 12; AEP Ohio Ex. 13 at 10.) It is appropriate that AEP Ohio, as a wires company, no longer provide generation-related backup and maintenance services. (AEP Ohio Ex. 3 at 12.) As Company witness Moore explained, the Company is not well positioned to do so because it does not own generation. (AEP Ohio Ex.13 at 10.) The generation component of SBS can be obtained on an energy-only basis through the SSO auction product for non-shopping customers or in an alternative form for customers taking service from a CRES.

Company witness Moore also explained that elimination of the generation component of the Company's TOU tariffs is appropriate given the rate design the Commission ordered in AEP Ohio's Base Distribution Case, Case No. 11-351-EL-AIR, which will be effective beginning January 1, 2015. (*Id.*) Specifically, that rate design will flatten the energy rate on residential tariffs, making the distribution time-of-use residential rates the same as the regular residential tariffs and showing no benefit of operating during on and off-peak (*Id.*) Because the General Service TOU Distribution rates will remain different until the Company's next base distribution case, those tariffs will continue for the distribution portion of the bill. (*Id.*) Direct Energy supports the Company's "move toward allowing CRES provider time of use . . . products." (Direct Energy Ex.1 at 6.) So do Exelon and Constellation. (Exelon Ex. 1 at 11.) As Exelon witness Campbell explained, "CRES providers and the competitive market should be the exclusive providers of time-of-use products" because EDUs "have been ordered to leave the business of the supply function behind" and "should focus on their role as a distribution utility, and operations that are part and parcel of that role." (*Id.*) Although OCC witness Williams expressed concerns about the availability of TOU rates in the market (OCC Ex. 11 at 33), it is apparent that CRES providers are willing and eager for the opportunity to provide them to customers.

b. Schedule IRP-D

Through its Application, the Company proposed to eliminate schedule IRP-D because the benefits of interruptible service relate, for the most part, to the provision of generation service. As the Company will be procuring the generation service requirements of SSO customers through a full-requirements auction, it appeared to AEP Ohio that, as a wires-only company, it might not be the entity best able to provide an interruptible service product. (AEP Ohio Ex. 13 at 9; AEP Ohio Ex. 3 at 12.)

OEG recommends that the Company offer two interruptible rate options. As one option, OEG recommends that the Company should continue to offer a form of schedule IRP-D. Under OEG's proposal for continuing IRP-D, the participating customer would continue to receive a credit of $8.21/kW-month, which is the amount of the credit currently available under IRP-D, and there would be no limitations on the frequency, duration and timing (*i.e.*, interruptions could occur in any month of the year) of emergency interruptions. OEG witness Baron contends that the unlimited frequency of potential interruptions increases the reliability value of the interruptible load compared to the PJM Limited Emergency program, thus justifying the larger monthly credit for that option. Mr. Baron explained that, as another option, the Company should offer an interruptible rate that provides for an interruptible credit equal to 50% of Net CONE (currently about $5.36/kW-month) patterned after the PJM Limited Emergency program, which limits interruptions to 10 times during the months of June through September. Because an important purpose of an interruptible load program is to promote energy efficiency and reduce the Company's peak demand, Mr. Baron recommends that AEP Ohio should recover the costs associated with any interruptible credits through Rider EE/PDR. (OEG Ex. 2 at 17-18.)

Due to changed circumstances since it filed the Application in this case, the Company would not object to the Commission authorizing it to continue offering a modified version of schedule IRP-D. The changed circumstances that support continuing to offer an IRP-D tariff include, first, the recent polar vortex, which illustrated that there may still be an important role for demand response programs even when sponsored by a wires-only company. Second, a federal appeals court issued a decision that calls into question to some extent the Federal Energy

Regulatory Commission's approval of PJM's demand response programs while emphasizing the states' role in overseeing demand response programs for retail customers.[41] In addition, it may be appropriate to maintain the IRP-D tariff in a modified form in order to provide a more stable revenue stream for certain customers that are able to provide emergency demand response services that can benefit the reliability of the electrical grid in AEP Ohio's service territory or that can assist in meeting the state's EE/PDR mandates. Accordingly, the Company would not object to continuing schedule IRP-D for existing IRP-D tariff customers and as an option for economic development purposes, along with the existing $8.21/kW-month credit, and for purposes of unlimited emergency interruptions only. Thus, the IRP-D tariff would no longer include discretionary (non-emergency) interruptions. In addition, the Company's support for continuing IRP-D is also contingent upon its ability to recover the costs of any interruptible credits through Rider EE/PDR in the manner that OEG suggests.

The Company does not believe that the lower-priced limited emergency interruption program that OEG has also recommended is appropriate.

B. The Company's Distribution-Related Proposals Are Reasonable And Should Be Approved.

Company witness Dias explained that improving reliability requires a long-term strategy with multiple, coordinated activities on varied fronts. (AEP Ohio Ex. 4 at 3.) Mr. Dias, in his role as Vice President of Distribution Operations for Ohio Power Company, discussed the Company's comprehensive distribution reliability plan and how it will benefit customers. (*Id*. at 3-5.) Specifically, that plan includes the approval of the DIR, ESRR, the gridSMART® Phase 2

[41] *Ind. Util. Regulatory Comm'n v. FERC*, 668 F.3d 737, 737 (D.C. Cir. 2012).

Rider, SDR, and SSWR, as proposed in the Company's Application. (*Id.* at 4; AEP Ohio Ex. 1 at 9-11.)

The criticism that the programs proposed as riders in this case should be proposed in the context of a rate case filing and not part of this ESP is without merit. The General Assembly updated the electric utility optionality in SB221 to ensure that the Commission had the ability to act progressively and maintain a flexible oversight that recognized more timely recovery through riders as part of an ESP. However, it is clear that OCC witnesses do not agree with the Commission's underlying ability to even implement riders. OCC witness Effron testified that he believed that riders are contrary to sound regulatory policy and the fact that the Commission had approved them in the prior ESPs was just an indication that the Commission could have done better in the past. (Tr. XII at 2740.) That is not a surprise as Mr. Effron indicated that in all of his appearances before the Commission on behalf of OCC that he had never testified in support of a rider. (*Id.* at 2739.) Mr. Williams, an OCC witness and employee, shared Mr. Effron's preference for operating in the confines of a rate case as opposed to using the tools provided by the General Assembly to address issues in an ESP proceeding. (Tr. VI at 1470-71.) Mr. Effron did back off his absolute position on the imprudency of riders to state that he agreed that it is not unusual to have riders and that regulators should review riders to weigh their advantages and disadvantages. (Tr. XII. at 2741-2742.)

AEP Ohio agrees with the Commission's past decisions to utilize the rider option provided by the General Assembly in R.C. 4928.143, as opposed to a rigid rate case-only approach. Company witness Dias summed up the differences very succinctly when he discussed the need for traditional rate cases but stated that they were the "slow turtle dinosaurs" of rate recovery. (Tr. II at 424.) Mr. Dias was discussing the policy debate of riders versus rate cases in the context of the DIR proposal in this proceeding. Based on his thirty years of experience, Mr. Dias pointed out the progressive nature of the Ohio regulatory system and the benefit of the hybrid system that allows riders along with base rate cases, which enables utilities to take a proactive approach to make rapid infrastructure improvements in the system. (*Id.* at 424.) Mr. Dias recognized the O&M changes and the appropriate time for base rate cases, but complimented the Ohio system that allows riders which allow for nothing more than the cost of recovery of the actual expenses. (*Id.* at 427.) As Mr. Dias pointed out, "[y]ou don't recover any more or any less than what you expend." (*Id.* at 427.) Whereas, the rate case model he described as a "set and forget" model of ratemaking. (*Id.*) The Company proposes the continuation and establishment of a number of riders to ensure it is responding to customer needs and proactively investing in the infrastructure and future of the system.

1. Continuation And Expansion Of The Distribution Investment Rider Is Reasonable.

a. Purpose and background of the Distribution Investment Rider

The Distribution Investment Rider or DIR allows for continued capital investment in the distribution system to support customer expectations tied to reliability. The Commission previously approved this rider in the *ESP II* proceeding (Case No. 11-346-EL-SSO, *et al.*) to encourage a proactive replacement of aging infrastructure. (AEP Ohio Ex. 4 at 9.) Specifically, the Commission stated, "[w]e believe that it is detrimental to the state's economy to require the utility to be reactionary or allow the performance standards to take a negative turn before we encourage the electric utility to proactively and efficiently replace and modernize infrastructure and, therefore, find it reasonable to permit the recovery of prudently incurred distribution infrastructure investment costs."[42] The DIR program supports replacement of aging infrastructure and improvement of the reliability system. (AEP Ohio Ex. 4 at 14.) Mr. Dias discussed the DIR benefits when explaining the value of replacing assets often more than fifty years old, the strength and wind/ice resistance of new distribution lines, and the ability to consider the needs of hospitals, fire and police stations to ensure that electric service to these facilities can be restored quickly when outages occur. (*Id.*)

The DIR provides the Company needed capital carrying costs for incremental distribution investment to ensure continued investment in the distribution system without the risk of regulatory lag. (*Id.* at 9.) The continuation and modification of the rider will assist in meeting customer expectations related to reliability performance and provide stability for retail electric service.

b. Statutory authority for the DIR

R.C. 4928.143(B)(2)(h) provides the statutory authority to approve the DIR as proposed in this proceeding. The Commission previously relied upon this statutory provision in its August 8, 2012 Opinion and Order in *ESP II*. The Commission has previously found that the DIR is an incentive ratemaking device that accelerates recovery of the Companies' investment in distribution service.[43] This same rationale applies to the DIR continuation and expansion under review by the Commission in this Application. According to that statutory provision, the Commission may include in an ESP:

> Provisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking, a revenue decoupling mechanism or any other incentive ratemaking, and provisions

[42] *ESP II*, Opinion and Order at 47 (Aug. 8, 2012).

[43] *ESP II*, Opinion and Order at 46 (Aug. 8, 2012).

> regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include a long-term energy delivery infrastructure modernization plan for that utility or any plan providing for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

R.C. 4928.143(B)(2)(h). The Company's proposed DIR fulfills the requirement of this division of the statute and should be approved by the Commission. This statutory section requires the Commission to examine the reliability of an electric utility's distribution system and ensure that customers' and the electric utility's expectations are aligned and that the electric utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.[44] As shown below, the Commission has the record evidence necessary to make that finding in this proceeding.

c. The structure and updates to the ESP III DIR are reasonable and should be approved.

As Company witness Moore testified, the Company is requesting to expand the types of costs allowable for recovery under the DIR. (AEP Ohio Ex. 13 at 5-7.) The Company will continue to use the FERC Form 3Q and Form 1 for the quarterly updates to the DIR. (*Id.* at 5-6.) The Company will use the distribution ledger for the general plant additions including reconciliation by functional ledger back to the total general plant balances on the Form 3Q and Form 1. (*Id.* at 5-6.) In addition, the Company is requesting to modify the mechanism for recovery in the DIR to more accurately reflect the plant balance to be applied to each component

[44] *ESP II*, Opinion and Order at 46 (Aug. 8, 2012).

of the carrying charge. (*Id.*) Depreciation is calculated using gross plant, in order to reflect the return of the rate base, and property taxes are calculated based on net plant in service. (*Id.*) Lastly, the benefits of Accumulated Deferred Income Taxes, ordered by the Commission to be returned through the DIR mechanism, are based on a return component only as these costs would normally be represented as rate base, or net plant; therefore, the Company is proposing to continue applying this credit as approved in its current DIR Rider in Case No. 13-419-EL-RDR. (*Id.*) The Company is proposing to maintain the filing schedule as well as the process for rates to be automatically approved within 60 days of the quarterly DIR filing absent a Commission order that states otherwise. (*Id.*) Finally, the Company is proposing a rate cap on the DIR of $155 million in 2015, $191 million in 2016, $219 million in 2017 and $102 million for the first five months of 2018, or $246 million on an annualized basis. (*Id.*; AEP Ohio Ex. 14.)

The Company also proposes caps to manage the rider's stability. (AEP Ohio Ex. 13 at 6; AEP Ohio Ex. 14.) The DIR provides a streamlined approach to recovery of costs associated with distribution investments, which will encourage investment that can improve reliability. The reliability benefits also relate to stabilizing retail electric service through the necessary replacement of aging infrastructure.

i. The Company's and customers' reliability expectations are aligned.

The Commission Staff agrees with the Company's present proposal and recommended that the Commission find that AEP Ohio's reliability expectations are in alignment with those of its customers. (Staff Ex. 10 at 6.) Mr. Baker explained Staff's analysis of AEP Ohio's compliance with R.C. 4928.143(B)(2)(h) through the Company's interactions with and oversight by Staff. (*Id.* at 3-5.) Mr. Baker explained the Staff's involvement in establishing reliability standards and the Staff's ongoing monitoring of the Company's performance. (*Id.* at 3-4.) He discussed the Commission's finding in the *ESP II* case that the Company's expectations were consistent with those of its customers. (*Id.* at 5.) He also pointed out that Staff already investigated the single 2011 missed reliability standard and determined that it was caused by a substantial reduction in the number of short-duration customer interruptions. (*Id.*)

The customer surveys support the continuation of the DIR in this proceeding. The responses in the most recent surveys, included in Company witness Dias testimony, show that 19% of residential and 18% of commercial customers expect their reliability expectations to increase in the next five years. (AEP Ohio Ex. 4 at 5, Exhibit SJD-1.) When that is added to the number of customers that are expecting the utility to maintain the current level of reliability, the number stands at 89% of residential and 94% of commercial customers. (*Id.*) As shown in the surveys, customers have an expectation that the Company will continue to work and improve or maintain reliability. Mr. Baker also discussed the consideration of customer survey data and indicated that the results indicated that customers were generally satisfied with the Company's ability to provide service without interruption and that satisfaction levels were higher than those supporting the Company's prior reliability standards. (Staff Ex. 10 at 6.) At hearing, OCC asked Mr. Baker if those survey numbers could also be interpreted as showing that customers do not expect service to get better, or to decrease, because the large majority of customers did not expect reliability to change. (Tr. V at 1336-71.) Those types of questions show OCC's fundamental misunderstanding of the DIR's purpose and benefit. Those questions indicate an analysis that relies on the false assumption that ending the investment in the DIR will deliver the same level of reliability that customers currently experience. It will not.

ii. The DIR as proposed ensures the replacement of aging infrastructure.

A key aspect of the DIR is that it allows the Company to maintain the current level of reliability by replacing aging infrastructure before it fails. OCC witness Effron agreed that the decision of when to replace distribution infrastructure is a decision better left to the system engineers. (Tr. XII at 2742-43.) OCC witness Effron also agreed that as a general rule it is better to replace equipment before it fails and interrupts customers' service as opposed to waiting for it to fail and then taking action to replace the equipment. (*Id.* at 2744-45.) This brief discussion with OCC witness Effron undermines the apparent OCC preference for reportable improvements after failures on the system rather than a proactive reliability approach, and it is a microcosm example of the underlying purpose of the DIR – to replace aging infrastructure before it fails. The DIR allows the engineers and system planners to study system performance and replace aging infrastructure prior to it failing and adversely impacting customer service. While waiting for equipment to fail and detrimentally impact customer service and restoration efforts would produce a quantifiable metric, it would not be good for customers. Quantification has a role in the DIR effort but it is not the underlying goal of infrastructure investment. The Company should not run equipment to failure and interrupt customer service or delay restoration efforts just so the Company can report a metric. The Company prefers to use its expertise to manage its distribution system and replace equipment prior to failure so that customers continue to receive at least the same level of service that they are currently experiencing and also receive an increased level of service over time as technological sensitivity increases and demands increase. Company witness Dias testified that reliability is a moving target, and without continuous improvement, the general reliability of the distribution system may unintentionally decline over time. (AEP Ohio Ex. 4 at 3.) Absent approval of the DIR, it will be difficult for the Company to meet those customer expectations.

The expanded nature of the DIR is a further extension of this underlying goal of investing in distribution infrastructure with a focus on replacing aging infrastructure to meet customer reliability expectations. The updates requested in this ESP application are to invest in a variety of areas but largely focus on the communications system and service centers. This investment will ensure a faster response to customers experiencing service outages. The improvements to the service centers and in particular the replacement of the practically obsolete communications system will directly benefit customer restoration efforts at the time of outages when customers are most concerned with reliability efforts. (AEP Ohio Ex. 4 at 19; Tr. II at 432.)

iii. The Company will continue to work with Staff in the development of the DIR plans, including the consideration of general plant items.

The Commission previously approved the DIR with an expectation that the Company would work with Commission Staff to develop an appropriate DIR plan each year. The Company and the Commission Staff interacted throughout the year, and the planning sessions to develop the DIR plan were an important part of those ongoing efforts. The Company would expect to continue to develop the DIR plans and filings with the Commission Staff in the future. The Staff's support for the DIR program speaks to the benefits of the program and the good relationship between the Company and the Staff representatives that work on it. Staff witness Baker supported the application of R.C. 4928.143(B)(2)(h) as the statutory basis in his testimony (Staff Ex. 10 at 2-6), and Staff witness McCarter also supported continuation of the DIR mechanism, in general, with some modifications. (Staff Ex. 17 at 2.)

Staff witness McCarter expressed concerns with including general plant in the DIR, a recommendation on the gross up factor, and a property tax adjustment. (*Id.* at 3-5.) The inclusion of general plant, as discussed above, is intended to have a direct impact on customers and reliability. OCC witness Effron agreed that while not an operations man he agreed that the radio system is important in the restoration effort of the distribution system after a major storm. (Tr. XII at 2747.) Staff witness McCarter also made clear that the Staff position is not a complete prohibition on inclusion of general plan, just a careful review of what is included in the DIR. On cross-examination Staff witness McCarter was uncomfortable agreeing to the appropriateness of any general plant recovery in the DIR as a general matter, but did admit that certain parameters put in place may help resolve some of the items requested in general plant to be recovered in the DIR. (Tr. IX at 2294.) That conversation continued to discuss the fact that SMED (Service Monitoring and Enforcement Department), the Commission Staff responsible for developing the DIR plan with the Company, does have input and review of the DIR plan in a separate docket. (*Id.* at 2294-95.) Ultimately, Staff witness McCarter did agree that she may be able to include certain investments categorized as general plant, namely the radio system, in the DIR if they had been fully reviewed by Staff. (*Id.* at 2295.)

Ms. McCarter additionally raised the issue of the provision of data to assist in the processing of auditing the DIR mechanism. The Company has and will continue to work with Staff and any outside auditor to ensure any necessary data is provided to provide a transparent understanding of the DIR spending.

iv. The recommendation to adjust the gross up factor and property tax is without adequate record support.

Staff witness McCarter also discussed a concern with the gross up factor and the property tax adjustment. Specifically, Staff witness McCarter did not feel there was a need for an increase in the gross up factor because the PUCO and OCC budgets have not increased. (Staff Ex. 17 at 4.) It was shown during cross-examination, however, that there could be a shortfall in AEP Ohio's recovery relative to the increased assessment the Company would have to pay due to increased revenues associated with riders in the case. (Tr. IX. at 2301.) Ms. McCarter agreed that there could be a shortfall on recovery by the Company but "[n]ot enough to build it into every single dollar you take in on a one-for-one basis." (*Id.*) The fact remains that an adjustment to the gross up factor is appropriate considering the changes proposed in the Application in order to ensure that there is no shortfall.

A proposal was also raised by OCC witness Effron and supported by Staff witness McCarter, to adjust the property tax calculation in the DIR. Staff witness McCarter testified that the property tax component of the carrying cost rate should be reduced, which would reduce the overall carrying cost rate for the DIR. (*Id.* at 2302.) However, she admitted that she did not look deeper into OCC witness Effron's proposed adjustment beyond the one component he recommended for adjustment to see if something like the property tax rate had gone up since the carrying charge rate was set in 2011. (*Id.* at 2304-05.) And she admitted that in order to be accurate, one could perform a property tax calculation, which has not been done in relation to Mr. Effron's proposal. (*Id.* at 2305.) Upon further examination, she admitted that if the property tax rates have gone up since 2011 that it could mitigate the concern about this issue. (*Id.*) Cross-examination of OCC witness Effron also revealed that Mr. Effron did not look back into existing rates to make his determinations about Company plant and changes in policies. (Tr. XII at 2748-49, 2753.) The Commission should reject efforts by intervenors to raise a concept or change without reviewing the underlying data and failing to take into account all parts of an equation to make that change.

v. The DIR furthers state energy policy objectives.

Continuation of the DIR provides for continued deployment of emerging distribution system technologies where they can improve the efficiency and reliability of the distribution system and encourages the use of energy efficiency programs and alternative energy resources. (AEP Ohio Ex. 3 at 4-5.) Those policies that the DIR advances include R.C. 4928.02(A),(D), (E), (G), and (M). (*Id.*)

The Commission should find that the DIR as proposed satisfies the statutory requirements for approval under R.C. 4928.143(B)(2). The DIR provides carrying charges to maintain and meet future customer reliability expectations, and the Commission should approve it as proposed.

2. Continuation Of The Enhanced Service Reliability Rider Is Reasonable.

The Enhanced Service Reliability Rider (ESRR) should be approved as a reasonable incremental program to address a need to focus on vegetation management issues in the AEP Ohio territory. The Commission can approve such a program, as it has in the past, pursuant to R.C. 4928.143(B)(2)(h). The continuation of the ESRR promotes the state policy objectives set forth in R.C. 4928.02(A) and (E) by enhancing electric distribution service consistent with the value customers place on service reliability targets for service quality. (*Id*. at 5-6.)

The Commission first approved the ESRR, then known as the ESRP, in *ESP I.*[45] The ESRR is intended to ensure a proactive tree trimming program resulting in trimmed circuits end to end every four years. (Tr. I at 80-81.) The program provides storm hardening by reducing the risk of tree contact during storms, having a set cycle for trimming, and by removing danger trees.

[45] *ESP I*, Opinion and Order at 32-34 (Mar. 18, 2009).

(AEP Ohio Ex. 4 at 20.) As discussed by Company witness Dias, AEP Ohio has requested continuation of the ESRR in the form of the necessary incremental funding over the $24.2 million base for both the completion of the transition to a cycle-based vegetation management program in the amount of $16 million and maintenance of the program through an additional increase beginning in 2015. (*Id.* at 10.) Mr. Dias testified that recent estimates demonstrate that instead of the $18 million beginning in 2015 initially contemplated under the ESRR, approximately $25 million of O&M and $1 million in capital above the base will be needed to fund the on-going cycle-based program. (*Id.*) He testified that the recent estimate reflects the history of actual expenditures experienced since the start of the program in 2009. (*Id.*)

Commission Staff supports the continuation of the rider and need for ongoing funds to continue the end-to-end circuit trimming enabled by the program, but Staff supports continuation at the $18 million level – for now. (Staff Ex. 10 at 9-11.) Staff witness Baker is uncomfortable with the increased incremental amount associated with continuation of the program and prefers the $18 million approved in the last ESP proceeding. Mr. Baker does indicate that if the actual spend to achieve the purpose of trimming end-to end is greater than $18 million that the Staff would be willing to review those expenditures to determine whether they were prudently incurred. (Tr. V at 1350-53.) Mr. Baker's testimony did not calculate the $18 million he relies upon, it is merely an amount supplied by the Company in a previous case on older non-specific data.

The Company has an updated estimate based on the actual costs to trim vegetation in Ohio under the current program, and it decreased those costs by 30% based on the experience of an affiliated operating company that also moved to a four year trim cycle and experienced a 30% decrease in costs after moving from the catch-up period to the ongoing four year cycle. In the absence of Staff's own quantification and argument, the evidence in the record supports only one outcome – the $25 million estimate for planning and application to the ESRR at the end of each audit period.

Staff agreed that the underlying purpose of the ESRR is to ensure a proactive four year trim cycle and whatever prudent costs it takes to do a four year cycle should be recovered. (*Id.* at 1353, 1360.) The most up-to-date and accurate data says it will take $25 million, not $18 million. Therefore, to ensure that those prudent costs are planned for and spent prudently, the Commission should defer to the recently updated and Ohio-specific data and the experience of a particular AEP Ohio affiliate that recently went through a similar transition to get to a four year trim cycle, rather than rely on the older system-wide data relied upon in the last ESP proceeding. The evidence supports an increase to $25 million to ensure that the four year proactive cycle can be maintained. As shown on cross-examination, Staff has not done any independent quantification to determine what the proper amount of spending to maintain the four year trim cycle. (*Id.* at 1349-50.) Upon re-cross-examination, it was discovered that Staff preferred the *ESP II* estimate because it had more factors included in the estimate. (*Id.* at 1358.) But it also became apparent that when making the Staff recommendation on this point, that Staff was unaware that the 30% decrease that AEP Ohio included in its proposal based on the very similar experiences and transition experienced by an AEP Ohio affiliate in Oklahoma. (*Id.* at 1356; 1359.)

Again, Staff supports the Company recovering the proper amount it takes to prudently complete a four year trim cycle. (*Id.* at 1360.) Staff will have available to it the prudency review at the end of each year. Staff witness Baker already admitted on cross-examination that Staff has been able to ask adequate questions in the past to determine prudency in ESRR spending through the audit process. (*Id.* at 1352.) The only issue is the amount the Company should use to plan its operations. Company witness Dias testified that it would be difficult to design a trim cycle to achieve the result he knows is desired by Staff for $18 million, and that if the Commission only approves an $18 million budget in this case that the Company will have to scale back the program accordingly. (AEP Ohio Ex. 4 at 10.)

The evidence of record supports the $25 million budget, and the Company and Staff agree that there are safeguards in place to ensure that is spent appropriately. The Commission should approve the estimate of the only party to validate its estimate in this case (AEP Ohio at $25 million) and enable the Company to proactively prevent tree-related outages as initially approved by the Commission in AEP Ohio's initial ESP.

3. The Company's Proposed gridSMART® Phase 2 Rider Is Reasonable.

The Company proposes continuation of the gridSMART® rider approved in the *ESP I* Order as part of the Application in this case. Company witness Dias discussed wrapping up gridSMART® Phase 1 and the directives from the Commission in his pre-filed direct testimony. (AEP Ohio Ex. 4 at 10-11.) Mr. Dias also discussed that fact that the Company was ordered to file its proposed expansion of the gridSMART program (Phase 2) and did so in Commission Docket 13-1939-EL-RDR on September 13, 2013. (*Id.* at 11.)

The Company proposes to roll any remaining costs associated with Phase 1 into the DIR. As shown by Company witness Moore, the spending for Phase 1 ceased at the end of 2013. (AEP Ohio Ex. 13 at 7.) Those gridSMART Phase 1 regulatory assets are not currently in base rates and, to date, they have been excluded from the DIR. (*Id.*) The inclusion of these previously-considered assets in the DIR will dedicate the gridSMART Rider to recovery of gridSMART® Phase 2 costs after their approval. (AEP Ohio Ex. 4 at 11.) The gridSMART®

Phase 2 program, if approved by the Commission in the 13-1939 docket, would support storm hardening through use of new technologies and the communication infrastructure developed with redundancy and protection to ensure continued service during storm events. (*Id.* at 15.) The Company expects that the Commission will approve the recovery of gridSMART® Phase 2 costs prior to issuing an order in this proceeding. (*Id.* at 11.)

The Company previously filed for approval of the gridSMART® rider under a number of options for the Commission. R.C. 4905.31(E) creates a specific cost recovery mechanism opportunity for "acquisition and deployment of advanced metering, including the costs of any meters prematurely retired as a result of the advanced metering implementation." Further, in setting forth the energy policy for the State of Ohio, the General Assembly included new language to ensure that the Commission will encourage "implementation of advanced metering infrastructure."[46] And, in the specific context of an ESP, the General Assembly included a long-term energy delivery infrastructure modernization plan as a permissible item to be included in an ESP.[47] Continuation of the gridSMART® Phase 2 Rider provides for continued deployment of emerging distribution system technologies where they can cost-effectively improve the efficiency and reliability of the distribution system, develop performance standards and targets for service quality for all consumers, and encourage the use of energy efficiency programs and alternative energy resources. (AEP Ohio Ex. 3 at 4-5.) Those policies advanced by the Company's gridSMART® proposal include R.C. 4928.02(A),(D), (E), (G), and (M). The Commission should approve the continuation of the rider under its broad authority.

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[46] R.C. 4928.02(D).

[47] R.C. 4928.143(C)(2)(h).

In her testimony in this proceeding, Ohio Environmental Council (OEC) and Environmental Defense Fund (EDF) witness Roberto makes a number of substantive proposals regarding gridSMART® Phase 2. (OEC/EDF Ex. 1 at 3-8.) OEC/EDF has already presented those same proposals to the Commission in the 13-1939 docket, and the Commission is considering them there. (Tr. XII at 2801.) Because they relate to the Company's application in that docket and not the Company's requests regarding the gridSMART® Phase 2 Rider here, and because the Commission will properly consider them in that proceeding, AEP Ohio respectfully submits that the Commission should disregard Ms. Roberto's substantive proposals regarding gridSMART® Phase 2 for purposes of this proceeding.

Continuation of the gridSMART® rider is practical and reasonable. Movement of the costs associated with Phase 1 already considered by the Commission allows the rider to focus on any new potential gridSMART® costs once they are approved by the Commission and will ensure the costs of future programs are transparent for any future consideration of comparisons to benefits.

4. The Modified Storm Damage Recovery Mechanism And Rider Is Reasonable.

The Company proposes a continuation of the Storm Damage Recovery Mechanism and Rider (SDR) established in the *ESP II* proceeding with some modifications. The authority for this reliability rider is also found in R.C. 4928.143(B)(2)(h). The continuation SDR promotes the state policy objectives set forth in R.C. 4928.02(A) and (E) by ensuring that the Company is able to continue to perform and fund its normal responsibilities. (AEP Ohio Ex. 3 at 5-6.)

The determination of a major storm would continue to be defined by the IEEE Guide for Electric Power Distribution Reliability Indices as set forth in O.A.C. Rule 4901:1-10-10(B). (AEP Ohio Ex. 4 at 12.) However, the Company proposes to create an annual true-up, including a provision that establishes a carrying charge based on the Weighted Average Cost of Capital (WACC) for major storm costs exceeding the $5 million baseline if the major storm costs are deferred and remain unrecovered for longer than 12 months. (AEP Ohio Ex. 1 at 11; AEP Ohio Ex. 17 at 9-10.) The $5 million baseline was approved by the PUCO in the *ESP II* Order.[48] (*See* AEP Ohio Ex. 18 at 6; AEP Ohio Ex. 4 at 12.)

Staff witness Lipthratt recommends three modifications to the Company's SDR rider and mechanism proposal. Those modifications, however, are unfounded, and the Commission should not adopt them. First, Staff witness Lipthratt recommends that the SDR carrying charge use long-term debt as opposed to WACC. (Staff Ex. 12 at 3-4.) Second, he proposes a limitation on the labor recovery in major storm events to limit the amount of hours that qualify for major storm overtime and to deny any recovery for exempt or management employees over 40 hours. (*Id.* at 4-6.) Finally, he seeks to offset the recovery of major storm expenses through the rider by the asserted revenues received by AEP Ohio as a participant in the mutual assistance partnerships with other utilities. (*Id.* at 6-7.)

There is no justification for Staff's proposal to use long-term debt instead of the weighted average cost of capital for the SDR's carrying charge. Staff witness Lipthratt expressly admitted that he provides no justification for the use of long-term debt over WACC in his testimony. (Tr. VII at 1696.) When probing his understanding of his proposal, it was clear that Mr. Lipthratt did not understand the application of his recommendation. He admitted that he would not be surprised if a company used both debt and equity to finance a major storm restoration effort. (*Id.* at 1695.) He also admitted he did not understand the impact of using long-term debt on the Company's capital structure to avoid the same debt being used twice. (*Id.* at 1731.) Most tell

[48] *ESP II*, Opinion and Order at 68-69 (Aug. 8, 2012).

was that, when pressed on his understanding of the distinctions between the two types of carrying costs and why he recommended a long-term debt carrying cost, Mr. Lipthratt said there were other witnesses more knowledgeable about long-term debt and that he consulted and funneled the recommendation through them to make his recommendation. (*Id.*) When asked who specifically, he identified Staff witness McCarter and stated that he had conversations with her and that he was comfortable that she is in agreement with the position. (*Id.*) However, when questioned about her involvement in Mr. Lipthratt's carrying cost recommendation, Staff witness McCarter indicated that she had no input into the recommendation:

> Q. If you'll accept, subject to check, that in the transcript he [Mr. Lipthratt] indicated that his position that a long-term debt rate is appropriate for SDR deferrals and that that recommendation was funneled through you, he said you were in agreement with his position. Is that accurate or not?
>
> **A. I didn't have input into the rate that was going to be used in the storm.**

(Tr. IX at 2322-23.) Mr. Lipthratt's only defense of his recommendation is that he discussed the matter with Staff Witness McCarter, and she testified that she did not have any input. The Staff position on that issue thus is without record support and should be disregarded.

Conversely, AEP Ohio did propose and justify the use of WACC after twelve months without recovery of major storm expenses above the $5 million threshold. Company witness Hawkins testified to the appropriateness of using WACC for carrying charges on riders that collect charges that take longer than 12 months to recover. (AEP Ohio Ex. 17 at 9-10.) Likewise, Company witness Allen on rebuttal made clear that the Company's assets are financed with a combination of debt and equity and if the Company carries additional assets, a regulatory asset in this case, for a period of greater than one year it is appropriate that the carrying costs reflect the Company's WACC. (AEP Ohio Ex. 33 at 13-14.) As clarified by Company witness Allen, to assign a long-term debt rate to a regulatory asset fails to recognize that the debt component of the Company's capital structure has already been used to fund other investments. (*Id.* at 14.) In short, Staff witness Lipthratt's proposal failed to consider that it would effectively use the same dollar of debt to finance two investments simultaneously, which is a financial impossibility. (*Id.*) Mr. Allen testified that if the Commission were to adopt the Staff proposal, it would be necessary to remove the value of all regulatory assets that accrue a carrying cost based upon a long-term debt rate from the long-term debt component of the WACC, which would have the impact of increasing the WACC for all other investments. (*Id.*)

Mr. Lipthratt's recommendation on the types of recoverable expense suffers from similar flaws. Mr. Lipthratt testified that major storm responders should not be paid overtime until they have completed 40 hours of regular work and that exempt and management employees should never be paid more than the traditional 40 hour work week. (Staff Ex. 12 at 5-6.) Although his stated position would require union employees to work a full 40 hours of regular time before being paid overtime or major storm restoration compensation, Mr. Lipthratt admitted that he did not review any of the Company's union contracts to see how his sweeping policy recommendation will impact AEP Ohio and its current obligation. (Tr. VII at 1699.)

Mr. Lipthratt had information available to him to make an informed recommendation that he did not factor into his analysis. Company Witness Allen points out in his rebuttal testimony that Mr. Lipthratt had Staff's discovery (requested by Mr. Lipthratt) available to him. Indeed, Staff DR 6-008 (see Exhibit WAA-R7) discusses the incremental nature of labor and overtime and where to look for more information. It also discusses the unique accounting codes for major storms and the accounting of storms consistent with the Staff witness Hecker's approach in Case Nos. 11-346-EL-SSO and Company witness Mitchell's Exhibit TEM-2 in Case No. 12-3255-EL-RDR (the 2012 storm case upon which Staff witness Lipthratt relied exclusively in cross-examination). If this discovery requested by Staff had been figured into the analysis, then Mr. Lipthratt might have seen that his recommendation was contradicting the structure of the existing rates and prior Staff positions. All of the applicable incremental major storm O&M expenses including Company overtime are paid in accordance with its policies and contract labor are included in the monthly determination of the over/under deferral calculation compared to the $5 million major storm threshold. (AEP Ohio Ex. 33 at 11-12.) However, based on the record and testimony in this case, none of these factors were considered by Staff witness Lipthratt because he did not review AEP Ohio's contracts or policies in making his recommendation that the Commission simply start storm damage recovery for labor at the forty-first hour of every employee. (Tr. VII at 1699-1700.) Hence, the Staff recommendation contradicts the very analysis used by Staff in the creation of the $5 million threshold and the development of the base case.

There are distinct differences between performing major storm restoration and working a normal day's work and the compensation reflects those differences. As Company witness Allen showed, major storm restoration personnel work 16 hour days, sometimes in extreme conditions, to restore power as quickly and safely as possible. (AEP Ohio Ex. 33 at 11-12) Employees can be reassigned away from home to other parts of the state to assist in the effort and the Company labor contracts all recognize the heightened nature of major storm restoration response and adjust the overtime in a non-discretionary manner in reaction to the major storm. (*Id.*) Staff witness Lipthratt's recommendation fails to consider the harsh realities of major storm restoration. He admitted that this recommendation is more of an accounting exercise that counts a 16 hour day restoring power in extreme conditions the same as two normal 8 hour days. (Tr. VII at 1701.) When asked if he met with and vetted the impact of his accounting recommendation with the

Director of the Service Monitoring and Enforcement Department (SMED) of Staff he admitted that he did not consult with the SMED Director. (*Id.* at 1733-35.) He testified that he understood that SMED interacted with utilities during these major storms and that he recalls one conversation with Staff witness Pete Baker, but that all Staff could have reviewed his recommendation with the Attorney General's office before it was filed if desired. (*Id.*) But when asked if in preparing his recommendation on behalf of the entire Staff he called the SMED Director to see how his recommendation lined up with real world application he admitted that he did not do that. (*Id.* at 1735.) He did agree that the impact both emotionally and physically is different from a 16-hour restoration day versus going to the office for two consecutive days, but he made no adjustment for that in his accounting exercise/recommendation. (*Id.* at 1702.) Mr. Lipthratt's recommendation has no basis in any evidence of record, and he openly admits that it is an accounting recommendation. The Commission should not rely on the baseless recommendation that contradicts prior Staff recommendations and Commission findings.

Mr. Lipthratt's recommendation on exempt employee and management compensation similarly ignores storm restoration realities and recent Commission precedent. The Commission recently faced this exact issue in Case No. 12-3255-EL-RDR (*AEP Ohio 2012 Storm Case*). The hearing in that case involved the consideration of a settlement, but the one party that did not sign the stipulation made the same argument that Mr. Lipthratt now advances, and the Commission rejected the argument. The Commission discussed its prior denial of such compensation in a case involving another utility that had not applied its exempt overtime policy consistently.[49] The Commission in the *AEP Ohio 2012 Storm Case* found that AEP Ohio had established an internal policy of providing overtime compensation to exempt employees for major storm restoration

[49] *AEP Ohio 2012 Storm Case*, Opinion and Order at 25 (Apr. 2, 2014).

work and that policy had been followed in the 2012 storms.[50] The Commission noted that in contrast to Duke, AEP Ohio witness Dias had thoroughly explained the workings of the Company's major storm restoration policy, including the basis on which the overtime pay is determined and reasons supporting the decision to implement the policy.[51] The Commission determined that the payment of overtime compensation to exempt employees was not a matter of discretion. Mr. Lipthratt testified in this proceeding that he was not aware of any Commission precedent on this issue. (Tr. VII at 1704.) He also admitted that he did not review the AEP exempt overtime compensation policy for purposes of this case, and instead relied on Staff's position taken in the prior *AEP Ohio 2012 Storm Case* prior to hearing and settlement and that he relied upon his general recollections from that proceeding. (*Id.* at 1702; 1704.) Mr. Lipthratt's recommendation lacks any foundation in the record evidence or Commission precedent and should be rejected.

Mr. Lipthratt's analysis is inconsistent with his own testimony. Mr. Lipthratt agrees that if AEP does not use its exempt and management personnel in major storm restoration efforts that it can recover the cost it would spend on contractors to do those same jobs. (*Id.* at 1705-06). This undermines his recommendation. AEP Ohio can and should take steps to restore service as quickly and safely as possible and that includes utilizing exempt and management resources versus seeking outside resources when needed. If AEP is able to hire new contractors unfamiliar with its territory and operations and recover that expense, it should be reasonable to pay internal exempt and management employees to do that work, work that is not currently required of them

[50] *Id.*

[51] *Id.*

in their positions. AEP has a policy and applies it consistently to ensure it can focus on safe and efficient restoration by utilizing its available resources.

Mr. Lipthratt also failed to adequately review the prior Staff consideration of labor in the major storm expense baseline. Specifically, the labor and the establishment of the historical $5 million average approved by the Commission includes all Company personnel overtime (exempt and non-exempt). (AEP Ohio Ex. 33 at 13.) As Mr. Allen pointed out in rebuttal, if Staff now recommends in this proceeding, converting incurred Company paid overtime to straight time, it must recommend a comparable decrease in the $5 million threshold. (*Id.* at 13.)

Finally, Mr. Lipthratt recommends that the recovery of major storm expense through the SDR rider be offset by the revenues AEP Ohio receives through its participation in mutual assistance with other utilities. The nature of this recommendation shows that Mr. Lipthratt does not understand how the mutual assistance process works in Ohio and across the country. His testimony under cross-examination confirms this and exposes his lack of review of AEP Ohio's rates. First, Mr. Lipthratt testified that the revenues he is referring to in this regard include reimbursements for labor, equipment, and other resources provided to mutual assistance partners. (Tr. VII at 1706.) Again, he refers to his review of this issue and the basis of his recommendation as an accounting issue. (*Id.* at 1707.) He asserts that the reimbursement another utility gives AEP Ohio for the meals eaten by AEP Ohio's employees to get to other utilities in need (like to New Orleans during Hurricane Katrina or New Jersey during Superstorm Sandy) are expenses that may have been in base rates but he does not know. (*Id.* at 1708.) He stated that he tried to look through base rates, but he could not find the detail so he cannot say if it is in there or not. (*Id.* at 1709-10.) When asked about labor dealing with mutual assistance he said that there was no adjustment for mutual assistance labor. Mr. Lipthratt admitted that despite his role as an auditor for Staff that he cannot source the basis of his recommendation in rates. (*Id.* at 1712-14.)

Mr. Lipthratt's assumptions about AEP Ohio's rates are incorrect and again fail to recognize the information that the Company provided to Staff in discovery. Revenues and expenses associated with mutual assistance provided to other utilities are not included in rates or in the storm threshold baseline established by the Commission, as proposed by Staff in prior cases. (AEP Ohio Ex. 33 at 10-11.) In his rebuttal testimony, Mr. Allen provided the Staff data request from Mr. Lipthratt to which the Company responded in this case. That response provided Staff the information Mr. Lipthratt said he was unable to find in his review – and this information indicated that these mutual assistance expenses and revenues are included in Account 186. (See *Id.* at Exhibit WAA-R6.) Account 186 is not included in base rates. (*Id.*) Company witness Dias, who testified prior to Mr. Lipthratt, stated that the incidentals (lodging, food, fuel) are incremental real expenses that AEP Ohio incurs while employees are out providing assistance to other utilities, and their reimbursement is strictly for those costs the Company incurs. (Tr. II at 458.) The costs associated with providing mutual assistance to peer utilities are not included in base rates and as such it would be improper to credit the revenues that offset the cost of providing mutual assistance in the SDRR. (AEP Ohio Ex. 33 at 10-11.) Mr. Lipthratt alluded to the offering of mutual assistance as a commodity or for-profit business venture, rather than the industry courtesy the nation relies upon to avoid the carrying of staff and resources year round to be prepared for the worst of catastrophes.

The policy argument that Mr. Lipthratt claims to make does not hold up under review. He claims that Ohio customers are paying the salary in rates of the workers involved in mutual assistance in other territories. However, he admitted on cross-examination that AEP Ohio employees may have to stagger or delay the work they leave behind for a later time when responding to mutual assistance requests.[52] (Tr. VII at 1725.) That was confirmed by Company witness Dias, who testified that regardless of the response to mutual assistance, the work back in the AEP Ohio territory does not go away and that when those employees return home, they have to catch up on their work. (Tr. II at 458-60.) Therefore, Mr. Lipthratt's argument that AEP Ohio customers are paying for work left undone is false. Finally, and perhaps most importantly, Mr. Lipthratt fails to recognize the benefit received by AEP Ohio customers due to the Company participating in mutual assistance agreements. Mr. Lipthratt provided testimony that mutual assistance may not be beneficial from year to year from an accounting point of view. (Tr. VII at 1716.) While Ohio customers may not need to take advantage of mutual assistance every year, when the state does need help, it needs it immediately and in force. Mr. Lipthratt did eventually admit that mutual assistance is a very beneficial program to this state, to other states, and to customers in general. (*Id.* at 1717.) After some discussion, Mr. Lipthratt also agreed that customers are avoiding the increased cost from ramping up employment by their utility to be ready for the worst storms by participating in mutual assistance agreements. (*Id.* at 1727.) While Mr. Lipthratt on behalf of Staff may not want to state that participation in mutual assistance programs benefits customers, AEP Ohio is confident that the Commission understands the benefit. Mutual assistance is an important element of the utility industry and cannot be viewed solely as an accounting exercise. The Commission should reject the Mr. Lipthratt's attempt to relegate this important national responsibility to a ledger and should instead recognize the value received for Ohio and the responsibility of its utilities when called upon in times of major storms.

[52] This same analysis applies to the 40 hour work week argument and shows that the non-major storm typical work is still waiting when the emergency response and restoration efforts are completed.

As Company witness Dias demonstrated, absent the SDR mechanism, forecasted O&M funds would be constantly diverted to cover the expense of major storms, which could disrupt planned maintenance activities and impact system reliability. (AEP Ohio Ex. 4 at 12.) The Commission should approve the SDR as proposed by the Company and decline to adopt the undeveloped and unsubstantiated modifications proposed by Mr. Lipthratt.

5. The Proposed Sustained And Skilled Workforce Rider Is Reasonable.

The Sustained and Skilled Workforce Rider (SSWR) is a new rider that the Company proposed to support the comprehensive strategy for long-term improved reliability. (AEP Ohio Ex. 4 at 22.) The authority for this reliability rider is found in R.C. 4928.143(B)(2)(h) as a means to ensure that distribution infrastructure. The purpose of the SSWR is to provide a mechanism to recover the incremental O&M labor cost to address the projected shortfall of internal labor resources, both in front-line construction and construction support, required to execute infrastructure investment. (*Id.*) Company witness Dias explained the two specific issues the Company needs to address to improve reliability related to the labor workforce. Mr. Dias stated that the first issue is the addition of labor resources to support future work requirements, and the second is the need to achieve an optimal balance of workforce labor resources, including internal employees and contractors. (*Id.*) Mr. Dias supported the Company's concerns by showing how additional labor will be required to meet the Company's infrastructure plans, but that it takes 5 years to train an employee adequately through the different levels of experience needed and deserved by Ohio customers. (*Id.* at 23.)

Mr. Dias testified that this integration of new skilled workforce is an important part of the Company's long-term reliability strategy, with labor being one of the multiple coordinated activities. (*Id.*) The proposal is to increase the current full time equivalent by 150 employees over a three year period (50 FTEs each of the next three years). (*Id.* at 26.) The incremental additions over three years will allow for a structured and systematic hiring process, allowing for a smooth transition as the different employees moved toward the needed five year journeyman skill level. (*Id.* at 25-26.) Only the O&M costs associated with the 50 employees yearly will be collected through the SSWR. (*Id.* at 26.) Any work done attributable to capital recovery will be allocated elsewhere and not recovered independently through the SSWR. (*Id.*)

Staff's only opposition to the concept addressed by the SSWR was the use of a rider as opposed to a base rate case. (Staff Ex. 8 at 4.) Staff appeared to understand the need to train the skilled labor required to work safely on the distribution system. (*Id.*) The Staff's only concern appeared to be timing and the use of a base rate case. As discussed elsewhere in this brief, the existence of a base rate case does not eliminate the option of recovering costs needed for operations in an electric security plan. Although the Company has the ability to recover such costs in a base rate case, the General Assembly has also provided it the ability to recover such important costs to ensure safe and efficient operations for years to come through an ESP. With Staff's primary concern being the use of a rider versus a base rate case and because it did not raise any concerns with the underlying idea of the cost recovery itself, the Commission should approve the SSWR as proposed and allow the benefits of timely training of the skilled workforce to begin as soon as possible.

6. The North American Electric Reliability Corporation Compliance And Cybersecurity Rider Placeholder Is Reasonable.

The Commission also should approve the Company's proposed NERC Compliance and Cybersecurity Rider (NCCR), which would serve as a placeholder for significant future increases in AEP Ohio's cost of complying with the North American Electric Reliability Corporation's compliance and cybersecurity requirements. (AEP Ohio Ex. 1 at 11.) The Company intends to track and defer both the capital and O&M costs associated with new requirements or new interpretations of existing requirements, with a carrying cost, starting on the date of the decision in this case and going forward through the entire term of the proposed ESP. (AEP Ohio Ex. 1 at 11; AEP Ohio Ex. 2 at 16.) The NERC capital- related costs to be deferred would be calculated using Company witness Hawkins' investment levelized carrying charge rates (AEP Ohio Ex. 17 at Exhibit RVH-4.) The Company would then file a rider application during the ESP III term to recover those costs, but initially, and until the Commission approved the recovery of the costs, the NCCR would be a placeholder rider established at a level of zero. (AEP Ohio Ex. 1 at 11-12; AEP Ohio Ex. 2 at 16.)

The approval of a placeholder rider through which the Company can seek to recover its future NERC compliance costs is necessary and prudent in light of the recent increase in federal and state interest and emphasis on cybersecurity. As Company witness Vegas testified, all bulk power system owners, operators, and users have been required since 2007 to comply with NERC's reliability standards, which FERC-approved Regional Entities implement an d enforce. (AEP Ohio Ex. 2 at 13-14.) Cybersecurity encompasses not only equipment and systems that communicate, store, and act on data, but also the protection and security of physical distribution and transmission grids, substations, and offices, both utility-owned and customer or third-party component that interact with the grid. (*Id.* at 14.) Finally, there are human elements to cybersecurity, including system operators, customers, and criminals interacting at all levels of a system. (*Id.*)

The dynamic and broad cybersecurity landscape is continuously evolving and merits dedicated attention and constant vigilance to protect customers and our energy infrastructure.

(*Id.*) As an example, AEP Ohio complied with 67 NERC reliability standards in 2007, the year they were first implemented. (*Id.* at 15.) Since then, AEP Ohio has complied with 73 additional new or revised versions of the standards. (*Id.*) The moving target with which the Company must comply is expected to change and expand further, requiring a significant effort to remain in compliance. (*Id.*) As Mr. Vegas explained, these issues are of national importance and have been the subject of recent PJM conferences, comments by the U.S. Legislature and President Obama, and proposed federal cybersecurity legislation. (*Id.* at 15-16.)

Mr. Vegas also explained that the NCCR is necessary in order for the Company to recover compliance costs for cybersecurity in this rapidly-evolving area in future years. (*Id.* at 17.) Importantly, the approval of the NCCR would enable the Company to address effectively these emerging cybersecurity issues, in furtherance of the state policy articulated in R.C. 4928.02(E). (AEP Ohio Ex. 3 at 8.) Those costs that the Company would seek to recover through the rider in the future include capital-related costs and O&M compliance costs associated with items like information technology infrastructure, physical security, workforce training, supervisory control and data acquisition (SCADA) systems, smart grid security systems, internal and external audits, external reporting, and recordkeeping that are not recovered through other regulatory mechanisms. (AEP Ohio Ex. 2 at 17.) The Company would ensure that only NERC-related capital costs not recovered through other regulatory mechanisms would be included in future rider applications. (*Id.*)

Perhaps because they recognize the importance of cybersecurity and the NCCR's furtherance of state policy objectives, no intervenor in these proceedings offered testimony opposing the Company's proposed NCCR. Staff witness Pearce, however, testified that implementation of the rider is "premature" because the Company has not yet identified specific expected costs that it would seek to recover through the rider. (Staff Ex. 11 at 4-5.) But Mr. Pearce agreed on cross-examination that Staff would not be opposed to AEP Ohio's recovery of NERC compliance costs. (Tr. VI at 1424.) He also agreed that NERC compliance and cybersecurity is "very important" and that Staff does not want to pursue recommendations that would discourage prudent investment in cybersecurity and NERC compliance. (*Id.* at 1424-25) Importantly, Mr. Pearce also conceded that the Commission has approved zero dollar placeholder riders in electric security plans in the past. (*Id.* at 1431.)

By his own concession, therefore, Mr. Pearce's recommendation against the NCCR as being premature is not supported by Commission precedent, including most recently for AEP Ohio, the Commission's approval of the zero dollar placeholder generation resource rider (GRR) in *ESP II*.[53] Mr. Pearce's present recommendation also is at odds with Staff's support for the GRR in *ESP II*.[54] For each of these reasons, the Commission should overrule Mr. Pearce's position on this issue.

The Company is proposing the NCCR merely as a zero-cost placeholder rider at this time. Any costs sought to be recovered through the rider would be fully reviewed in a future docket or dockets. The Commission has repeatedly recognized that it has discretion over its dockets to approve the placeholder at zero dollars and order a later process to determine the eligibility for the rider to be populated – and it has done so in other SSO proceedings, including *ESP I* and *ESP II*. Accordingly, the NCCR is reasonable and should be approved as proposed.

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[53] *ESP II*, Opinion and Order at 24-25 (Aug. 8, 2012) (citing other placeholder riders approved in *ESP I* and prior ESPs filed by Duke and FirstEnergy).

[54] (*SEE ESP II*, Staff Ex. 110 at 7 (Staff witness Fortney recognizing the state policy goals achieved through approval of the placeholder rider).)

7. Continuation Of The Pilot Throughput Balancing Adjustment Rider And Residential Distribution Credit Riders Is Reasonable.

The Company also is requesting approval to continue its Pilot Throughput Balancing Adjustment Rider (PTBAR), a revenue decoupling mechanism, and Residential Distribution Credit Rider (RDCR). The Commission initially approved both riders in its December 14, 2011 Opinion and Order in Case Nos. 11-351-EL-AIR, *et al.* (AEP Ohio Ex. 1 at 12.)

The Company proposes to continue the PTBAR revenue decoupling pilot program for residential and GS-1 tariff schedules, as currently implemented, throughout the ESP III term. (*Id.*; AEP Ohio Ex. 3 at 10; AEP Ohio Ex. 13 at 4.) The rider is intended to compensate AEP Ohio for the loss of load associated with energy efficiency and peak demand reduction programs. (Tr. I at 230.) Weather (*id.* at 42-43) and the economy also cause changes in load. The Commission previously authorized the extension of the rider in Case Nos. 11-351-EL-AIR, *et al.* until otherwise ordered. (AEP Ohio Ex. 3 at 10.) Both the Company and the Commission are happy with the pilot program as currently implemented. (Tr. I at 230-31.)

No party appears to substantively oppose the Company's proposal to continue the rider, but OCC witness Williams objected to its extension in this proceeding rather than with extension of AEP Ohio's EE/PDR plan. (OCC Ex. 11 at 37.) Mr. Williams seeks merely to elevate form over substance. It is within the Commission's discretion to approve the rider's continuation in this proceeding, and the Commission should do so. No other party appears to oppose the Company's proposal to continue the RDCR for all residential tariff schedules, as currently implemented, through ESP III's term. (AEP Ohio Ex. 1 at 12; AEP Ohio Ex. 13 at4.) As such, the Commission should approve it as well.

8. The Company's Proposed Weighted Average Cost Of Capital And Capital Carrying Cost Rates Are Reasonable And Should Be Approved.

As part of its proposed ESP the Company requests that a WACC be used for certain capital investments associated with several distribution riders. The WACC is used as a component of the overall capital carrying cost rates for riders designed to recover capital investments. It is also proposed to be used with riders that recover expenses that are deferred for periods longer than a year. Riders for which the WACC is used as a component of a capital carrying cost rate include the DIR, the capital components of the gridSMART® Rider, the capital component of the ESSR (also sometimes referred to as the Vegetation Management Rider), and any capital component of the NCCR. Riders for which the WACC would be used to recover the cost of carrying expenses deferred for periods longer than a year would include the SDR and the NCCR.

As explained in more detail below, the WACC is based upon the Company's cost of equity and cost of long-term debt, each weighted according to the Company's target capital structure. Company witness Hawkins sponsored and supported the WACC, including the target capital structure used and the long-term cost of debt. (AEP Ohio Ex. 17 at 4-12, Exhibits RVH-1 and RVH-3.) Ms. Hawkins utilized the cost of equity developed by Company witness Avera. (*Id.* at 8-9.)

The proposed capital carrying cost rates are comprised of the WACC, a depreciation component, an income tax component, and an administrative and general cost component. Ms. Hawkins also sponsored and supported the Company's proposed capital carrying cost rates. (*Id.* at 12-13 and Exhibit RVH-4.)

a. Capital structure

Ms. Hawkins explained that the Company proposes to use the expected capital structure and cost of capital for the wires business as of May 31, 2015, for the ESP III. (*Id.*) She further explained that AEP Ohio's capital structure was determined based upon the liabilities and assets post-corporate separation and based upon an evaluation of the capital structure necessary to maintain a strong investment grade credit rating. (*Id.* at 6.) Based upon the expected size and scope of a wires-only company, the targeted capital structure that she recommends using for AEP Ohio as of May 31, 2015 is 52.5% long-term debt and 47.5% equity. (*Id.* at 8.)

b. WACC

In Exhibit RVH-1 to her direct testimony, Ms. Hawkins computes the total WACC for AEP Ohio. The calculated embedded cost of long-term debt, based on the remaining debt outstanding post corporate separation and as of May 31, 2015 is 6.05%. (AEP Ohio Ex. 17 at 7-8, Exhibit RVH-1.) The cost of equity that Ms. Hawkins used is 10.65%, based upon the estimate that Dr. Avera developed. (*Id.*) When weighting the outstanding balances of debt and equity as of May 31, 2015, and using those long-term debt and equity cost rates, the resulting pre-tax weighted cost of capital is 10.86% and the after-tax weighted cost of capital is 8.23%.

c. Cost of equity

Dr. William E. Avera sponsored the Company's return on equity (ROE) recommendation for use in connection with the WACC and capital carrying cost rates. Dr. Avera explained that the ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. (AEP Ohio Ex. 19 at 4.) Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. (*Id.*) To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[55] and *Hope*[56] cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate investors for capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity. (*Id.*).

Dr. Avera reviewed current conditions in the capital markets and their implications in evaluating a fair ROE for AEP Ohio. (*Id.* at 5.) Against that background, he conducted well-accepted quantitative analyses to estimate the current cost of equity for a reference group of comparable-risk electric utilities. (*Id.*) These analysis included the discounted cash flow (DCF) model, the empirical form of the Capital Asset Pricing Model (ECAPM), and an equity risk premium approach based on allowed ROEs for electric utilities (*Id.*) Based on the cost of equity estimates indicated by those analyses, Dr. Avera evaluated a fair ROE for AEP Ohio's electric utility operations taking into account the specific risks for its jurisdictional utility operations in Ohio, AEP Ohio's requirements for financial strength that provides benefits to customers, as well as flotation costs, all of which are properly considered in setting a fair rate of return on equity. (*Id.*)

Dr. Avera tested his recommended ROE for AEP Ohio's electric utility operations based on the results of alternative ROE benchmarks for his proxy group, including applications of the traditional Capital Asset Pricing Model (CAPM) and by reference to expected rates of return. (*Id.*) Further, he corroborated his utility quantitative analyses by applying the DCF model to a group of extremely low risk non-utility firms. (*Id.*)

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[55] *Bluefield Water Works and Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

[56] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

In presenting his recommendation, Dr. Avera cautioned that regulatory signals are a major driver of investors' risk assessment for utilities. He noted that security analysts study commission orders and regulatory policy statements in order to advise investors where to put their money. If the Commission's actions instill confidence that the regulatory environment is supportive, investors make capital available to Ohio's utilities on more reasonable terms. (*Id.* at 6.) When investors are confident that a utility has reasonable and balanced regulation, they will make funds available even in times of turmoil in the financial markets. (*Id.*) The bottom line is that, when AEP Ohio negotiates with investors and vendors from a position of financial strength, it can get a better deal for its customers. (*Id.*) Dr. Avera noted that the ROE determined in this case will be a signal to investors, and especially to credit rating agencies, such as Moody's, which recently declined to upgrade AEP Ohio's current bond rating because they are waiting to see what the results of this proceeding will be. (Tr. V at 1291-92.)

The cost of common equity estimates produced by the DCF, ECAPM, and risk premium analyses that Dr. Avera conducted are presented on page 1 of Exhibit WEA-2. Based on these analyses, he recommended an ROE, including an allowance for flotation costs, of 10.65% for AEP Ohio's electric utility operations. (AEP Ohio Ex. 19 at 6.)

The bases for his conclusion are as follows: First, in order to reflect the risks and prospects associated with AEP Ohio's jurisdictional utility operations, Dr. Avera's analyses focused on a proxy group of twenty-one other utilities with comparable investment risks. (*Id.* at 13-18.)

Next, Dr. Avera conducted DCF, ECAPM, and equity risk premium analyses for the proxy group. Based on Dr. Avera's evaluation of the strengths and weaknesses of those methods, he concluded that the cost of equity for the proxy group of utilities is in the 9.5% to

11.0% range. (AEP Ohio Ex. 7, Exhibit WEA-2 at 1.) In evaluating the results of the DCF model, he considered the relative merits of the alternative growth rates, giving little weight to the internal "br+sv" growth measures. (*Id.* at 22-36, and 36; Table WEA-3 as revised at Tr. V at 1241-43).) He concluded that the forward-looking ECAPM estimates suggest an ROE in the range of 10.6% to 11.6% (*Id.* at 36-40); and the utility risk premium approach implies an ROE estimate on the order of 10.4% to 11.3% (*Id.* at 40-43).

Based on his evaluation of the results of those analyses, Dr. Avera recommended a "bare bones cost of equity," that is, the cost of equity before flotation costs, for AEP Ohio of 10.53%, which falls within the upper zone of his recommended range of 9.5% to 11.0%. (AEP Ohio Ex. 19 at 56.) He explained that an ROE from above the midpoint of the range is supported by the fact that current bond yields are anomalously low, and result in DCF values that are understated. (*Id.* at 7.) Dr. Avera also explained that widespread expectations for higher interest rates going forward (particularly by 2015-2018, when the rated established through this proceeding will be in effect (Tr. V at 1302-03)) emphasize the appropriateness of considering the impact of projected bond yields in evaluating the results of the ECAPM and risk premium methods. He emphasized that, apart from the expected upward trend in capital costs, a cost of equity of 10.53% is consistent with the need to support financial integrity and fund capital investment even under adverse circumstances. (AEP Ohio Ex. 19 at 7.) Dr. Avera also included a flotation cost adjustment of 12 basis points to his 10.53% cost of equity resulting in his final recommendation of an ROE of 10.65%. (*Id.* at 6-7, 43-46.)

The results of alternative ROE benchmarks that Dr. Avera used to test and corroborate his recommended ROE, which are presented on page 2 of Exhibit WEA-2, support the reasonableness of his "bare bones" ROE recommendation of 10.53% for AEP Ohio.

Specifically, Dr. Avera's alternative benchmarks tests showed that the traditional CAPM approach suggests a current cost of equity on the order of 9.7% to 11.0%; expected returns for electric utilities suggested an ROE range of 9.6% to 10.5% (excluding any adjustment for flotation costs); and DCF estimates for an extremely low-risk group of non-utility firms suggest an ROE range of 11.6% to 12.8%. (*Id.* at 56.)

These confirmatory tests confirm that Dr. Avera's cost of equity recommendation of 10.65% falls in the reasonable range necessary to maintain AEP Ohio's financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital. (*Id.* at 7.)

i. Wal-Mart's criticisms are unfounded.

Wal-Mart witness Chriss asserts that in setting the Company's ROE the Commission should consider the impact of resulting rates on customers, alleged reduced risk from regulatory lag through the DIR, and ROEs approved by other state regulatory Commissions in 2012, 2013, and thus far in 2014. (Wal-Mart Ex. 1 at 7-10.) Mr. Chriss did not, however, recommend a specific ROE. (Tr. V at 1380.) With regard to the impact the proposed ESP will have on customers' total bills, Company witness Roush showed that, in most cases, customers' total bills, including SSO generation service, will actually be declining. (AEP Ohio Ex. 12 at 6-7.) With regard to the impact of the ROE alone, Dr. Avera concurred that, compared to the very low ROE recommendation by OCC (the only other party to recommend an alternative, the incremental cost of the Company's ROE proposal would be relatively small. (Tr. V at 1291-96.) Accordingly, the incremental cost of the Company's proposed ROE compared to OCC's proposal is not large. However, he warned that, on the other hand, authorizing a very low ROE would adversely affect investors' perceptions of Ohio's regulatory environment. (*Id.* at 1295-96.) With regard to alleged reduced risk from regulatory lag that the DIR provides, Dr. Avera explained that riders, such as the DIR, are commonplace and so do not distinguish AEP Ohio's risk level. (*Id.* at 1299.) While riders might reduce risk from regulatory lag, they do not eliminate disallowance risk (*id.* at 1298) and, in any event, the impact on the risk faced by AEP Ohio as a result of the DIR is factored by investors into their perceptions regarding AEP Ohio's cost of equity and, thus, is incorporated into Dr. Avera's ROE estimates. (*Id.* at 1299-1300.) With regard to Mr. Chriss's recommendation that the Commission look at other ROEs authorized by state commissions, the Company would note that, in that vein, the most relevant historical ROE values would be those authorized for AEP Ohio by the Commission. The most recent authorized ROEs include in addition to the 10.0% (for Columbus Southern Power Company) and 10.3% (for Ohio Power Company) (10.2% on a combined basis), ROEs that the Commission authorized in the Company's last distribution rate case,[57] the 11.15% ROE authorized by its even more recent decision in the Company's capacity pricing proceeding.[58] The 10.65% ROE that Dr. Avera recommends is squarely within that range recently established by this Commission for this Company – 0.55% above the 10.2% level and 0.50% below the 11.15% level. Moreover, the fact that the ROE established in this case will be used for rates that do not go into effect until June 2015, when interest rates and costs of equity are likely to be higher further supports Dr. Avera's recommendation. (*See* AEP Ohio Ex. 19 at 7.)

ii OCC's recommendations should be rejected.

OCC witness Woolridge recommends a 9.0% ROE for the Company. (OCC Ex. 12 at 2 and Att. JRW-1; as revised by OCC Ex. 12A.) Where Dr. Woolridge disagrees with Dr. Avera's

[57] Case Nos. 11-351 and 11-352-EL-AIR, Opinion and Order at 5 (December 14, 2011).

[58] Case No. 10-2929-EL-UNC, Opinion and Order at 34 (July 2, 2012).

approach, and what leads Dr. Woolridge to such an inordinately low ROE result, include his criticisms of: Dr. Avera excluding DCF cost of equity results for members of his electric utility proxy group that are implausibly low; Dr. Avera's reliance in his DCF analysis of earnings per share (EPS) growth rates published by investor analysts and Value Line; the equity risk premium that Dr. Avera uses in his electric utility risk premium method; the bond yield that Dr. Avera used in his (empirical) capital asset pricing model; and the adjustment for flotation costs Dr. Avera recommends. (OCC Ex. 12 at 6-7.)

With regard to excluding inordinately low ROE results from the DCF analysis, Dr. Avera followed the procedure that FERC prescribes.[59] Moreover, it would be illogical to include DCF results in the analysis that are essentially at or below long-term corporate bond rates. (AEP Ohio Ex. 19 at 35; Tr. V at 1266-68.)

With respect to EPS growth rates published by investor analysis and Value Line, Dr. Avera explained that the goal of the exercise is to estimate investor; growth rate expectations, and analyst and Value Line estimates of EPS growth rates proved the best source of that information. (AEP Ohio Ex. 19 at 26.)

With regard to the equity risk premium that Dr. Avera used, his computation was straightforward. He based his estimates on surveys of previously authorized ROEs, which provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities. (*Id.* at 40-43.) A principle input to Dr. Avera's CAPM analysis is the expected growth rate for earnings. Dr. Woolridge's criticism here is that the expected growth rate for earnings that Dr. Avera has utilized, which is based on what investors believe will occur,

[59] There is a high-end test that FERC also uses, but none of the DCF values for the proxy group members crossed that threshold. (Tr. V at 1268.)

is higher than the rate at which economic forecasts suggest the economy will grow. Dr. Avera explained that the point of the analysis is not to determine forecasts of the growth of the overall economy, *i.e.*, Gross Domestic Product. Rather, the goal of the analysis is to determine what investors believe the growth rate of earnings will be and, ultimately then, what investors require in the way of return on equity. (Tr. V at 1270-74.) Dr. Avera supported a very conventional and conservative method for estimating flotation costs, and his recommendation on that component of the ROE should be adopted also. (AEP Ohio Ex. 19 at 43-46.)

d. Capital carrying cost rates

Ms. Hawkins explained that capital carrying costs are the annual costs associated with the investment in capital projects. Investors require both a return of and a return on their capital expenditures. (AEP Ohio Ex. 17 at 12.) Capital investments or expenditures are recovered over the life of the related asset. (*Id.*) The capital carrying cost is determined by applying an annual carrying cost rate to the total amount spent on a capital project or projects. (*Id.*) Ms. Hawkins observed that the capital carrying cost rate includes the cost of money, or WACC, described above, a depreciation component, an income tax component, a property and other taxes component, and an administrative and general cost component, but it does not include direct operations and maintenance expenses. (*Id.*) Also, Ms. Hawkins explained, because of the depreciation component, the overall capital carrying cost rate varies inversely based on the expected life of the project. (*Id.*) Specifically, the rate is higher when the life of the project is shorter. (*Id.*) Consequently, the Company will apply the appropriate annual levelized capital carrying cost rate to an investment based on its projected service life. (*Id.*) The Company's expected levelized capital carrying cost rates as of May 31, 2015, are provide at Exhibit RVH-4 to Ms. Hawkins testimony.

e. A long-term debt rate is not an appropriate cost of capital rate for use in recovering the costs of regulatory assets deferred for periods longer than a year.

AEP Ohio requests that a WACC carrying cost be earned on riders, such as the SDRR and NCCR, that may have deferrals longer than a year. (AEP Ohio Ex. 17 at 9.) Company witness Hawkins explained that the Company incurs capital costs when it finances its business, which it does using a combination of debt and equity in a manner consistent with its credit ratings and in order to maintain its financial integrity. (*Id.* at 10.) As such, rate recovery that occurs more than a year after an expense is incurred should account for the fact that the expense has been financed with both debt and equity, and a WACC carrying charge should apply until recovery is complete. (*Id.*)

Ms. Hawkins explained that a WACC return is appropriate for those expenses whose recovery has been deferred for longer than a year and thus are booked as a regulatory assets. (*Id.* at 11.) A WACC return is appropriate for such expenses and consistent with the Company's capital structure because those expenses become long term assets on the Company's books when they are booked as a regulatory asset. (*Id.*) She further explained that the WACC rate is appropriate for regulatory assets both during the period of deferral and during recovery because recovery does not change the Company's cost "and expectation of reasonable recovery during the entire period that there is an asset balance, even though the balance is declining through the period of recovery." (*Id.*)

The Commission should not apply a long-term debt rate to AEP Ohio's recovery of regulatory assets deferred for longer than a year. Assigning a long-term debt rate to such recovery does not allow the Company to recover all of its capital costs. (*Id.* at 10.) Although the Commission applied a long-term debt rate in *ESP II* due to the lingering recession, Commission precedent, and the reduction in the risk of non-collection once collection of a regulatory asset begins, that approach should not continue in this case. The United States Supreme Court has repeatedly recognizes that a utility's revenues must recover both operating expenses and capital costs. In *FERC v. Hope Natural Gas Co*., the Court stated:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock.[60]

Similarly, the Court recognized in *Bluefield Waterworks Improvement Co. v. Pub. Serv. Comm'n of W.Va.* that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public . . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[61]

The Commission should recognize and follow the Supreme Court's instructions on this issue, and should authorize the Company to recover all of its capital costs by applying a WACC rate of return on regulatory assets established as a result of the rate mechanisms implemented.

Further, as discussed with respect to Staff witness Lipthratt's proposals regarding the SDRR (*see* Section III.B.4, *supra*), Company witness Allen explained that using a long-term debt rate to calculate carrying costs on regulatory assets is inappropriate because it "fails to recognize that the debt component of the Company's capital structure has already been used to fund other investments." (*Id.*) Thus, all regulatory assets that accrue a carrying cost limited to the long-term debt rate must be excluded from the long-term debt component of the WACC. (*Id.*) Otherwise, the same debt would be used to finance multiple assets which is inconsistent

[60] 320 U.S. 591, 603 (1944).

[61] 262 U.S. 679, 692-93 (1923).

with how the Company finances its operations. (*Id.*, *see also* AEP Ohio Ex. 17 at 11.) Moreover, the correct treatment of the long-term debt component of the WACC if only long-term debt is used to finance regulatory asserts would have the impact of increasing the equity component of the WACC, and thus the overall WACC rate, for all other investments. (AEP Ohio Ex. 33 at 14.)

For each of these reasons, the Commission should order that a WACC carrying cost, not a long-term debt carrying cost, applies to both the Company's riders that have a capital expenditure component and those booked as a regulatory assets.

C. The Proposed Basic Transmission Cost Rider Is Reasonable.

AEP Ohio proposes to establish a new, nonbypassable Basic Transmission Cost Rider (BTCR) to recover non-market based transmission charges from all customers. (AEP Ohio Ex. 1 at 12.) As Company witness Vegas explained, AEP Ohio currently recovers all of its PJM-assessed transmission costs for SSO customers through the previously-approved bypassable Transmission Cost Recovery Rider, while CRES providers currently include their PJM-assessed transmission costs in their rates to Shopping customers. (AEP Ohio Ex. 2 at 10.) Under the proposed BTCR, AEP Ohio would recover non-market based transmission charges from all customers, while market based transmission charges would be included in the auction product offering for SSO customers and continue to be assessed by CRES providers for shopping customers. (*Id.* at 11.)

The purpose of AEP Ohio's transmission cost recovery proposal is to ensure that all customers only pay the actual costs of non-market based transmission expenses. (*Id.*) The proposed change has the additional benefits of aligning the Company's transmission cost recovery mechanism with other Ohio electric distribution utilities, which provides clarity for customers about non-market based transmission charges, and enabling CRES providers and SSO suppliers to operate throughout the state using similar price rate offerings. (*Id.* at 11-12; *see also* FES Ex. 1 at 3 (noting that AEP Ohio's proposal "allows for greater consistency across the state").) Company witness Spitznogle also explained that the BTCR enhances the transparency of AEP Ohio's SSO pricing and gives consumers greater knowledge about their electric charges, enabling them to make informed decisions about their service and supplier and ensure that they are receiving reasonably priced service. (AEP Ohio Ex. 3 at 3-4.) It thus advances the state policy directives set forth in R.C. 4928.02(A), (B), (H), and (I). (*Id.*)

Annual filings for the BTCR will comply with the requirements set forth in O.A.C. Chapter 4901:1-36. (AEP Ohio Ex. 1 at 13.) The BTCR's mechanics will operate the same as the current TCRR as it relates to basic transmission costs. (AEP Ohio Ex. 13 at 8.) The basic transmission costs proposed for recovery through the BTCR include Network Integration Transmission Service (NITS), Transmission Enhancement charges, Reactive Supply and Voltage Control, Transmission Owner Scheduling, System Control, and Dispatch Service and Point-to-Point Revenues. (AEP Ohio Ex. 13 at 8, Ex. AEM-3.)

Exelon and RESA witness Campbell agrees with AEP Ohio's proposal to bill non-market based transmission charges through the BTCR, expressly agreeing that the proposal advances the state energy policy objectives set forth in R.C. 4928.02. (Exelon Ex. 1 at 28-30; RESA Ex. 1 at 4-7.) Both he and FES witness D'Alessandris also propose that PJM Invoice Item No.1930 be included in the BTCR. (Exelon Ex. 1 at 30-31; RESA Ex. 1 at 6-8; FES Ex. 1 at 3-4.) AEP Ohio agrees that inclusion of PJM Invoice Item No. 1930 in the BTCR is appropriate.

IEU witness Murray contends that AEP Ohio's proposed changes to its transmission cost recovery mechanism could disrupt contractual relationships between shopping customers on term contracts and their CRES providers and cause customers to pay twice for transmission-related services. (IEU Ex. 1B at 29-33.) Mr. Murray conceded on cross-examination, however, that most CRES contracts "have . . . a regulatory out clause in them," particularly those between CRES providers and industrial customers. (Tr. VI at 1518-19.) Moreover, it was established on cross-examination that the pool of customers that would face the issue that is the subject of Mr. Murray's concern is limited. (*Id.* at 1518-28.) CRES providers and the affected customers have a reasonable amount of time to make contractual adjustments for this transition, since the Application was filed last year and the BTCR will not become effective until June 2015. Finally, Mr. Murray conceded that there are other ways that the Commission could address his concern besides simply rejecting the BTCR. (*Id.* at 1529.)

The Company's BTCR proposal is reasonable, fair, comports with state energy policy goals, and brings AEP Ohio's transmission cost recovery mechanism into line with other EDUs. The Commission should approve it.

D. The Proposed Purchase Of Receivables Program And Bad Debt Rider Mechanism Are Reasonable And Should Be Approved As Proposed.

In response to the Commission's suggestion in the *ESP II* Order, AEP Ohio considered a purchase of receivables (POR) program and, although not legally required to offer one, ultimately did propose such a program in this proceeding that should be approved by the Commission. The POR is offered as a means to support the competitive market by encouraging a greater number of competitive suppliers and offerings from that expanded list of suppliers. The POR proposed includes a bad debt rider as an integral part of the structure of the mechanism.

AEP Ohio proposed a straight forward POR offering. The AEP Ohio proposal calls for consistent application across the consolidated billed customers. The proposed program is focused on the commodity charge of CRES offerings. AEP Ohio proposes a bad debt rider to be implemented in place of a discount rate and for the CRES providers to cover the administrative costs of developing and implementing the program to ensure the Company is financially made whole for offering the POR program.

1. The Benefits Of The Company's Proposed POR Program, As Proposed Voluntarily By The Company, Support The Program's Approval As Part Of The ESP Package.

There are numerous benefits for customers of a POR program. As AEP Ohio witness Gabbard testified, the customers get the benefit of an increased number of providers and an increased number of products to residential customers whereas the focus has been on other classes of customers. (AEP Ohio Ex. 11 at 4.) In other words, the addition of a POR program will assist in the development of competition because it promotes competition. (*Id.*) Another advantage for customers is the access to AEP Ohio's Average Monthly Payment (AMP) program for both distribution and generation charges. (*Id.*) Under the *status quo*, a shopping customer desiring a monthly billing option must sign up for one with AEP Ohio and, if offered by their CRES supplier, a separate budget plan with the generation provider. Customers also will see the benefit of only dealing with one entity for billing questions and commodity charges. (*Id.*) AEP witness Gabbard explained that explaining options and payment priority logic is challenging because it is difficult for customers to understand under the current system. (*Id.*) Customers also get the advantage of receiving one bill and only dealing with one company if that bill is past due. (*Id.*) Still another benefit for customers of the POR plan proposed by AEP Ohio is the fact that customers will be free from duplicative credit checks and potential adverse impacts to credit scores which should produce a more positive shopping experience. (*Id.*)

There are also significant benefits for the CRES providers from a POR program. Specifically, as included in the testimony of AEP Ohio witness Gabbard:

- CRES providers are paid in a predictable time frame for the generation services provided,
- CRES providers have certainty regarding the amount of incoming receivables,
- CRES providers would only need to address billing and payment issues or customer questions on a limited basis,
- CRES providers would not be responsible for performing duplicative credit checks or securing collateral for accounts on consolidated billing, and
- CRES providers would not be involved in in collection of unpaid debt from customers for commodity charges,
- POR streamlines processes for both the utility and the CRES provider, promoting cost efficiencies in the market.

(AEP Ohio Ex. 11 at 5-6.)

The only entity that does not appear to receive any direct benefits is the electric distribution utility. Mr. Gabbard testified that recognizing the fact that there are not inherent benefits for a utility to offer a POR program, the Commission should ensure that a POR program, if implemented, should not do any harm to the implementing utility. (*Id.* at 6.)

2. The POR As Proposed By The Company Will Ensure Consistent Application Among CRES Providers And Customers Utilizing Consolidated Billing.

As proposed by AEP Ohio, the POR program will apply to all CRES providers offering consolidated billing and be applied consistently across the territory. (AEP Ohio Ex. 11 at 6.) Dual billing will still be an option for CRES providers if that is their preference. (*Id.*) The consistent application of the POR program is an important factor because allowing CRES providers to enroll some consolidated accounts in POR and not others would be costly to program and to maintain processes in AEP Ohio's EDI and Computer Information System. (*Id.* at 6-7.) In addition, call center support for the two processes is inefficient and not good for customers, and an all-in approach keeps providers from only placing the customers with a higher risk of collection into the POR program. (*Id.*) A customer who is currently enrolled in dual billing and has 60 or more days of charges in arrears will not be eligible for consolidated billing (and the POR program) until the customer is in arrears 30 days or less. (*Id.* at 7.) The intent of this restriction is to prevent large dual billed customers at risk of default from being moved to the POR program to avoid incurring bad debt expense. (*Id.* at 8.)

3. The POR Program Is Limited To The Purchase Of The CRES Receivables That Are Commodity Related Charges.

The POR program would also be limited to the purchase of receivables associated with the commodity related charges to generation. (*Id.* at 8; Gabbard Attachment SDG-01.) As indicated by Company witness Gabbard, that does not include early termination charges because those charges are between a CRES and customer and could easily be disputed as opposed to generation usage. (*Id.*) The Company decided not to collect termination fees to be consistent with the Duke system and as a tool to address slamming which tends to increase as markets grow. (Tr. III at 787-88.) AEP Ohio will take title to the generation commodity-related receivables at the time of the consolidated billing. The importance of limiting the POR program to the generation commodity related charges is due to the fact that the program as proposed will utilize the right to disconnect the customer for nonpayment. To ensure this is allowed by the Commission, the Company is seeking a waiver of O.A.C. 4901:1-18-10(D) which prohibits disconnection for nonpayment of consolidated billed CRES receivables. (AEP Ohio Ex. 11 at 12.) As stated by Company witness Gabbard, the inability of CRES providers to disconnect for non-payment is the very reason CRES providers are unable to factor receivables and why POR programs are implemented. (*Id.* at 12.) The purchase of the receivable will make the generation commodity-related costs the costs of the utility and, therefore, subject to the normal collection rights and responsibilities of a regulated utility up to and including the right to disconnect for nonpayment.

4. The $0.77 Administrative And Implementation Charge Proposed By The Company Is Reasonable And Should Be Adopted.

The Company's proposal includes a $0.77 yearly per consolidated bill fee charged to CRES providers to cover the recovery of the initial capital investment over five years and the ongoing administrative costs to offer the voluntary POR program. (*Id.* at 14.) That fee is figured based on the Company's estimates for implementation and administration of the program. The fee is not a fee for consolidated billing; it is to recover the administrative costs for the ongoing POR program as well as initial implementation. (Tr. III at 784.) The Company anticipates at least $1.5 million in implementation costs. (AEP Ohio Ex. 11 at 13.) Those costs relate to the changes to the computer information system to track receivables appropriately and to modify the EDI systems to provide purchase and discount data to CRES providers. (*Id.*; Tr. III at 784-85) The Company also forecasts $207,600 or incremental ongoing yearly O&M support costs associated with system and program maintenance. (AEP Ohio Ex. 11 at 13.) The fee charged to the CRES provider will be based on the current number of customers registered for consolidated billing each year. (*Id.* at 14.) After the fifth year, the fee will only be based on the ongoing administrative costs. (*Id.*) The CRES will also have to sign a declaration of authority if it wants to participate in consolidated billing, authorizing PJM to bill transmission costs to AEP Ohio rather than the CRES provider. (*Id.* at 15.) The Company expects to implement the POR program as proposed by the Company nine months to one year after approval.

The Commission has encouraged each utility to move to a POR process that makes sense the utility. AEP Ohio has voluntarily created just such a program. The implementation of the POR program as proposed will support competition in Ohio, streamline customer billing functionalities, and eliminate redundant functionalities currently with CRES providers and the utility. (AEP Ohio Ex. 11 at 17.)

5. A Purchase Of Receivables Program With A Zero Discount Rate Supported By A Bad Debt Rider Is Essential To Successful Implementation Of The Company's Voluntarily Offered POR Proposal.

The POR mechanism offered voluntarily by the Company relies upon the implementation of a bad debt rider for implementation of the POR concept. The Abacus Report, the annual baseline assessment of customer choice in Canada and the U.S., shows that the states around Ohio that have POR programs have a higher number of suppliers registered and more product offerings. (Tr. III at 829.) Company witness Gabbard pointed out that one of the factors weighed in offering those rankings is how bad debt is handled and whether purchase of receivables programs are offered. (AEP Ohio Ex. 11 at 17.) This makes the Company's proposal as requested very important to the success or failure of the voluntary POR offering.

The current amount of bad debt factored into rates as a result of the 2010 test year is $12,221,000. (*Id.* at 9.)

The bad debt rider proposed by the Company would recover from, or return to, customers the incremental amount above or below that amount in base rates. (*Id.*) Any revenues received from the collection of the late payment fee also proposed in this proceeding would be factored into this rider to decrease the bad debt. If the bad debt in a year is lower than the $12,221,000 in base rates or the late payment revenues counteract any increase in the bad debt to the point that the final amount is lower than the base rate threshold, then there would be a credit to customers related to the amount of bad debt expense through the rider. (*Id.* at 10.) The initial bad debt rider factor will be set at $0 during the first year it is in effect before the incremental difference is trued up. The rider will be trued up each year with the Application period January 1 through December 31st. (*Id.*) The incremental rider structure will remain until a new base rate case is filed at which time the level of bad debt in base rates will be removed leaving only the rider to account for incremental bad debt expense each year. (*Id.* at 9.)

The discount rate for the POR program will be zero; therefore the bad debt rider is needed to ensure that the Company does not incur new uncollectible debt. (*Id.* at 7.) Company witness Gabbard pointed out a number of benefits to the utilization of a bad debt rider in conjunction with a POR program: 1) a bad debt rider is commonly used in POR programs in other deregulated markets, including in Ohio, and is used in the Duke territory, 2) bad debt can vary from year to year leaving the amount in base rates unrepresentative of the actual amount, 3) the rider would be used to recover bad debt associated with both shopping and default customers and trued up yearly and accurately, and 4) the sharing of these costs across all customers prevents cross-subsidization of shopping versus non-shopping customers in one mechanism. (*Id.* at 8-9.)

Staff provided two witnesses to deal with the POR and the bad debt rider. Staff witness Donlon testified on the Staff preferences in a POR program and Staff witness Bossart testified concerning the use of a bad debt rider. The Company and Staff do agree on some important issues related to the establishment of a POR program. Staff witness Donlon agreed, as outlined in the Staff's report to the Commission in its market investigation in Case 12-3151-EL-COI ("*Market Investigation*"), that the establishment of a POR removes a potential market barrier and increases the number of active suppliers. (Tr. IX at 2163-64.) Staff agrees that an increase in shopping options generally corresponds to a decrease in generation prices. (*Id.* at 2176-77.) Staff agrees there is a need for POR; it just has a different preference for implementation. (*Id.* at 2165.) Staff witness Donlon agrees with Company witness Gabbard that if a company is offering a benefit to others voluntarily (like the POR proposal), it should be held harmless from the impact of that voluntary offering. (*Id.* at 2168.)

Staff witness Donlon supported a POR program that is fundamentally different from the Company's voluntarily proposed program. Staff disagreed with the use of a bad debt rider, the establishment of a late payment fee offsetting the bad debt rider, and the establishment of an annual administrative fee to CRES providers to pay for implementation and administrative costs. (Staff Ex. 14 at 4.) Staff also proposed that industrial and large commercial customers be excluded from participation in the POR consolidated billing. Staff proposed its own extra layer of partial payment tracking system that is only necessary if Staff's POR model is adopted. (*Id.* at 12.) Staff also developed its own discount rate and implementation cost fee structure, both developed internally within Staff. (*Id.* at 7-13.) The Staff proposal fails to take into account any of the AEP Ohio specific proposals and is inconsistent with prior Staff positions and the need for consistency to develop the competitive market.

a. A Purchase of Receivables Program with a zero discount rate supported by a bad debt rider is the consistent model for the Ohio Market.

Staff's position in this case and the past market study has supported consistent application of policies to encourage the growth of the competitive market, but its position on the bad debt rider and POR does not appear to mirror that underlying goal. The record shows that Duke Energy Ohio had a POR program with a discount rate prior to 2011, but that its level of competition grew substantially after implementing a zero discount and making up the bad debt in a bad debt rider established in Commission Case No. 11-3549-EL-SSO. (Tr. IX at 2185.) In fact, in the description of the increase of suppliers at the time in Duke's territory, the Staff specifically identified the POR program (that at that time had a zero discount factor) as a contributing factor that cannot be minimized to stress the impact that that POR program had on the increase in competitive suppliers. (*Id.*)

The Staff Report in the *Market Investigation* case included an overall section dedicated to the need for consistency in the market for competitive suppliers to be able to compete. As discussed by Staff witness Donlon, the Staff Report expressed the belief that in order to enhance the market, efforts must be taken to standardize practices and market roles of the various EDUs in Ohio. (*Id.* at 2178.) In fact the first workshop held in the *Market Investigation*, overseen in large part by Staff Witness Donlon as one of the Staff architects in the investigation, was titled "How do we create consistency in operation support across the state?" (*Id.* at 2162, 2178.) Mr. Donlon verified that Staff's position is that inconsistencies can create barriers and when appropriate Ohio should streamline the industry as much as possible and urged the Commission to consider consistency impacts when implementing policies that deal with the *Market Investigation*. (*Id.* at 2179-80, 2182.)

Curiously, however, Staff's view of the need for consistency to assist in the development of the competitive market across Ohio apparently does not apply to the POR program proposed by the Company. Duke and the five other gas companies have POR programs that are structured similarly to the Company's proposal, with a zero discount factor and recovery of bad debt in a rider. (*Id.* at 2139.) Staff now proposes an approach that is fundamentally inconsistent with the existing Duke program's zero discount rate and its recovery of any outstanding bad debt through a bad debt rider. That is asserted here despite the fact that Staff in the *Market Investigation* took the position that inconsistencies were created for valid reasons at the time, but as the retail electric service market has developed and continues to evolve, that inconsistencies must be reduced. (*Id.* at 2180.) The record shows, however, that consistency in the market translates into lower prices for customers. Company witness Gabbard testified that the AEP Ohio proposal is very consistent with the Duke program, and the suppliers have noted consistencies in markets drive efficiencies, and those efficiencies reduce costs and, ultimately, suppliers' prices for customers. (Tr. III at 875.)

The issue becomes what would justify an inconsistency in the major factors that impact competitive suppliers that could risk the lowering of prices for customers. In an attempt to differentiate the Staff position filed in testimony in this case from the Staff's position in the *Market Investigation*, Mr. Donlon states that it is appropriate that Duke and AEP Ohio are inconsistent because Duke is more advanced due to its better understanding of its data. (Tr. IX at 2183.) When this issue was explored, Mr. Donlon agreed that once AEP Ohio understands its data it will be "mature enough" to offer a bad debt rider as part of its POR. (*Id.* at 2184.) This basis for a major difference in the structure of AEP Ohio's POR compared to Duke's contradicts Mr. Donlon's own testimony, does not recognize the Company's proposal (a rider set at zero as an initial rate), and disregards AEP Ohio's own industry experience.

Mr. Donlon testified, prior to being faced with the apparent contradiction in Staff positions on consistency in this case and in the *Market Investigation*, that he agreed that the utility has the data in its control to understand its experience with bad debt. (*Id.* at 2173.) Mr. Donlon's argument that AEP Ohio needs time to understand the data (which he testified is already understood) is also undermined by the fact that the Company's proposal calls for the establishment of the initial rider amount at $0, meaning that the Company will have time with the data prior to any rider cost or credit being implemented. Mr. Donlon had already agreed under cross-examination by counsel for RESA that the Company will have the ability to gather the data it needs to determine the impact of the CRES uncollectible riders during the time between the start of the POR program and any approval of a rate. (*Id.* at 2145.) Finally, Company witness Gabbard testified that the Company is familiar with Duke's POR program and has talked with Duke about it. (Tr. III at 856.) The Company discusses issues with other utilities on a normal basis, and the Commission's Order in the *Market Investigation* case pointed out the need for ongoing collaboration. Staff's justification for an inconsistency on the bad debt rider and the discount rate is not adequate, as shown by Staff's own admission. Mr. Donlon testified that a POR that does not encourage market entry is not meeting the goal of offering a POR program. (*Id.* at 2163.) As shown by Staff's highlighting of the increased competition realized in Duke's territory after the zero discount POR and bad debt rider were implemented, the Staff's proposal in this case will not achieve the same level of intended benefits, and it will not meet the purpose of implementing a POR plan.

Many of the intervenors proposed their own nuanced programs or changes to the AEP Ohio proposal that should not be adopted. Some of the programs proposed by intervenors were clearly at the investigatory stages and would benefit from some discussion in the collaborative environment. Other proposals were clearly attempts to maintain market share or power on behalf of established CRES providers. The launch of a POR and the competitive support in this ESP proceeding should be limited to those proposed by the utility that voluntarily included these provisions. An ESP should not be used as an opportunity to debut the latest ideas and see if they stick. The Commission should focus on the implementation of a consistent POR offering and implement the program as proposed by the Company.

b. The Staff's proposed discount rate discriminates against at-risk populations and does not support the underlying goal of a POR program.

Staff's proposal for an independent discount rate for each and every CRES provider is untenable and undermines the greater expansion of CRES service offerings to at-risk populations. Staff witness Donlon outlines the structure of the discount rate calculation and admits that the structure is to develop an independent discount rate for each and every CRES provider based on their individual past experience. (Staff Ex. 14 at 7-11; Tr. IX at 2131.) Mr. Donlon admitted under cross-examination that he did not share this formula with interested industry parties during the *Market Investigation* workshops, and he does not know what the competitive suppliers think about his proposal. (*Id.* at 2185-86.) Staff did agree that the application of its discount rate formula could have a chilling effect on CRES providers marketing to at-risk populations that have a higher credit risk. (*Id.* at 2186-87.) Company witness Gabbard testified to the advantages of the Company proposal that does provide security for competitive suppliers to pursue at-risk populations and avoid any socioeconomic discrimination in the CRES marketing. (Tr. III at 799.) The public policy portion of the statute found in R.C. 4928.02(L) also encourages the protection of at-risk populations through elements of ESP plans. The Staff proposal admittedly limits this benefit in contradiction to the policy statute, while the Company proposal extends the benefits of competition supported by the Staff to this at-risk population. The Commission should reject the Staff's limiting discount rate and adopt the Company's voluntary POR program as proposed.

c. The Company's credit collection efforts and history of managing bad debt support the establishment of a bad debt rider as the Company proposes.

Staff opposes the establishment of a bad debt rider based in part because it was unable to determine the benchmarks the Company uses to review its collections procedures. The Staff position on this issue ignores the information provided to Staff and the application of that information to the standards to which Staff refers in Staff witness Bossart's testimony. The Staff position also ignores the lack of any criteria that would be used by Staff to judge benchmarks.

Staff insinuates that a lack of benchmarks for evaluation of bad debt collection practices is a fatal flaw and a barrier to the establishment of a bad debt rider. Yet upon cross-examination, it became apparent that Staff is unaware if any electric distribution utility has the set of benchmarks that Staff appears to require to approve a bad debt rider in this proceeding. Staff witness Bossart testified that the Staff reviews Duke's collection practices based upon the recommendations provided in Case No. 08-1229-GA-COI (gas investigation) but not an independent Commission or Staff standard or benchmark. (Tr. VIII at 1903-05.) Ironically, in the gas investigation proceeding cited by Ms. Bossart, the Commission declined to establish a benchmark for bad debt collection and instead instructed Staff to determine a bad debt benchmark and monitor the utility's bad debt collection efficiency. (*Id.* at 1916-17.) Yet, Staff witness Bossart admitted that Staff does not have a set position on the acceptable level of bad debt expense. (*Id.* at 1912.) This is further exposed when Ms. Bossart testified that she is not aware if FE has collection benchmarks for its bad debt rider and is unaware if DP&L has a bad debt rider and did not review any benchmarks that they use as part of the development of Staff's recommendation in this case. (*Id.* at 1906-07.) AEP Ohio appears to be held to a standard that no other utility is held to (including those already with a bad debt rider and collecting from customers). Moreover, it appears to be a standard that Staff itself has never developed.

The Staff concern is actually focused on one distinct area of credit collection – third party collection activity. Staff witness Bossart admits that her review of AEP Ohio's credit and collection practices deals with the collections by third party collectors. (*Id.* at 1909-10.) Ironically, AEP Ohio outperforms past Commission direction on utility recommendations concerning the use of third party collections. The only standard established in prior Commission proceeding concerning third party collection agencies is found in the 08-1229-GA-COI case cited by Ms. Bossart. In that case the auditor made a recommendation that the gas company it was reviewing should not rely on a single third party vendor to do all of its last resort collections because an exclusive contract does not promote competition. (*Id.* at 1917.)[62] The Commission in that order recommended that the gas company use multiple third-party vendors unless it could provide a reason why using only one was appropriate.[63] But that is not a concern for AEP Ohio. As shown in the record and agreed to by Staff witness Bossart, AEP Ohio uses a number of outside third parties for last resort collections. (Tr. VIII at 1917.) There is also testimony in the record from Company witness Moore that she and Staff witness Bossart previously discussed AEP Ohio's monitoring of third-party collection performance and how the Company moves accounts around vendors from one to another based on performance. (Tr. VIII at 1913.)

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[62] *See also* Case No. 08-1229-GA-COI, Opinion and Order at ¶ 37 (Dec. 14, 2011).

[63] *Id.* at ¶ 39.

Specifically, AEP Ohio operates its outside vendors on a competitive basis, moving more business to those whose collection results are superior, just as the auditor in the gas investigation recommended. AEP Ohio's policies are far beyond the standard approved in that investigation.

Staff's contention that it is without sufficient information to make a determination regarding the appropriateness of Company's credit collection practices and efforts to avoid bad debt is without merit. Staff admits that it did not find that the Company's practices are ineffective, only that it did not have information to evaluate beyond the reports detailing the results. (Tr. VIII at 1911.) A review of the record shows that Staff had the information to compare how the Company has used its third-party vendors to the Commission's prior consideration of that benchmark. Even if the Company had some other standard, there would not be a Staff standard or benchmark to compare it to for reasonableness, because Staff did not develop any standards. (*Id.* at 1912.)

The record shows that AEP Ohio manages its bad debt and takes steps to minimize bad debt levels. Staff witness Bossart testified that the Staff's relationship with the AEP staff was an open and transparent relationship. (*Id.* at 1899-1900.) She also testified to the programs and efforts the Company is already undertaking to improve collections and avoid or decrease bad debt. Ms. Bossart validated that the Neighbor to Neighbor program, which includes a contribution of shareholder dollars, provides assistance to customers having difficulty paying bills (*i.e.,* it is a program to assist customers at risk of not paying, which also addresses bad debt concerns). (Tr. VIII at 1920-21.) Ms. Bossart also recognized that AEP Ohio defended the Commission's "benefit of service" rule in a complaint case where a Receiver was attempting to avoid paying the past debt associated with the property it was appointed to manage even though the account was being maintained. (*Id.* at 1922.) She also recognized that at times there are issues that may add to bad debt that are out of the Company's control, like working with the Commission Staff to avoid a disconnection of service for a customer. (*Id.* at 1925-26.) Finally, as AEP witness Spitznogle discusses in his testimony, AEP Ohio seeks approval in this proceeding for the establishment of a late payment fee on all residential tariffs at 1.5% of the unpaid account balance. (AEP Ex. 3 at 10-11.) Ms. Bossart recognized that the late payment fee requested as a part of this proceeding is another policy attempt by the Company to address bad debt concerns. (Tr.VIII at 1923.) Overall, Ms. Bossart agreed that the customers, and their ability or choice to actually pay their bills, is the most important factor in collection activity. (*Id.* at 1914.) That factor combined with the rules followed by the Company, the programs to assist customers and the extra efforts to defend those Commission rules and ensure their application show that the Company is dedicated to managing bad debt levels and that the Company's actions in this area should be seen as supporting the approval of a bad debt recovery mechanism.

The POR program as proposed by the Company satisfies the goals of increasing competition without discouraging the utility from voluntarily offering the program. Staff agreed that the implementation of POR should not harm the utility, yet its proposal serves to create that risk by capping the level of bad debt recovery and shifting risk to the utility. The Commission should approve the bad debt recovery rider in conjunction with the purchase of receivables program as proposed in the Application and supporting testimony by the Company.

E. Continuation Of The Energy Efficiency/ Peak Demand Reduction Rider Is Reasonable.

The Company proposes to continue the Energy Efficiency/Peak Demand Reduction Rider (EE/PDR Rider) as approved in *ESP II*. (AEP Ohio Ex. 1 at 13.)[64] As Company witness

[64] *See also ESP II*, Opinion and Order at 65-66 (Aug. 8, 2012).

Spitznogle explained, continuation of the EE/PDR Rider "enables AEP Ohio to continue offering innovating energy efficiency programs for all customer segments, allowing the Company to achieve the established benchmarks for both the energy efficiency and peak demand reduction programs." (AEP Ohio Ex. 3 at 6.) The continuation of the EE/PDR Rider also advances the state policy goals set forth in R.C. 4928.02(A), (D), and (M). (*Id.* at 6-7.) No other party has opposed the Company's EE/PDR proposal. The Commission approved the continuation of the EE/PDR Rider in *ESP II*, and it should do so again for AEP Ohio's ESP III.

F. Continuation Of The Economic Development Rider Is Reasonable.

The Company proposes the continuation of its Economic Development Rider (EDR) for reasonable arrangements with mercantile customers, approved by the Commission. AEP Ohio witness Spitznogle explained that the EDR supports mercantile customers with Commission-approved reasonable arrangements that retain existing and create new Ohio jobs. Accordingly, AEP Ohio proposes to continue the existing EDR throughout the entire term of the new ESP. (AEP Ohio Ex. 3 at 9.) While AEP Ohio is proposing to continue the EDR as part of the new ESP, it does so on the basis that it is entitled to recover foregone revenues associated with reasonable arrangements approved by the Commission under R.C. 4905.31.

As Company witness Spitznogle explained, the continuation of the EDR comports with state energy policy because it facilitates the state's effectiveness in the global economy pursuant to R.C. 4928.02(N). (AEP Ohio Ex. 3 at 5.) No party has objected to the continuation of the EDR. However, while generally supporting the Company's EDR proposal, the OEC/EDF, through their witness Roberto, make several recommendations related to commitments to meet energy-efficiency objectives. However, it is not clear who, Company or customer, would be responsible for ensuring that the objectives are met. Nor is it clear what exactly it would take to meet the commitments OEC/EDF are advocating. What is clear, though, is that the OEC/EDF recommendations are not capable of implementation and, consequently, would render the EDR unworkable.

For example, Ms. Roberto recommends that "prior to seeking recovery [of foregone revenues] the Company [should] be required to undertake good faith efforts to reduce the costs to be recovered from all customers through the deployment of all cost-effective energy efficiency measures for which the investment would be recovered during the term of the unique arrangement at the facilities of the customers enjoying the discounted electricity." (OEC/EDF Ex. 1 at 9.) First, the uncertainty of what it would take to meet OEC/EDF's "good faith effort" standard or what would be included in "all cost-effective energy efficiency measures", makes the goals of her proposal completely subjective and, thus, impossible to implement. Moreover, making the Company responsible for meeting subjective and uncertain energy efficiency goals and holding the Company's recovery of foregone revenues hostage until it ensures that those goals are achieved, when it is the customer, not the Company, that has authority to implement OEC/EDF's desired efficiency measures ensures that the recommendation will fail to achieve its purpose.

Perhaps realizing that her recommendation would be criticized for being misdirected at the Company, Ms. Roberto appears to change, or at least hedge, the recommendation, at page 10, lines 20-22 , where she states that "[r]equiring unique arrangements customers to deploy all cost-effective energy efficiency [measures] can benefit the Company and its other customers by reducing the costs of this rider . . . ." (*Id.* at 10.) At least at this point Ms. Roberto imposes the requirement on the customer, which is the party to the reasonable arrangement that would be in a position to achieve OEC/EDF's energy efficiency goals, whatever they might be. However, imposing the standard on the right target does not cure the underlying subjectivity of Ms. Roberto's proposed standard.

The fundamental disagreement that Ms. Roberto has with the EDR is that she does not believe that large sophisticated customers, like Timken, will make the correct decisions regarding investments in cost-effective energy efficiency measures unless their decisions are regulated and overseen by those in a better position to make such judgments, presumably entities like OEC/EDF. Her fishing analogy is revealing in that regard. According to Ms. Roberto, we need to teach customers how to fish for a lifetime, rather than just give them a fish so they can feed themselves for a day. (*Id.*) That is, she believes that we need to teach customers how to invest in energy efficiency, rather than just subsidize the rate that they pay for electricity day by day. When asked whether she thought that Timken "knows how to fish", *i.e.*, knows how to invest in energy efficiency, she responded that while Timken might know how to fish in shallow water, she believes that it needs to be taught to fish in deeper waters. (Tr. XII at 2799.) There simply is no basis for Ms. Roberto's position that reasonable arrangements customers like Timken do not know how to make cost-effective investments over the appropriate term in any asset, including energy efficiency measures. Moreover, there is no statutory duty to pursue all cost effective energy efficiency.

In any event, Ms. Roberto never explains, by analogy or directly, why AEP Ohio' recovery through the EDR of revenues foregone pursuant to Commission-approved reasonable arrangements should depend on whether those customers meet OEC/EDF's energy efficiency goals. Her recommendations should not be adopted.

G. Continuation Of Statutory And Other Miscellaneous Riders Is Reasonable.

The Company plans to continue implementing other existing riders during the term of the ESP III. (*See* AEP Ohio Ex. 1 at 14; AEP Ohio Ex. 13 at Ex. AEM-1.) As detailed in the testimony of Company witness Moore, those riders include the Universal Service Fund Rider, the Deferred Asset Phase-In Rider, the kWh Tax Rider and the Transmission Under Recovery Rider. (AEP Ohio Ex. 13 at Ex. AEM-1.) Those riders are not directly linked to the substantive ESP proposals, but they should nonetheless continue unaltered during the ESP III.

The Company also plans to continue collecting the Retail Stability Rider (RSR) approved in *ESP II* through the term of ESP III to recover the capacity charge deferrals, inclusive of carrying charges, consistent with the Commission's decision in the *ESP II* proceeding. (Appl. at 14).[65] AEP Ohio will file a separate application to continue the RSR. (AEP Ohio Ex. 1 at 14.) Accordingly, the Commission should not consider any issues related to the RSR's continuation in these proceedings.

H. The Proposed Early Termination And Reopener Provision Is Reasonable And Should Be Approved.

The Company reserves the right to terminate the proposed ESP III one year early, *i.e.*, by June 1, 2017, if there is either (a) a substantive change in Ohio law (including Commission rules or orders), or (b) a substantive change in federal law (including FERC rules or orders) or PJM tariffs or rules with respect to capacity, energy or transmission regulation, or pricing, that affects the Company's SSO obligations and/or SSO rate plan options under R.C. Chapter 4928. (AEP Ohio Ex. 1 at 15; AEP Ohio Ex. 2 at 8.) The Company proposes that it may exercise this early

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[65] *See also ESP II*, Opinion and Order at 36 (Aug. 8, 2012).

termination right, at its sole option and discretion, by giving written notice to the Commission no later than October 1, 2016. (AEP Ohio Ex. 1 at 15.) If the Company exercises the right to early termination, it will propose a new SSO rate plan to encompass the June 1, 2017 through May 30, 2018 period. That SSO rate plan would also include an auction schedule that would provide for delivery of SSO supplies beginning June 2017, and it may also encompass a longer time period consistent with applicable law. (*Id.*; AEP Ohio Ex. 2 at 8.)

As Company witness Vegas explained, the "substantive changes" that the early termination and reopener right addresses are those "fairly significant changes in the provisions of how the Company would provide supply to its customers." (Tr. I at 66.) He testified that the universe of conditions that could materially affect supply is broad, noting that the Company has seen substantive rule change recommendations to PJM, federal court challenges to PJM auction outcomes resulting from court decisions related to the demand response component of the PJM market operation, and new greenhouse gas regulation guidelines "just in this year alone." (*Id.* at 67.)

Mr. Vegas also explained why it is imperative that the Company be able to adapt to such changes:

> [I]f there were substantive changes in federal law in rules around the PJM market operation or in rules or law changes in the state of Ohio that affect how we provide supply, it's under those circumstances that we think it's very prudent and responsible to have the flexibility to adapt to those changes and to be able to end the term of this ESP should our customer supply options be changed because of those rules, and then be able to come back in and ask for the approval of a new ESP to replace this current one under that circumstance.

(*Id.* at 66.) Simply put, "the Company believes that it would be irresponsible to not have the flexibility to incorporate the impacts of [such significant] changes should they occur." (*Id.* at 67.) Importantly, customers and the Commission will receive ample advance notice if the

Company exercises its right to terminate ESP III early. (AEP Ohio Ex. 1 at 15; AEP Ohio Ex. 2 at 8.) Moreover, a new SSO to replace ESP III would have to be approved by the Commission before ESP III would end. (Tr. 1 at 65-66.)

Given the rapidly changing legal and regulatory environment, and the attendant supply risks, the Company's assertion of its right to terminate ESP III early and reopen it in the event of a significant change affecting the Company's SSO obligations and/or SSO rate plan options is reasonable, prudent, and necessary to protect both customers' and the Company's interests. The Commission should agree that AEP Ohio is able to exercise that right should the need to do so arise, and it should approve AEP Ohio's proposal regarding that right in this proceeding.

IV. THE ESP IS MORE FAVORABLE IN THE AGGREGATE AS COMPARED TO THE EXPECTED RESULTS OF AN MRO.

With regard to the Commission's review and approval of a proposed ESP, R.C. 4928.143(C) provides in relevant part that:

> The Commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code.

Accordingly, if the proposed ESP, including its pricing and all other of its terms and conditions is more favorable in the aggregate than the expected results of an MRO, then the Commission shall approve the ESP.

AEP Ohio witnesses Allen, other Company witnesses, and Staff witness Turkenton provide testimony that confirms that AEP Ohio's proposed ESP, including its pricing and all other terms and conditions, is more favorable in the aggregate as compared to the expected results of an MRO. There are both quantitative and qualitative aspects of the MRO Test. The quantitative evaluation includes a comparison of the ESP pricing to the expected results from an

MRO, as well as a consideration of other quantifiable, non-price, benefits that result from the ESP that would not be available under the MRO option. Company witness Allen and Staff witness Turkenton identify and confirm the value of these benefits. The MRO Test also considers other more qualitative benefits that the proposed ESP provides, not available in an MRO. These qualitative benefits, while not readily quantifiable, are nevertheless of significant value and, therefore, must also be considered as part of the assessment of the ESP in the aggregate. There are a number of such qualitative benefits that result from the Modified ESP, which Mr. Allen and Staff witness Turkenton describe.

The Company's proposed ESP is more favorable to customers, whether evaluated from a quantitative and a qualitative perspective. Moreover, as Mr. Allen testified, the Company's proposed ESP provides significant customer benefits that are not readily available through a more narrowly focused MRO process. This is possible, he explained, because a comprehensive ESP can more holistically address many components of electric service, whereas an MRO is primarily a plan just for power procurement. (AEP Ohio Ex. 7 at 3-4.)

A. ESP Pricing And Quantitative Benefits

Company witness Allen noted that, under either an ESP or an MRO, the Company would be acquiring all generation services for SSO customers from competitively bid wholesale auctions and, as such, there is no quantifiable difference in the commodity prices that would result from an ESP or an MRO. (AEP Ohio Ex. 7 at 4.) Similarly, Staff witness Turkenton also concluded that, because SSO generation rates will be 100% market based beginning June 1, 2015, under the proposed ESP, there should be no differences between market based generation rates under an MRO as compared to the ESP. (Staff Ex. 15 at 3.)

As one example of the array of benefits that the proposed ESP offers, Mr. Allen observed that the Company believes that it will be able to maintain base distribution rates constant over the period June 1, 2015, through May 31, 2018, while making significant investments in distribution infrastructure and improving the reliability of service through the DIR and ESRR. (AEP Ohio Ex. 7 at 4.) Ms. Turkenton also cited these benefits of the proposed ESP. (Staff Ex. 15 at 4.)

Mr. Allen explained that the DIR mechanism and associated revenues under the Company's ESP proposal provide a benefit to customers that is equal to or greater than the customer benefits that would be expected under an MRO. He noted that the DIR provides a streamlined approach to recovering many of the costs associated with investment in distribution infrastructure. Specifically, these same types of costs would be recoverable from customers through base distribution cases but with higher costs to customers and other parties as the result of the added complexity of distribution base rate cases. (AEP Ohio Ex. 7 at 4.) As Ms. Turkenton explained, maintaining current base rates and utilizing riders to collect the costs of incremental distribution investments, allow the parties to avoid the significant time and costs of typical base distribution rate cases. (Staff Ex. 15 at 3.) Although perhaps not so readily quantifiable as other pricing elements of the proposed ESP, the reduced time and expense related to the streamlined process used to implement the DIR through an ESP amounts to a cost advantage for all participants in that process compared to what would be necessary in an MRO environment. In addition, the reliability benefits that the DIR provides to customers, which might be characterized as being of a more qualitative nature, would likely be delivered sooner than would be the case if traditional base distribution rate cases were used to recover the same investment costs. (Tr. II at 615-18; Tr. IX at 2118.) The ESRR that the Company will continue to implement under the ESP approach provides the same type of streamlined approach and accelerated delivery of customer benefits that the DIR provides, which, again, would not be possible through the traditional base rate case approach. (AEP Ohio Ex. 4 at 3-4.)

In addition, as part of its total ESP III proposal, the Company is extending the Residential Distribution Credit Rider through May 31, 2018. That rider is currently scheduled to expire on May 31, 2015. Mr. Allen calculated that extending this rider provides an annual benefit to residential customers of $14,688,000 or $44,064,000 over the three-year term of the ESP. This benefit would not exist under an MRO. (AEP Ohio Ex. 7 at 4.) Also, the Company's proposed PPA Rider, a principal benefit of which is to stabilize customer rates by providing a hedge against market volatility, is estimated to provide, in addition, an $8 million net credit over the three-year period of the ESP, as a result of including in it the OVEC power participation benefits and requirements. (AEP Ohio Ex. 33 at 10; Tr. XIII at 3251-52.)

B. Qualitative Benefits Of The ESP

The proposed ESP also will provide very substantial qualitative benefits. As the Commission recognized in its order approving the Company's current ESP (ESP II), the accelerated move to fully market based rates by June 1, 2015, could only be accomplished under an ESP approach. The Company's proposed ESP in this proceeding (ESP III) helps, and indeed is a necessary part of that accelerated process, to achieve the Commission's objective of "true competition in the state of Ohio."[66] Similarly, Ms. Turkenton noted, in ESP II, it was the Commission's intention to get to 100% market based SSO rates in the Company's territory as soon as practical and that beginning June 1, 2015 that goal will be achieved. In that regard, she confirmed that the Company's ESP III application is an extension of the prior ESP II application.

[66] *ESP II*, Opinion and Order at 76 (Aug. 8, 1012).

(Staff Ex. 15 at 4.) Accordingly, one of the substantial qualitative benefits of ESP III is that it enables the transition to fully market-based rates sooner than would be possible under an MRO.

Mr. Allen also identified other non-quantifiable benefits of the proposed ESP that would not occur under an MRO. First, the Company has proposed the Power Purchase Agreement Rider which, as Mr. Allen also explains in his testimony, provides increased rate stability for customers who will be subject to the volatility of fully market based rates. The increased rate stability provided by the PPA Rider would not exist under an MRO. (AEP Ohio Ex. 7 at 5, 8-11.) In addition, the Company has also included in its proposed ESP a purchase of receivables program described and supported by Company witness Gabbard. Mr. Allen reiterates that the benefits of the POR program (which Mr. Gabbard further explains and supports) include, among other things: (1) a likely increase in registered CRES providers; (2) additional payment options for customers including Budget or Monthly Average Payment programs; (3) CRES providers are paid in a more predictable time frame for the generation services that they provide; and (4) increased certainty for CRES providers regarding the amount of incoming receivables. The benefits of the POR program would not be available under an MRO. (AEP Ohio Ex. 7 at 5.) Staff witness Turkenton also believes that a POR program could provide such benefits, that would not have been available outside of the ESP approach. (Staff Ex. 15 at 4-5.)

C. Intervenors' Criticisms That The ESP Is Not More Favorable Than An MRO Are Without Merit.

OCC witness Kahal and IEU witness Murray raise several criticisms of the Company's and Mr. Allen's evaluation of the relative costs and benefits, both quantitative and qualitative, of the proposed ESP. They conclude that the proposed ESP is not more favorable, in the aggregate, than what would result from an MRO. These criticisms are misguided, and their conclusion that the proposed ESP is not more favorable than an MRO is incorrect.

Mr. Kahal first questions whether the $14,688,000 per year residential rate credit that the Company proposes to continue during ESP III, which would total $44,064,000 over three years, is a "new benefit" for the residential customers, because it was first implemented by the Company as part of a Stipulation and Recommendation approved by the Commission to resolve the Company's prior distribution rate case. He believes that this credit "may" be needed to correct excess revenue collections under the DIR during ESP III. (OCC Ex. 13 at 28.) Mr. Kahal's concern is without basis, and his effort to dismiss the value of the Company's proposal must be rejected. The $14,688,000 per year residential credit expires as of May 31, 2015, and there is no requirement that the Company provide that credit after that date, either as part of an ESP, or as part of a future distribution rate case. Even Mr. Kahal concedes that, absent the Company's proposal to include the rate credit in its proposed ESP, residential customers' rates would increase by $14,688,000 per year beginning June 1, 2015. (Tr. IX at 2129-30.) As noted above, Staff witness Turkenton acknowledges, inclusion of the residential rate credit in the proposed ESP is a quantifiable benefit for residential customers. IEU witness Murray, the only other intervenor witness to provide testimony regarding the MRO Test, also acknowledges that the residential rate credit is a real, quantifiable benefit of the proposed ESP. (IEU Ex. 1B at 18-19.)

Mr. Kahal also contends that the proposed extension and modification of the DIR, along with the Sustained and Skilled Workforce Rider and the Enhanced Service Reliability Rider, will result in customers paying $240 million more than what would result from an MRO. (OCC Ex. 13 at 23-24 and 25.) The flaw in this criticism is that it fails to recognize that, for purposes of the MRO Test analysis, the revenue requirements associated with the recovery of incremental distribution investments are considered to be the same whether recovered through a provision included in an ESP or through a distribution rate case conducted in conjunction with an MRO. In other words, they are regarded as "a wash," and not treated quantitatively as a cost of the ESP or the MRO alternative.[67]

Both Mr. Kahal and Mr. Murray claim that the proposed nonbypassable PPA Rider will create significant, quantifiable costs that are not included in Mr. Allen's MRO Test and that offset any quantifiable benefits of the proposed ESP. According to Mr. Kahal, based upon OCC witness Wilson's analysis, the impact of including the OVEC PPA in the PPA Rider over three years of the proposed ESP will cost customers $116 million. (OCC Ex. at 25.) Mr. Murray contends that the costs of including the OVEC PPA in the rider over the three years will be as much as $82 million. (IEU Ex. at 7-12 and 21.)

There are two basic flaws in Mr. Kahal's and Mr. Murray's analyses. The primary flaw is that the criticisms fail or refuse to recognize the benefits that the PPA Rider provides to customers. The PPA Rider is designed to stabilize rates for all customers by providing a hedge against market volatility. Mr. Allen and Dr. McDermott explained this very valuable benefit to customers from the PPA Rider. (AEP Ohio Ex. 7 at 8; AEP Ohio Ex. 32 at 8; AEP Ohio Ex. 33 at 2-5.)

The second basic flaw in the their analyses regarding the cost of the PPA Rider to customers over the three year period of the ESP is that Mr. Kahal and Mr. Murray are simply wrong. As Mr. Allen explained in his rebuttal testimony, even during the first three years when

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[67] *In Re FirstEnergy Companies*, Case No. 12-1230-EL-SSO, Opinion and Order at 55-56 (July 18, 2012). As noted above, while there are no quantifiable costs of the DIR, SWRR, and ESRR to be included in the MRO Test analysis, there are cost savings from these riders due to the streamlined process that the ESP provides for implementing them, as compared to the complexity of the base rate case process. In addition, there are qualitative benefits from the accelerated implementation through the ESP of the investment programs that these riders support and, thus, the more rapid delivery to customers of the accompanying reliability and service quality advantages that the riders' programs provide.

the PPA Rider will be in effect, the best estimate of the impact of including the OVEC PPA in the nonbypassable PPA Rider is that it will provide an $8.4 million net credit to customers. (AEP Ohio Ex. 33 at 10; Tr. XIII at 3251-52.) As Mr. Allen further explained, the analyses that Mr. Wilson did (which Mr. Kahal relied upon) and that Mr. Murray did suffered from very basic flaws that render each of them inaccurate and unreliable for use by the Commission. (AEP Ohio Ex. 33 at 9-10.) In short, rather than imposing a quantitative cost, the PPA Rider, when OVEC is included, provides a quantitative benefit for the MRO Test in the amount of $8.4 million.

Mr. Murray also contends that, contrary to Mr. Allen's testimony, ESP III cannot be regarded as providing the qualitative benefit of facilitating the transition to a fully competitive market, because that qualitative benefit was already attributed to the ESP II. (IEU Ex. 1B at 23.) Mr. Allen properly attributed to this proposed ESP III application a significant qualitative benefit because it continues to enable the accelerated transition to competition. As Ms. Turkenton explained, this ESP III application for the most part is an extension of the ESP II application, necessary to complete the transition to a fully competitive market for generation services in the Company's service territory, and so it is appropriate to recognize this qualitative benefit that this application provides. (Staff Ex. 15 at 4.)

VI. OTHER ISSUES

A. ESP III SEET Threshold

Although the Company does not agree that the Commission can set a prospective significantly excessive earnings test (SEET) threshold for the ESP III term, if the Commission does set such a threshold in this proceeding, the Company believes that a 15% threshold would be reasonable. (*See* AEP Ohio Ex. 7 at 8.) A 15% SEET threshold would be consistent with the thresholds that the Commission set for AEP Ohio in previous proceedings. (*Id.* at 6-7 (noting that the Commission established a 17.6% SEET threshold for the Company's 2009 earnings, a 17.56% threshold for the Company's 2010 earnings, and that the Company has recommended a SEET threshold between 22.30% and 24.32% for 2011 earnings and 23.77% and 25.98% for 2012 earnings in Case Nos. 13-2250-EL-UNC, *et al.* using the methodology that the Commission adopted in AEP Ohio's 2010 SEET proceeding).)

A 15% SEET threshold also would be consistent with the SEET thresholds that the Commission has recently established for at least one other EDU.[68] Accordingly, if the Commission sets a prospective SEET threshold, which the Company does not think it should do, then a 15% threshold is reasonable and should be adopted.

B. Marketers' MEP And Other CRES Proposals

RESA has proposed that a Market Energy Program "MEP" be implemented in the Company's service territory during the term of the ESP III. (RESA Ex. 2 at 4-8.) RESA witness Pickett explained that under RESA's proposed program, new and eligible residential and small commercial customers in the Company's service territory that are not currently receiving electric service from a CRES provider and that call AEP Ohio's call center for any reason other than termination or emergency would be offered a competitive product for a 6-month period that would be a three percent discount to the price-to-company at the time of enrollment. (*Id.* at 4.) A CRES provider would be eligible to participate in the MEP if it: (1) is certified by and in good standing with the Commission; (2) is registered to serve residential and small commercial customers in one or both zones of AEP Ohio's service territory; (3) is in full compliance with the Company's financial security requirements; (4) completes all EDI testing with AEP Ohio; and

[68] *See, e.g.,* Case Nos. 11-3549-EL-SSO, *et al.* Opinion and Order at 35 (approving and adopting a 15% SEET threshold for the term of Duke Energy Ohio, Inc.'s 2011 ESP).

(5) applies to participate in the MEP by submitting a participation form to both the Company and the Commission. (*Id.* at 5-6.) RESA proposes that recovery of MEP costs be recovered through "a per-enrolled customer charge at a level that will recoup the MEP estimated stat-up costs amortized over a 3-year period, as well as ongoing program maintenance costs." (*Id.* at 7.) Other CRES intervenors have made various other proposals. (*See, e.g.,* IGS Ex. 2 at 22-25; RESA Ex. 3 at 10-11, Direct Energy Ex. 1 at 6-8.)

Intervenors' proposals should not be adopted. As is the case with intervenors' proposals in response to the Company's POR program, some of the programs that intervenors propose clearly are at the investigatory stages and would benefit from discussion and further development in a collaborative environment. The lengthy cross-examination of RESA witness Pickett showed that there are still bumps to work out on the MEP program before it is ready for implementation in Ohio. Other proposals appear to be CRES providers' attempts to maintain market share or power. The Commission's consideration of the Company's ESP should be limited to those proposals that AEP Ohio included in its Application, witness testimony, and briefing in this case. An ESP is not the appropriate proceeding in which other parties' new or experimental ideas should be presented or adopted. Instead, the Commission should defer consideration of such proposals, if at all, to another proceeding.

V. CONCLUSION

For the foregoing reasons, Ohio Power Company respectfully requests that the Commission approve the proposed ESP without modification. More specifically, as clarified or modified through the Company's testimony and briefing, AEP Ohio requests that the Commission:

1. Approve the proposed ESP without modification, including all accounting

authority needed to implement the proposed riders and other aspects of the proposed ESP;

2. Approve new rates under the proposed ESP effective with the first billing cycle of June, 2015 and continuing through the last billing cycle of May, 2018;

3. Find that the Company's proposed ESP is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142 of the Revised Code; and

4. Approve the Company's proposed tariffs.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of *Ohio Power Company's Initial Post-Hearing Brief* upon counsel for all other parties of record in this case, on this 23rd day of July, 2014.

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