BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to § 4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	))))))	**Case No. 11-346-EL-SSO** **Case No. 11-348-EL-SSO**
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.	))))	**Case No. 11-349-EL-AAM** **Case No. 11-350-EL-AAM**

OHIO POWER COMPANY'S INITIAL POST-HEARING BRIEF

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I. INTRODUCTION

Parties to this proceeding want to focus on SB 3 and hearken back to the deregulatory vision and goals of that legislation, while conveniently ignoring 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 substantially changed the standard service offer (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 That hybrid regulatory regime is effective today and SB 3's requirement for "market-based" SSO pricing was repealed in 2008. The indisputable reality is that both the law and the facts have changed since the passage of SB 3 and there are other intervening developments that make a flash-cut extrication from regulated to market pricing difficult and complex. While the passage of SB 221 was not a U-turn in regulatory policy, the reality is that the General Assembly did turn 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corner when it passed SB 221; most notably, the singular provision in RC 4928.14 requiring market-based SSO rates was repealed and was replaced by two very different options.

Under SB 221, the utility alone has the choice (not required) to pursue the market rate offer (MRO) option, under which there is a new and extended period of transition required to reach fully market-based rates. Thus, even the MRO option does not involve a flash-cut to fully competitive market rates but involves a 6-10 year transition. Alternatively, the utility may consent to an Electric Security Plan (ESP), which is more regulatory in nature, with flexible pricing such as automatic (but regulatory-prescribed) rate increases. While flexible, the ESP rate plan must be more favorable in the aggregate than the expected results under an MRO; thus, while it is not a mechanical or purely quantitative comparison, an ESP rate plan is indirectly subject to roughly the same pricing parameters as an MRO. And neither an MRO or an ESP mirrors market rates.

Unlike the prevailing assumption during passage of SB 3 that market rates would be lower than regulated rates, the General Assembly's new regime in passing SB 221 was premised upon market rates being higher than existing rates. Indeed, the Public Utilities Commission of Ohio's (Commission) *ESP I*[1] decision found that the cost of AEP Ohio's[2] first ESP ($1.4 billion) was less than half the expected cost of an MRO ($2.9 billion). (AEP Ohio Ex. 134 at 72.) Further, AEP Ohio Ex. 142 (at 18) shows that the prevailing market price during 2008 (when SB 221 was passed and the *ESP I* proposal was considered) was substantially higher at 8.52¢/kWh, while the *ESP I* Opinion and Order (at 22) ordered that the generation rates for 2009 were not to exceed 5.47¢/kWh and 4.29¢/kWh for CSP and OP, respectively, on average. The Commission, in fact, determined that the *ESP I* plan provided a benefit of $1.5 billion as compared to an MRO. Based on the projections of high market rates with relatively lower legacy SSO rates, SB 221 established a new and extended transition period to very gradually subject customers to market rates over a period of several 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. In light of these changes in market conditions that have combined to dramatically reduce both capacity and energy market prices, it is understandable that the Commission, the competitors, and customer groups all want to get to market prices as quickly as possible. That

[1] In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets, Case No. 08-917-EL-SSO; In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan, Case No. 08-918-EL-SSO.

[2] Ohio Power Company (dba AEP Ohio) formerly consisted of two separate companies, Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo). Effective at the end of 2011, CSP merged into OPCo with OPCo being the surviving entity.

result, however, is not required under law or under Ohio energy policies and there are existing legal obligations that need to be unwound before AEP Ohio can make the transition to fully competitive SSO rates that avoids undue financial harm to the Company.

Nonetheless, the Commission is presently embracing an aggressive move toward fully competitive SSO pricing. While AEP Ohio is willing to continue its long tradition of following the Commission's lead even where the law does not require the desired outcome, AEP Ohio needs to consent to the resulting ESP and has attempted to present a balanced plan that achieves both objectives. In response to the Commission's policy directives, AEP Ohio has abandoned its long-held regulated business model and is again following the Commission's lead toward a competitive market business model. Not only does the Modified ESP fundamentally restructure AEP Ohio's business model and drive the potential for achieving a statewide consensus model for an auction-based SSO rates (*see* AEP Ohio Ex. 100), the proposal also incorporates an impressive array of customer and public policy benefits that promote state energy policies.

The Company's original January 27, 2011 ESP Application was significantly changed in the Modified ESP proposal. The Modified ESP simplifies the number and operation of the proposed generation service riders. The Modified ESP proposes to establish fixed and frozen base generation rates during the pre-auction period of the ESP. By dropping the non-bypassable riders and establishing fixed base generation rates, the Modified ESP transfers substantial risk from customers to AEP Ohio while simultaneously improving rate certainty and stability for customers.

Upon the effective date of the ESP, AEP Ohio will be locked into providing SSO service for three years at the agreed rates – no matter what else happens. If the economy recovers and energy prices substantially increase, AEP Ohio will provide SSO service at the agreed rates. If one or more of AEP Ohio's generation units suffers a catastrophic failure, AEP Ohio will provide SSO service at the agreed rates. If new costly environmental requirements are imposed during the term of the ESP, AEP Ohio will provide SSO service at the agreed rates. If customers all shop this year based on favorable market conditions and they all return during the last year of the ESP, AEP Ohio will provide SSO service at the agreed rates. Under normal circumstances, this default service obligation – also known as the Provider of Last Resort obligation – is a serious obligation that carries significant business and financial risks. Under the extraordinary circumstances presented by the total restructuring of AEP Ohio, the default service obligation takes on even greater business and financial risks. The proposed Retail Stability Rider (RSR) tethers AEP Ohio to a stable source of non-fuel generation revenue during the risky transition period and enables AEP Ohio to provide the many benefits contained within the Modified ESP, including rate stability for non-shopping customers and discounted capacity pricing for CRES providers and shopping customers.

The Modified ESP also provides for a non-bypassable rider, Generation Resource Rider (GRR), which shall act as a placeholder until such time as the Commission approves any project-specific costs to be included in the GRR. When seeking authorization from the Commission for cost recovery through the GRR, AEP Ohio must demonstrate how the proposed project satisfies all applicable requirements set forth in R.C. 4928.143(B)(2). Upon adoption of the GRR, both the parties and the Commission fully reserve their ability to support or oppose the future establishment of a non-zero charge for inclusion in the GRR. Conversely, rejecting the GRR would preclude the possibility that the Commission could subsequently approve the Turning Point Solar (TPS) project and recovery of the project's costs. Allowing for recovery of the costs of new generation plants dedicated to serving Ohio customers encourages the construction of new plants in Ohio that can: 1) enhance the reliability of the electric system; and 2) provide a cost-based hedge against fluctuations in market prices.

In order to enable AEP Ohio to implement an auction-based SSO for both energy and capacity procurement after the Modified ESP transition period, the Commission needs to also approve the full corporate separation of AEP Ohio's generation business from its wires businesses as proposed in Case No. 12-1126-EL-UNC. While it is the subject of a separate proceeding, corporate restructuring is a cornerstone requirement to many of the individual provisions contained in the Modified ESP. AEP Ohio has filed a separate application to implement structural corporate separation as contemplated in the Modified ESP. With approval of the Modified ESP, the Commission has the necessary information, including, among other things, the rates through mid-2015 after which generation rates can be determined based on a competitive bidding process, in order to approve the corporate separation, which complies with Ohio law.

The appropriate pricing for capacity paid by competitive retail electric service (CRES) providers for use of AEP Ohio's capacity to support retail shopping is a contentious issue that the Modified ESP resolves through a combination of the two-tiered capacity charge structure as well as the RSR – without the need to play out the substantial federal-state conflict that is currently staged and on hold at the Federal Energy Regulatory Commission (FERC) pending consideration of the Modified ESP.

Prior to 2007, when PJM Interconnection, LLC (PJM) implemented a capacity market pricing construct known as Reliability Pricing Model (RPM), American Electric Power Service Corporation (AEPSC),[3] as well as other parties, expressed concern over the long-term negative

[3] In this context, AEPSC (or AEP) represented the interests of the AEP-East operating companies, including AEP Ohio and others.

impacts of the RPM capacity market on vertically integrated utilities and their customers. A special provision was drafted to ensure that those entities could request a cost-based method of recovering their capacity costs and avoid RPM pricing; this provision is known as the Fixed Resource Requirement (FRR). AEP was the only FRR entity in PJM for years – and was applauded by this Commission for selecting the FRR option.

Because no CRES providers in Ohio have elected to self-supply their own generation resources to support retail service offerings, those CRES providers have chosen to act merely as middle-men on capacity flowing from AEP Ohio to support retail generation service. Leaving aside the constrained ATSI zone where prices coincidentally increased to the same level as AEP Ohio's cost-based capacity charge proposal, the auction prices in the AEP zone for the next several years have dropped to levels that would prevent AEP Ohio from receiving anything remotely approaching full compensation from CRES providers for AEP Ohio's capacity costs. These dramatic price drops in the RPM market caused AEP Ohio to pursue its option before the FERC to establish a cost-based rate. While these CRES providers are using AEP Ohio's capacity resources, they (unlike AEP Ohio's non-shopping SSO customers) avoid paying the embedded generation capacity costs that are on the books of AEP Ohio.

AEP Ohio proposes several key actions to follow the Commission's lead in aggressively pursuing a fully competitive SSO environment, including: (1) opting into the RPM market starting in mid-2015 (the soonest possible date that AEP Ohio's existing FRR obligations can be terminated), (2) immediately pursuing full legal corporate separation to be effective by the end of 2013, (3) aggressively pursuing termination of the AEP Interconnection Agreement (aka generation Pool) at the end of 2013, (4) proposing competitive SSO energy procurement in 2013 and full SSO energy auctions for delivery in 2015, and (5) facilitating a fully competitive auction-based SSO structure by mid-2015. The net result of the Modified ESP's auction-based SSO and capacity transition is to achieve a fully competitive SSO in three years – half the minimum period that is possible under a Market Rate Offer. If adopted without further change, the Modified ESP would resolve the pending FERC litigation regarding capacity.

While some intervenors and Staff may complain that AEP Ohio is not getting "from Point A to Point B" quickly enough through these aggressive transitory measures, the fact remains that none of these actions are required under the current law. Further, it is simply not feasible or realistic to expect AEP Ohio to unwind such complex obligations like the Pool and the 2012-2015 FRR plan any faster than is being proposed. Adopting the Modified ESP without further changes would also resolve the *Section 205 FERC Application*[4] and the *Section 206 FERC Complaint*[5] presently pending before the FERC. On the other hand, the consequences of failing to adopt the Modified ESP's resolution of the capacity pricing issue must also be considered: protracted and extensive litigation at the Commission, at FERC, and in the federal and State courts.

Just as AEP Ohio does not regret its prior cooperative partnership with the Commission in keeping SSO rates below market, the Commission should not forget AEP Ohio's indisputable track record of making reasonable accommodations that benefit its customers. Likewise, the Commission should not deny – as a few intervenors would advocate – the regulatory history that lead AEP Ohio to the place it is today. More importantly, the Commission should act in accordance with that regulatory history and the Company's track record of cooperation in reaching a fair and reasonable decision in this case.

[4] FERC Docket No. ER11-2183-000

[5] FERC Docket No. EL11-32-000

II. REGULATORY HISTORY

After the passage of SB 3 in 1999, some Ohio utilities such as the FirstEnergy operating companies recovered billions of dollars of stranded investment costs under SB 3, based on the book value of their generation fleet being much higher than projected market prices. FirstEnergy argued that it would be financially weakened if forced to make full transition to market rates in the time stipulated. It asked for and received a two-phase, five-year transition, and a rate structure that paid it $7 billion to offset costs associated with the transition. The most significant component of these transition costs, approximately $4.9 billion, consisted of above-market generation costs.[6] In contrast, when AEP Ohio began its transition, it agreed not to pursue its opportunity to recover stranded generation costs through generation transition charges, and it would go on over the next decade to provide below-market generation rates for customers.

Following SB 3's market development period (MDP), when generation rates were supposed to be market-based, the Commission encouraged electric distribution utilities (EDU) to avoid market-based rates and to provide rate stabilization plans (RSP).[7] The RSPs were to promote rate certainty, financial stability, and allow for competitive market development prior to charging customers market-based rates.[8]

In AEP Ohio's RSP case, the Commission stated: "At the outset, we will note that AEP proposed a rate stabilization plan because we requested it."[9] The Commission found a competitive bidding process (CBP) would not be effective and that the Company's proposed

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[6] *See* Case No. 99-1212-EL-ETP, Direct Testimony of FirstEnergy Corp. witness Harvey L. Wagner at Attachment 9 (filed Dec. 22, 1999).

[7] *In re DP&L*, Case No. 02-2779-EL-ATA, September 2, 2003 Opinion and Order at 29 (*see also* AEP Ohio Ex. 120, Tab 1 at 29).

[8] *In re Ohio Edison*, Case No. 03-1461-EL-UNC, September 23, 2003 Entry at 4-5 (*see also* AEP Ohio Ex. 120, Tab 2 at 4-5); Tr. VII at 2231.

[9] *In re AEP Ohio*, Case No. 04-169-EL-UNC, January 26, 2005 Opinion and Order at 13 (*see also* AEP Ohio Ex. 120, Tab 3).

rates were more favorable to customers than the market-based rates would be because competitive markets had not adequately developed.[10] That finding was based on the fact that market prices for generation were higher and more volatile than the stable, low prices that AEP Ohio was providing through its regulated generation rates. As Exelon witness Fein confirmed in his testimony, market rates were generally higher than AEP Ohio's SSO rates during the RSP period. (Tr. XIII at 3535.) Moreover, Mr. Fein testified specifically that, although SB 3 permitted AEP Ohio to go to higher market rates starting in 2006, the Company was prevented from doing so through the RSP plan administered by the Commission. (*Id.*) In a long tradition of cooperative partnership with its regulator, AEP Ohio complied with the Commission's request and filed an RSP. Customers continued to enjoy favorable rates as a result.

At the same time, customers of Monongahela Power Company in southeast Ohio (Mon Power) 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 Monongahela Power (which had refused to submit an RSP) and AEP Ohio obliged.[11] In approving the betrothed 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.[12] 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.

AEP Ohio's cooperation with the direction provided by the Commission continued in other areas as well. Based on its desire to maintain the stable, low rates that AEP Ohio was providing and avoid retail customers being subject to the market, the Commission strongly

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[10] *See* AEP Ohio Ex. 120, Tab 3 at 14.

[11] *In re Monongahela Power*, Case No. 05-765-EL-UNC, June 14, 2005 Entry (*see also* AEP Ohio Ex. 120, Tab 5).

[12] *In re Monongahela Power*, Case No. 05-765-EL-UNC, November 9, 2005 Opinion and Order at 10 (*see also* AEP Ohio Ex. 120, Tab 6 at 10).

encouraged AEP Ohio to operate under the FRR option to serve its SSO load as a member of PJM. As an FRR entity, AEP Ohio must self-supply its capacity to serve its load (rather than procuring it through the RPM market) and it has the option to establish cost-based charges for CRES providers using its capacity to serve retail customers. In its public comments, the Commission Staff complimented the FERC for accepting this approach. (Tr. VIII at 2451-53; AEP Ohio Ex. 125.) Staff witness Dr. Choueiki explained that "the Ohio Commission was, the Ohio staff at that time, was interested in making sure that we have an alternative in case, you know, RPM goes – the results are not beneficial to Ohio, we wanted to have that alternative to go under a traditional resource requirement." (Tr. VIII at 2453.)

Though IEU (and other intervenors) now feverishly advocate the redeeming qualities of the RPM capacity market, that self-serving admiration is a product of recent market developments and has not been the case for long. The current RPM price (in effect at the time this Modified ESP was filed) was the result of a Base Residual Action (BRA) conducted in May 2008, which was also when Governor Strickland signed SB 221. (Tr. X at 3050.) Just a few months prior to that, a document presented on behalf of IEU complained that "PJM is pushing its *very expensive* RPM (reliability pricing model) proposal and contending with strong opposition from almost every stakeholder sector," lamenting that RPM should be renamed the "*revolting* pricing model." (Tr. X at 3052-53 (emphasis added).) As with many of its positions, IEU's pejorative moniker and perspective on RPM has flip-flopped.

In any case, AEP Ohio once again followed the Commission's direction in opting out of RPM market as an FRR entity and is now contractually committed to FRR capacity supply through May 31, 2015. 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. The General Assembly passed SB 221 to change Ohio's regulatory framework once again. During the legislative debates leading up to passage of SB 221, IEU advocated for re-regulation and partially succeeded. As reflected in IEU's "Electricity Post 2008: A Common Sense Blueprint for Ohio," IEU recommended that the statutory declaration that generation service is competitive be repealed, so that generation could be classified as a noncompetitive service which "would better align Ohio law with reality" and would make generation service subject to traditional cost-based standards for pricing. (AEP Ohio Ex. 136 at 2, 10-11.) IEU's Common Sense Blueprint also successfully advocated for reversal of R.C. 4928.17(E)'s declaration that generation assets could be freely transferred, in order to avoid "schemes like those of Monongahela Power," who "threatened to go to market" to competitively procure generation supply at market prices. (*Id.* at 2, 5.) The Common Sense Blueprint also stated that "[t]he term 'market-based' is not defined by Ohio law or PUCO regulations" and suggested that the Commission should assert control to avoid "rate shock" that would be caused by going to higher market prices. (*Id.* at 4-7.) IEU's Common Sense Blueprint also concluded that "[t]here is nothing in SB 3 that requires an auction or competitive bidding process to be used to establish a 'market-based' price for the SSO." (*Id.* at 7.) During the same pre-SB 221 period, IEU advocated against adopting an EDU- proposed competitive bidding process, asserting that rate shock "is built into auction-driven electric pricing" and predicting that "the auction results are almost certain to produce prices significantly higher than they are today." (AEP Ohio Ex. 137 at 3-4.) As important as IEU's legislative successes are to understand, its unsuccessful advocacy of several additional concepts at that time reveals a more accurate view of reality and severely undercuts IEU's present claims regarding SSO requirements its proposed blanket prohibition of "above market" cost recovery.

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 is a new and extended period of transition to reach fully market-based rates. Unlike the prevailing 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.

Under SB 221, AEP Ohio once again presented a re-regulatory proposal in 2008 as its first ESP (*ESP I*). Specifically, 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." *ESP I*, March 18, 2009 Opinion and Order at 72. More specifically, the Commission's *ESP I* decision found, based on the testimony of then-Staff witness Hess, that the cost of the proposed ESP ($1.4 billion) was less than half of the expected cost of an MRO ($2.9 billion). (AEP Ohio Ex. 134 at 72.) 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. (Tr. X at 2993-94; *see also* AEP Ohio Ex. 132 at Ex. JEH-1.) Further, AEP Ohio Ex. 142 (at 18) shows that the prevailing market price during 2008 (when SB 221 was passed) was substantially higher at 8.52¢/kWh, while the *ESP I* Opinion and Order (at 22) ordered that the generation rates for 2009 were not to exceed 5.47¢/kWh and 4.29¢/kWh for the CSP and OP rate zones, respectively, on average. The cooperative partnership between AEP Ohio and the Commission thus continued after passage of SB 221, accruing substantial benefits to customers and the State of Ohio.

SB 221's hybrid re-regulatory approach (applicable today) does not require market rates (even under the so-called market rate offer) until after a long transition period – but it does permit cost-based rate adjustments, among other features. Thus, one stark difference between SB 3 and SB 221 is that SB 221 requires an additional 6-10 year transition period to get to fully market-based rates. While the original SB 221 as enrolled contained language in R.C. 4928.142 that enabled the Commission to more aggressively blend market rates and SSO rates under the MRO rate blending transition period (which also applies indirectly to ESP plans through application of the MRO test), a subsequent piece of legislation passed later in 2008 made the 6-10 year transition to market mandatory and removed the Commission's discretion to adopt a quicker transition period. *See* Am.Sub.H.B. No. 562. In any event, SB 221's ultimate extended transition period to market pricing (which applies directly and indirectly to an MRO and an ESP, respectively) severely undercuts the present argument by some intervenors that today's SSO rates must be fully market-based and cannot have cost-based rate adjustments. There is simply no basis for that point under SB 221.

III. OVERVIEW OF THE PROPOSED MODIFIED ESP

A. Executive Summary Of The Modified ESP

As indicated by the numerous AEP Ohio witnesses in this case the Modified ESP plan applied the guidance provided by the Commission in previous entries and provided a balanced approach to transitioning the AEP Ohio territory to a more sustainable competitive environment. To accomplish this goal the plan had to provide some benefits and compromises to the interests of many stakeholders. But by balancing those interests in a fair manner it provides a plan the Commission can approve as-filed that will set the framework for the competitive system sought by the Commission.

The specifics of the proposed plan provide for different actions as different dates within the term to provide different benefits including the transition to a competitive bid process for the standard service offer.[13] The overall ESP term is set to be June 1, 2015 through May 31, 2015. However, six months after the final orders in the ESP and corporate separation cases, AEP Ohio has committed to holding a 5% auction for standard service offer through a competitive bid as part of the overall balance of the plan. Then on January 1, 2015 through May 31, 2015, AEP Ohio is proposing to conduct an energy auction for 100% of the standard service offer load. Those steps will then allow AEP Ohio to begin with full delivery and pricing of its standard service offer service through a competitive bid process starting June 1, 2015. Until such time as the capacity portion of the standard service offer for shopping customers can be included in the competitive bid in June of 2015, the plan involves the discount of capacity prices for CRES providers serving shopping customers in AEP Ohio's certified territory.

[13] The testimony of Robert Powers (AEP Ohio Ex. 101) also gives an overview of the plan including a bullet summary of the ESP plan found in his exhibits at RPP-1.

The proposed plan includes a few riders to enable the Company to move forward as directed by the Commission and provide some necessary elements in the plan. The retail stability rider (RSR) mitigates the financial harm to the Company of offering integrated ESP package of terms and conditions, including the discounted capacity pricing. The RSR is a critical component of the Modified ESP because it helps maintain financial stability for AEP Ohio during a period of transition, thus enabling the various pro-competitive and SSO pricing proposals reflected in the Modified ESP. Without the RSR, the Modified ESP could be difficult or impossible to pursue – depending on the outcome of the Capacity Charge docket.

The distribution investment rider or DIR allows for continued investment in the distribution system tied to reliability improvements. The rider was also previously assumed in the Company's last distribution case settlement in 11-351-EL-AIR et. al, providing an offset to the increase in rate base in that case, a credit to residential customers, and funding for the continuation of Partnership with Ohio's participation in AEP Ohio's Neighbor to Neighbor program to assist at-risk populations to pay their electric bills. The DIR is supposed to fund those elements from the distribution case, plus provide the benefit of increased investment in the distribution system for the benefit of all customers.

The Company also proposed the establishment of the alternative energy rider (AER) and the generation resource rider (GRR). The AER is a recovery mechanism to support the request for an alternative energy renewable credit tracking system. The creation of this rider will allow the Commission and others to see exactly what is attributed to alternative energy and deal with any associated renewable energy certificates that may arise under those arrangements. The GRR is intended to serve as a placeholder to authorize the Turning Point Solar project in Southern Ohio if the Commission later determines that AEP Ohio should move forward with the project.

The ESP statute allows the Commission some greater flexibility than previous regulation, and the ability to set up a mechanism like the GRR and later determine whether AEP Ohio should move forward with production puts the Commission in control of Ohio's destiny and preserves safety mechanisms for the Commission and Ohio customers. The GRR will only be populated with actual costs if the Commission later determines that is appropriate. These new riders being proposed as part of the Company's ESP are integral to providing the balance needed for AEP Ohio to move forward under the proposed plan.

The proposed plan also includes the continuation of mechanisms through the term of this ESP that were previously approved by the Commission in the prior ESP or established as a result of items in the recent cases like the distribution rate case settlement. Those items include the more well known items such as: the Universal Service Rider fund, Deferred Asset Recovery Rider, kWh Tax Rider, Residential Distribution Credit Rider, Pilot Throughput Balancing Adjustment Rider, Transmission Cost Recovery Rider, EE/PDR, Economic Development Rider, Enhanced Service Reliability Rider, gridSMART® Rider,[14] Electron Transfer Rider, Renewable Energy Credit Purchase Offer Rider, Renewable Energy Technology Program Rider, and the Fuel Adjustment Clause (unified in 2013). Each of these are tied to programs already or previously approved by the Commission and are necessary for continuation of the programs and to provide the proper accounting. For the complete list please review the pre-filed testimony of Company witness David Roush (AEP Ohio Ex. 111), attachment DMR-4, that lists all of the mechanisms that are part of the plan.

The plan also eliminates some riders previously approved or raised before the Commission. Specifically, the plan eliminates the Emergency, Curtailable Service Rider, Energy

[14] gridSMART is a registered trademark of AEP.

Price Curtailable Service Rider, and the Environmental Investment Carrying Cost Rider that is not combined with the base rate. These riders will no longer be formal mechanisms for the Company's functions.

The Company also seeks treatment of some other mechanisms to position AEP Ohio to fulfill the goals of the Commission. For instance, AEP Ohio is proposing to delay the collection of the Phase in Recovery Rider (PIRR) of the deferred fuel from the first ESP until 2013. As proposed by the Company this is proposed to help alleviate any rate impacts of the immediate plan and coincide the merger of the fuel adjustment clause between the two rate zones which will result in offsetting the PIRR costs. The Company also seeks a Storm Damage Recovery mechanism as part of the balance ESP proposal. The approval of this mechanism provides the Company accounting authority to recover the incremental expenses incurred as a result of major storms and provide the ability to address storm outages without taking funds from the work planned and being done every day in the certified territory. The other accounting mechanism that is sought to be created in the proposed ESP is the Pool Termination Provision. This request concerning the pool termination is solely seeking permission to file a subsequent application if needed to recover lost revenues as part of the termination of the pool and move to competitive markets. The Commission would still have full control of that proceeding and the Company would not file if the annual effect of the termination or new arrangement is less than $35 million. Finally, another main component of the plan is the approval of the Timber Road renewable energy purchase agreement. The plan seeks Commission approval of the recovery of the renewable contract costs through the fuel adjustment clause and the alternative energy rider.

The specifics of the varying elements of the plan can be found in the testimony of AEP Ohio witnesses, many of which are summarized in the next section of the brief. Regardless, the

Modified ESP is the only plan provided to the Commission in this proceeding that balances the interest of all parties and achieves the ultimate goal of the Commission.

B. Summary Of AEP Ohio Witness Testimony

AEP Ohio provided the testimony of 12 witnesses on direct and 2 on rebuttal in support of the reasonableness and balance of the Modified ESP.

Robert P. Powers, the Executive Vice President and Chief Operating Officer of AEP, presented testimony in this case presenting the overall Modified ESP and introducing the subject matter experts provided by the Company in support of the various ESP proposals. His pre-filed testimony was admitted as AEP Ohio Ex. 101 and his live testimony spanned Volumes I and II from page 26 to page 433. As indicated in his testimony, in accordance with the Commission's order on February 23, 2012, Mr. Powers' testimony provides an overview of the Company's Modified ESP plan, which covers the period from June 1, 2012 through May 31, 2015. He discusses AEP Ohio's commitment to a reasonable transition to a competitive market, the value that a competitive market involving a reasonable transition can provide to both customers and investors, and the unique risks within the State of Ohio's electricity environment. Mr. Powers discusses the balance between AEP Ohio's compromise solution in the Modified *ESP II*, which includes discounted capacity as well as a transition to market, and AEP Ohio's litigation position in the capacity charge proceeding(Case No. 10-2929-EL-UNC). He also discusses the necessity of receiving all of the benefits of the balanced package of terms in the proposed ESP, including a mechanism to help ensure AEP Ohio's financial stability during the transition in order for the Company to be in a position to provide discounted capacity and transition to a competitive auction as quickly as proposed.

Selwyn J. Dias, Vice President of Regulatory and Finance for AEP Ohio, also provided pre-filed direct and supplemental testimony for this proceeding. His pre-filed testimony was admitted as AEP Ohio Ex. 118 and his supplemental Commission-ordered testimony was admitted as AEP Ohio Ex. 119. Mr. Dias' live testimony is found in Volumes VI and VII from page 1821 to page 2206. . His pre-filed direct testimony discusses how the Modified ESP advances state policies, summarizes significant benefits of the Company's proposed plan, including additional customer benefits in the proposal compared to the stipulated agreement and compared to the original filing in January of 2011, and addresses certain proposed riders and their associated customer benefits. He also discusses how the elimination of the environmental rider providers rate certainty for customers and that the Company will take on the risk of the cost of future environmental investments. Mr. Dias also discusses the Company's alternative energy requirements for the Modified ESP's term. In his supplemental testimony, Mr. Dias further clarified the purpose of the RSR and the varying benefits of the balance of the overall Modified ESP filing.

Philip J. Nelson, Managing Director of Regulatory Pricing and Analysis for AEPSC, provides testimony that overviews the generation-related aspects of the Modified ESP plan including the corporate separation plan that has been filed in a separate application before this Commission. His pre-filed testimony was admitted as AEP Ohio Ex. 103, his supplemental Commission-ordered testimony was admitted as AEP Ohio Ex. 104, and his live testimony can be reviewed in Volume II from page 499 to page 728. He presents information responsive to the Commission's directive in its March 7, 2012 Entry in Case 10-2376-EL-UNC *et al*. to address the plan for AEP Ohio's generating assets, including retirements and divestitures. Mr. Nelson describes the SSO contract between AEP Ohio and AEP Generation Resources Inc. (Genco). He also discusses the current Fuel Adjustment Clause (FAC) and the Company's request to continue the FAC for part of the Modified ESP's term. Mr. Nelson proposes a new Alternative Energy Rider (AER) which will segregate the Renewable Energy Credit (REC) value from Renewable Energy Purchase Agreements (REPAs). He also discusses the creation of the GRR to recover costs associated with investment in new generation resources dedicated to retail customers. Finally, Mr. Nelson sponsors a pool termination provision to recover potential increases in rates if needed as a result of termination of the AEP Interconnection Agreement and if the Company's corporate separation plan is not approved. Mr. Nelson's supplemental Commission-ordered testimony discusses the revenue requirement associated with the costs of the Turning Point Solar facility during the ESP period.

David M. Roush, Director of Regulated Pricing and Analysis for AEPSC, provided testimony discussing AEP Ohio's requested rate relief that is supported by the various Company witnesses. His pre-filed testimony was admitted as AEP Ohio Ex. 111, his supplemental Commission-ordered testimony was admitted as AEP Ohio Ex. 112, and his live testimony is located in Volume IV from page 1060 to page 1251. Mr. Roush also described the required modifications to the Company's Tariffs and Terms and Conditions of Service, explained the design of the Company's proposed rates and certain riders, and provided the resulting rate impacts on CSP and OP rate zone customers. Mr. Roush's supplemental Commission-ordered testimony dealt with the potential rate impacts as impacted by the addition of costs for the Turning Point Solar facility.

William A. Allen, Director of Regulatory Case Management for AEPSC, provided testimony on capacity pricing and the related implementation plans as well as certain riders. His pre-filed testimony was admitted as AEP Ohio Ex. 116 and his live testimony in the direct case is located in Volume V at page 1363 to page 1690. Mr. Allen also provided rebuttal testimony that was admitted as AEP Ohio Ex. 151. His live rebuttal testimony is located in Volume XVII from page 4755 to page 4949. Specifically, he discusses the current level of shopping in AEP Ohio's service territory, the discounted capacity proposal to encourage shopping, the Distribution Investment Rider (DIR), and the proposed RSR. He also describes the current status of governmental aggregation programs in the AEP Ohio service territory and how the proposed ESP supports such programs. He also discusses an alternative option to the plan that utilizes shopping credits to encourage customer shopping. Mr. Allen's rebuttal testimony refutes claims by various parties relating to the RSR, DIR, and discounted capacity pricing. Mr. Allen also provides a response to statements made concerning the financial harm to AEP Ohio if FES witness Banks' recommendations are adopted.

Laura J. Thomas, Managing Director of Regulatory Projects and Compliance for AEPSC, provides testimony to support the Aggregate Market Rate Offer Test, which includes the development of Competitive Benchmark prices. Her pre-filed testimony was admitted as AEP Ohio Ex. 114, her supplemental Commission-ordered testimony was admitted as AEP Ohio Ex. 115, and her live testimony can be found at Volume IV from page 1257 to page 1343. She supports the MRO Price Test, which is only one of many elements that must be considered in evaluating the Modified ESP. Ms. Thomas'testimony, together with the Company's other witnesses, demonstrates that the Company's Modified ESP is more favorable in the aggregate than the expected results of an MRO. Her supplemental Commission-ordered testimony applied the revenue requirement provided by AEP Ohio witness Nelson for the Turning Point Solar facility to the MRO test.

Renee V. Hawkins, Managing Director of Corporate Finance for AEPSC and Assistant Treasurer of Ohio Power, provided testimony sponsoring AEP Ohio's capital structure and weighted average cost of capital (WACC) for the purposes of determining the carrying costs to be applied to Non-Fuel Adjustment Clause riders included in the proposed Modified ESP. Her pre-filed testimony was admitted as AEP Ohio Ex. 102 and her live testimony can be reviewed in Volume II from page 448 to page 497. Ms. Hawkins calculated the various components of the carrying charges for the various riders proposed as part of the Modified ESP and discussed by other witnesses. She also discussed both securitization and provided updated credit rating agency reports.

Oliver Sever, Managing Director of Financial Forecasting for AEPSC, provided testimony detailing the Company's pro forma financial statements for the term of the Modified ESP (July 2012 through May 2015). His pre-filed testimony was admitted as AEP Ohio Ex. 108 and his live testimony can be reviewed in Volume III from page 894 to page 958. His testimony describes the forecast methodology he utilized and provides an overview of the major assumptions required to develop this forecast.

Thomas Mitchell, Managing Director of Regulatory Accounting Services for AEPSC, provided testimony that described the over/under accounting for certain portions of the Modified ESP. His pre-filed testimony was admitted as AEP Ohio Ex. 107 and his live testimony is located in Volume III from page 847 to page 887. His testimony involved the FAC mechanism, the continuation of the remaining riders approved in the *ESP I* proceeding, and certain new riders proposed in the Modified *ESP II*. Mr. Mitchell also provided testimony on accounting deferrals proposed for future recovery.

Thomas Kirkpatrick, Vice President of Distribution Operations for AEP Ohio, provided testimony explaining how AEP Ohio maintains the present distribution system, including the current vegetation management program. His pre-filed testimony was admitted as AEP Ohio Ex. 110 and his live testimony is located in Volume IV from page 994 to page 1055. Mr. Kirkpatrick recommended that the Commission continue its support of the ongoing Enhanced Service Reliability Rider. He also described the current state of the AEP Ohio distribution system and the need for ongoing capital investment. Mr. Kirkpatrick additionally provided examples of the types of investments a Distribution Investment Rider would provide. He also discussed the volatility associated with major storms in Ohio and the need to establish a Storm Damage Recovery Mechanism.

Jay F. Godfrey, Managing Director of Renewable Energy for AEPSC, provided testimony supporting the Company's request for the Commission to establish prudency and allow for the cost recovery of the 20-year Ohio-based Timber Road wind REPA. His pre-filed testimony was admitted as AEP Ohio Ex. 109 and his live testimony can be reviewed in Volume III from page 964 to page 974.

Frank C. Graves, Principle and co-leader of the Utility Practice Area at The Brattle Group, provided testimony explaining the adequacy of the power supply when AEP Ohio switches from being an FRR entity to relying on capacity supplied via PJM's Reliability Pricing Model auctions. His pre-filed testimony was admitted as AEP Ohio Ex. 101 and his live testimony can be reviewed in Volume III from page 760 to page 842. Mr. Graves' testimony also describes how PJM's capacity markets operate, how they have performed, and what effects potential coal plant retirements could have on supply adequacy in AEP Ohio's service territory.

William E. Avera, President of FINCAP, Inc., provided rebuttal testimony rebutting the testimony of OEG witness Kollen and Ormet witness Wilson. Dr. Avera's rebuttal testimony was admitted as AEP Ohio Ex. 150. His live rebuttal testimony is located in Volume XVII from page 4676 to page 4750. Dr. Avera confirmed the reasonableness of using a 10.5% ROE in developing the RSR's revenue target and discussed the flaws in the other ROE witnesses' analyses.

IV. STANDARD OF REVIEW

Two key statutory standards apply to the Commission's consideration of AEP Ohio's Modified ESP proposal. First, the Commission must determine whether the provisions of the Modified ESP, 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 Modified ESP as part of the price test component of the MRO test, but the Commission needs to also consider the non-quantitative components over the term of the plan in order to fully examine whether the proposed Modified ESP is more favorable in the aggregate than the expected results under an MRO. As demonstrated below, the Modified ESP passes under the aggregate MRO test.

Second, if the Commission does not approve the Modified ESP as proposed and instead adopts changes or modifications to the proposed Modified ESP, AEP Ohio has the right to withdraw the Modified ESP 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 terms Modified ESP because many of the significant provisions presented in the Modified ESP may not even be possible in another context (*e.g.*, auction-based SSO, below-cost discount of wholesale capacity charge, deferred recovery of the Phase In Recovery Rider, *etc.*).

V. THE TERMS OF THE PROPOSED MODIFIED ESP ARE LAWFUL AND REASONABLE AND ADVANCE STATE ENERGY POLICIES.

As AEP Ohio witnesses' testimony demonstrates, the proposed Modified ESP provides the Commission with a balanced plan that advances a variety of state energy policies and provides a lawful and reasonable path to transition the AEP Ohio service territory to the type of competitive market envisioned by the Commission. The Commission directed the Company to modify the plan that the Company previously presented as part of the prior stipulation in this case. The Company did just that, balancing those parts of the prior plan that the Commission previously found beneficial with new provisions that ensure stability and an orderly transition that can be overseen by the Commission. The elements of the proposed Modified ESP balance the concerns of all parties involved, advance state and Commission energy policies, and heed the Commission's guidance regarding AEP Ohio's rapid transition to fully competitive, market-based SSO pricing.

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

1. The proposed base generation rates are reasonable.

In an effort to minimize overall rate impacts on customers and help stabilize non-fuel base generation rates, the Company is proposing to freeze current base generation rates until such time as those rates are established through a competitive bidding process. The Company's proposal to freeze non-fuel generation rates benefits customers by transferring substantial risk from customers to AEP Ohio while simultaneously achieving state policy goals. As explained by Company witness Dias, "[f]ixed non-fuel generation pricing for SSO customers ensures the availability of adequate, reliable, safe, efficient, nondiscriminatory and reasonable priced electricity", in furtherance of the state policy goal enumerated in R.C. 4928.02(A). (AEP Ohio Ex. 118 at 4.)

The Company in proposing only one change to the base generation charges included in its SSO tariffs. The change is to relocate the charges under the current Environmental Investment Carrying Cost Rider (EICCR) into base generation rates and to eliminate the EICCR. As explained in Company witness Roush's testimony, "[t]his change is simply a roll-in of the EICCR charges and is bill neutral for all customers." (AEP Ohio Ex. 111 at 8). Elimination of the EICCR provides greater price certainty for AEP Ohio's customers.

The Company's proposal to freeze its base generation rates until such time as those rates are established through a competitive bidding process is reasonable, provides rate stability and certainty for AEP Ohio's customers, and should be adopted.

2. Continuation and unification of the Fuel Adjustment Clause is reasonable.

The Commission approved AEP Ohio's current FAC, which began in 2009, as part of the Company's *ESP I* proceeding. The FAC recovers the actual cost of fuel and purchased power, including capacity and other variable production costs such as environmental variable costs. The Company's FAC is a well-established rate adjustment mechanism in accordance with R.C. 4928.143(B)(2)(a).

The Company proposes to continue the FAC during the term of this ESP but only until January 1, 2015, after which time the Company's SSO load will be supplied through the auction process. For the period of the ESP between corporation separation (January 1, 2014) and the 2015 full requirements auction, the Genco will bill AEP Ohio its actual fuel costs in the same or similar form and detail as contained in the current FAC monthly accounting performed by AEP Ohio. AEP Ohio would then recover those costs through the FAC. As discussed in the following section, the Company is proposing to modify the FAC by separating out the REC expense component of the fuel clause and recovering the REC expense through the proposed AER. AEP Ohio witness Nelson sponsors the continuation of the FAC and the establishment of the AER in his testimony. (*See* AEP Ohio Ex. 103 at 14-20.)

AEP Ohio witness Roush supports the Company's proposal to unify the FAC rates for the two rate zones (CSP and OPCo) into a single set of merged rates to be effective June 2013. (AEP Ohio Ex. 111 at 5-6.) The Company is proposing to delay unification of the FAC rates until June 2013 to coincide with the implementation of the Phase-In Recovery Rider (PIRR). (*Id.* at 6.) Simultaneously unifying the FAC and the PIRR limits the impact on both CSP and OPCo rate zone customers and is a benefit of AEP Ohio's proposed ESP. (*Id.*) Staff witness Turkenton also recommends merging the FAC rates and agrees that simultaneously unifying the FAC and PIRR limits the impact on both CSP and OPCo rate zone customers:

> [O]nce you merge fuel and the PIRR, which is my recommendation to do them simultaneously, CSP customers are advantaged. Under nonmerging, they actually have a slight increase.
>
> ***
>
> I do think if you're going to merge fuel, you should merge fuel. So if you merge the FAC, you should merge the PIRR. But absent that, from a rate impact standpoint, the company is a merged company and, as I stated before, there really is little effect or little difference, I guess, in terms of CSP customers do benefit a little bit, but in terms of Ohio Power merging or not merging is really essentially the same as Company Witness Roush pointed out that I agree with. So it makes no sense to not merge. We should merge.

(Tr. XVI at 4539-4540.) AEP Ohio witness Roush quantified the benefit of simultaneously merging the FAC and PIRR in his testimony. The table on the top of page six of Mr. Roush's testimony shows a net decrease in rates of $0.69/MWh for a typical CSP transmission voltage customer and a net increase in rates of $0.02/MWh for a typical OPCo transmission voltage customer. (AEP Ohio Ex. 111 at 6.)

As the Company has demonstrated, continuation and unification of the FAC is reasonable and should be approved. Additionally, as acknowledged by Staff witness Turkenton, simultaneously unifying the FAC and PIRR as proposed by the Company is reasonable and results in a limited rate impact for both CSP and OPCo rate zone customers. The Commission, therefore, should approve each of these proposals.

3. Establishment of the Alternative Energy Rider is reasonable.

The Company proposes to begin recovery of REC expenses, associated with REPAs or direct REC purchases, via the AER upon implementation of this ESP. The energy and capacity portions of renewable energy cost will continue to be recovered under the FAC, while it still exists. After the FAC terminates, energy and capacity associated with REPAs will be sold into the PJM market and netted against the total cost of the REPAs, leaving only the residual REC expense to be recovered from SSO customers via the AER. The AER will be bypassable for those customers who switch to another supplier.

In his testimony, AEP Ohio witness Nelson sponsored the AER proposal, discussed how the value of the REC will be determined when purchased as part of REPA, and explained the accounts that would be split out from the FAC into the AER. (AEP Ohio Ex. 103 at 18-19.) The AER is consistent with R.C. 4928.143(B)(2)(a) and is essentially a partial unbundling of the FAC to provide greater price visibility of prudently-incurred REC compliance costs under R.C. 4928.66. The Company will make quarterly filings, in conjunction with the FAC, to review the AER.

Staff witness Strom testified in support of the rider, stating that he finds it reasonable and does not oppose the establishment of recovery of costs. (Staff Ex 104 at 2; Tr. VIII at 2503.) Mr. Strom's only concern related to a desire to have an audit process related to the rider, which can be addressed and accommodated. (*Id.*) Thus, the establishment of the AER for recovery of costs is uncontested, reasonable, and should be approved.

4. The proposed Generation Resource Rider placeholder is reasonable.

AEP Ohio proposes to establish the GRR, a nonbypassable rider, to act as a placeholder until such time as the Commission approves any project-specific costs to be included in the GRR. The GRR is designed to recover renewable and alternative capacity additions, as well as more traditional capacity constructed or financed by the Company and approved by the Commission in accordance with R.C. 4928.143(B)(2)(c). At this time, the GRR will only be used for future recovery of the proposed TPS project, if that project is approved by the Commission in a separate proceeding. It is not expected that there will be any additional projects included in the rider during the term of this ESP.

At the hearing, some intervenor witnesses expressed concern over the proposed nonbypassability of the GRR based on a misunderstanding of how the mechanism is intended to work. (*See* Tr. V at 1700-1702 (Wal-Mart witness Chriss); Tr. IX at 2648-2649 (NRDC Witness Lyle); Tr. XV at 4318-4319 (IGS Witness Parisi); Tr. XVI at 4500 (FES Witness Banks).) Much, if not all, of the concerns raised by these witnesses rested on the flawed assumption that if the rider was nonbypassable, shopping customers would receive no benefit from the projects recovered through the GRR despite paying for the costs associated with the project. This concern is unfounded for two reasons. First, as explained by Company witnesses Roush and Dias, because a customer can periodically switch between shopping and not shopping, it is likely that all customers will at some point benefit from projects recovered through the GRR – this is especially true considering the expected life of a generating facility like the TPS facility is nearly 25 years. (Tr. IV at 1166-69; Tr. VII at 2057-2060.)

Second, the Company has proposed that the energy and capacity associated with the TPS facility be sold in the market and the revenues from those sales credited against the cost of the facility recovered through the GRR, thereby reducing the costs to be recovered under the GRR. Both shopping and non-shopping customers would receive the benefit of these offsetting revenues. Moreover, as Company witness Dias explained, "the RECs that come out of the Turning Point Solar Project will be divided each year between the SSO customers and those customers that shopped" such that the "value of those RECs will ultimately get distributed back out to SSO customers and CRES providers." (Tr. VII at 2139-2140.) Accordingly, both shopping and non-shopping customers would in fact receive benefits as a result of the TPS project and the GRR in general. Thus, nonbypassable cost recovery is both appropriate and reasonable, not to mention statutorily permitted under R.C. 4928.143(B)(2)(c) so long as certain requirements enumerated in that section are met.

To be clear, the Company is not seeking recovery of any costs associated with the TPS project at this time, nor is it now seeking approval of any GRR rates. The Company will seek Commission approval of the nonbypassable charge for the life of the proposed TPS facility in a later proceeding after the Commission determines the need for the facility in Case Nos. 10-501-EL-FOR and 10-502-EL-FOR ("*Need Cases*") and establishes the GRR as requested in this proceeding. For now, the GRR would be a placeholder rider established at a level of zero. The Commission can establish the process for its review of the ultimate costs and decide whether to move forward with the Turning Point project as part of this case, but those ultimate decisions on the final costs need not be finalized at this point in time. The Commission has the 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*.

It is premature, therefore, to include as a cost under the Company's current ESP proposal the costs associated with the TPS project. As explained further below in Section VI.E.4, assuming, *arguendo*, that the costs of the TPS project should be included in the consideration of whether to approve the GRR in this case, it would be appropriate to consider only those project costs expected to be incurred during the term of this ESP, not the total costs to be incurred over the 25-year life of the project as OCC witness Hixon had done in her ESP versus MRO comparison. (Tr. XII at 3298.) However, as Staff witness Fortney explained, it would be inappropriate to consider any costs associated with the TPS project in this proceeding, especially costs to be incurred beyond 2015, because those costs are unknown. Specifically, he testified:

> [W]hether or how much the Commission will allow [the Company] to recover for [sic] in the GRR rider is the subject of another hearing at a future time, future unknown time, and [the Company] will be applying for future unknown costs, and I just did not believe it was a valid cost to include as part of the ESP because it's unknown.

(Tr. XVI at 4589).

Staff witness Fortney also testified in support of the GRR, noting the state policy goals achieved through the rider: "if there is an established need for additional generation in the future, the GRR provides a mechanism to enable the Commission to allow for the construction of generation facilities, while committing to the diversity of state supply, and allowing the applicant to fulfill its REC obligations." (Staff Ex. 110 at 7.)

The Company is proposing the GRR merely as a zero-cost placeholder rider at this time. Any consideration of the costs associated with the TPS facility, or the allocation of costs under the rider, is premature and are appropriately left for consideration in other dockets. The Commission should still recognize the process it outlined for the determination of need in its rules through the resource planning process and should formally recognize the pending outcome of the *Need Cases* as part of this decision in this proceeding. As proposed by the Company, the GRR is reasonable and should be approved.

5. The proposed interruptible service rates are reasonable.

AEP Ohio is proposing to restructure, and expand, its existing interruptible service offerings to reflect the transition to participation in the PJM Base Residual Auction in the June 2015 to May 2016 delivery year and the transition to the use of a competitive bid process to meet AEP Ohio's SSO obligation. As Company witness Roush explained:

> In today's environment, interruptible service is more typically represented as an offset or modifier to firm (standard) service rates than as a separate and distinct rate. As such, Schedule Interruptible Power—Discretionary (IRP-D) will be restructured as a Rider IRP-D. A modified rider IRP-D will be available to existing schedule IRP-D customers and new customers desiring interruptible service, subject to the Rider provisions related to maximum enrollment, during the ESP period.

(AEP Ohio Ex. 111 at 8). The costs associated with Rider Interruptible Power – Discretionary (IRP-D) will be collected through the RSR. Upon approval of the RSR, OPCo is willing to increase the IRP-D credit to $8.21 per kw-month.

While no party outright opposes Rider IRP-D, OCC witness Ibrahim suggests a different methodology for allocating the costs of the rider, and Staff witness Scheck calculates a different dollar amount for the credit. These positions are internally inconsistent and untenable for several reasons. OCC witness Ibrahim recommends that only those customers who are eligible to take interruptible service should be responsible for the costs associated with the IRP-D Rider (Tr. VII at 2258-2259; 2270.) Notwithstanding this position, Mr. Ibrahim recognizes that even customers who aren't eligible to take interruptible service benefit from its existence (*id.* at 2289-2290) and also admits that his approach "will discourage customers from participating in the IRP-D program." (*Id.* at 2296-2297). The inherent disconnect between Mr. Ibrahim's proposal and the acknowledged outcome discredits him as a witness. All customers, whether directly (by receiving a credit for taking interruptible service) or indirectly (by paying lower rates and receiving more reliable service) benefit from the existence of interruptible service offerings. As Company witness Roush explained, "the genesis of IRP was, rather than having to build additional generation, having interruptible reduced costs for all customers and a credit was given to those customers who accepted that lower level of service." (Tr. IV at 1126.)

Staff witness Scheck miscalculates the credit under the IRP-D rider to be $3.34 per kw-month for customers who take interruptible service, as opposed to the Company's $8.21 per kw-month credit if the RSR is approved. In calculating his figure Mr. Scheck improperly relied on the price of capacity paid by shopping customers as the basis for determining the interruptible credit, despite recognizing that only non-shopping customers are eligible for taking interruptible service: "[t]he value of the interruptible credit would be based on the $146.47 that Ms. Medine put forward which would translate to $3.44 per kW per month as an interruptible credit." (Tr. XV at 4138). Because non-shopping customers pay a price for capacity that reflects the Company's fully embedded costs and because only non-shopping customers are eligible for interruptible service, Mr. Scheck's calculation of the credit utilizing a discounted price for capacity is inappropriate and should be rejected.

As the Company's witnesses demonstrated, and as OEG agrees in its initial post-hearing brief, *see* Post-Hearing Brief of The Ohio Energy Group at 11-21 (June 25, 2012), the interruptible service rates that the Company proposes are reasonable and should be approved.

6. The proposed Retail Stability Rider is reasonable.

i. Overview of the proposed RSR features and benefits

The Modified ESP includes establishment of a nonbypassable Retail Stability Rider (RSR). Because the Company is proposing the RSR as part of the integrated package of terms and conditions in the proposed ESP, including but not limited to highly discounted capacity pricing to support shopping load, the Company would be in a precarious financial position during the ESP term without the RSR. This would cause the Company to implement significant cost controls and could trigger negative job impacts in Ohio. In order to provide stability and certainty to both customers and the Company, the RSR is a generation revenue decoupling charge that shopping and non-shopping customers would pay during the period prior to June 2015 when the Company will no longer be providing capacity to serve its entire connected load as an FRR entity. Moreover, the RSR is appropriate mechanism to reflect and mitigate some of the risks AEP Ohio will incur in being the Provider of Last Resort, as discussed above.

While some parties initially understood the RSR to be linked exclusively to the discounted capacity charges or to the level of shopping, AEP Ohio witness Dias filed supplemental direct testimony to clarify that the purpose of the RSR is to allow AEP Ohio to meet a number of Ohio policy objectives while protecting the financial integrity of the Company during the transition period:

> This includes the ability (1) to freeze non-fuel generation rates, (2) to provide highly discounted capacity pricing to CRES providers to encourage Ohio shopping, (3) to meet its PJM FRR and Interconnection Agreement (Pool) obligations, and (4) to move to

> auction based SSO pricing faster than the law can require - all while balancing Ohio's expedited transition to a fully competitive auction bid process by June 1, 2015. Without the RSR non-bypassable rider mechanism, AEP Ohio will be financially harmed by being forced to adhere to obligations entered into prior to the Commission's renewed vigor and expedited focus towards full competition in the near term. Approving the Modified ESP II integrated package allows for mitigation of Ohio electricity investment uncertainty, decreased Ohio energy investment turmoil, and a continuing partnership with state and local agencies to attract new investment and associated job growth within the state.

(AEP Ohio Ex. 119 at 1-2.)

AEP Ohio witness Powers also described the need for the RSR as being tied to the total ESP package and not just the discounted capacity pricing:

> From the Company's perspective, the need for a RSR charge stems largely from the financial harm to AEP Ohio that would otherwise result from the Modified ESP package as a whole. For example, the three-year FRR commitment the Company has with PJM to supply capacity for AEP Ohio load, as well as the obligations that AEP Ohio has under the existing system Pool Agreement, must be considered as AEP Ohio transitions to market. Although the Modified ESP II plan commits the company to a full competitive auction bid process for AEP Ohio's SSO by June 1, 2015, the Company must continue to meet its PJM capacity obligations during the interim. The need for a reasonable transition stems from AEP Ohio's contractual FRR and Pool Agreement obligations as well as its reliance on more than a decade of direction from the Commission to avoid subjecting customers to market-based generation rates. Despite its legal commitments, the Company is offering to discount its capacity and will also continue to offer base generation rates at existing levels and bear the going-forward risk of environmental compliance. In exchange for offering these and other benefits of the proposed ESP package, the Company proposes a RSR to decouple generation revenues over the ESP II term ending May 31, 2015. The RSR will provide economic stability and certainty for AEP Ohio, our customers and other stakeholders during the market transition term of the Modified ESP II and until corporate separation and the Pool Agreement elimination is complete.

(AEP Ohio Ex. 101 at 18-19.) Thus, the RSR is premised on the package of terms and conditions in the Modified ESP in order to provide some measure of financial stability to the Company in exchange for the rate stability and other benefits that customers will receive under the Modified ESP proposal.

Mr. Dias further clarified the key customer benefits tied to the RSR in his Supplemental Direct testimony:

- Frozen non-fuel generation rates: These non-fuel generation rates are proposed to be frozen at levels equivalent to those that were in effect at the end of the 2009-2011 ESP. This action will result in AEP Ohio bearing the risk of making any generation related investments, including but not limited to, the environmental retrofit investments and expenses required by EPA rules.

- Tempered rate increases: The proposed rate increases to individual customers in every class, will be modest during the term of the ESP II – see Company witness Roush direct testimony;

- Discounted Capacity: Higher percentages of Tier 1 priced capacity are achieved for governmental aggregation initiatives, non-mercantile customers, in 2012 even if the level of Tier 1 Set-Aside has been exceeded – see Company witness Allen's direct testimony;

- Certainty and Stability: Stability is provided by the approval of the generation RSR mechanism which is coupled with a delay in the implementation of the Phase-In Recovery Rider and unification of the FAC, in order to minimize customer rate impacts – see Company witness Roush's direct testimony.

(AEP Ohio Ex. 119 at 4.) All of these major provisions and features of the Modified ESP are tied to being able to collect the RSR. In addition, Mr. Dias also testified that the RSR enables the Company to enhance AEP Ohio's economic development efforts through an increased IRP-D credit (since the existing IRP-D credit is reflected in base generation revenues used to calculate the RSR revenue target recovery, as explained below). (AEP Ohio Ex. 118 at 12.) Thus, the

RSR is an integral component of the Modified ESP without which the plan could not stand as proposed.

Conversely, there are also adverse consequences of not adopting the RSR as proposed. Mr. Dias generally described the potential consequences of rejecting the RSR:

> Without the regulatory certainty and stability provided by AEP Ohio's request within the state of Ohio, it would be irresponsible of AEP Ohio management to promote new investment beyond required spending to meet AEP Ohio's obligation to serve. Future cash flows for AEP Ohio impact investment and spending decisions that can impact its assets and community partnerships. The decrease in value of the Company could lead to lower property taxes. Property tax decreases are an important link in the chain funding communities and other local organizations. Unless mitigated, the ripple effect across AEP Ohio's distribution territory will continue to decrease area jobs across the entire supply chain. Without approval of the RSR and the corresponding reduction of regulatory risk within Ohio, modifications to the proposed ESP could cause AEP Ohio to minimize spending in the state which could lead to broader financial harm.

(AEP Ohio Ex. 119 at 6.) During his cross examination, Mr. Powers also addressed the potential negative impact of discounting capacity charges without the RSR on AEP jobs in Ohio, as follows:

> Q. And your belief is also that if AEP Ohio is compelled to charge for capacity using RPM market pricing, it could cost thousands of Ohio jobs.
>
> A. Yes.
>
> Q. Have you performed any analysis of the job impact of using RPM-based pricing over the next three years?
>
> A. I mentioned earlier this morning or early this afternoon that if the balance as provided in this ESP is not struck at discounted capacity to CRES providers, mitigation of rate impact to customers, mitigation of financial harm to AEP, there's a $650 million a year impact to AEP Ohio's revenues. $650 million is a lot of money and that's a lot -- and we would have to take action in response as we discussed in my deposition and, unfortunately, one

> of the actions we'd have to take is to reduce O&M expense in response like any business would and that, unfortunately, involves jobs.
>
> So, yes, I think $650 million a year impact can be pretty straightforward, in a straightforward manner be linked to jobs in Ohio.

(Tr. I at 257-258.) Mr. Powers also added with respect to job cuts "I hope that doesn't come to pass." (Tr. I at 258.)

AEP Ohio witness Allen described the proposed RSR as being similar to a generation decoupling mechanism. (AEP Ohio Ex. 116 at 13.) As a result of being a generation revenue decoupling mechanism that is based on the entire package of terms and conditions, including the below-cost capacity charges to CRES providers, Mr. Allen acknowledged that one effect of the RSR would be to replace a portion of lost revenue associated with shopping customers served through CRES providers that rely on the discounted capacity. (*Id.*) Mr. Allen also explained the basis for the RSR proposal's annual non-fuel generation revenue target of $929 million and set forth an example of how the RSR would be calculated in his Exhibit WAA-6. The $929 million non-fuel generation revenue target was based on 2011 financial results adjusted down to a 10.5% return on equity and reflects a $3/MWh credit for shopped load related to possible energy margins that could be realized by AEP Ohio for reductions in SSO load. (*Id.* at 13-14.)

As Mr. Allen explained in his testimony, using an annual revenue target instead of an earnings target is preferable because: (i) revenue decoupling provides greater stability and certainty for customers; (ii) revenues are easy to objectively measure and audit, whereas earnings are more prone to dispute and litigation as proven by the SEET proceedings; (iii) operational and cost risk of generation operations are borne by AEP Ohio under a revenue approach; (iv) AEP Ohio can make spending decisions for their generation assets with a focus on the transitional nature of the assets; (v) a revenue-focused approach avoids the need for and the complexity of evaluating the returns of a deregulated entity post-corporate separation. (*Id.* at 15.)

As set forth in Mr. Allen's testimony, the proposed RSR would be designed to collect a total of $284 million over three years. (AEP Ohio Ex. 116 at Ex. WAA-6.) AEP Ohio witness Roush explained the rate design for the RSR as being a per kWh charge that varies by customer class, based on an allocation of the class's average contribution to AEP Ohio's load during the five highest peak loads. (AEP Ohio Ex. 111 at 12.) The RSR would be subject to over-under accounting, in order to enable accounting deferrals and/or reconciliation to the annual revenue target, as explained by AEP Ohio witness Mitchell. (AEP Ohio Ex. 107 at 9.) As Mr. Roush explained, there will be an annual reconciliation of the RSR with a final true-up shortly after the ESP term. (AEP Ohio Ex. 111 at 12-13.) Details of the initial proposed rates for each customer class are found on Mr. Roush's Exhibit DMR-3. (*Id.* at Ex. DMR-3.)

There are multiple bases for justifying the RSR from a legal standpoint. Division (B)(2)(d) of the ESP statute, R.C. 4928.143, supports approval of the RSR, as that provision permits charges relating to default service that have the effect of stabilizing or providing certainty regarding retail electric service. Division (B)(2)(e) of the ESP statute also permits automatic increases or decreases and encompasses a revenue decoupling mechanism relating to SSO service such as the RSR. Further, to the extent that RSR also promotes economic development and job retention, as discussed above, division (B)(2)(i) also provide an additional source of authority for the RSR. Moreover, if the Commission uses the RSR in conjunction with the capacity charges approved for CRES providers to compensate AEP Ohio for its capacity resources dedicated to support retail shopping, there may be additional legal bases to justify the RSR. In addition, AEP Ohio witness Dias testified to numerous customer benefits under the

Modified ESP and demonstrated in detail how Ohio energy policies are advanced by the Modified ESP. (AEP Ohio Ex. at 118 at 8-14, 3-7.)

Finally in this regard, the Commission has already adopted a similar charge for Duke Energy Ohio in its recent SSO case. *See* Case Nos. 11-3549-EL-SSO et al., November 22, 2011 Opinion and Order adopting a nonbypassable Electric Service Stability Charge (ESSC) that conveys $330 million to Duke Energy Ohio (Stipulation Para. VII.A). As Exelon witness Fein stated in his testimony, Duke's ESSC was a "similar construct" to AEP Ohio's proposed RSR. (Exelon Ex. 101A at 9.) In sum, there are no legal barriers to adoption of the proposed RSR and there is ample factual and policy reasons for doing so, as outlined above.

ii. The RSR should be used to avoid any adverse financial harm to AEP Ohio resulting from a parallel decision in the Capacity Charge docket, Case No. 10-2929-EL-UNC.

AEP Ohio submits that the Commission has a duty to avoid imposing a rate plan that, in tandem with the expected decision in the capacity charge docket (Case No. 10-2929-EL-UNC), results in confiscatory rates through an unconstitutional taking of the Company's property without adequate compensation. This is especially true during the period in which AEP Ohio remains an integrated utility pursuant to Commission-approved functional corporate separation plans. Because there are various potential outcomes of the pending capacity charge docket, which may be decided during the course of the Modified ESP briefing cycle, it is necessary to address the RSR in the context of a number of potential outcomes in the capacity charge docket.

Division (D)(4) of the MRO statute, R.C. 4928.142, provides:

> Additionally, the commission may adjust the electric distribution utility's most recent standard service offer price by such just and reasonable amount that the commission determines necessary to address any emergency that threatens the utility's financial integrity or to ensure that the resulting revenue available to the utility for providing the standard service offer is not so inadequate

> as to result, directly or indirectly, in a taking of property without compensation pursuant to Section 19 of Article I, Ohio Constitution.

Thus, if the market-SSO rate blend involved in an MRO would result in a financial emergency or an unconstitutional taking without compensation, the Commission should avoid such an unjust result by making an adjustment to the authorized rates.

The same concept should also apply in the context of an ESP, because: (i) the Commission has ample authority to adopt the RSR under the ESP statute; (ii) the effect of the financial emergency/taking without compensation provision in the MRO statute would result in a corresponding increase in the MRO price test (the MRO test impact of this provision is discussed in greater detail below); and (iii) it makes no sense to conclude that the General Assembly intended to remedy a confiscatory MRO rate but would not provide for a similar remedy in an ESP. Ultimately, explicit language was not needed in the ESP statute to ensure this result because an ESP is consensual and is not a permanent path toward market rates like the MRO. Thus, it is also appropriate to avoid imposing a result in an ESP that would result in a financial emergency or unconstitutional taking.

In a similar vein, AEP Ohio witness Dr. Avera testified that his understanding of the SSO regulatory regime in Ohio requires avoidance of an unconstitutional taking without compensation or a financial emergency resulting from a rate decision:

> I understand that some of the statutes in Ohio talk about avoiding confiscation and avoiding financial impact, negative financial impact. * * * So I think the Ohio statutes follow generally the guidance of *Hope* and *Bluefield*, the constitutional requirement that when this Commission has authority over the assets of a utility, it has to make sure there's an opportunity to earn a fair return.

(Tr. XVII at 4692 (emphasis added).)[15] Dr. Avera went on to conclude that there is a definite responsibility to avoid confiscation during a period when the utility is being regulated such that the regulator asserts control over the price:

> I think if AEP has an obligation to serve and is under the control of this Commission, then this Commission has an obligation not to take * * * This Commission has a responsibility to make sure it does not confiscate AEP Ohio's property by allowing an inadequate return.

(*Id.* at 4693-94.) Dr. Avera went on to explain a potential outcome where there could be lasting and significant consequences of a ratemaking decision that inflicts material financial harm on AEP Ohio:

> [AEP Ohio's credit rating is] BBB now, there's one more notch, Triple-B-minus, and then we go into junk. So a downgrade would be a significant event which I think would shuffle the deck for investors. There are some Triple-B-minus utilities in the country, but not many. But if AEP Ohio were to join them, that would limit the ability of the company * * * to raise capital.

(*Id.* at 4752.) In other words, this is a precarious financial circumstance for AEP Ohio and an adverse decision could conceivably render AEP Ohio's investors as investors in junk bonds. Such a harmful result would materially increase the cost of service – including the regulated wires services – for years to come.

Mr. Allen also explained the long-term deleterious impact of such a decision:

> We talked about how AEP is only two notches above junk. If the Commission took an action that resulted in the company's bonds being downgraded, that wouldn't just increase cost for customers in the near term, those bonds exist well into the future, and the customers of AEP Ohio would continue to pay those costs for a long time to come, and that would be an unfortunate consequence for customers of an action that doesn't protect AEP Ohio's interests during this transition period.

[15] Of course, the *Hope* and *Bluefield* cases referenced by Dr. Avera are *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 391 (1944) and *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923). (AEP Ohio Ex. 150 at 24.)

(*Id.* at 4888.)

In this regard, Dr. Avera also issued a stern opinion about the investor reaction to a decision that is harmful to AEP Ohio's financial interests:

> [I]f the Commission seriously considers proposals like the staffs' and other intervenors' that would drive the opportunity to earn way down, that concern will be more significant. Perhaps so significant that AEP Ohio will not be able to raise capital.
>
> So I think the Commission should properly be on notice that the investment community is concerned, and that means that to put money in this company investors need higher compensation. And if their concerns become more pronounced, it could, in the extreme, lead to an inability to raise funds to make the capital investment that customers need in order to keep the lights on.

(*Id.* at 4725.) Thus, Dr. Avera articulated the potential dire consequences of any Commission failure to address the adverse financial impact associated with its decisions, which could conceivably push AEP Ohio to the financial brink.

In addition to showing the general financial consequences of intervenor proposals on AEP Ohio's ability to raise future capital and the associated potential for higher cost of service even for the wires services of the utility, AEP Ohio also demonstrated with specificity how various proposals advanced in this case relative to capacity pricing would result in confiscatory rates for the Company. Specifically, on rebuttal, Mr. Allen calculated that RPM pricing without the RSR yields a projected 1.1% ROE total company in 2013 with a loss to the generation function. (AEP Ohio Ex. 151 at 11.) As Mr. Allen testified, "a result that produces an ROE of only 1.1% for a utility in any period, much less in a period in which the Company is undergoing a significant transformation from an integrated utility into a wires only entity is unacceptable and dangerous." (*Id.*) Further, Mr. Allen referenced the Staff's position that the RSR should recover the difference between the Staff's cost-based rate calculation of $146/MW-day and RPM pricing (if that is ordered by the Commission), and calculated the impact of this scenario to be that the total company ROE would drop clear down to 4.6% in 2013 even using a higher RSR of $5/MWh, with a loss to the generation function. (*Id.* at 12-13; Tr. XVII at 4879.) Mr. Allen also calculated the impact of OEG witness Kollen's levelized RPM pricing proposal as resulting in a 2.4% total company ROE in 2013. (AEP Ohio Ex. 151 at 14.) These projected returns are for 2013, the first full year they would be in effect, and they are far below a level that could be considered reasonable (as discussed in greater detail below). Mr. Allen previously testified that even the Company's proposals described in the Modified ESP (including the two-tiered capacity discount) would be unreasonable without the RSR because the Company's 2013 ROE would only be 6.4%, with an even lower ROE for the generation function. (Tr. V at 1546, 1548.)

Mr. Allen explained why adopting the intervenor or Staff proposals would be "unacceptable and dangerous" in his opinion:

> As the company goes through this transition period and we're spinning off our generation into an unregulated subsidiary, the company still has an obligation to meet the needs of our customers, both for capacity and energy, and provide reliable transmission of power into the system.
>
> If this Commission were to determine that an approach such as that proposed by Witness Banks were adopted, the company would not have the financial wherewithal to invest in the significant transmission system that we have today or the capacity that we have to serve customers.
>
> That transmission and capacity has been serving customers of AEP Ohio for a number of years. The financial wherewithal that this Commission has previously provided that allowed us to make those investments allowed AEP to create a robust transmission system that in instances such as 2003, when other utilities were unable to maintain the lights on, the robust transmission system we had kept the lights on, the robust generation fleet that's providing the capacity today kept the lights on, so when the rest of the east coast blacked out, AEP kept the lights on.

> And if we didn't have the wherewithal, those kind of things could happen because investments can't be made. Investments in things like transmission are very important to the state of Ohio to ensure that low-cost power can be imported into the state now and well into the future.

(Tr. XVII at 4877-78.) Mr. Allen went on to clarify what he meant when he used the 2003 Blackout as an example:

> What I'm saying is that there are significant benefits that are provided to customers of Ohio as a result of the company's ability to make sound investments in our transmission, distribution, and generation system.
>
> To the extent that the Commission provides a result through the capacity case or this ESP case that doesn't provide the company with that financial stability, the company will have to pare back spending and investment and we don't know in the future what kind of impact that would have.
>
> What we do know, though, is that when a company can make those investments and makes those investments in a sound, thoughtful manner with foresight into the future, instances such as we saw in 2003 can be avoided.

(*Id.* at 4886-87.)

AEP Ohio witness Dias had previously explained the connection between the proposed RSR and AEP's ability to make such investments as transmission upgrades:

> AEP Ohio's had a great track record on transmission investments in Ohio; our customers have benefited from it, our communities have benefited from it. We have a robust transmission network in this unconstrained zone, and I referenced earlier the problem we've seen in the ATSI constrained zone.
>
> So I believe American Electric Power will want to help fix that problem by relieving congestion and by doing so making investments in the transmission system in that zone similar to what we have done in this zone. That's the kind of investments that I'm referring to.
>
> We have to stay financially -- AEP Ohio has to be financially stable to be able to provide the dividends to the corporation that

> ultimately get to those kind of investments from subsidiary companies through the transmission company, et cetera.
>
> I mean, this ATSI zone issue is a huge problem. You know, I just looked at that thing doing some simple math, customers in that zone are going to see almost $600 million of increased costs as a result of that problem annually. That's a problem to us we would like to fix by making investments.

(Tr. VII at 2130-31.) If AEP Ohio is financially harmed through a combination of decisions in the capacity charge case and this proceeding, it will not be able to continue making investments and creating jobs in Ohio. The RSR is needed to ensure financial stability for the Company during a brief transition period and for customers in the long run.

iii. The 10.5% return on equity used to develop the RSR's non-fuel generation revenue target is reasonable and appropriate, but it does not support total Company earnings at 10.5% ROE, let alone guarantee such earnings.

Mr. Allen recommended using a 10.5% ROE to develop the RSR revenue target, based on his review of recently-awarded authorized returns for AEP Ohio and its affiliates operating in the AEP East jurisdictions. (Tr. V at 1617, 1623-26.) This consideration included the fact that Dr. Avera supported an ROE of 11.15% in AEP Ohio's recent distribution rate case. (*Id.* at 1619.) The recently-approved ROEs for AEP East utilities ranged from 10% to 10.9%. (Ormet Ex. 103.) Thus, Mr. Allen's use of a 10.5% ROE for developing the non-fuel generation revenue target under the RSR was reasonable and appropriate.

Contrary to the testimony of FES witness Dr. Lesser and multiple OMA witnesses, Mr. Allen demonstrated through his rebuttal testimony that the 10.5% ROE used to develop the RSR revenue target translated into total company earnings lower than 10.5%.

> Just because the RSR was designed to produce non-fuel generation revenues consistent with a 10.5% ROE based on conditions present in 2011, that does not mean that total company earnings in future years will be equal to 10.5%; operation of the RSR only involves

> decoupling of the non-fuel generation revenue and there are many other factors that affect total company earnings. Indeed, as shown in Company witness Sever's Exhibit OJS-2, the projected ROEs for AEP Ohio in 2012 and 2013 are 9.5% and 7.5%, respectively. Exhibit OJS-2 is a pro forma projection of AEP Ohio's earnings based upon all of the elements of the Company's proposed ESP, including the RSR. These projected earnings clearly demonstrate that the RSR does not guarantee the Company will earn a 10.5% ROE. Rather, the Company's projections affirmatively demonstrate that AEP Ohio will likely earn an ROE substantially below 10.5%.

(AEP Ohio Ex. 151 at 2-3.) Thus, the RSR by no means translates into a guarantee of earnings at a particular level – let alone 10.5% earnings.

AEP Ohio witness Dr. Avera filed rebuttal testimony in response to the intervenor positions that challenged Mr. Allen's use of a 10.5% ROE in developing the RSR's revenue target. Specifically, Dr. Avera testified that the ROEs recommended by Mr. Kollen and Dr. Wilson "are simply far too low and fail to reflect the risk perceptions and return requirements of real-world investors in the capital markets." (AEP Ohio Ex. 150 at 4.) He further maintained that "[b]ecause their recommendations fail to provide AEP Ohio an opportunity to earn a return commensurate with other investments of comparable risk, they violate the regulatory and economic standards underlying a fair rate of return." (*Id.*) When appropriate revisions are made to the flawed positions of Ormet witness Dr. Wilson and OEG witness Kollen, it is evident that the 10.5% ROE used by AEP Ohio witness Allen to develop the RSR revenue target is reasonable and appropriate.

In support of his recommendation of 8-9% ROE, Ormet witness Dr. Wilson conducts a Discounted Cash Flow ("DCF") analysis and applies the Capital Asset Pricing Model ("CAPM"), purportedly mirroring the Staff's Report of Investigation ("Staff Report") in AEP Ohio's last retail rate case. According to AEP Ohio witness Dr. Avera, Dr. Wilson's applications of these models are flawed and violate the very principles Dr. Wilson articulates in his own testimony. (AEP Ohio Ex. 150 at 25-32.) Dr. Avera corrected and supplemented Dr. Wilson's analyses, which resulted in the following cost of equity estimates:

TABLE WEA-1
COST OF EQUITY – REVISED WILSON ANALYSES

		Indicated ROE		
Revised Wilson DCF Analysis				
Corrected Mid-Year Cash Flows	(a)		10.03%	
AEP DCF Estimate	(a)		10.60%	
Staff Proxy Group Including AEP	(a)		10.10%	
Revised Wilson CAPM Analysis				
Current Bond Yields	(b)		10.88%	
Projected Bond Yields	(c)		11.28%	
Average CAPM			11.08%	
Average - Revised Wilson Results	(d)		10.59%	
Baseline Cost of Equity Range	(e)	10.09%	--	11.09%
ROE Range inc. Flotation Costs	(f)	10.24%	--	11.26%

(a) Exhibit WEA-5.
(b) Exhibit WEA-6.
(c) Exhibit WEA-7.
(d) Average of revised DCF inc. AEP and average of current and projected CAPM.
(e) Average of revised Wilson results, plus (minus) 50 basis points.
(f) Baseline cost of equity range incorporating Wilson flotation cost adjustment factor.

(*Id.* at 5.) The midpoint of this adjusted range for the cost of equity is above 10.5%.

With respect to the analyses contained in Dr. Wilson's testimony, Dr. Avera concluded that:

- The DCF results are biased downward because the methodology incorrectly assumes that investors receive dividend payments at the end of the year, instead of through periodic payments;

- The results of the historical CAPM analysis should be entirely ignored because:

    - Historical data violates the assumptions of the CAPM approach and fails to reflect current capital market requirements;

    - Yields on medium-term Treasury notes are irrelevant in estimating the required return for common equity, which is a long-term asset;

    - Dr. Wilson's application ignored adjustments to correct for differences in firm size that were quantified and explained in the same data source on which his CAPM was based.

- Dr. Wilson's recommendation is woefully inadequate to compensate investors in AEP Ohio when evaluated against the results of the expected earnings approach for his own proxy utilities;

- Allowed ROEs also demonstrate that the recommended ROE range contained in Dr. Wilson's testimony is too low to be reasonable;

- DCF cost of equity estimates for a low-risk group of non-regulated companies provide an important benchmark that is consistent with financial theory, how real-world investors operate, and the guidelines underlying a fair ROE;

- Because of flaws in the selection criteria:

    - Wilson's proxy group is artificially constrained to only seven companies, which undermines the reliability of their quantitative results;

    - Almost one-half of the utilities in Wilson's proxy group are rated single-A, which implies less risk and a lower rate of return than what is necessary to compensate for the risks of AEP Ohio's "BBB" rating;

    - AEP Ohio's parent, American Electric Power Company, Inc. ("AEP"), was erroneously excluded from Wilson's analysis, even though it meets the selection criteria and provides the Company's only source of investor-supplied equity capital.

- If AEP Ohio is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms, and investors will be denied an opportunity to earn their opportunity cost of capital; and,

- The evidence contained in my rebuttal testimony supports the reasonableness of the 10.50% ROE requested for AEP Ohio in this case, and supports an ROE within the upper end of the 10.24% to

> 11.26% range based on corrections and revisions to Wilson's analyses.

(*Id.* at 5-6.) Thus, as Dr. Avera explained, Dr. Wilson's analysis is flawed and would not produce earnings that permit AEP Ohio to attract capital investment.

Regarding the testimony of OEG witness Kollen, Dr. Avera acknowledged that Mr. Kollen correctly identifies the Commission's objective in this case of, "ensuring an incumbent electric utility provider's ability to attract capital investment to meet its FRR obligations." (*Id.* at 3, *quoting* OEG Ex. 101 at 5.) But Mr. Kollen's ROE recommendation "is overly simplistic and based on speculations about embedded debt costs and pre-tax equity returns that are not indicative of the current ROEs necessary to attract capital investment." (*Id.* at 4.) Dr. Avera testified as follows with respect to Mr. Kollen's flawed position:

> Mr. Kollen reasons that an ROE of 7.0% is equivalent to a before-tax return of 10.8%, which is double the cost of new long-term debt, and that 7.0% is comparable to earned returns for other AEP affiliates in 2010 and 2011. But these comparisons are meaningless for a number of important reasons. First, equity investors rationally focus on after-tax returns, not on the 10.8% pre-tax figure cited by Mr. Kollen. The certainty of tax payments means that the after-tax return is the benchmark in the regulatory arena for ROE.
>
> Second, equity investors are exposed to considerably greater levels of risk than debt holders, and the after-tax return on equity must be significantly higher than debt yields to attract capital. As demonstrated by the controversy that surrounds establishing a fair ROE in the regulatory arena, there is no basis to support Mr. Kollen's position that his simplistic comparison between a hypothetical pre-tax return and bond yields has any relationship whatsoever to the ROE required by investors.

(*Id.* at 10.) Mr. Kollen did not even make an evaluation of the financial impact of his recommendations on the Company. (Tr. X at 2846.) Dr. Avera's testimony demonstrates that

OEG witness Kollen's 7% recommendation simply would not allow the company to attract capital investment. (AEP Ohio Ex. 150 at 10.)

In sum, neither OEG witness Kollen nor Ormet witness Dr. Wilson set forth a reasonable ROE that would enable AEP Ohio to attract capital investment in today's financial markets. As demonstrated by AEP Ohio witness Dr. Avera, the 10.5% ROE used to develop the RSR revenue target is reasonable and is within the 10.24%-11.26% range of the revised Wilson analysis (as corrected by Dr. Avera). Thus, the Commission should not modify the 10.5% ROE used to develop the RSR revenue target.

iv. It was reasonable and generous to reflect a $3/MWh credit, related to possible energy margins realized for freed up energy from shopped load, in developing the RSR's non-fuel generation revenue target.

When developing the proposed RSR charge, AEP Ohio witness Allen applied a $3/MWh credit toward meeting the revenue target to account for possible energy margins that could be realized as a result of reduced SSO load through shopping. (AEP Ohio Ex. 116 at 13, Ex. WAA-6.) Notwithstanding unsubstantiated criticisms by intervenors that suppose the credit should be higher,[16] Mr. Allen demonstrated on rebuttal that the $3/MWh credit for shopped load is appropriate. No intervenor presented credible testimony supporting a higher credit and the Commission should not arbitrarily raise the credit, especially because such a credit for potential wholesale sales is not even required and was proposed by AEP Ohio as part of the larger compromise on the capacity pricing issue.

As a threshold matter, it is important to note that this amount is margin and not the full price for sales of MWh freed up by shopped load. This can easily be confirmed by reviewing the

16 For example, OEG witness Kollen believes the $3/MWh energy credit used in the RSR is too low, though he has not done any quantitative evaluation of the energy credit. (Tr. X at 2871.)

Company's response to OCC Interrogatory 146 which is provided as part of Mr. Allen's rebuttal testimony. (*See* AEP Ohio Ex. 151 at Ex. WAA-R2.) As Mr. Allen testified, the East Physical Margins for 2011 of $262M (excluding CRES capacity payments) generated by sales of 22,343 GWh result in an average margin of $11.73/MWh. (*Id.* at 5.) For 2012, the projected East Physical Margins of $153M (excluding CRES capacity payments) were generated by sales of 24,721 GWh resulting in an average margin of $6.19/MWh. (*Id.*) This shows that projected margins are clearly declining as a result of currently depressed prices for energy.

To determine the off-system sales (OSS) margin benefit that is created when a customer shops, one must consider: (i) the effect of the AEP Interconnection Agreement (AEP Pool), as well as (ii) the fact that a reduction in retail load does not result in an equal increase in off-system sales. As a conservative measure, Mr. Allen used the actual margins from 2011 (the same exercise can be done for the projected 2012 margins) in verifying the reasonableness of his proposed $3 credit. (*Id.*) As a member of the AEP Pool, Ohio Power only retains 40% of any OSS margins created; therefore the potential margin of $11.73/MWh is reduced by 60% to only $4.69/MWh. This result is further reduced to a range of $2.35/MWh to $3.75/MWh when recognizing that only 50%-80% of reduced retail sales results in additional off-system sales. (*Id.*) Using this same methodology applied to projected margins for 2012 results in margins in the range of $1.24/MWh to $1.98/MWh. (*Id.*) This exercise demonstrates that the $3/MWh credit for shopped load included in the RSR mechanism is appropriate and conservative.

Even if Mr. Allen's estimate of a $3/MWh credit for margins from sales based on energy freed up from shopping was deemed to be low, there is no basis for AEP Ohio's retail customers – let alone CRES suppliers – to claim a right to confiscate profit margins based on wholesale sales. AEP Ohio's current SSO rates do not reflect an adjustment for OSS margins; the

Commission affirmatively rejected OCC's proposal to establish such an adjustment to offset fuel costs. *ESP I*, March 18, 2009 Opinion and Order at 17. Likewise, the Commission has affirmatively rejected the notion that OSS margins be subjected to the SEET and is presently defending that decision before the Supreme Court of Ohio. *See* Sup.Ct. Case No. 2011-751, PUCO September 26, 2011 Merit Brief at 13-19. Due to the unique regulatory regime associated with SB 221, the Commission has seen fit to decline to make any retail rate adjustments to credit OSS margins to retail customers. And rightly so, given that AEP Ohio is at risk of losing those customers to CRES providers for generation service. In short, CRES providers and their customers should not have a better OSS margin credit than retail customers.

Of course, customers in AEP East operating companies' other jurisdictions that involve OSS margin sharing also pay rates reflecting 100% embedded costs for the underlying generation assets; unlike Ohio where a customer (and the CRES provider's service of that customer) can come and go, the rates in those traditionally regulated jurisdictions are established under a regulatory compact that guarantees recovery over the life of the asset. Based on that relationship, there is generally sharing of OSS margins – not confiscation of 100% of those margins. Of course, only a portion of OSS margins even relate to physical assets; a substantial portion is tied to hedging, trading and non-physical transactions. Thus, if the Commission does entertain applying a larger credit than \$3/MWh based on projected OSS margins, it should certainly not appropriate all of the margins retained by AEP Ohio (some of which are completely independent of the capacity supplied to CRES providers). For example, even if one ignored the fact that only 50-80% of energy freed up from shopping is sold as demonstrated by Mr. Allen in his testimony, the result would be \$4.69/MWh for 2011 and the \$2.48/MWh for 2012 and a simple 50/50 sharing approach applied to such margins would also yield a credit of less than

$3/MWh. For these reasons, as supported by the testimony of AEP Ohio witness Allen, the proposed $3/MWh credit is more than reasonable and should not be modified.

B. The Modified ESP Reflects Significant Pro-Competitive Proposals.

1. The Modified ESP achieves a fully competitive SSO format in less than half the time permitted under the MRO and incorporates significant up front energy auctions, which are remarkable features given that the Commission's policy only recently shifted in favor of the auction-based SSO format.

One very significant pro-competitive aspect of the Modified ESP is that it would allow AEP Ohio to achieve a fully-competitive SSO format in less than half the time it would take the Company to do so under an MRO. AEP Ohio's Modified ESP proposal is even more impressive when one considers the fact that an MRO itself, by comparison, is voluntary to begin with. In and case, the Modified ESP proposes three commitments to effectuate this transition: (1) a commitment to adjust the Company's business plan to conduct a competitive market-based energy and capacity auction to serve SSO load by June 1, 2015; (2) a commitment to conduct an energy auction for 100% of SSO load in January 2015; and (3) a commitment to conduct an energy-only, slice-of-system auction for 5% of SSO load prior to the SSO energy auction. (*See* AEP Ohio Ex. 100 at 10-11; AEP Ohio Ex. 101 at 11-12, 19-21.) There are no statutory or regulatory requirements for an auction-based SSO as part of an ESP and the Modified ESP's proposals in this regard are valuable benefits voluntarily brought forth by the Company.

The Company is committed to a reasonable transition to a competitive market and developed the proposals described above in response to the Commission's recent policy directive instructing the Company that "[t]he Commission expects that [the Company's] Modified ESP application will include . . . provisions that provide for market-based pricing for standard service offer customers in a manner more expeditious than proposed within AEP Ohio's Notice of

Intent." Entry at 5-6 (Mar. 7, 2012). In its March 5, 2012 Notice of Intent to submit a Modified ESP application, the Company had proposed only to conduct an auction-based SSO on June 1, 2015. Notice of Intent of Ohio Power Company at 5 (Mar. 5, 2012). Thus, the additional commitments to conduct 5% and 100% energy auctions during the term of the Modified ESP reflect the Company's commitment to moving, as the Commission has directed, to market-based pricing for SSO load in an expeditious manner.

Company witness Powers explained in detail each of the Company's three auction commitments which collectively provide an accelerated path to fully competitive energy and capacity SSO markets in AEP Ohio's service territory. He explained that AEP Ohio commits to filing a competitive bid process (CBP) case for its SSO load, which would provide for a full requirements SSO auction for delivery beginning in June 2015, within 90 days after it receives final orders providing for the elimination of the AEP Pool agreement and providing for full corporate separation. (AEP Ohio Ex. 101 at 19-20.) The details of and process for the June 2015 CBP will be developed in another filing; however, the Company anticipates that the process will be similar to those that the Commission approves for other Ohio utilities. (*Id.* at 20.) Importantly, the Company's CBP for delivery beginning in June 2015 will determine 100% of SSO energy and capacity prices for AEP Ohio's SSO load. (*Id.*)

Moreover, prior to the full requirements SSO auction for delivery beginning in June 2015, the Company will conduct a CBP to determine the price of energy for AEP Ohio. (*Id.*) This auction will determine the price of energy for 100% of SSO load for delivery commencing January 2015, provided that the Company's corporate separation plan and pool termination are approved and implemented at that time. (*Id.*; AEP Ohio Ex. 100 at 11.)

Finally, for the purpose of facilitating a smooth transition to the full SSO energy auction, AEP Ohio is willing to conduct an energy-only, slice-of-system auction for 5% of SSO load for delivery prior to January 2015, contingent upon the Company being made whole financially. (AEP Ohio Ex. 100 at 11; AEP Ohio Ex. 101 at 20-21.) Delivery under this auction would begin six months after final orders are issued adopting both the Modified ESP as proposed and the corporate separation plan as filed and would extend through December 31, 2014. (AEP Ohio Ex. 100 at 11; AEP Ohio Ex. 101 at 21.) The details of this auction will be addressed upon the issuance of final orders in the ESP and corporate separation cases. (AEP Ohio Ex. 101 at 21.)

These auction commitments will promote and enhance competition considerably faster than would be possible under an MRO. As discussed in Section II, *supra*, an MRO requires a mandatory 6-10 year transition to market. *See* R.C. 4928.142(D)-(E). The Company's proposed ESP, by contrast, would take less than 3 years – and less than half the time required under an MRO – to transition to market. The auctions voluntarily proposed in the Modified ESP thus clearly are beneficial and pro-competitive, and they should be approved.

2. The Modified ESP proposal to provide discounted capacity charges is reasonable and lawful.

As part of its Modified ESP, the Company proposes a two-tiered capacity pricing mechanism under which all of its shopping load will be charged a discounted price of either \$145.79/MW-Day (Tier 1) or \$255.00/MW-Day (Tier 2) for capacity during the ESP period. (*See* AEP Ohio Ex. 101 at 15; AEP Ohio Ex. 116 at 6.) Approximately 21% of AEP Ohio's total retail load (based on total MWh retail sales) in 2012, 31% in 2013, and 41% in 2014 and continuing through May 2015 will receive capacity discounted at the Tier 1 price. (AEP Ohio Ex. 116 at 6.) Tier 1 capacity will be available to each customer class in proportion to their relative retail sales, as set forth in Table 1 of Company witness Allen's direct testimony:

Table 1 – Tier 1 Priced Capacity Set-Asides
(MWh of Customer Load)

Revenue Class	Jun-Dec 2012	Jan-Dec 2013	Jan 2014-May 2015
Residential	3,061,000	4,533,000	5,918,000
Commercial	2,996,000	4,461,000	5,923,000
Industrial	4,009,000	6,001,000	7,939,000
Total	10,066,000	14,995,000	19,780,000

(*Id.* at 7.) All shopping load in each class beyond the 21%, 31%, and 41% set-asides will receive capacity discounted at the Tier 2 price.

The Modified ESP capacity pricing mechanism also is designed to support governmental aggregation initiatives. (*Id.* at 6-7.) For 2012, additional allotments of Tier 1 priced capacity will be available to non-mercantile customers in communities that approved an aggregation program on or before November 8, 2011, even if the 21% Tier 1 set-aside has already been met. (*Id.*) In 2013 and 2014, the Tier 1 set-aside will increase and the load of customers in governmental aggregation initiatives will have access to those set-asides that is identical to that of individual shopping customers. (*Id.* at 7.)

These proposals reflect a significant benefit to customers in AEP Ohio's service territory. Over the term of the Modified ESP, CRES providers will receive discounted capacity from AEP Ohio for $989 million less than the Company's embedded cost of capacity. (*Id.* at 8-9; *see also* Tr. I at 332-333 (Company witness Powers explaining the proposed discounted charges).) This benefit should increase headroom for CRES providers and flow through to shopping customers in the form of lower competitive electric service rates, additional retail shopping opportunities, and expanded competition in AEP Ohio's service territory.

i. *Absent the Modified ESP capacity pricing proposal, the Company is entitled to charge CRES providers a cost-based rate of $355.72/MW-day for capacity supporting shopping load.*

AEP Ohio maintains, as addressed in detail in Case No. 10-2929-EL-UNC, that it is entitled to recover an embedded cost-based charge from CRES providers, equal to approximately $355/MW-day, for the capacity that it supplies them. (*See* AEP Ohio Ex. 101 at 15; *Capacity Case*, Ohio Power Company's Initial Post-Hearing Brief (May 23, 2012); *Capacity Case*, Ohio Power Company's Reply Post-Hearing Brief (May 30, 2012).) As they did in the *Capacity Case*, many intervenor witnesses argue the merits of the Company's entitlement to a cost-based capacity charge. (*See, e.g.,* FES Ex. 101 at 3-32; FES Ex. 102 at 9-43; FES Ex. 105 at 4; IEU Ex. 126 at 29-48.) Those arguments have, for the most part, been fully argued and briefed in the *Capacity Case*, and it is expected that the Commission will address them in its decision in that proceeding; thus, the Company will not repeat them here.

As he did in the *Capacity Case*, FES witness Lesser argues that AEP Ohio's embedded cost of capacity is less than $355/MW-day, although this time he states that the Company's embedded cost rate should be not more than $93.64/MW-day. (*See* FES Ex. 102 at 18-25.) This number, however, is significantly understated because Dr. Lesser's analysis failed to eliminate all of the capacity equalization payments that correspond to the post-2000 investments that his analysis eliminated. (*See* Tr. IX at 2608-2621.) Dr. Lesser's miscalculations should be disregarded, as the record evidence of this case and the *Capacity Case* demonstrate that the Company's embedded cost of capacity equals $355.72/MW-day.

ii. The proposed two-tiered capacity pricing represents a reasonable compromise of AEP Ohio's litigation position in Case No. 10-2929-EL-UNC as part of the ESP's package of terms and conditions.

The two-tiered capacity pricing mechanism represents a reasonable compromise of AEP Ohio's litigation position in Case No. 10-2929-EL-UNC. Approval of the Company's Modified ESP, including the highly discounted capacity pricing proposal, would settle the contested issue of the appropriate amount of AEP Ohio's capacity charge and would eliminate the need for the Company to pursue other available legal remedies or avenues of relief before state or federal administrative agencies or courts. Under the PJM RPM construct, a load serving entity (LSE) has two options. It may either self-supply generation resources under the Fixed Resource Requirement (FRR) alternative or it may procure capacity through the three-year forward PJM auction. (*See* AEP Ohio Ex. 101 at 14.) Under the FRR approach, an LSE opts out of the RPM market and secures its own capacity to serve its load, including shopping load. (*Id.*; Tr. III at 824-825 (Company witness Graves explaining the differences between the FRR and RPM options under PJM, including "[t]he fundamental difference" that the FRR obligation "applies regardless of how much load is being served" and is "a multiyear commitment").) AEP Ohio operates under the FRR option, and its attendant capacity supply obligations, until June 1, 2015.[17] (AEP Ohio Ex. 101 at 4; AEP Ohio Ex. 103 at 9-10.) Therefore, AEP Ohio is not a participant in or held to duties and obligations of the PJM RPM capacity market until June 1, 2015.

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[17] CRES providers also have the option to supply their own capacity and participate as an FRR entity, which would require them to commit their resources three years in advance. They can also choose to avoid long-term commitments and simply buy their capacity from an FRR entity. To date, in the AEP Ohio's service territory, CRES providers have purchased their capacity requirements from AEP Ohio. (AEP Ohio Ex. 101 at 14.) Company witness Graves testified that CRES providers in fact "have an incentive *not* to bring their own capacity to the market under the conditions where they can get it from AEP [Ohio] at RPM prices." (Tr. III at 825-826 (emphasis added).)

As discussed above, AEP Ohio's embedded cost of capacity is approximately $355/MW-day. (AEP Ohio Ex. 101 at 15; Tr. V at 1368, 1512.) Nonetheless, as part of the integrated package of terms proposed in its Modified ESP, the Company has proposed a discounted two-tiered capacity pricing mechanism whereby highly discounted capacity charges are offered during the remaining period that AEP Ohio remains contractually obligated under the FRR alternative. Both the Tier 1 and Tier 2 capacity prices represent a substantial discount from the cost AEP Ohio incurs to supply capacity. (AEP Ohio Ex. 101 at 15; Tr. I at 332-333, 338; Tr. V at 1455.)

Moreover, as Company witness Powers explained, the proposed capacity pricing arrangement is intended in part to mitigate significant financial harm of more than $600 million in lost revenue that AEP Ohio would potentially suffer annually if the Commission required it to supply CRES providers with capacity at an RPM-based price, while still offering CRES providers an opportunity to attract AEP Ohio's customers and mitigating rate impact to retail customers. (Tr. I at 200-201.) On cross-examination, Mr. Powers explained the complexities present in attempting to balance these interests and the historical context underlying the Company's discounted capacity pricing proposal as follows:

> AEP [Ohio has] been asked to not go to market for more than a decade. Now we want to go to market. We've had a stipulation, it was unapproved. We've been asked to try and balance customer needs, CRES provider needs. We certainly have come to the table and said we need to balance the financial harm to AEP [Ohio]. We put our thinking caps on, we put a comprehensive package in place.
>
> Believe me, when you start to pull the levers to try to mitigate rate impact, provide capacity that is attractive to CRES providers, [and] minimize financial harm, it's complicated, and it's complicated to the point where we just want to point out that this is a solution we found to be acceptable.

> We will always be open to other solution sets, but we would emphasize that those options just need to be in the same envelope that this represents in terms of providing balance between the various parties.

(Tr. II at 382.) The proposed compromise approach provides stakeholders with a great deal of balance during the period in which AEP Ohio remains subject to FRR obligations. (*See* Tr. I at 213; Tr. V at 1407.) Moreover, it provides stakeholders with certainty and stability. As Mr. Powers explained, if the Company's capacity proposal is not accepted, the resultant revenue losses likely would result in reduced spending on operations and maintenance and could result in the loss of thousands of jobs in Ohio. (*Id.* at 257-258.) Such results are undesirable for customers, employees, and the Company for a number of reasons. The Company's compromise two-tiered capacity pricing proposal mitigates these risks and represents a reasonable resolution of multiple interests. For this reason, the Commission should approve the Company's discounted capacity pricing mechanism as proposed.

iii. The proposed two-tiered capacity pricing would preserve and expand competition in AEP Ohio's service territory.

AEP Ohio's two-tiered capacity pricing proposal will promote and support expedited growth of robust competitive supply options for retail customers. (*See* Tr. I at 332-333 (Company witness Graves testifying regarding two-tiered capacity pricing's positive effect on shopping); Tr. IV at 1263 (Company witness Thomas discussing benefit of capacity pricing proposal on non-shopping customers because all customers benefit from additional shopping opportunities).) As Company witness Allen demonstrated, significant customer switching has occurred at the $255/MW-day Tier 2 capacity price. (AEP Ohio Ex. 116 at 4.) Specifically, Mr. Allen testified that as of March 1, 2012, 26.1% of AEP Ohio's connected load had switched to a CRES provider, 2.2% of load had a switch pending, and an additional 8.4% of load had provided notice to the Company of intent to switch. (*Id.*) Thus, a total of 36.7% of the Company's load either switched or indicated an intent to switch as on March 1, 2012. Notably, as of March 1, 2012, 3.2 million MWh, representing 6.8% of the total AEP Ohio load, switched when the capacity charge to CRES providers equaled $255/MW-day. (*Id.*) Moreover, during the first nine months that the two-tiered capacity pricing structure was in place (September 2011 through May 2012), the level of customer shopping nearly tripled, growing from 11.63% to 31.09%. (AEP Ohio Ex. 151 at 10.) This demonstrates that, contrary to the arguments by FES witness Banks and RESA witness Ringenbach (*see* FES Ex. 105 at 7, 10-12; RESA Ex. 102 at 8), the two-tiered capacity pricing structure is not confusing. (*Id.*)

Mr. Allen further testified that the amount of customer switching at the proposed Tier 1 and Tier 2 pricing levels will increase over the term of the Modified ESP. (AEP Ohio Ex. 116 at 4-5) One factor contributing to the projected increased switching is the fact that forward energy prices in the PJM market for the remainder of 2012 have decreased by approximately $10/MWh – or approximately 25%. (*Id.* at 4.) This is a significant reduction in the forward price of energy and, because it reduces a CRES provider's overall cost of providing electric service, Mr. Allen testified that it should translate into increased headroom for CRES providers and additional shopping opportunities for retail customers. (*Id.*) Considering this information, as well as current and historical shopping statistics for Ohio Power and historical shopping statistics for other EDUs in Ohio, Mr. Allen projected that customer switching during the term of the Modified ESP will increase as follows by the end of 2012: 65% of residential load, 80% of commercial load, and 90% of industrial load (excluding one single large customer) is expected to switch to competitive electric service. (*Id.* at 5.) These levels of shopping are expected to remain through the end May 2015. (*Id.*)

The Company's proposed capacity pricing structure therefore will not, as a number of parties contend, adversely affect competition. (*See, e.g.,* FES Ex. 104 at 43-49; IEU Ex. 126 at 40; OMA Ex. 101A, 102A, 103A, 104A, 105A, 106A.) Moreover, requiring AEP Ohio to provide CRES providers with the further-discounted capacity that some parties request would only serve to improperly subsidize CRES providers and would represent uneconomic and unsustainable competition that would harm AEP Ohio. (AEP Ohio Ex. 101 at 17; AEP Ohio Ex. 151 at 11.) The Company has demonstrated that competition in AEP Ohio's service territory will continue to expand significantly under its proposed capacity pricing mechanism. For this reason too, the Commission should approve the capacity pricing structure as proposed.

iv. The proposed two-tiered capacity pricing does not constitute an untimely request for recovery of stranded generation investment.

IEU witness Hess claims that AEP Ohio's two-tiered capacity pricing proposal conflicts with the provisions of SB 3 and the settlement in Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP (ETP Stipulation) (IEU-Ohio Ex. 124 at 16-20, 23-25.) FES witness Lesser also advocated that AEP Ohio can no longer recover any embedded generation costs that are above market rates, proposing to dramatically reduce any cost-based capacity charge on that basis. (FES Ex. 102A at 19, 24; Tr. IX at 2598-2600.) Other witnesses also briefly invoke this argument as well, including Kroger witness Higgins, FES witness Frame, IEU witnesses Bowser and Murray and OMAEG witness Forshey. Since IEU witness Hess sets forth the most detailed and thorough (though equally misguided and flawed) argument in this regard, AEP Ohio's response herein will be focused primarily on Mr. Hess's testimony, as the other witnesses' points are subsumed within that discussion. In any case, all of these arguments are without merit because SB 3 and the ETP Stipulation are not applicable to this case, and because the factual underpinning of the arguments is inaccurate. Notably, the Commission has considered and rejected these same arguments at least once already in this proceeding. In its decision initially approving the *ESP II* Stipulation, the Commission stated "[w]e reject the Non-Signatory Parties' claims that SB 3 or the ETP cases foreclosed or conflicts with AEP-Ohio's ability to pursue cost-based capacity rates, at this time." December 14, 2011 Opinion and Order at 55.

Generation transition charges were a statutorily-defined (R.C. 4928.40) cost recovery mechanism for stranded generation investment that were to be recovered via retail generation transition charges. Specifically, under SB 3, electric utilities were given an opportunity to recover transition revenues via retail rates that could include the amount of generation investment that would not be recoverable in a competitive market. The determination of whether such investments were stranded under SB 3 was done based on an analysis of 2000-vintage information as to whether the net book value for generation assets exceeded the long-term market value of the assets (using projected market price estimates for electricity at that time). As part of the ETP Stipulation, AEP Ohio agreed not to pursue SB 3's opportunity for recovery of stranded generation investment via retail generation transition charges.

Conversely, this Modified ESP proceeding involves the two-tiered wholesale capacity pricing proposal based on a discount from AEP Ohio's embedded capacity costs and a potential recoupment of a portion of the discount through the RSR mechanism. It does not involve R.C. 4928.40 retail generation transition charges, which, importantly, were only applicable to a specific and limited time-period (2001-2005). IEU witness Hess conflates these two distinct concepts – retail generation transition charges and wholesale capacity prices - with complete disregard for the differences surrounding each or an appreciation of the relevant regulatory history and stark changes in the regulatory regimes in place.

The issue of whether AEP Ohio could recover stranded asset value from retail customers under SB 3 is a totally different exercise from establishing a wholesale price that permits AEP Ohio's competitors to use that same capacity. There are major legal and factual differences between the two situations, including those illustrated in the following table:

	Stranded Cost Determination under SB 3	**Wholesale Capacity Charge Determination**
Legal Standard	SB 3 provisions	• Federal Law • Reliability Assurance Agreement (RAA) • SB 221 provisions
Context	One-time historical inquiry for transition revenue during 5-year market development period (MDP); predates major regulatory regime change adopted in SB 221 wherein cost-based rate adjustments are permitted	Ongoing dispute involving AEP's exercise of rights under the RAA based on its status as a Fixed Resource Requirements entity through May 2015
Parties Involved	Restricted recovery of stranded generation costs from retail customers during the MDP, in exchange for charging market-based rates after MDP (which never happened)	Involves wholesale charges for CRES providers to use OPCo's capacity resources
Valuation Issues	Long-term view of projected energy prices compared to then-present projected revenue stream under cost-based regulation, using 2000 vintage data	Embedded 2010 cost versus the short-term Reliability Pricing Model auction price
PUCO Precedent	• AEP Ohio agreed not to pursue recovery of transition revenues during MDP relating to stranded generation investment • FirstEnergy authorized to collect nearly $7 billion from retail customers	Case of first impression remains pending

As further explained below, IEU's stranded cost theory is misguided and should be rejected or ignored.

a. IEU witness Hess's present position that AEP Ohio's generation assets are stranded in the market is severely undercut by his prior testimony that there never was stranded generation cost for AEP Ohio in the past.

As a threshold matter, all of IEU witness Hess's prior testimony on the subject of whether AEP Ohio's generation investment is stranded in the market conflicts with his present position that there is stranded investment. Regarding Staff's evaluation of AEP Ohio's stranded investment under SB 3 and his subsequent testimony in the *ESP I* cases, Mr. Hess testified that "There were no stranded investments in 2000 and there were no stranded investments in 2009." (Tr. X at 2986-87.) Mr. Hess also agreed that the Commission "never made a finding about the economic value of AEP's generation fleet." (Tr. X at 2987.) He further acknowledged that the Staff "never believed that AEP Ohio did have stranded investment." (Tr. X at 2987.) Indeed, as Mr. Hess testified before this Commission in the *ESP I* cases, Staff believed that the net value of the generating fleet remained positive. (Tr. X at 2988; AEP Ohio Ex. 132 at 8.) Mr. Hess's current position that AEP Ohio has stranded generation investment does not square with his consistent prior testimony that AEP Ohio never had stranded generation investment.

b. Wholesale charges to CRES providers are fundamentally distinguished from stranded cost recovery from retail customers under SB 3.

It is undisputed that the capacity charges to CRES providers are wholesale prices. This is important because the ETP cases from 2000 did not establish wholesale capacity prices for CSP and OPCo, and any generation transition charges established in those cases would have been retail charges. The ETP cases were retail ratemaking cases and they have no bearing on a wholesale capacity rate charged to CRES providers. Accordingly, any restrictions on recovery of generation costs through retail pricing that resulted from S.B. 3 and the Commission's 2000 orders in Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP are simply inapplicable to wholesale capacity pricing. Moreover, any conclusion that SB 3 precludes AEP Ohio from recovering capacity costs through its wholesale rate conflicts with the RAA and would be preempted under the Federal Power Act.[18]

c. The Company's stranded cost analysis done in the ETP cases, which is heavily relied upon by Mr. Hess in his testimony, performs an energy-only price projection and cannot be used as a baseline for comparison between the proposed capacity charges and any capacity market price.

Mr. Hess agreed that the stranded generation cost analysis performed under SB 3 involved an evaluation of the Company's generation fleet based on a comparison of: (i) the present value at that time of future net revenues based on projected market prices, and (ii) net book value of the generating assets as of the year 2000. (Tr. X at 2973.) The price projections from 2000 necessarily did not contain a capacity component and are not comparable to RPM prices today, which are the basis Mr. Hess presently uses to conclude that the two-tiered capacity charges are above market. As a related matter, Mr. Hess agreed that if we were to do a stranded generation cost analysis today, we would get a different answer because "things have changed." (Tr. X at 2981.)

In his ETP testimony, Dr. Kahn (an outside expert retained by AEP Ohio to testify regarding stranded cost issues) specifically indicated that the modeling outputs would be used by Dr. Landon (another outside witness brought in by AEP Ohio in the ETP cases to help address

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[18] *See* Federal Power Act Section 201(b), 16 U.S.C. § 824(b) (2012); *e.g.*, *Mississippi Power & Light Co. v. Mississippi ex rel Moore*, 487 U.S. 354,374, (1988) ("Congress has drawn a bright line between state and federal authority in the setting of wholesale rates"); *FPC v. Southern Cal. Edison Co*., 376 U.S. 205, 215-16 (1964) ("Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis. This was done in the Power Act by making FPC jurisdiction plenary and extending it to all wholesale sales in interstate commerce..."); *U.S. v. Public Utilities Comm'n of California*, 345 U.S. 295, 308 (1953) ("Congress interpreted [Attleboro] as prohibiting state control of wholesale rates in interstate commerce for resale, and so armed the Federal Power Commission with precisely that power").

stranded cost issues) "to estimate energy revenues by multiplying the regional price in an hour by the plant-specific generation in that hour and summing over all 8,760 hours in a year and all plants in the target sample." (AEP Ohio Ex. 130 at 18.) Dr. Kahn further stated that the capital costs of the generating plant and its fixed operating and maintenance costs "do not affect the determination of the [market clearing price] in the short run" and "are irrelevant for determining the short-run price for electricity in a competitive market." (*Id.* at 6.) In a competitive market, only generating plants that recover sufficient amounts of their fixed costs to make them viable investments on an ongoing basis will remain in the market; if a plant cannot recover sufficient revenues over time to defray the plant's fixed expenses, it will be retired. (*Id.* at 7.)

Thus, while Dr. Kahn was aware of some markets that incorporated a capacity structure (*Id.* at 10-11), he did not incorporate a capacity charge (or a revenue stream associated with capacity) and relied instead on an energy-only construct, as admitted by IEU witness Hess. (Tr. X at 2978.) The table on page 16 of Dr. Kahn's testimony (AEP Ohio Ex. 130) shows that one of the structural assumptions used in the forward price modeling at that time was the "Energy Only" ISO market structure. All of the price projections made by Dr. Kahn were listed as $/MWh units, which is further confirmation of using energy-only pricing. (*See e.g*. AEP Ohio Ex. 131 at Schedule EPK-5.)

As a practical and undisputed matter, Mr. Hess acknowledged that there was no PJM capacity market in 2000 when the ETP testimony was filed. (Tr. X at 2977.) Mr. Hess also agreed that Dr. Kahn's analysis on behalf of AEP Ohio in the ETP cases "assumed an energy-only market" using the market clearing price. (Tr. X at 2978.) Mr. Hess further agreed that Dr. Kahn developed energy prices to estimate future energy revenues. (Tr. X at 2979.) An argument that the analysis done by Dr. Kahn and Dr. Landon included a capacity price component comparable to today's RPM prices cannot reasonably be supported.

When asked about how he could possibly compare such an embedded capacity price (even if it had existed and been included) to the current capacity market price, Mr. Hess acknowledged that he did not know how to back out any capacity component of the market price projections used by Dr. Kahn and Dr. Landon for the 2012-2015 time period; he also admitted that he has not attempted to compare any such results with the current RPM prices. (Tr. X at 3049.) In any case, Mr. Hess's argument that the energy-only stranded cost analysis done in the ETP cases subsumes the subsequently emerging issue of wholesale capacity pricing improperly relies on an "apples to oranges" comparison.

Another reason why the ETP analysis cannot be used as a baseline for conclusion that the two-tiered capacity pricing amounts to stranded cost recovery is because it does not reflect investment made since 2000 or additional plants acquired since then. For example, Mr. Hess admitted that the stranded cost analysis done by Dr. Kahn and Dr. Landon did not reflect plants that were subsequently acquired by AEP Ohio, such as the Darby and Waterford plants. (Tr. X at 3046.) In addition, Mr. Hess did not demonstrate that the capital costs assumed by Dr. Landon (including environmental compliance costs and capital maintenance costs) matched up with the actual investment that has occurred during the dozen years that have elapsed since the ETP analysis was performed.

Regardless of whether the capital investment assumed in the ETP case was accurate, nothing in the stranded investment recovery restrictions under SB 3 apply to prevent recovery of future investments. Thus, recovery of post-2000 capital investments – including investments made in existing plants as well as capital costs of Darby and Waterford – are not precluded by

SB 3 and Mr. Hess did not do any analysis to compare those investments to the level of supposed above-market cost recovery. These additional flaws further undermine Mr. Hess's sweeping (and incorrect) conclusion that the two-tiered capacity charge amounts to untimely recovery of stranded costs in violation of SB 3 and the ETP Stipulation.

d. A comparison of the two-tiered capacity pricing to RPM pricing for 2012-15 period cannot support a conclusion that AEP Ohio's generation investments are stranded above market.

It would be extremely unfair and disingenuous for the Commission to currently find that AEP Ohio's cost-based capacity charge is barred by virtue of a 2000 era market analysis done under the previously-effective provisions of SB 3 that were applied in a different factual context. Not only is the 2000 vintage view of stranded generation investment inapplicable to the current situation, a short-term view of the market cannot support any valid conclusions about generation investment being stranded in a competitive market. Mr. Hess's view that the relatively brief period during which the Stipulated blended capacity charges would apply (*i.e.*, 2012- May 2015) should not be used to judge whether a cost-based rate could be characterized as recovering costs stranded in a competitive market. It strains credulity to even compare the product of the long-term analysis done in the ETP to the one-year RPM prices that are established by auction three years in advance, let alone reach the conclusions asserted by Mr. Hess.

Mr. Hess agreed that observations or conclusions about stranded costs that are reached based on a subset of the 30-year timeframe used by Dr. Kahn and Dr. Landon might yield a different answer than the full 30-year analysis. (Tr. X at 3053, 3055.) Mr. Hess acknowledged that the forward projection of net revenues based on market prices should match up with the remaining useful life of the asset and would be a long-term analysis for most generating units. (*Id.* at 2974.) But his own analysis directly violates this principle.

In asserting that AEP Ohio's proposed rates would collect stranded generation costs because they are "above market," Mr. Hess admitted that his statement simply means that the proposed rates are above the current RPM prices. (*Id.* at 2976.) Mr. Hess also admitted in this regard that he did not do any kind of long-term view of forward RPM prices as part of his analysis. (*Id.* at 2975.) He further agreed that a "three-year analysis of stranded costs may end up with a different result than we ended up with in the 30-year calculation, yes." (*Id.* at 3056.) In fact, Mr. Hess emphatically agreed that he thought it would be "very improperly done to just look at a portion of it" because the "whole picture has to be looked at" in making a stranded cost calculation. (*Id.* at 3054.)

Yet, that is precisely what Mr. Hess does. His theory critically relies upon a comparison of the proposed two-tiered capacity charges to the RPM prices over three years, a small subset of the remaining useful life and of a proper long-term stranded cost analysis. (*Id.* at 2976.) Thus, Mr. Hess's own testimony on these specific points defeats his sweeping stranded cost theory.

e. The re-regulation of the SSO pricing adopted as part of SB 221 renders the stranded cost arguments based on SB 3 inapplicable.

IEU's reliance on the ETP Stipulation is disingenuous and incorrect, because the Company merely gave up the right under SB 3 to recover stranded generation costs during the market development period. It is inherently implausible to suggest, as Mr. Hess does, that the ETP Stipulation forever gave up the right to charge a rate that could for some future period of time arguably be considered above-market, even if the market was not yet in existence (*e.g.*, the RPM capacity market) or if the legal and regulatory construct materially changes (as it has). Since even Mr. Hess cannot dispute that numerous factors have changed since 2000 (including the legal and regulatory regime applicable to SSO pricing), any determination under SB 3 as to whether a particular plant was stranded in the competitive market as of 2000 simply has no bearing on establishing wholesale capacity prices in this case. The General Assembly enacted SB 221 to change SB3. Eventually, during his cross examination, Mr. Hess agreed that SB 221 is "a sensible balance between regulation and competition as it provides utilities with the option of pursuing either a competitive market pricing plan or an electric security plan." (Tr. X at 3009.) But IEU's theory of stranded cost being advanced here relies upon a hypothetical parallel universe where SB 3's deregulatory market-based SSO rate requirement is again in effect. Back in reality, the legal/regulatory environment applicable to this case under SB 221 is not tied to market pricing and, instead, involves an MRO test (further discussed below) that permits above-market ESP rates during periods when market rates fall below SSO rates.

Chief among the materially-changed circumstances since SB 3 is the fact that AEP Ohio was never permitted to charge fully market-based generation rates starting in 2006, even though that was the *raison d'etre* for the market development period and transition cost recovery under SB 3. Mr. Hess agreed that Ohio moved toward restructuring the electric industry under SB 3 with the belief that competitive market forces would develop and hold down prices. (*Id.* at 3006.) Contrary to SB 3's "best laid plans" for price reductions, however, market prices ended up *doubling* by the end of the market development period as compared to prices at the time SB 3 passed. (AEP Ohio Ex. 142 at 18.)

Ultimately, utilities were not permitted to fulfill SB 3's promise of fully competitive market rates starting in 2006, upon which utilities entered into their ETP plans. In colloquial terms, the General Assembly's promise of post-MDP market rates was broken and there was, thus, a material breach of the agreement to deregulate SSO pricing. If the ETP Stipulation were a contract, AEP Ohio's performance under any of the obligations would be excused because the *quid pro quo* (*i.e.*, the promise that AEP Ohio would be permitted to charge a fully competitive market rate at the end of the MDP) was revoked. Regardless, it is clear that the passage of SB 221 created a new regime with new rules; though the retail choice platform itself was retained, the entire SB 3 de-regulatory SSO pricing construct was repealed and replaced with a re-institution of regulatory control over SSO prices. More to the point of IEU's misguided theory that a strict prohibition of any rate "above market" continues to apply *ad infinitum* by virtue of SB 3, SB 221 cannot be reasonably interpreted (and never has been interpreted) as requiring SSO rates to always be equivalent to market prices for any given period of time. As IEU witness Murray agreed, the rate stabilization plans of the mid-2000s were an additional transition for electric distribution utilities. (Tr. XII at 3415.)

As noted above, the provision in RC 4928.14 requiring market-based SSO rates was repealed and was replaced by two alternative options, both of which mandated regulatory control and approval for SSO rates that would, by design, be significantly lower than prevailing market rates. Mr. Hess could not seem to remember these important regulatory developments, even though he was the Chief of the Electricity and Accounting Division of the Commission's Utilities Department at the time he left the Commission, which was one of the highest ranking Staff positions concerning electricity issues. (Tr. X at 3008.) Nonetheless, after extensive cross examination, Mr. Hess reluctantly agreed to the salient points, as discussed herein.

Mr. Hess steadfastly maintained that AEP Ohio's SSO rates during the Rate Stabilization Period (2006-2008) must be considered "market rates" based on his understanding of SB 3, even though he did not know whether the statutory term was "market rates" or "market-based rates." (*Id.* at 3010-11.) Although he could not muster agreement with the notion that the SSO rates were below market during the RSP period, he did agree that no CRES provider could offer rates below Ohio Power's SSO rates during this time period. (*Id.*) Further, despite his current reluctance and inability to recall these matters, the Commission's findings based on Mr. Hess's testimony in the *ESP I* proceeding confirmed the fact that market rates were higher than SSO rates at the time SB 221 was passed and implemented.

Specifically, in the *ESP I* proceeding, the Commission made a finding based on the testimony of Mr. Hess that the cost of the proposed ESP ($1.4 billion) was less than half of the expected cost of an MRO ($2.9 billion). (AEP Ohio Ex. 134 at 72.) 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), Mr. Hess reluctantly agreed that this finding confirms that market rates were much higher than SSO rates at the time of the *ESP I* decision. (Tr. X at 2993-94; *see also* AEP Ohio Ex. 132 at Ex. JEH-1.) Further, AEP Ohio Ex. 142 (at 18) shows that the prevailing market price during 2008 (when SB 221 was passed) was substantially higher at 8.52¢/kWh, while the *ESP I* Opinion and Order (at 22) ordered that the generation rates for 2009 were not to exceed 5.47¢/kWh and 4.29¢/kWh for CSP and OP, respectively, on average.

Mr. Hess testified that his characterization of the RSP rates as being equivalent to market rates is based on the Commission's decision in Case No. 04-169-EL-UNC, AEP Ohio's RSP case. (Tr. X at 3010.) In its January 26, 2005 Opinion and Order in that case, the Commission quoted (at 7) R.C. 4928.14's requirements that SSO rates starting in 2006 were to be "market-based" rates and were also to be "determined through a competitive bidding process." Interestingly, the RSP decision frankly admitted (at 14) that "we do not want to simply allow market forces to be unfettered" and the then-low level of shopping activity lead the Commission "to seriously doubt the efficacy of initiating a competitive bid" as referenced in the statute.

Further, the Commission observed (at 14) that "[m]any parties argue that AEP's proposed RSP is not a market-based standard service offer because it is not based upon the market." Ultimately in this regard, the Commission found (at 14) that the RSP constituted "an appropriate market-based standard service offer, as required by Section 4928.14(A), Revised Code." Thus, there can be no doubt that the Commission understood the distinction between an unfettered market rate (which they consciously and intentionally avoided through the RSPs) and a "market-based standard service offer" rate (which the RSPs satisfied based on avoiding unfettered market rates).

Mr. Hess's attempt to conflate the two distinct concepts ("market-based" SSO rates under SB 3 and prevailing market prices) is unpersuasive and should be rejected. After being confronted with the 2005 Commission decision involving Monongahela Power Company (Mon Power), contained in AEP Ohio Ex. 120, Mr. Hess agreed that there "certainly were" differences between the "market rates" involved with the competitive bidding process and the "market-based standard service offer rates." (Tr. X at 3029.) More specifically, the AEP Ohio "market-based" SSO rate level were lower than the CBP-based market rates. (*Id.*at 3029.) Mr. Hess also acknowledged that the Commission's November 9, 2005 Opinion and Order in the Mon Power case found based on the evidence that Mon Power customers, being acquired by AEP Ohio, will be "far better off" under the SSO rates than the CBP because the evidence substantiated that the CBP charges would be "much higher" than AEP Ohio's SSO rates. (*Id.* at 3028-29; AEP Ohio Ex. 120, Tab 6, at 10-11.)

Perhaps the most glaring error in the stranded generation investment argument is that it ignores the fact that the entire regulatory regime for standard service offer pricing has substantially changed with the enactment of SB 221 in 2008. During the period 2001 through 2008, the Company's generation rates were well below market and the Company's retail customers benefited greatly. Yet, even though SB 3 was premised on the ability to charge market rates starting in 2006, at no time during the past decade was AEP Ohio ever permitted to charge a true market rate for its standard service offer. The ESP option under SB 221 now involves several cost-based rate adjustments and amounts to a hybrid system of regulation and market-based pricing. IEU witness Murray agrees that SB 221 repealed the requirement that SSO rates must be market-based[19] and that the SB 221 ESP and MRO options replaced the SSO pricing standard previously enacted under SB 3. (Tr. XII at 3395, 3415.)

Even an MRO option under SB 221 involves an additional transition period of 6-10 years before a full market price is charged for the standard service offer. Another significant change made through SB 221 regarding generation assets is that a utility is required to obtain approval from the Commission to transfer generation assets. Under SB 3, an electric utility could freely transfer generation assets. In its first ESP filed under SB 221, the Company sought to transfer a limited amount of its generation and its request was denied. Yet another significant aspect of SB 221 is application of the significantly excessive earnings test. All of these factors limit an electric utility's ability to charge and retain market rates for generation service and manage the business and financial risks associated with its fleet of generation assets.

Based on an illustration reflected in AEP Ohio Ex. 138, IEU witness Hess also admitted that it is permissible under a proper application of the MRO test to collect substantial levels of ESP revenue that exceed the projected market price during the same period. (Tr. X at 3043-44.) While Mr. Hess asserted there would probably be "quite a bit of shopping" under the example used, he also later admitted that some customers would not shop because it was only the average

[19] *See* Am.Sub.S.B. 221 (repealing requirement, previously contained in R.C. 4928.14(A), that SSO rates be "market-based" and repealing the requirement, previously contained in R.C. 4928.14(B), that required utilities to conduct an auction for SSO load).

ESP rate that was above the average projected market rate and he also said that he did not know how much or how fast shopping would occur under the illustration. (Tr. X at 3044, 3059.) In any case, Mr. Hess agreed that the design of the MRO price test permits some level of above-market ESP pricing to be permissible. IEU witness Murray also conceded that it is possible to have ESP rates that are higher than prevailing market rates and still pass the MRO test/satisfy the SSO statute. (Tr. XII at 3402.) He also agreed in the context of an MRO that a blend of legacy ESP rate and CBP is not necessarily equivalent to a market rate. (Tr. XII at 3416-17.) While the premise and design of SB 221 was to delay and further expand the transition to then-higher market rates, by imposing a mandatory 6-10 year additional transition to market rates (only if the utility opted down the permanent path to an MRO), it is an indisputable fact that the mathematical application of the MRO price test also permits above-market pricing for an ESP. Specifically, because SB 221 also encouraged continued stability through the consensual ESP option which would also be subject to the MRO test to ensure that it was lower than the pricing blend that was designed to heavily weight the adjusted SSO rate so as to dilute to impact of higher market rates. Thus, the enactment of SB 221 conveyed "relief" from the prospect of higher market rates by imposing new regulatory controls and creating a new, extended period for transitioning to fully competitive market SSO rates. Of course, the same relief for customers also rescinded SB 3's promise to utilities that they would be permitted to charge market rates for SSO service after the MDP. Not only was SB 3's requirement for "market-based" SSO rates repealed through enactment of SB 221, it is mathematically impossible for a utility to charge an unfettered market rate under either the MRO (prior to 6 years) or the ESP options when market rates are higher than SSO rates (as contemplated when SB 221 was passed).

f. Conclusions regarding stranded cost arguments

The Commission should reject the perverse argument advanced by some Intervenors that the absence of stranded investment recovery from customers under SB 3's opportunity for receipt of transition revenues precludes the Commission from presently adopting a cost-based capacity charge. Intervenor arguments in this regard are especially inequitable in light of the fact that AEP Ohio continued to provide stable rates at the Commission's request and has avoided the volatile and uncertain RPM market for capacity through its election to be a FRR Entity, which was applauded by the Commission at the time AEP Ohio made its election. AEP Ohio saved its customers billions of dollars by avoiding higher market prices over the past decade. It would truly live up to the saying that "no good deed goes unpunished" and be unreasonable for the Commission to currently find that AEP Ohio's cost-based capacity charge is barred by virtue of a 2000-era market analysis done under the previously-effective provisions of SB 3 that were applied in a different factual and legal context.

v. The Company's alternative embedded cost-based capacity proposal is reasonable.

In addition to its two-tiered capacity pricing proposal, the Company also has proposed a reasonable alternative capacity pricing option. (AEP Ohio Ex. 116 at 15-17.) Under the alternative option, the Company would charge CRES providers a cost-based rate of $355.72/MW-day during the term of the ESP and would provide shopping credits to retail customers. (*Id.* at 15.) The shopping credit proposed in this alternative option would be $10/MWh and would be subject to a cap of $350 million over the period from June 2012 through December 2014. This would equate to a credit approximately equal to 10 to 20% of the generation rate a typical customer pays. (*Id.* at 16.) Company witness Allen explained that, under this option, a typical residential customer would receive shopping credits of more than $100 per year. (*Id.*)

Customers would receive the shopping credits on a first come, first served basis by customer class. (*Id.*) Credits would be provided for up to 20% of each class's load from June 2012-May 2013, 30% from June 2013-May 2014, and 40% from June 2014-December 2014. AEP Ohio would perform a monthly calculation to determine the MWh of shopping credits still available over the period, which it would post on the Company's Customer Choice website each month. (*Id.*)

The alternative option, like the proposed two-tiered capacity structure, would encourage shopping during the term of the Company's Modified ESP. (*Id.*) As Mr. Allen explained, shopping credits encourage customers to shop by providing them with a direct and tangible benefit in the form of a bill credit to shopping customers. (*Id.*) Indeed, under some circumstances, "the $10 credit would essentially turn a CRES offer that was above the Company's SSO rate into an offer that provided a discount to the customer." (Tr. V at 1434.) Moreover, shopping credits provide shopping customers with fixed and known savings that are available to the customer regardless of the CRES offer they select. (*Id.*) As Company witness Powers explained, the alternative option "help[s] focus the benefit of this transition to market and the balance between the CRES providers and the customer to ensure that the incentive was provided to the *customer* to shop" and would assure "that all the benefit went to the customer." (Tr. II at 427 (emphasis added).)

Mr. Powers explained why the Company did not make the alternative option its first capacity pricing recommendation as follows:

> We didn't at the end of the day, make this our first recommendation, and the reason for this is, again, [that] we tried to

> be balanced in our approach and suspected that the CRES providers wouldn't like this option and realized that as stakeholders in this process we needed to provide balance between desires of the CRES providers, customer rate impacts, … [and] our financial well-being.

(*Id.*) Thus, although the Company's primary capacity pricing proposal remains the two-tiered structure, the Company has demonstrated that its alternative option is reasonable and promotes competition for electric service and customer choice.

3. The Modified ESP reasonably incorporates termination of the AEP Interconnection Agreement and includes a Pool Termination Provision.

The Modified ESP reasonably accounts for the planned termination of the AEP Pool and, in the event that corporate separation is not approved as the Company has proposed, the Modified ESP includes a reasonable pool termination provision that is designed to offset significant revenue losses caused by the Pool's termination. As Company witness Nelson explained, AEP Ohio and other members of the AEP Pool provided written notice to each other on December 17, 2010, setting forth their mutual desire to terminate the existing agreement, and concurrently terminate the Interim Allowance Agreement (IAA), on three years notice in accordance with the terms of the Pool Agreement. (AEP Ohio Ex. 103 at 21.) Concurrent with the AEP Pool termination, AEP Ohio plans to implement its corporate separation plan. (*Id.*) As discussed in greater detail below, the requested corporate separation was filed with this Commission in a separate proceeding (Case No. 12-1126-EL-UNC).

Mr. Nelson explained that the termination of the AEP Pool is an important issue for the Company because a significant portion of AEP Ohio's total revenues come from sales of power to other Pool members. (*Id.*) With the termination of the AEP Pool, the Company will need to find new or additional revenue to recover the costs of its generating assets, or it will need to reduce the cost of those assets, because the lost revenues from member sales capacity cannot be mitigated by opportunity sales in the market alone. (*Id.*) Due to this potentially significant decrease in revenues, the Company has proposed that it be permitted the opportunity to make a subsequent application with this Commission, if needed, to recover lost revenues as part of the move to competitive markets. (*Id.* at 21-22.)

Notably, so long as the proposed corporate separation plan is approved and implemented, the Company is <u>not</u> seeking compensation for the loss of revenue resulting from termination of the AEP Pool. (*Id.* at 22.) The Company's corporate separation plan includes elements that mitigate the loss of capacity revenue. Nonetheless, AEP Ohio has proposed a pool termination provision, which would be triggered only if the Company's corporate separation plan is denied or amended. (*Id.*) Under the provision, if the corporate separation plan is denied or amended, then the Company would be permitted to charge a nonbypassable rate to compensate it for any loss of earnings associated with the AEP Pool termination. (*Id.*) That compensation would be determined in a subsequent filing made under this ESP. In general, the proposed pool termination provision would function as follows.

- The Company would compare the lost AEP Pool capacity revenue to increases in net revenue related to new wholesale transactions or decreases in generation asset costs that result from the AEP Pool termination. (*Id.* at 22-23.) Specifically, the actual AEP Pool capacity revenue in the most recent twelve-month period preceding the effective date of the change in the AEP Pool will be compared to increases in net revenue related to new wholesale transaction or decreases in generation asset costs. (*Id.* at 23.)

- If there is substantial decrease in net revenue, then the Company may avail itself of the pool termination provision and seek recovery of the lost net revenue from retail customers. (*Id.* at 23.)

Importantly, the Company would not adjust the proposed ESP rates unless the annual effect of the AEP Pool termination is equal to or greater than $35 million on an annual basis during the ESP term. (*Id.*) The Company's proposals concerning Pool termination are reasonable and balanced, and the Commission should approve them as proposed.

4. The Modified ESP is premised upon approval of full structural corporate separation, in accordance with Section 4928.17, Revised Code.

In its Modified ESP Application, the Company provides a description of its corporate separation plan, which will be adopted under §4928.17, Ohio Rev. Code, and Rule 4901:1-37, Ohio Admin. Code, through a separate application filed in Case No. 12-1126-EL-UNC.[20] Full structural legal separation (*i.e.*, generation divestiture) is a necessary prerequisite for the Company's Modified ESP proposal to transition toward and implement an auction-based SSO. Accordingly, Company witnesses Powers and Nelson discuss the Company's corporate separation plan in their testimony in support of the Modified ESP.

[20] In addition to Commission approval, Mr. Powers describes that corporate separation will also necessitate several FERC filings. In one FERC filing, AEP Ohio will ask for the transfer its generation assets at net book value (NBV) to Genco by January 1, 2014. (AEP Ohio Ex. 101 at 21.) This filing will involve the full NBV transfer of all of AEP Ohio's current generation assets to the Genco, a provision that was highlighted by the Commission in their February 23, 2012 Order. (*Id.*) Another FERC filing will propose termination and replacement of the Pool Agreement, for which the member companies, including AEP Ohio, provided notice of termination on December 17, 2010, which established a three year termination commitment by January 1, 2014. (*Id.*) In another separate application with the FERC, certain generating assets, the Mitchell generating plant and Ohio Power Company's share of Unit No. 3 of the Amos generating plant, will be transferred at net book value from the Genco to Appalachian Power Company (APCo) and Kentucky Power Company (KPCo). (*Id.*) Finally, from January1, 2014-May 31, 2015, the Genco will have an interim power sales agreement (SSO Contract) with AEP Ohio to allow AEP Ohio to meet its FRR capacity requirements and serve its non-shopping retail energy load until January 1, 2015. (*Id.*) This agreement will require a separate application at the FERC as well. (*Id.*)

i. Description of corporate separation and asset transfer

As Mr. Nelson explains, the principal purpose of the corporate separation filing is to achieve full structural corporate separation of AEP Ohio's generation and marketing businesses, on the one hand, from its transmission and distribution businesses, on the other, consistent with Ohio's corporate separation mandate. (AEP Ohio Ex. 103 at 4.) Corporate separation is a fundamental requirement of the Company's plan that will lead to full market-based pricing of generation service for retail customers and will promote retail shopping in Ohio. (*Id.*) Under corporate separation, transmission and distribution-related assets of AEP Ohio will remain in AEP Ohio, which will essentially be a wires-only company upon closing. (*Id.*) AEP Ohio's existing generation units and contractual entitlements, fuel-related assets and contracts, and other assets related to the generation business will be transferred at net book value to AEP Generation Resources Inc. (Genco). (*Id.* at 5.; Tr. II at 507-08.) AEP Ohio does not plan to transfer its renewable purchase agreements to Genco. (AEP Ohio Ex. 103 at 4.) The renewable energy credits associated with those agreements will stay with AEP Ohio, which will remain subject to state-imposed renewable energy obligations. (*Id.*) Genco will also assume at closing the liabilities associated with the transferred assets including the retired plants and the liabilities associated with the retired plants. (*Id.*)

Immediately after transferring the assets and liabilities to Genco, Appalachian Power Company (APCo) will obtain the transferred interest in Unit No. 3 of the Amos generating plant and appurtenant interconnection facilities and related assets and liabilities (APCo already owns the remaining interest in Amos Unit No. 3) and an 80% undivided interest in the Mitchell generating plant and appurtenant interconnection facilities and related assets and liabilities (collectively, "Mitchell"), and Kentucky Power Company (KPCo) will obtain the remaining 20%

undivided interest in Mitchell. (*Id.*) Mr. Powers provides the rationale that APCo and KPCo have long relied on AEP Ohio generating assets through the Pool Agreement to supply part of the capacity and energy needed to meet their respective load requirements (and APCo and KPCo have long paid for using those assets through capacity equalization charges). (AEP Ohio Ex. 101 at 22.) The applicable Amos and Mitchell units are physically located in West Virginia, and are of sufficient capacity to cover the expected shortfall (including the required reserve margin) for those FRR companies after the existing pool agreement is terminated. (*Id.*) Thus, the transfers to APCo and KPCo are logical and appropriate.

The long-term indebtedness of AEP Ohio is composed of general obligations that are not secured by the generation assets being transferred to Genco or by any other assets of the Company. (AEP Ohio Ex. 103 at 5.) This unsecured, long-term indebtedness currently consists of two types: senior notes ("Senior Notes") and pollution control revenue bonds ("PCRBs"). (*Id.*) In order to manage debt maturities before the closing of corporate separation, AEP Ohio may issue new notes to AEP and use the proceeds to repay those debt maturities in the normal course of business. (*Id.*) The notes would be subject to approval by the Commission. (*Id.*)

The proposed corporate separation plan includes several steps, each of which will occur one after another at closing. (*Id.* at 6.) The steps of the transaction are detailed in the Company's March 30, 2012 application it filed in Case No. 12-1126-EL-UNC. Exhibit PJN-1 to Mr. Nelson's direct testimony is a chart showing AEP Ohio, the other AEP East operating companies, and the Genco on a pre- and post-corporate separation basis. (*Id.* at Ex. PJN-1.) The Company intends to close the corporate separation transaction on January 1, 2014. (*Id.* at 6.)

ii. SSO contract between AEP Ohio and Genco

In the Modified ESP, the Company is proposing that there will be an auction-based competitive bidding process for the delivery period beginning January 1, 2015 for energy and a separate auction for delivery beginning June 1, 2015 for both energy and capacity. (*Id.*) Between the time of corporate separation and the delivery date of the January 1, 2015 SSO energy auction, the Genco will sell wholesale power to AEP Ohio under a full requirements agreement to supply AEP Ohio's non-shopping retail load. (*Id.*) The SSO Contract will allow AEP Ohio to serve SSO customers, i.e., those AEP Ohio retail customers that are not being served by a Competitive Retail Electric Service (CRES) provider. (*Id.*) From January 1, 2015 through May 31, 2015, the Genco will provide capacity at $255/MW-Day, but will no longer supply the energy for SSO customers under the SSO contract. (*Id.*) Beginning June 1, 2015 both energy and capacity will be provided by the SSO auction and, therefore, the SSO contract between the Genco and AEP Ohio ends on that date. (*Id.* at 7.)

iii. AEP Ohio's payments to Genco

In general, AEP Ohio will pass through generation-related revenues to the Genco for providing capacity and/or energy for the SSO load. (*Id.*; Tr. II at 515.) AEP Ohio will pay the Genco the non-fuel generation charges billed to AEP Ohio's SSO customers under applicable retail rate schedules, as well as the Genco's actual fuel costs. (AEP Ohio Ex. 103 at 7.) AEP Ohio will also reimburse Genco, on a dollar-for-dollar basis, for any transmission, ancillary, and/or other service charges that Genco may be billed by PJM in connection with the SSO Contract. (*Id.*) In addition, revenues that AEP Ohio may receive from PJM in connection with capacity payments made by CRES providers under PJM's Reliability Assurance Agreement ("RAA") would be remitted to the Genco in return for Genco providing capacity to AEP Ohio to fulfill AEP Ohio's Fixed Resource Requirement (FRR) obligations, as well as the obligations of the CRES providers. (*Id.*) Also, capacity payments will be made by AEP Ohio to the Genco at $255/MW-Day in connection with the energy only auctions occurring while AEP Ohio is still an FRR entity in PJM. (*Id.*) Also, any revenues related to moving to a competitive generation market in Ohio, such as the Retail Stability Rider, will be remitted to the Genco as compensation for the fulfillment of its obligations. (*Id.* at 8; Tr. II at 519, 614.)

iv. AEP Ohio must remain a FRR entity until June 1, 2015.

AEP Ohio and the AEP East system are contractually obligated to remain a FRR entity in PJM until June 1, 2015. (AEP Ohio Ex. 103 at 8.) An auction-based SSO cannot be established for AEP Ohio's non-shopping load before corporate separation is implemented and before the AEP Pool is terminated because doing so would expose AEP Ohio or other AEP Pool members to significant financial harm. (*Id.*) First, the AEP Pool was not designed for, nor does it have specific provisions that would address this situation; thus, conducting an SSO auction could have substantial impacts on the other members or subject them to recovery risks in their state jurisdictions. (*Id.*) Conversely, depending on how an auction is treated for AEP Pool settlements, AEP Ohio might be exposed to significant financial harm. (*Id.*) It would also potentially remove AEP Ohio's generation from participating in the SSO auction due to the timing difference between the auction and corporate separation. (*Id.*)

v. AEP Ohio customers will have adequate capacity.

As outlined above, once the Pool Agreement is eliminated and corporate separation is complete, there will be a SSO Contract between the Genco and AEP Ohio over the *ESP II* term. (AEP Ohio Ex. 101 at 23.) To further support the Commission's intent to encourage competition in an expedited manner, from January 1, 2015-May 31, 2015, AEP Ohio will auction the energy component of SSO load for delivery from January 1, 2015 through May 31, 2015. (*Id.*) For delivery effective June 1, 2015, AEP Ohio will use a CBP for supply of capacity and energy supporting SSO load in the same manner as other Ohio electric utilities do today. (*Id.*) The assurance of adequate capacity will become a function and obligation of PJM. (*Id.*; Tr. II at 570.)

C. Continuation Of The Transmission Cost Recovery Rider Is Reasonable.

The Company proposes to retain the Transmission Cost Recovery Rider (TCRR) mechanism as it is presently comprised, except that AEP Ohio proposes to unify the rates for each rate zone into a single set of merged rates effective upon implementation of the Modified ESP, as described by AEP Ohio witness Roush. (AEP Ohio Ex. 111 at 6-7.) AEP Ohio witness Mitchell described the proposed regulatory accounting for the TCRR, being over-under accounting with no carrying charge on the investment and a long-term interest carrying charge on any unrecovered balance. (AEP Ohio Ex. 107 at 8.) Annual filings for the TCRR will comply with the requirements of Chapter 4901:1-36, Ohio Admin. Code. The Commission approved the TCRR as being reasonable in the *ESP I* decision (Opinion and Order at 49-50) and should do so again as part of *ESP II*.

D. The Proposed Distribution-Related Rates Are Reasonable.

1. The Distribution Investment Rider is reasonable.

The Distribution Investment Rider provides the Company needed carrying costs on incremental distribution investment to ensure continued investment in the distribution system without the risk of regulatory lag. The approval of the rider will assist in customer reliability, improvements on the distribution system and provide stability for retail electric service. As such the Commission should approve the DIR as allowed under R.C. 4928.143(B)(2).

The structure of the DIR is straight forward and provides for caps each year of the ESP. The carrying charge will include elements to allow the Company an opportunity to recover property taxes, commercial activity tax, earn a return on (and associated income taxes) and of plant in service associated with distribution net investment associated with FERC Plant Accounts 360-374. (AEP Ohio Ex. 116 at 9.) The return earned will be based on the cost of debt of 5.64% and a return on common equity of 10.20% utilizing 47.73% debt and 52.25% common equity capital structure. (*Id.*; *see also* AEP Ohio Ex. 102.) The net capital additions included in the DIR will reflect gross plant in service incurred after August 31, 2010, adjusted for growth in accumulated depreciation. (AEP Ohio 116 at 10.) The methodology for calculating the revenue requirement for the DIR is detailed on Exhibit WAA-5 attached to the testimony of Company witness Allen. The DIR is capped at $86 million in 2012, $104 million in 2013 and a cap of $124 million in 2014 (the revenues collected for the first five months of 2015 will be capped at $51.7 million). (*Id.* at 11.)

The Commission is not limited by the statutory provisions offered to justify worthy mechanisms like the DIR. However, the Company would respectfully offer R.C. 4928.143 (B)(2)(h) and/or (d) as potential justifications for the rider. Both statutory provisions provide the Commission with the authority to create the rider and the record contains factual support for both options. The testimony of AEP Ohio witnesses Allen and Kirkpatrick supports the usage of R.C. 4928.143 (B)(2)(d) as authority for the DIR. The statute allows a plan to include:

> (d) 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;

As indicated by Mr. Allen, the DIR will allow recovery of carrying costs on incremental distribution plant. (AEP Ohio Ex. 116 at 9.) Mr. Allen also pointed out the inter-related nature of the approval of the DIR to the stabilizing of the distribution rates due to the credit applied to distribution rates expected to be recovered through the DIR. (*Id.* at 10-11.) As indicated, failure to approve the DIR will require the Company to immediately seek a base distribution case increase. (*Id.* at 11 and 12.) The Company also proposes caps to manage the stability of the rider. (*Id.*) Mr. Allen points to the streamlined approach to recovery of costs associated with distribution investments which will encourage investment that can improve reliability. (*Id.* at 12.) The reliability benefits also relate to stabilizing retail electric service through the necessary replacement of aging infrastructure as pointed out by Company witness Kirkpatrick. (AEP Ohio Ex. 110 at 18-19.) The elements of the DIR and the impact of the DIR on retail electric service provide the Commission with R.C. 4928.143(B)(2)(d) as authority for approval of the rider.

The statutory provision the Commission elected to utilize in its December 14, 2011 Opinion and Order, to approve the DIR is also again available as a basis to approve the DIR in this case – R.C. 4928.143 (B)(2)(h). The Commission recognized the applicability of this statutory provision in its ESP Stipulation Opinion and Order on December 14, 2011. The Commission found that the DIR is incentive ratemaking to accelerate recovery of the Companies' investment in distribution service. (ESP Stip O&O at 45.) That same rationale applied by the Commission applies today. According to this statutory provision, the Commission may include in an ESP:

> (h) 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 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.

The DIR proposed by the Company fulfills the requirement of this statute and should be approved by the Commission. As discussed by the Commission in the December 14th ESP Stipulation O&O, "the Staff continually monitors each electric utility's distribution system reliability through service complaints, electric outage reports, and compliance with Rule 4901:1-10-10, O.A.C., among other provisions of Chapter 4901:0-10 O.A.C." (Dec. 14th ESP Stipulation O&O at 46.) Staff witness Baker testified that the Commission Staff examines the reliability of utilities through its application of the minimum reliability service standards. (Staff Ex. 106 at 5-6.) Staff witness Baker also indicated on cross examination that he is interacting with utilities year round beyond the reports filed on the reliabilty indices. (Tr. XV at 4339.) Mr. Baker also referred to Staff data requests in this case that provided more information on the level of reliability in the Company's territory. (*Id.* at 4345-4346; see also AEP Ohio Ex. 146.) He also agreed that the information provided by the Company is reliable data that represents what is occuring in the field. (Tr. XV at 4350.) Staff witness Cleaver also testified that the Company has not violated any federal safety reliability regulations. (Staff Ex. 107 at 4376-4377.) The Staff examines the Company's reliability on a continual basis and did so also in the confines of this case as evidenced by the testimony of Staff witnesses and the documents presented as exhibits. As such the Commission can find that it has examined the reliability of the Company as part of its analysis in this case.

The expectations of the customer and Company are also aligned in this case. The Commission previously pointed out the customer survey responses and percentage of customers that had increased expectations for their reliability as an indication that expectations were aligned in its December decision. The responses in the most recent surveys are almost identical to the results relied upon the Commission previously. Company witness Kirkpatrick includes the updated numbers to show that 19% of residential and 20% of commercial customers expect their reliability expectations to increase in the next five years. (AEP Ohio Ex. 110 at 19.) When that is added to the number of customers that are expecting the utility to maintain the level of reliability at the level it is today the number jumps to 90% of residential and 93% 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.

Staff indicated in the testimony of Peter Baker that the Company and customers' reliability expectations are not in line and used a single missed reliability standard out of 8 in the past two years as its proof. The Commission should find that the Company and its customers' expectations are aligned as the Staff's analysis is flawed and contradicts its own underlying rationale for making its determination.

The responses to questions from Attorney Examiner See provided some key facts the Commission should rely upon to find that the customer and Company expectations on reliability are aligned. Upon examination by Examiner See in the hearing, Staff witness Baker was questioned on the Staff's ability to determine the customer's reliability expectations. Judge See questioned Mr. Baker on how to quantify the "high percentage" of survey results referred to by

Mr. Baker, in his testimony on page 7, showing that residential and commercial customers were satisfied with the overall level of service reliability provided by the Company at the time of setting the standards. (Tr. XV at 4366.)

According to Mr. Baker, the survey results from customers at the time of setting the standards that he referred to as a "high percentage" were at the 75-80% service reliability levels. (*Id.*) Then in response to further questions from Judge See, Mr. Baker replied that the Staff uses the reliability standards for its determination of customer expectations and the reason in part is because those standards are based upon the customer surveys that help create the standards. (*Id.* at 4366-4367.) Based on this testimony one would expect customer responses to the same question on the most recent surveys to be lower than the 75-80% testified to by Staff witness Baker. However, a review of the customer surveys provided as Attachment JDW-2 to the pre-filed direct of OCC witness James Williams, marked OCC Exhibit 113, shows that Staff's assumption that customer expectations are not aligned with the Company's is incorrect. According to the customer surveys the residential customers responding to the same question referred to by Mr. Baker, rated the Company with an 85% positive rating in the category of "Providing Reliable Service." (OCC Ex. 113 at Attachment JDW-2 page 1 of 8.) According to that same survey the commercial customers rated the Company with a 92% positive rating in that same category "Providing Reliable Service." (OCC Ex. 113 at Attachment JDW-2 page 5 of 8.) The best evidence concerning the customer's expectations is the direct response from those customers on the single point of reliability shows that customer satisfaction is actually 10-17% or 5-12% better than 75-80% levels cited by Mr. Baker based on the same survey questions used to create the standards. By Staff's own analysis and more importantly according to the responses of actual customers the Company's expectations are aligned with customer expectations.

Even putting aside the best evidence of the direct customer feedback from the surveys showing the expectations are aligned, Staff's position that a single missed reliability standard in a single year is proof of misaligned expectations is also without merit. First and foremost missing one of eight standards in a two year period is not a rule violation. According to O.A.C. 4901:1-10-10(E) "[f]ailure to meet a performance standard for two consecutive years shall constitute a violation of this rule." There are many uncontrollable occurrences that can cause a utility to miss a standard in a single year. Staff witness Baker admits issues like storms that do not get excluded from the standards and trees out of the right-of-way can cause a utility to miss a standard. (Tr. XV at 4344-4345.) There is a recognition by Staff that there are matters beyond the utility's reasonable exercise of power that can cause a standard to be missed.

The Company provided the Commission Staff with a presentation of the factors that contributed to the one-time miss of this particular reliability standard for 2011. (AEP Ohio Ex. 146.) That presentation highlights the unique nature of the circumstances faced by the Company compared to the years used to set the standards. The Company discussed AEP Exhibit 146 with Staff witness Baker on the stand. He verified it was the document shared with the Commission Staff concerning the one-time miss of the one standard. (Tr. VX at 4347.) A review of this document shows the extreme occurrences beyond the Company's control that were also well outside of the parameters of those same outage causes for the historical years used to set the standards. According to the testimony of Staff witness Baker, the historical data used (2006-2009) to determine the standards was used "* * * because performance in these years better reflects the current operating conditions of the system* * *." (Staff Ex. 105 at 7.) The data in AEP Ohio Ex. 146 shows that there was a 42% increase in weather events from the historical period used to set the standards and the events experienced in 2011. (AEP Ohio Ex. 146 at 3.)

The data on page 6 of the exhibit shows that there was increase of 3,720,444 customer minutes of interruption due to weather related outages; this represents a 32% increase above the historical period used to set the standard that as Mr. Baker testified, better reflected the operating conditions of the system. Trees out of the right-of-way were another uncontrollable outage causer typically beyond the utility's direct right to control. As indicated on page 9 of the exhibit it shows that outages caused by trees out of the right-of-way rose 13% above the average used to set the standard from the historical period. In minutes of interruption these increase in outages due to trees out of the right-of-way was 3,520,553 minutes more than the minutes out due to the same cause in the historical period used to set the standard – that is a 17.8% increase in the number of minutes interrupted. In total just the differences in weather-related outages and trees out of the right-of-way would add up to 7.60 minute increase in the missed CAIDI standard missed by the Company in 2011. (*Id.* at 14.) The Company only missed the standard by 3.42 minutes. That meant in reality the Company performance was 4.18 minutes better than the standard when the actual weather is compared to the weather used to set the standard. The Company's performance in the presence of such an abnormal swing of outage events should be commended not condemned. Regardless, a review of the actual underlying numbers highlights why the Commission did not make missing a standard in a single year a violation of the rule and shows why Staff should not use the missing of one out of eight standards as an indication that customer and company reliability expectations are not aligned.

The Commission should find that the DIR as proposed satisfies the statutory requirements for approval under either R.C. 4928.143(B)(2)(H) or (D). The DIR provides carrying charges to maintain and meet future customer reliability expectations. The DIR also impacts the distribution settlement that resulted in an offset to the Company's rate base increase and is providing credits to residential customers and providing funds to the Partnership with Ohio for assistance for at-risk populations in AEP Ohio's territory.

2. Continuation of the gridSMART Rider is reasonable.

The Company requests a continuation of the gridSMART Rider as part of the Modified ESP. The request is for a continuation of the same rider previously approved by the Commission in Case Nos. 08-917-EL-SSO, 08-918-EL-SSO and 10-164-EL-RDR. As stated by AEP Ohio witness Kirkpatrick, the proposal is to maintain the existing rider for the recovery of the cost of assets already installed or planned to be installed as part of the completion of Phase I. (AEP Ohio 110 at 10.) As AEP Ohio witness Roush indicated, the gridSMART Rider will continue to include the costs of Phase I of the program, with the prudence of the costs determined as part of the annual true-up filing. (AEP Ohio Ex. 111 at 7.) Mr. Roush also points out that the calculations for this and other riders will utilize information for the merged Ohio Power Company going forward. (*Id*.)

The Commission Staff is supportive of the continuation of the gridSMART Rider. Staff witness Gregory Scheck filed testimony supporting the recovery of gridSMART costs through the gridSMART Rider. (Staff Ex. 105 at 6.) Mr. Scheck testified that he believes all gridSMART related costs should be recovered from this rider and not other sources. (*Id.*)

Staff did express concern with any expansion of the gridSMART program beyond Phase I. The Staff deferred any decisions on the future of the program to after the data from Phase I has been completed, gathered and analyzed. Staff witness Cleaver testified that gridSMART Phase I should be completed first and then the results analyzed to better determine the total costs and the benefits of system wide deployment. (Staff Ex. 107 at 12; see also Tr. XV at 4181, Cross of Staff witness Scheck.) The one category related to gridSMART that Staff indicated it would be accepting of further investment in, volt-var, can proceed under a DIR investment mechanism. (Tr. XV at 4183.) But as Mr. Scheck testified on cross-examination, he and Staff witness Cleary agree that all of Phase I should be complete before moving on or relying up on the results of first phase for anything in the future. (*Id.* at 4184.)

The Staff's view of moving forward on gridSMART is not inconsistent with the Company's filing. Mr. Kirkpatrick indicates that any future expansion of the program will be done by working with Staff and others to develop a long-term strategy for additional deployment. (AEP Ohio 110 at 10.) The intent of the Company is not to include any future expansion at this time to other phases through the gridSMART Rider. AEP Ohio witness Kirkpatrick indicated in his testimony that at this time expansion of any elements of gridSMART would be through the normal business operations under the DIR review in concert with Staff. (*Id.*) The only distinction is that gridSMART could not be expanded slowly over time under the Staff's proposal and would have to wait for future approval in future proceedings to advance. Under the Company's proposal, elements of gridSMART could be expanded under the construct of the DIR.

To the extent any future development involves retiring old meters, AEP Ohio witness Mitchell describes the accounting authority needed to properly defer the cost of any retired meters associated with future retirements from expansion of the program. (AEP Ohio Mitchell at 10). This will of course be done in accordance with the cooperation of Staff, but the accounting authority to defer if such a program were started is important to remove a barrier should that become a viable option agreed to pursue.

Ultimately, the Company and the Staff are in agreement that the gridSMART Rider should continue to recover the costs associated with Phase I of the program. The ability to attempt gridSMART investment in the system in the future depends on how the Commission wants to allow or restrict further development.

3. Continuation of the Enhanced Service Reliability Rider is reasonable.

The Commission Staff support the continuation of the Enhanced Service Reliability Rider (ESRR) through 2014 (Staff Ex. 106 at 12). AEP Ohio witness Kirkpatrick testified concerning the status of the Enhanced Service Reliability Plan and the delay due to the issues in resolving this ESP. (AEP Ohio Ex. 110 at 7-8.) Mr. Kirkpatrick, the Vice President of Distribution Operations for AEP Ohio, testified to the necessary funding to complete the Commission's initial plan to move to a cycle-based trimming program. (*Id.* at 8.) Staff did not take issue with completing the move from the reactive trimming program to the proactive program and the Commission should allow the program initially started under the previous ESP to continue as intended under the present ESP plan.

Staff raises two issues related to the ESRR approval dealing with implementation and maintenance of the program after the movement to the cycle based trim is complete. The implementation issue deals with Staff's attempt to attribute meaning to portions of a black box settlement that were not enumerated in the stipulation settling the distribution rate case nor the Commission order approving the settlement. The other issue deals with the level of funding allowed for ongoing maintenance of the cycle based trimming system once the enhanced program is complete.

Mr. Baker ignores the black box settlement filed by the parties in the 11-351 et al. distribution case and states that the Company overstated the incremental cost of the ESRR for years 2012 through 2014 by not recognizing a higher ESRR baseline resulting from the recent distribution rate case. (Staff Ex. 106 at 12). Staff witness Baker testifies that Staff believes that

Ohio Power has overstated the incremental cost of the ESRR for the years 2012 through 2014 due to its failure to recognize the higher ESRR baseline that results from that distribution case. (Staff Ex. 106 at 12.) In support of his statement Mr. Baker cites to a Staff's litigation position in the case as the source for the change. On cross-examination Staff witness Baker was unable to identify a single place in the 11-351 et al stipulation or the December 12, 2011, Opinion and Order to support his claim. (Tr. XV at 4363.) When asked what he relied upon to make this representation in his testimony, Mr. Baker replied that it was based on his understanding of the Staff's position. (*Id.* at 4364.) Yet Mr. Baker admitted that the settlement was a black box settlement meaning that different parties understood that regardless of their personal belief of the positions taken in litigation the black box meant that you could not attribute items specifically to those positions. (*Id.* at 4365.) Mr. Baker ultimately admitted that this was just Staff's view of the black box settlement that this amount was part of the final numbers in the case. (*Id.*)

The Staff's attempt to define issues in the black box of the 11-351 et al. settlement should be rejected by the Commission. The Stipulation enumerated all of the items that any party raised as an issue in need of specific consideration beyond the black box. As many black box settlements area structured, a final number is reached without enumerating the detail of how the final number was reached. This allows parties with divergent interests to settle a case even though they do not agree on matters within the case. The Staff's attempt to reach into that black box and pull out its litigation position and apply it after the fact to the ESSR is improper. The parties agreed to specific terms in the agreement but absent a specific reference of the issue that Staff raises it cannot be considered an enumerated settlement term. The Commission should not afford the Staff the opportunity to undermine the settlement process and improperly claim its litigation position from a previous case as a final non-appealable order of the Commission, when the only witness offered to sponsor that fact could not identify any indication of the parties' agreement to this term or the Commission's acceptance of the position. Accordingly, there is no factual support for the Staff's position in the record and the amounts reflected in Chart 2 of AEP Ohio Exhibit 110, the pre-filed testimony of Thomas Kirkpatrick, reflect the appropriate amount of incremental funding to apply above the existing base without the application of Staff's unapproved litigation position in the distribution proceeding.

Staff's also raises an issue with the level of funding in 2014 and beyond to maintain the cycle-based trim program that ignores the reality of the proactive change in operations. The increased level of funding necessary to maintain the proactive approach underlying the ESSR is an integral part of ongoing operations to ensure retention of the program's value. AEP Ohio witness Kirkpatrick testified that an incremental amount above the current base level of O&M will be required to maintain the program going forward. (AEP Ohio Ex. 110 at 9.) Not providing the level of funding needed to maintain a proactive end to end clearing program only serves to undermine these initial incremental efforts to get to a cycle-based program. Now the Staff will expect ongoing compliance with the cycle-based system without the additional funding to maintain that level of trimming. The Commission should also consider the fact that the Company has agreed to a distribution rate stay-out until June of 2015, so even if Staff's position is adopted, which it should not, the Staff's proposal would leave the Company without an opportunity for recovery of those funds. The Commission should also consider the fact that Staff makes this recommendation at a time when the Company is already funding the residential credit, donation to the PWO, and not collecting the rate base increases authorized in the 2011 approval of the distribution rates all that were set to be offset by the DIR in the Stipulation phase of ESP and not funded in the future without approval of the DIR in this case. A decision that does not recognize the annual costs of maintaining a cycle-based approach, that are even lower than the incremental costs to catch up to cycle-based trim, provides an unfunded mandate that AEP Ohio will unfairly be expected to meet.

The continuation of the Enhanced Service Reliability Rider is supported by both the Staff and the Company. The changes proposed by the Staff to the level of incremental funding and the base are without merit and seek to improperly apply litigation positions from previous cases versus providing factual proof of any approval. Likewise, the argument to deny any ongoing funds to continue the increased operations and maintenance of the cycle-based trim program is counterintuitive to the purpose of the enhanced program and sets up the potential need for a future larger spend to again catch up to the point we are approaching now as a result of this program. Ultimately, the Commission should reject the Staff arguments and approve the continuation of the ESRR and the ongoing level of funding needed to maintain those positive results.

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

The Modified ESP includes modification and continuation of a Energy Efficiency/ Peak Demand Reduction Rider (EE/PDR Rider). While the Company proposes to unify the rates for each rate zone into a single set of merged rates, the proposed rider is otherwise the same rider approved and addressed by the Commission in Case Nos. 08-917-EL-SSO, 08-918-EL-SSO, 09-1089-EL-POR, 09-1090-EL-POR, 11-5568-EL-POR and 11-5569-EL-POR. The rider rate will continue to be updated periodically. AEP Ohio witness Mitchell described the proposed regulatory accounting for the EE/PDR Rider, being over-under accounting with no carrying charge on the investment and no carrying charge on the over/under balance. (AEP Ohio Ex. 107 at 8.)

Further, AEP Ohio witness Dias also described continuation of the EE/PDR Rider as facilitating continuation of AEP Ohio's innovative energy efficiency programs through the *ESP II* period, by the collection of EE/PDR costs through the EE/PDR. (AEP Ohio Ex. 118 at 11.) In implementing the Commission's Alternative Energy Portfolio Standard rules, AEP Ohio led a DSM collaborative during the 2009-2011 ESP period to develop energy efficiency and demand response programs for all customer segments, as outlined in Case No. 09-1089-EL-POR and Case No. 09-1090-EL-POR. (*Id.* at 12.) Through implementation of these programs, AEP Ohio customers have the potential to save approximately $630 million in reduced electricity bills over the life of the programs, helping to reduce power plant emissions. (*Id.*) Mr. Dias testified that AEP Ohio's energy efficiency and peak demand response programs were very successful in 2009 and 2010, and it is expected that the 2011 report to be filed in May, 2012 will continue that success, achieving the benchmark requirements for both programs. (*Id.*)[21]

The Commission approved the EE/PDR Rider as being reasonable in the *ESP I* decision and should do so again as part of *ESP II*.

F. Continuation Of The Economic Development Rider Is Reasonable.

The Modified ESP includes continuation and modification of a nonbypassable Economic Development Rider (EDR). As described by AEP Ohio witness Roush in his testimony, while the Company proposes to unify the rates for each rate zone into a single set of merged rates, the proposed rider is otherwise the same rider approved and addressed by the Commission in Case Nos. 08-917-EL-SSO, 08-918-EL-SSO, 09-1095-EL-RDR and 10-1072-EL-RDR. (AEP Ohio Ex. 111 at 7.) The rider rate will continue to be updated periodically. AEP Ohio witness Mitchell described the proposed regulatory accounting for the EDR, being over-under accounting

[21] As expected, the Company reflected this success in its May 15, 2012 filing in Case No. 12-1537-EL-EEC.

with no carrying charge on the investment and a long-term interest carrying charge on any unrecovered balance. (AEP Ohio Ex. 107 at 8.) Further, AEP Ohio witness Dias also described continuation of the EDR as facilitating the State's effectiveness in the global economy, consistent with R.C. 4928.02(N). (AEP Ohio Ex. 118 at 7, 13.) As the Company has demonstrated, the proposed EDR is reasonable and should be adopted as part of the Modified ESP.

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

The Company plans to continue implementing other existing riders during the term of the Modified ESP. As detailed in the testimony of Company witness Roush, those riders include the Universal Service Fund Rider, the Electronic Fund Transfer Rider, the Renewable Energy Credit Purchase Offer Rider and the Renewable Energy Technology Program Rider. (AEP Ohio Ex. 111 at Ex. DMR-4.) These riders are not directly linked to the substantive ESP proposals or the recent distribution rate case, but should nonetheless continue unaltered by the Modified ESP.

H. The Timber Road REPA Is Prudent And Should Be Approved.

Ohio Power seeks authority for the one-time upfront prudence approval for the Timber Road Renewable Energy Power Agreement (Timber Road REPA). In particular, the Company seeks approval of the automatic recovery of costs through the fuel adjustment clause and/or the alternative energy rider during the contract term, subject to financial audit. The record fully supports a Commission finding authorizing the prudence and recovery of the Timber Road REPA costs.

As evidentiary support, the Company provided the testimony of Jay F. Godfrey, the Company's Managing Director of Renewable Energy. AEP Ohio Ex. 109 at 1. Mr. Godfrey testified as to AEP's overall experience in securing renewable energy purchases stating that AEP has entered into twenty-five (25) long-term renewable energy purchase agreements to serve customers of six of its regulated electric operating companies. (*Id.* at 5.) Mr. Godfrey also testified in support of the bid process used to select the Timber Road project and explained the corresponding benefits of the Timber Road REPA in his testimony.

As supported by Mr. Godfrey, AEP Ohio secured the contract through a request for proposal (RFP). The RFP was issued on June 1, 2009 (see Exhibit JFG-1), seeking bids for 1,100 MW of renewable energy resources that would be interconnected to the PJM Interconnection (PJM) or the Southwest Power Pool (SPP) with a minimum 20 MW (nameplate) of new renewable generation capable of being operational by December 31, 2011. (AEP Ohio Ex.109 at 10-11.) However, as Mr. Godfrey testified, AEP Ohio only considered project bids sited in Ohio due to its specific need for in-state renewable resources. (*Id.* at 11.)

AEPSC received thirty-three (33) conforming bids from renewable energy developers for projects interconnected to PJM totaling roughly 3,450 MW of renewable energy nameplate capacity. Of the 33 bids, eight (8) bids were for projects located in Ohio. Based upon AEP Ohio's need for Ohio-sourced RECs to meet its compliance benchmarks, only the bids for Ohio sited projects were considered. (*Id.* at 14.)

The Timber Road REPA under consideration in this proceeding is the result of that RFP process. AEP witness Godfrey testified that "[b]ased on AEP Ohio's need for in-state renewables and a final analysis of all relevant factors affecting both AEP Ohio and its customers, AEPSC selected the proposal from Paulding Wind Farm II LLC (a wholly owned subsidiary of EDP Renewables North America LLC also referenced herein to as "EDPR") for its 99 MW (nameplate) Timber Road wind farm." (*Id.*) As supported by the testimony of Mr. Godfrey, the agreement with Paulding Wind was at an attractive contract price that benefits from federal grant funding administered under Internal Revenue Code Section 48(d) and Section 1603 of the American Recovery and Reinvestment Tax Act of 2009. (*Id.*) Mr. Godfrey sponsored the exhibits detailing the confidential terms of the agreement with Paulding Wind. A summary of the terms and conditions of the Timber Road REPA resulting from the RFP process is found in Exhibits JFG-2A and JFG-2B (confidential and public versions), and the Timber Road REPA can be viewed in Exhibits JFG-3A, JFG-3B, JFG-4A and JFG-4B (confidential and public versions).

The Timber Road REPA will supply a 99 MW share of Timber Road wind farm's electrical output, capacity and environmental attributes to AEP Ohio for a period of twenty (20) years at a reasonable cost and favorable terms for the Companies and their customers and address state renewable requirements. Mr. Godfrey testified to the fact that the Timber Road REPA supports AEP Ohio's need to secure additional in-state renewable energy to meet its annually increasing renewable energy benchmarks established by SB 221. (*Id.* at 15.) The agreement also contains the ability to withdraw from the agreement if the Commission denies cost recovery; meaning AEP Ohio would not be obligated to purchase the output from the Timber Road wind farm. (*Id.*)

The Timber Road II wind project, which is owned by Paulding Wind, was developed under the direction of its parent company, EDPR, in Paulding County Ohio. (*Id.*) EDPR develops, constructs, owns and operates wind farms throughout North America. Based in Houston TX, EDPR NA owns and operates twenty-eight (28) wind farms across the United States totaling more than 3,500 megawatts ("MW") of capacity, ranking EDPR third in the country in terms of net installed capacity. (Paulding Wind Farm Ex. 101 at 1.) The Timber Road facility has a nameplate capacity (maximum output) of 99 MW and consists of fifty-five

Vestas V100 – 1.8MW wind turbines. (AEP Ohio Ex. 109 at 15-16.) The facility interconnects with the existing AEP Ohio transmission system at 138 kV and has reached commercial operation. (*Id.*)

AEP Ohio witness Godfrey provided testimony establishing the benefits of the 20-year term of the Timber Road REPA to the consumer. He testified that "[t]he 20-year agreement, which is also the expected life of the technology, allows renewable energy resource providers to secure long-term financing, thereby amortizing the cost of their projects over a longer period. Such financing has the effect of reducing the upfront costs and allows for a more economically levelized price over the term of the contract. (See also Paulding Wind Farm Ex. 101 at 4.) The 20-year term also provides price certainty for AEP Ohio's customers." (AEP Ohio Ex. 109 at 16.) Paulding Wind witness Irvin testified in support of the REPA that "[w]ind farms are capital-intensive but have the advantage of no fuel costs. Therefore, there are no significant cost variables that present long-term risk to ratepayers." (Paulding Wind Ex. 101 at 4.) AEP Ohio witness Godfrey also pointed out that the "Timber Road REPA stipulates that AEP Ohio will receive all current and future environmental attributes from the Project, including the associated Ohio non-solar RECs." (AEP Ohio Ex. 109 at 17.)

The Timber Road REPA provides AEP Ohio and its customers, with access to affordable renewable energy from an in-state resource. According to R.C. 4928.64(C)(3) half of the non-solar benchmark must be met with RECs produced by renewable energy resources sited in Ohio. AEP Ohio's year end non-solar renewable energy benchmark will increase from 1.44% in 2012 to 3.35% of sales in 2015. (*Id.* at 18.) The Timber Road REPA will contribute to compliance with the in-state portion of the non-solar renewable energy benchmark. (*Id.*)

The in-state support for renewable technology will also support the State policy goals found in R.C. 4928.02 including subsection (N) which calls for efforts to facilitate the state's effectiveness in the global economy. Investment in Ohio-based renewable resources is one way to facilitate those efforts. Paulding Wind witness Irvin stated in his direct testimony that "the Timber Road REPA serves as an example of the type of long-term contract that can spur development of additional, large-scale generation projects, ultimately increasing the likelihood of utility compliance [with the State's renewable energy requirements], and the realization of the market's full potential promised by SB 221." (Paulding Wind Ex. 101 at 5.) Without the support of long-term contracts, Mr. Irvin explained, "[s]ignificant new advanced energy generation resources are unlikely to be built in Ohio without the support of long-term contracts." (*Id.*)

There is not any significant stated opposition to the Timber Road REPA request in the Company's Modified ESP. Staff witness Cunningham testified, "I believe that this contract is reasonable at this time." (Staff Ex. 103 at 2.) When asked on cross-examination what was meant by "at this time," Mr. Cunningham clarified that he was supporting the prudency of the contract throughout the 20-year period and not just the length of this ESP period. (Tr. VIII at 2498-2499.) The only issue raised by Staff testimony was a request that the implementation of the contract should be subject to the annual Fuel Adjustment Clause (FAC) and Alternative Energy Rider (AER) audits. This is the understanding of the Company as well, as evidenced by the testimony of witness Philip J. Nelson. Mr. Nelson testifies in his pre-filed direct testimony that the energy and capacity portions of the renewable energy would continue to be recovered under the FAC, while it exists, with the REC expense recoverable as bypasssable under the AER. (AEP Ohio Ex. 103 at 18.) Mr. Nelson ensured that after the FAC terminates, that the Company will continue to acquire the RECs to meet portfolio standards for its standard service offer load and use the AER to recover the costs. (*Id.*)

The Commission should again support the prudency and recovery of the Timber Road REPA. The Commission previously found the REPA promotes the diversity of supply, as is consistent with state policies set forth in R.C. 4928.02 in its initial Opinion and Order in the ESP Stipulation proceeding in this docket. (*Dec. 14th ESP Stipulation O&O*, Dec. 14, 2011 Opinion and Order at 43.) Nothing in the subsequent vacating of that order related to the Commission's finding on this matter. The REPA as supported by AEP witness Godfrey, Paulding witness Irvin, NRDC witness Lyle and Staff witness Cunningham, was the result of a competitive bid process and resulted in a very competitive price. The dedicated output, including the RECs, will assist the Companies in complying with the renewable energy mandates while supporting the development of renewable resources in the State of Ohio. The evidence of record for the Commission to base its decision is overwhelmingly in support of the approval of the prudency of entering into the REPA and recovery through the fuel adjustment clause and alternative energy rider.

I. The Proposed Accounting Deferrals And Recovery Of Existing Regulatory Assets Are Reasonable.

The Company filed Case Nos. 11-4920-EL-RDR and 11-4921-EL-RDR to establish the Phase In Recovery Rider (PIRR) for collection of the deferred fuel expenses authorized for recovery starting in January 2012 by the Commission's final, non-appealable decision in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO. To date, the Commission has not approved the PIRR or otherwise implemented this aspect of *ESP I*, as is required under §4928.143(C)(2)(b), Ohio Rev. Code. Nevertheless, as part of the integrated package of terms and conditions presented in the Modified ESP and without waiving its lawful rights and remedies related to the PIRR implementation, AEP Ohio is proposing to delay the commencement of PIRR recovery until June 2013 (with the end of the recovery period remaining as December 31, 2018), while continuing to accrue during the continuing deferral period a weighted average cost of capital carrying charge as authorized in the *ESP I* decision. Accordingly, the Company requests that the Commission consider the delayed PIRR as part of the Modified ESP.

The delayed PIRR proposal is being coordinated with the delayed unification of the FAC rates, as discussed in the testimony of Company witnesses Dias and Roush. Mr. Dias explained that it is the Company's intention in proposing the PIRR delay to stabilize rates in coordination with the delayed unification of the FAC. (AEP Ohio Ex. 118 at 8.) As Mr. Roush discussed, the PIRR is related to deferred fuel costs that were not recovered due to the phase-in plan adopted by the Commission in the *ESP I* case. (AEP Ohio Ex. 111 at 4.) The Company's proposal to delay the PIRR collections until June of 2013 would help coordinate that rate impact (resulting from the prior ESP) with the proposal for unification of the FAC in June of 2013. (*Id.* at 6.)

Mr. Roush maintains that since the PIRR regulatory asset is on the books of the merged Ohio Power Company (along with all of the other assets and liabilities of the former Columbus Southern Power Company), it is appropriate for all AEP Ohio customers to pay the PIRR. Staff witness Turkenton recommends that the FAC and PIRR be immediately unified and implemented, because CSP customers benefit from a rate impact perspective with the merging of both rates. (Tr. XVI at 4539.) If the FAC is merged but the PIRR is not, CSP customers would see an even larger positive rate impact but Ms. Turkenton believes it is inappropriate to do so – if fuel rates are to be unified, she believes that both the FAC and the PIRR should be merged. (Tr. XVI at 4540.)

As demonstrated by Mr. Roush in his testimony, the net rate impact of these two components is nearly a perfect "wash" together resulting in a 69¢/MWh net reduction for the CSP rate zone and a 2¢/MWh increase for the OPCo rate zone. (*Id.*) The specific PIRR values are shown in Exhibit DMR-1 attached to AEP Ohio Ex. 111.

Staff witness Turkenton opposes the Company's proposal for a delayed PIRR, in favor of immediate implementation in order to reduce the total amount of carrying charges to be paid by customers. (Staff Ex. 109 at 5.) During cross examination, Ms. Turkenton acknowledged that the debate about whether to implement the PIRR now versus delaying recovery is a trade-off between immediate rate impact and reduction of the total amount of carrying charges to be paid under the PIRR. (Tr. XVI at 4547-48.) Ms. Turkenton maintained that her recommendation saved carrying charges overall but acknowledged that her recommendation also causes an immediate rate impact. (Tr. XVI at 4549-50.) Thus, this debate comes down to a balancing or prioritizing as between two legitimate goals: (i) the goal of mitigating present rate impacts, and (ii) the goal of reducing the total carrying charges to be paid. The Company's proposal was aimed at addressing the first goal and the Staff's position prioritizes the second goal.

The Company's proposal to delay implementation of the PIRR until June 2013 to coincide with the unification of FAC rates is reasonable, results in minimal immediate rate impacts to customers, and should be approved.

J. The Proposed Storm Damage Recovery Mechanism Is Reasonable.

The Modified ESP includes approval for accounting deferrals including a major storm damage recovery mechanism proposal. Mr. Kirkpatrick explains the volatility of major storms and major storm damage restoration O&M expenses from year to year. Specifically, AEP Ohio is proposing that a Storm Damage Recovery Mechanism be created in the amount of $5.0 million per the approved settlement in the 2011 AEP Ohio distribution rate case (Case Nos. 11-351-EL-AIR and 11-352-EL-AIR) beginning with calendar year 2012 to recover only the incremental expenses incurred as a result of major storm events. (AEP Ohio Ex. 110 at 20.) This mechanism is necessary to preserve forecasted O&M for planned maintenance activities. As Mr. Kirkpatrick testified, if funds are constantly diverted to cover the expense of major storms, it disrupts the completion of planned maintenance and ultimately has an impact on the reliability of the system. (*Id.*) The proposed accounting mechanism would not include capital investments associated with storm damage, as those investments would be covered by the proposed DIR. (*Id.* at 21.)

Based on his experience in the industry, AEP Ohio witness Kirkpatrick does not believe that vegetation management practices have a significant impact on damage caused by major storms. (*Id.*) Although increased vegetation management activity may reduce the impact of minor storms, the damage caused by major storms is typically unaffected by vegetation that would be controlled through a vegetation management program. Much of the damage caused by vegetation during a major storm is caused by vegetation from outside the right-of-way that would have not been part of the vegetation management program. Therefore, Mr. Kirkpatrick does not expect the impact from major storms to be reduced as AEP Ohio continues to make progress through its vegetation management program. (*Id.*)

AEP Ohio witness Mitchell described the accounting necessary to implement the proposed storm damage recovery mechanism, being that if the mechanism is approved, the Company will defer the actual incremental distribution expense above or below the $5 million storm expense included in base level expenses for future recovery beginning with the effective date of January 1, 2012. (AEP Ohio Ex. 107 at 9-10.)

The proposed storm damage recovery mechanism is reasonable and should be approved as part of the Modified ESP.

K. The Proposed Modified ESP Advances Ohio Energy Policies In A Balanced Manner.

The Company's Modified ESP advances an appropriate balance of state policies found in both the Ohio Revised Code and the Commission's own Mission Statement. AEP Ohio heard the Commission's February 23, 2012 concerns on rehearing regarding the ESP Stipulation. In response, the Company is proposing a Modified ESP filing that addresses prior concerns about customer rate impacts (by frozen non-fuel generation rates for non-shopping customers), offers discounted capacity charges for CRES providers and shopping customers, offers early auctions-based SSO procurement, sets forth a framework to provide a full competitive auction in 2015, provides certainty and stability in the ongoing rate mechanisms, maintains the Company's financial integrity, and advances the State of Ohio's competitiveness in the global economy.

A number of parties have advanced or referenced state policies throughout the record, with each party claiming to be the champion for the State of Ohio. The majority of those state policies cited are found in R.C. 4928.02. The preamble to the statutory provision provides a simple introduction that does not favor a single provision over another. The language states, "[i]t is the policy of this state to do the following throughout this state." Thus, the advancement of state policy requires the balancing of the many policies. Unlike the one-sided and self-serving "policy" positions advanced by many other parties to this proceeding, the Company's Modified ESP seeks to balance those varying policies in a cohesive plan that considers all stakeholders. The Modified ESP achieves the proper balance of state policy and the Commission's own mission; accordingly, the Commission should approve it as proposed in order to move Ohio's electric industry forward – the right way.

1. The Modified ESP advances state policy of R.C. 4928.02(A) to ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service.

The Modified ESP advances the first state policy listed in R.C. 4928.02. This policy is at the core of the purpose of the Commission and electric utility companies – to ensure adequate and reliable service to customers at a reasonable price. Under R.C. 4928.01(A)(27), "retail electric service" is defined as follows:

> "Retail electric service" means any service involved in supplying or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption. For the purposes of this chapter, retail electric service includes one or more of the following "service components" : generation service, aggregation service, power marketing service, power brokerage service, transmission service, distribution service, ancillary service, metering service, and billing and collection service.

The scope of retail electric service is broad, as is the reach of this Modified ESP, and the collective result of proposed ESP is intended to advance this goal through its provisions and by ensuring the future viability of the Company as a strong corporate partner. Absent the financial ability to operate, the Company would be crippled and every facet of operations would be impacted. It does customers no good to have the electric distribution utility in a dire financial position. At that point, each of the elements of the policy – adequate, reliable, safe, efficient, even reasonably priced retail electric service – are in danger.

The Modified ESP's freezing of non-fuel base generation rates also advances this state policy. As Company witness Dias testified, the "[f]ixed non-fuel generation pricing for SSO customers ensures the availability of adequate, reliable, safe, efficient, nondiscriminatory and reasonably priced electricity." (AEP Ohio 118 at 4.) The Company's willingness to freeze the non-fuel base generation rates as part of its Modified ESP furthers the policy of providing reasonably priced retail electric service, providing certainty and relief from increases in this area. An agreement to fix any pricing in a time of transition is always a risk on behalf of the party freezing the price, but it is offered nonetheless as part of the balance of the overall Modified ESP for Commission review in line with this state policy.

AEP Ohio's proposal to provide CRES providers with capacity at a discount to the Company's cost is another example of the Modified ESP's advancing and balancing of the state policy. As discussed above, the discount from the Company's embedded cost of capacity will support shopping while ensuring the availability of that capacity to CRES providers to provide to retail customers. As supported by Company witness Dias, the discounted capacity will also assist in the effort to seek reasonably priced electric service. (*Id.*)

The transparency in rates and certainty of AEP Ohio's standard service offer pricing structure ensures that customers know what they are paying for and what they need to compare to competitive suppliers to ensure nondiscriminatory availability of retail electric service. Company witness Dias pointed out that customer knowledge and education allows customers to make informed decisions and receive reasonably priced service. (*Id.* at 5.)

The Enhanced Service Reliability Rider (ESRR) proposed by the Company to continue under the Modified ESP also advances this state policy. As indicated in the testimony of Company witness Kirkpatrick, the ESRR program has led to reductions in tree-caused outages, resulting in improved reliability to the customer. (AEP Ohio Ex. 110.) A decrease in outages caused by trees enhances electric distribution service and, as Company witness Dias pointed out, is consistent with the value customers place on service reliability and targets for service quality. (AEP Ohio Ex. 118 at 6.)

The modest average rate increases associated with the Modified ESP also promotes this section of the state policy. (*Id.* at 7.) The goal is to provide a safe and reliable product at a reasonable price. AEP Ohio customers already understand that modest increases do not mean a price is not reasonable. National Federation of Independent Businesses (NFIB) witness Geiger admitted that, "[e]verybody recognizes that there are modest increases in everybody's pricing." (Tr. VIII at 2376.) The changes made between the stipulation previously approved in this case on December 14, 2012, and the Modified ESP filing addressed the size of that customer impact and led to the modest average increases in the proposed plan. Those changes further the state policy goal of reasonably priced retail electric service.

2. The Modified ESP advances state policy of R.C. 4928.02(B) to ensure 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.

Section B of the statute is also advanced in the balanced approach offered by the Company in the proposed Modified ESP plan. The transparency and certainty of the modest increases in the proposed Modified ESP advance the objectives of R.C. 4928.02(B). (AEP Ohio Ex. 118 at 5 and 7.) Just as discussed above within section A of the statute, the customer knowledge and the basic availability of service and capacity to receive service are benefits that fit within the goal of this policy. The move to a fully competitive market also should ensure the availability of unbundled and comparable retail electric service and quality options for customers. The plan proposed by the Company is a transition to a full competitive auction. The plan provides the path needed to meet that goal without any unnecessary negative consequences. Approval of the Modified ESP begins those crucial steps needed to meet that end goal.

3. The Modified ESP advances state policy of R.C. 4928.02(C) to ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies and suppliers and by encouraging the development of distributed and small generation facilities.

The Modified ESP also advances Section C of the statute. This policy provision is referred to by multiple parties in the record to different ends. The question those parties pose is what is the most effective manner in which to ensure a diversity of suppliers. It is the opinion of the Company that a balanced move to a full competitive auction and an appropriate transition to that fully competitive market is the proper manner in which to accomplish this goal. Just as mentioned above and in more detail below, as well as in the testimony of Company witness Dias, the proposed discounted capacity pricing should encourage a diversity of suppliers in furtherance of this goal. (*Id.* at 4.) The structural corporate separation of AEP Ohio's generation and marketing businesses from its transmission and distribution businesses will also lead to the emergence of competitive markets that can lead to a diversity of suppliers. (*Id.* at 5.) The modest overall increases and customer knowledge of secure rates can also lead to a diversity of providers knowing the prices they are competing against with the standard service offer.

A balanced move is needed to ensure a workable competitive system with a diversity of suppliers, otherwise the state could have a potentially broken competitive system with few providers. The then-Chairman of the Pennsylvania Service Commission, concerned about a merger in that state and the impacts it could have to thwart competition there, warned of markets that have few providers and are not open for competition despite the appearance of competition.[22] Chairman Cawley ominously labeled this section of his dissent "Ohio All Over Again." The Chairman was referring to the apparent monopoly that FirstEnergy Solutions Corp.

[22] The Attorney Examiner took Administrative Notice of this dissent at the hearing. (Tr. XVI at 4532.) That dissent is attached as Attachment A to this brief for ease of reference and includes the pertinent discussion section entitled "Ohio All Over Again."

(FES) has on the provision of retail electric service in the FirstEnergy electric distribution utilities' certified territories. Chairman Cawley pointed out that despite the stated competitive level of offering in those territories, FES serves over 80% of all customers' retail electric service. His point was that the market had allowed FES to not only provide service in the competitive market but also to use its assets and position to serve a large part of the standard service offer customers. Chairman Cawley was warning his counterparts to take action in their state to avoid the lack of competition in the retail market that he observed in Ohio in the FirstEnergy utilities' service territories and that he characterized as a "retail marketing strategy." (*See* Attachment A.)

FES witness Banks also discussed the need for effective competition in his testimony, but his cross-examination showed that his view of effective competition is not consistent with the state policy but, instead, is more in line with what concerned Pennsylvania Chairman Cawley. Mr. Banks was asked to define "effective competition" under cross-examination. In response, he stated:

> Well, I generally think effective competition means that you have customers able to choose their supplier and supply without any barriers; you have a market that has multiple suppliers, again, without any barriers to those suppliers entering the market; and then you just don't have any other unnatural barriers to the customers being able to shop.

(Tr. XVI at 4442.) When asked what a multiple of suppliers meant, Mr. Banks did not want to talk about the number or diversity of suppliers, he wanted to talk about the barriers facing the suppliers even if that is just one supplier. (*Id.* at 4442-4446.) When pressed to quantify what he meant by multiple suppliers, Mr. Banks stated that the diversity of suppliers is not the key, but that the existence of barriers are the key; thus, according to Mr. Banks, there could be "effective competition" with just one competitive supplier. (*Id.* at 4446.) Specifically, Mr. Banks stated:

> The point is, the effective competition isn't necessarily defined by how many suppliers are serving at any point in time, it's that you're allowing suppliers to enter into a market and fairly be able to compete with those customers. And on day one, yes, there could be one supplier possibly.

(*Id.*) This position should not surprise anyone when viewed from the point of view expressed by Pennsylvania's former Chairman Cawley – FES has already wrapped up most of the market in the FirstEnergy utilities' territories and, therefore, there is an absence of effective competition in those territories in Ohio. The question that remains to be determined is whether the Commission views only a few or even one competitive supplier as effective competition.

The plan proposed by AEP Ohio provides for a reasonable transition to market, not a flash-cut overnight that has no ability to support a diversity of suppliers. A tempered approach to a full competitive bid, faster than could be accomplished under an MRO filing, will assist the industry and the Commission in promoting a diversity of suppliers in line with the state policy. According to the testimony of Mr. Banks, Vice President of FES, one majority competitive supplier is adequate to meet the needs of the policy for a period of time. But as Chairman Cawley warned, that does not provide a competitive market. If the state's policy is to promote a diversity of suppliers, then the plan proposed by the Company should be adopted and the modifications proposed by the party with the limited view on effective competition should be disregarded.

4. The Modified ESP advances state policy of R.C. 4928.02(D) to encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand-side management, time-differentiated pricing, and implementation of advanced metering infrastructure.

Section D of the statute is also advanced in the balanced approach offered by the Company in the Modified ESP. Company witness Dias testified that "AEP Ohio's modification and proposal to enhance customers' interruptible and peak demand reduction mandates under SB221, encourages energy efficiency, development of distributed and small generation facilities and promotes economic development." (AEP Ohio Ex. 118 at 6.) Company witness Kirkpatrick also testified that the Company intends to extend the rider for recovery of gridSMART Phase I recovery and apply the lessons learned and future elements of the gridSMART program through the DIR implementation. (AEP Ohio Ex. 110 at 10.) This investment in the system and encouragement of peak demand reductions are examples of some of the balance in the Modified ESP that furthers the state policy.

5. The Modified ESP advances state policy of R.C. 4928.02(E) to encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote both effective customer choice of retail electric service and the development of performance standards and targets for service quality for all consumers, including annual achievement reports written in plain language.

The Modified ESP also advances Section E of the statute. As indicated by Company witness Dias, the distribution investment opportunities through the proposed distribution investment rider can provide for emerging distribution system technologies that can cost-effectively improve the efficiency and reliability of the system, develop performance standards, and set targets for service quality for all consumers. (AEP Ohio Ex. 118 at 6.) The same benefits can be realized through continuation of the ESSR. (*Id.*) A greater level of investment in the distribution system and proactive approach to reliability will provide customers with a more efficient system and will assist in setting future reliability standards.

6. The Modified ESP advances state policy of R.C. 4928.02(G) to recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment.

The Modified ESP also advances Section G of the statute. As Company witness Dias explained, structural corporate separation will continue the emergence of competitive electricity markets. (AEP Ohio Ex. 118 at 5.) The balance offered by the Company in this Modified ESP sets the table for a full competitive auction in 2015 and clears the path for the competitive environment envisioned by the Commission. As discussed throughout the hearing and in R.C. 4928.142(D), a standard service offer filed as an MRO would take 6-10 years of transition to complete and, therefore, could not reach market faster than the Modified ESP.[23] The Modified ESP gets the standard service offer to a competitive bid in June of 2015 with earlier auctions for some elements of the offer prior to that time. Moving to market faster than allowed under the MRO must be viewed as recognizing the emergence of competitive markets. Likewise, the proposed RSR reflects the very definition of the development and implementation of flexible regulatory treatment to reach this state policy goal. The General Assembly anticipated that the Commission may need to create flexible mechanisms to promote competitive markets as part of the Commission's ongoing oversight of the industry. While there was a time and a place to encourage the Company to avoid going to market to protect customers and maintain lower regulated rates (*see supra* Sections I and II), now that the times have changed this policy recognizes the importance of the Commission having tools, like the RSR, to facilitate the emergence of competitive electricity markets. The proposals included in the Modified ESP to move AEP Ohio further away from the regulated model currently governing its SSO to a

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[23] (*See, e.g.,* Tr. II at 378 (Company witness Powers explaining that the is "certainly making a package in this ESP that gets AEP Ohio to market faster than certainly would be allowed under the MRO"); Tr. XIII at 3517 (Exelon witness Fein); Tr. XVI at 4477 (FES witness Banks),)

competitive, auction-based model under an ESP provide the Commission with the tools necessary to make market-based SSO pricing a reality faster than otherwise permitted under an MRO without harming the utility or improperly subsidizing the competitive market.

7. The Modified ESP advances state policy of R.C. 4928.02(H) to ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates.

Section H of the statute is also advanced in the balanced approach offered by the Company in the Modified ESP plan proposed. The transparency and certainty of the SSO offering described by Company witness Dias highlights the customer knowledge and education of services that will ensure effective competition in the provision of retail electric service. (AEP Ohio Ex. 118 at 5.) While the SSO rates for non-shopping customers reflect recovery of embedded costs of capacity, the Company is proposing to provide capacity charges for shopping customers that are lower than its embedded cost of capacity; this will provide a benefit that cannot be viewed as an anticompetitive subsidy because it promotes competition (and does not inhibit it) and because the Commission as the regulator would approve the pricing. A setting of the rate at RPM rates, recognizing that the Company provides service an FRR entity with the right to charge a cost-based rate, would be an unwarranted and inappropriate subsidy to CRES providers that is not good for competition (*see* Tr. XV at 4270) and not aligned with the policy of the state as set forth in R.C. 4928.02(H).

8. The Modified ESP advances state policy of R.C. 4928.02(I) to ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power.

Section I of the statute is also advanced in the balanced approach offered by the Company in the Modified ESP plan proposed. As Company witness Dias explained, the transparent rates and certainty of the mechanism to determine the standard service offer giving customers comparable price to compare information in determining whether to select and alternative supplier advances this state policy provision. (AEP Ohio Ex. 118 at 5.) And as IGS witness Parisi agreed, certainty is needed so the market players know how to react. (Tr. XV at 4270.) A defined system with structure will allow customers to understand the system and will enable the Commission and others to educate consumers on the set rules of the Modified ESP plan so that sales practices and marketing efforts are easier to judge against the system that is in place. Transitioning the Company to the competitive market as outlined in the Modified ESP also assists in avoiding market deficiencies and an abuse of market power through a managed transition to market versus a flash-cut by ensuring a proper transition. (*See* AEP Ohio Ex. 101 at 10-12.) A final, approved Commission standard service offer that provides for the items identified in the Modified ESP ensures a clear and understandable transition to a competitively offered standard service offer and prevents the risk of an inadequate market for retail customers to engage.

9. The Modified ESP advances state policy of R.C. 4928.02(L) to protect at-risk populations, including, but not limited to, when considering the implementation of any new advanced energy or renewable energy resource.

The Modified ESP also advances R.C. 4928.02(L). Company witness Dias testified that the modest overall rate increases and rate design protect at-risk populations. (AEP Ohio 118 at 7.) The approval of the DIR also has a direct impact on the benefits for at-risk populations under the Modified ESP filing. OCC witness Williams testified on cross-examination that credits to residential distribution rates and funding to the Partnership with Ohio (PWO) group would be direct benefits for at-risk populations in AEP Ohio's territory. (Tr. XI at 3197-3198.) Upon further examination, it was established that the Commission recently approved a distribution case that applied funds that are expected to be collected under the residential distribution credits and funding for Partnership with Ohio. In particular, the distribution settlement applied $46.7 million of expected DIR funds to offset the increased rate base approved in the distribution case and another $15.7 of expected DIR funds to fund a residential credit and funding for the Partnership with Ohio's involvement in the Company's Neighbor-to-Neighbor bill pay assistance program. (*Id.* at 3199-3200.) OCC witness Williams also confirmed that the funding of those items attributed to DIR recovery would be maintained by the Company during the pendency of the Modified ESP even though the DIR was not being collected. (*Id.* at 3202-3204; *see also* AEP Ohio Ex. 140.) Beyond the fact that the Company is currently providing those benefits without any compensation from the DIR, the continuation of those matters was tied to the outcome of the DIR in the Modified ESP. (*Id.* at 3204.) In fact, the Company clarified that it would be able to file a new distribution rate case at any time depending on the outcome of the Modified ESP, but had included a provision in the Modified ESP that it would not seek an implementation of rates through a distribution rate case until after the proposed Modified ESP period if approved as filed. (*Id.*) Hence, the current benefits, totaling $62 million, being received by customers as a result of the distribution rate case are inextricably intertwined with the outcome of the Modified ESP and in particular the approval of the DIR. Approval of the Modified ESP will fund the $62 million benefit that includes the residential customer credit and the funding for the PWO for the AEP Ohio Neighbor-to-Neighbor program. As OCC witness

Williams testified, this is a direct benefit for at-risk customers because it protects their access to lower rates and systems to assist with bill payment.

10. The Modified ESP advances state policy of R.C. 4928.02(M) to encourage the education of small business owners in this state regarding the use of, and encourage the use of, energy efficiency programs and alternative energy resources in their businesses.

Section M of the statute is also advanced in the balanced approach offered by the Company in the Modified ESP plan proposed. The modest overall rate increases and the rate design considerations of the Modified ESP protect small business owners in the state. (AEP Ohio Ex. 118 at 7.) As previously mentioned, business owners understand that there will be rate increases. (*See* Tr. VIII at 2376 (NFIB witness Geiger agreed that "e]verybody recognizes that there are modest increases in everybody's pricing.") Modest rate increases like those proposed in the Modified ESP will allow sustainable companies to move forward and discuss energy efficiency programs to help offset the modest average increases. The DIR investments could also lead to encouraging the use of energy efficiency programs and alternative energy resources. (AEP Ohio Ex. 118 at 6.)

11. The Modified ESP advances state policy of R.C. 4928.02(N) Facilitate the state's effectiveness in the global economy. In carrying out this policy, the commission shall consider rules as they apply to the costs of electric distribution infrastructure, including, but not limited to, line extensions, for the purpose of development in this state.

Section N of the statute is also advanced in the balanced approach offered by the Company in the Modified ESP plan proposed. Company witness Dias testified that the Modified ESP as a whole enhances the state's effectiveness in the global economy. (*Id*. at 4.) He also indicated that the proposal to enhance customers' interruptible and peak demand reduction attributes encourages energy efficiency and development of distributed and small generation facilities and promotes economic development. (*Id*. at 6.) Likewise, the economic development cost recovery rider related to reasonable arrangements with mercantile customers also facilitates the state's effectiveness in the global economy. (*Id*. at 7.) The creation of the GRR and potential for the building of the Turning Point Solar project is another element of the Modified ESP that will facilitate the state's effectiveness in the global economy. The potential investment in solar technology in an area of Ohio in need of investment is good for the local economy and the development of Ohio as a leader in renewable technologies. NRDC witness Lyle testified that one of the goals of SB 221 was to incent investment in solar technology, and the building of the Turning Point Solar facility would lead to greater development of other solar resources in the state which would be fulfilling one of the goals of the legislation. (Tr. IX at 2669-2640.) The reality is that the Turning Point facility would be would also be a catalyst for new investment in a manufacturing plant, not just project investment in southeast Ohio. Perhaps most importantly, approval of the Modified ESP will avoid the massive reduction in spending and cuts in Ohio jobs by AEP itself, as described by AEP Ohio witnesses Powers and Dias.

12. The Modified ESP comports with the PUCO' mission statement and indicators of accomplishment.

The Commission's own mission statement and indicators of accomplishment should not be forgotten in the Commission's weighing of policies to consider while considering the Modified ESP. (*See* AEP Ohio Ex. 148.) The Commission's stated mission is:

> Our mission is to assure all residential and business consumers access to adequate, safe and reliable utility services at fair prices, while facilitating an environment that provides competitive choices.

(*Id.*) The Commission also maintains a list of criteria it considers to determine how its stated mission is accomplished. FES witness Banks supports the Commission's mission statement and indicators of accomplishment. (Tr. XVI at 4503-4504.)

The Modified ESP comports with those indicators of accomplishment and advances the Commission's mission.. One indicator is similar to R.C. 4928.02(A) and relates to the provision of adequate, safe, and reliable utility service. The Modified ESP furthers this indicator, as detailed above in the discussion on R.C. 4928.02(A). Other indicators encourage the strength of Ohio utilities and investment in the utility systems. One such indicator discusses the health of the regulated parties in the industry. Specifically, the indicator provides that the Commission's mission is accomplished by "[e]nsuring financial integrity and service reliability in the Ohio utility industry." (*Id.*) The balance proposed by the Company is premised upon maintaining the financial integrity and reliability for AEP Ohio. FES witness Banks even agreed that the Commission has wide latitude in figuring out how to protect AEP Ohio's financial integrity. (Tr. XVI at 4515.) Although Mr. Banks did not provide any ideas on how to protect the Company's financial integrity The Company, however, is advancing proposals that balance customer and competitive interests with financial stability. Specifically, the proposed RSR is an attempt to provide stability while pursuing an aggressive transition to the competitive market desired by the Commission. The Company also advances service reliability through the ESRR and the DIR, which invests dollars in the Ohio economy and increases reliability. Those proposals advance another indicator of accomplishment for the Commission, "[p]romoting utility infrastructure investment through appropriate regulatory policies and structures."

The Commission's indicators of accomplishment also address the importance of ensuring a fair and safe environment for utility operations and a fostering of competition through a fair framework. Just as outlined in the previous sections on customer transparency and clarity, the Commission's own indicators of accomplishment seek compliance with rules against deceptive, unfair, unsafe, and anti-competitive utility practices. Likewise, the Commission understands that competition is not an all-or nothing-focus, but is a part of the policies it oversees in its role as regulator. One of the indicators of accomplishment even reads, "[f]ostering competition by establishing and enforcing a fair competitive framework for all utilities." This indicator of accomplishment for the Commission is one of the underlying purposes of the Modified ESP. The Company proposed a plan that will provide an appropriate transition to a fully competitive market that is fair. Thus, under the Commission's own mission, ensuring a fair competitive framework for utilities is an important factor in the decision determining how to balance all of the competing interests and policies in this case. Any decision in this case must use that balanced approach focusing on fair competition for all utilities.

Overall, the consideration of the Company's Modified ESP filing must balance the enumerated state policies and adhere to the indicators of accomplishment of the Commission's Mission Statement. The parties to this case raise concerns from their individual points of view, criticizing different parts of the Modified ESP with self-interested arguments and tunnel vision on individual state policies. The Company's Modified ESP, by contrast, takes a number of state policies into account and stays true to the Commission's mission and indicators of accomplishment to provide a balanced plan that transitions to a full competitively bid market faster than permitted under an MRO. Moreover, it focuses on ensuring fair competition the right way for the long run in the Company's certified territory. Accordingly, the Commission should approve the Modified ESP as filed.

VI. 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, Revised Code § 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 Thomas, Powers, and Dias, as well as the other Company witnesses, provide testimony that confirms that AEP Ohio's Modified 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 really three aspects of that Aggregate MRO Test. The first aspect is the comparison of the ESP pricing to the expected results from an MRO (the MRO Price Test). Company witness Thomas provides this MRO Price Test comparison. (AEP Ohio Ex. 114 at pages 17-22.) Ms. Thomas has estimated that the relative ESP price impact, calculated on a weighted average basis over the June 2012 – May 2015 term of the Modified ESP, as compared to the price of an MRO, amounts to $1.77/MWH. (AEP Ohio Ex. 114 at Ex. LJT-1 page 2.) Ms. Thomas quantified the value of this benefit, for non-shopping customers, to be $256 million. (*Id.* at Ex. LJT-1 page 3.)

The next aspect of the Aggregate MRO Test involves evaluating other quantifiable, non-price, benefits that result from the ESP that would not be available under the MRO option. Ms.

Thomas explained that Company witness Allen quantifies the values of these benefits. First, Mr. Allen explained that under the proposed Modified ESP the Company is willing to supply capacity to CRES providers at reduced two-tiered prices, which are at a significant discount to the Company's cost of providing that capacity. Mr. Allen testified that the value of the of discounted capacity provided to CRES providers is $989 million. (AEP Ohio Ex. 116 at 8-9, Ex. WAA-4 page 1.) Mr. Allen also quantified the cost of the Retail Stability Rider, which enables the Company to offer the benefits of the proposed Modified ESP package (assuming the acceptance of the proposal for the two-tiered discounted capacity pricing) to be $284 million over the term of the ESP. (*Id.* at 13-14, Ex. WAA-6.) Ms. Thomas explained that the total quantifiable benefits of the ESP is in excess of $960 million. (AEP Ohio Ex. 114 at 6, Ex. LJT-1 page 1.)

The third aspect of the Aggregate MRO Test considers other benefits of the ESP, not available in an MRO, that are not readily quantifiable yet 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 benefits that result from the Modified ESP, which Ms. Thomas and Staff witness Fortney describe. For example, the ESP provides a substantially earlier transition to fully market-based prices (about three years) than would be possible through an MRO. (*See* AEP Ohio Ex. 114 at 6, 18, Ex. LJT-1 page 1; Staff Ex. 110 at 6-7 .) In addition, the ESP provides for no non-fuel generation rate increases, and the Company assumes the risk of increased environmental compliance costs for its generation assets through the elimination of the EICCR. Accordingly, the ESP provides substantial price certainty for SSO customers over its term. (*See* AEP Ohio Ex. 114 at Ex. LJT-1 page 1; Staff Ex. 110 at 6-7.) Unification of the Phase-In Recovery Rider and Fuel Adjustment Clauses for the CSP and OPCo zones will allow for the better management of customer bill impacts during the ESP. (*See* AEP Ohio Ex. 114 at Ex. LJT-1 page 1; AEP Ohio Ex. 111 at 5-6.) All of these factors, and others, which are described in greater detail below, confirm that the Modified ESP is more favorable in the aggregate as compared to the expected results under an MRO. (AEP Ohio Ex. 114 at 3-6.)

A. MRO Price Test

AEP Ohio witness Thomas explained that the expected prices that would otherwise occur under an MRO are determined by a weighting of adjusted prior ESP prices and competitive market prices. Ms. Thomas explained that two prices are needed to determine the expected results of an MRO during the proposed ESP period – a Competitive Benchmark price and a generation SSO price. (*Id.* at 9.) The Competitive Benchmark price is based on market data and includes the items that would be included by a supplier providing retail electric service to AEP Ohio customers, but also should recognize the Company's FRR obligation during the ESP period. (*Id.* at 10.) The generation SSO price is a function of generation pricing in effect on March 30, 2012, the date when the Modified ESP was filed. (*Id.*)

In her direct testimony, Ms. Thomas addressed how the proposed ESP prices (provided by Company witness Roush, *see* AEP Ohio Ex. 111), compare to the weighted MRO prices during the period of the Modified ESP. Once an auction occurs, for delivery starting January 2015, the proposed ESP price is the same as the competitive market price. (*See* AEP Ohio Ex. 114 at 9.)

1. Competitive benchmark price

A Competitive Benchmark price is determined using the components that would be expected in pricing retail generation supply in the competitive market during the period of the ESP. The Company's approach was based on ten distinct components using verifiable, publicly available information for each component wherever possible. (*Id.* at 10-11.) The experiences of various deregulated states were reviewed to help in the determination of pricing components to be used. (*Id.* at 11.) The Company included a component for the Alternative Energy Requirement in order to reflect Ohio's requirements that will be, or are anticipated to be, applicable to suppliers during the period of the proposed ESP. (*Id.*) Based on the ten components, Competitive Benchmark prices were developed for the residential, commercial and industrial classes and were then weighted based on MWh to determine total Competitive Benchmark prices for AEP Ohio. Prices were also developed for each planning year (PY) of the Company's proposed ESP. (*Id.* at 12.)[24]

Other than the capacity component, the other nine components of the CBP are:

> 1. Simple Swap (SS) – this component is the "around the clock" price of the industry standard energy product.
>
> 2. Basis Adjustment – this adjustment is based on the historic relationship between pricing points. Applying such an adjustment to the AEP-Dayton Hub SS prices results in prices at the AEP load zone, which is where PJM settles all AEP Ohio loads.
>
> 3. Load Following/Shaping Adjustment – this adjustment, applied to the SS component, accounts for the fact that customers do not use a constant amount of energy across all hours of the day and that customers will deviate from their historic load profile.
>
> 4. Ancillary services – this component prices the cost of ancillary services required by PJM to serve load in the Company's service territory.
>
> 5. Alternative Energy Requirements – Section 4928.64, Ohio Revised Code requires that all suppliers meet certain requirements for the mix of alternative energy resources that must be used to serve load in Ohio.

[24] A planning year (PY) is defined as June 1 through May 31 of the following year. The PYs included in the Company's Modified ESP are for the years 2012/2013, 2013/2014, and 2014/2015. (*Id.*)

> 6. ARR (Auction Revenue Rights) Credit – this item captures the credit allocated to offset PJM congestion charges.
>
> 7. Losses – this component captures the cost of distribution and fixed transmission losses that must be supplied in order to meet the customer's power requirements at the meter.
>
> 8. Transaction Risk Adder – this item reflects a variety of risks that vary based on the unique profile and business objectives of an individual bidder.
>
> 9. Retail Administration Charge – the component captures the costs that a supplier would incur to participate in an auction and fulfill the contractual obligations in the event the supplier was successful in the auction.

(*Id.* at 12-14.) Other parties did not dispute these nine components. The only difference in the components used by any party was Staff witness Johnson's update to the SS price. (*See* Staff Ex. 102 at 21-24.)

The final component of the CBP is the Capacity Component. Ms. Thomas explained that this component includes the capacity cost that a supplier, either a CRES (competitive electric retail service) provider or winning bidder in an auction, would incur to serve a retail customer in AEP Ohio's service territory. (AEP Ohio Ex. 114 at 15.) During the period of PYs 2012/2013, 2013/2014 and 2014/2015, AEP Ohio will be operating under its FRR obligation in PJM, and AEP Ohio must provide capacity for all customers during this period. AEP Ohio's capacity will be used for customers taking service from a CRES provider as well as SSO customers. Consequently, Ms. Thomas explained, the Competitive Benchmark price should reflect that capacity obligation. (*Id.* at 15.)

As the Company explained in the capacity charge case, the Company's FRR obligation extends through May 2015. The full capacity cost rate for AEP Ohio, as supported by Company witness Pearce in the Capacity Pricing case, is $343.98/MW-day (before capacity losses) or

$355.72/MW-day through May 2015 regardless of how energy is supplied to SSO customers. (*Id.*)

Using the full capacity rate, Ms. Thomas calculated Competitive Benchmark prices by customer class for each planning year of the proposed ESP. (*Id.* at 16, Table 1.)

2. Most recent generation price

The second price necessary to determine the expected results of an MRO during the proposed ESP period is, pursuant to § 4928.142(D), Ohio Rev. Code, the Company's "most recent standard service offer price" which may be adjusted for any of four identified cost components. Those four cost components are fuel, purchased power, costs of satisfying supply and demand portfolio requirements for Ohio (renewable and energy efficiency requirements), and costs to comply with environmental laws and regulations. (*Id.* at 16.)

The Company's "most recent standard service offer price" is the generation base rate in effect as of the date when the modified proposed ESP was filed on March 30, 2012. Also included are the generation components of the Transmission Cost Recovery Rider (TCRR), the EICCR, and full cost FAC. Company witness Roush supported these components of the SSO price. (*See* AEP Ohio Ex. 111 at Ex. DMR-2.) Ms. Thomas made no further adjustments. (AEP Ohio Ex. 114 at 6.)

3. The MRO annual price

As described in Section 4928.142, Ohio Revised Code, the MRO Annual Price is determined by weighting the Generation Service Price and the Expected Bid Price. The prices are weighted for each "year" of the period (January 2012 through May 2015) resulting in the weighted average MRO Annual Price shown in Line 14 of page 2 of 3 of Exhibit LJT-1 ($65.39/MWH) of Ms. Thomas's Direct Testimony. This MRO Annual Price is the basis for comparison to the Proposed ESP Price for the period. AEP Ohio witness Roush supports the Proposed ESP Prices shown on line 13 of page 2 of 3 of Exhibit LJT-1 of Ms. Thomas's Direct Testimony. (AEP Ohio Ex. 114 at 17 (Thomas); and AEP Ohio Ex. 111, Ex. DMR-2 (which provides the proposed ESP Prices for the June 2012 – May 2013, June 2013 – May 2014, and June 2014 – December 2014 periods.) The weighted average Proposed ESP Price is shown on line 13 of page 2 of 3 of Exhibit LJT-1 of Ms. Thomas's Direct Testimony ($63.62/MWH). (AEP Ohio Ex. 114 at 18.)

If AEP Ohio were to be in an MRO, R.C. 4928.142(D) would require that the MRO be phased in. Accordingly, Ms. Thomas applied MRO "blending" percentages to the Expected Bid Price and the current Generation Service Price for each of the three years of the ESP, corresponding to each of the three PJM planning years. The weightings that she used for each period to determine the MRO Annual Prices are summarized in Table 2 of her Direct Testimony. (*Id.* at 18.) Increased weightings were applied each Planning Year consistent with the increased weightings set forth in Section 4928.142(D), Ohio Revised Code. (*Id.* at 15.) For June 2012 – May 2013 (PY 2012/2013), a weighting of 10% was applied to the Expected Bid Price. For June 2013 – May 2014 (PY 2013/2014) a weighting of 20% was applied to the Expected Bid Price. A weighting of 30% was used for the June 2014 – December 2014 period (the first seven months of PY 2014/2015). (*Id.* at 18, Table 2.)

Notably, under the Company's proposed ESP, a full requirements energy-only auction for 100% of the Company's SSO load would be conducted for the January through May 2015 period (the last 5 months of the June 2014-May 2015 PY). This raises the question of whether the Competitive Benchmark Price/current SSO price weightings will have an impact on the outcome of the MRO Price Test beginning January 2015 when 100% of the SSO load is subject to a competitive bidding process. They do not. Ms. Thomas explained that there are two ways of viewing the MRO Price Test weightings once the pricing is based on competitive bidding (as will be the case beginning January 2015), and both approaches produce equivalent results. The first approach would continue the weighting of the current Generation Service Price, but adjustments would be made to that price in accordance with the provisions of Revised Code §4928.143(D). In particular, the fuel factor (and, indeed, the costs of the entire current generation price) would be replaced by purchased power costs that reflect the price that the full requirements, energy-only, competitively bid auction produces. The second approach is simply to assign a weighting of 100% to the Expected Bid Price and 0% to the current Generation Service Price beginning at the time that the price is based on the results of the auction. (AEP Ohio Ex. 114, at 19-20.) Ms. Thomas points out that either approach leads to the same result. That is, a weighting of the Generation Service Price (equal to the Expected Bid Price) with the Expected Bid Price is mathematically equivalent to the Expected Bid Price regardless of the price or the weighting. (*Id.* at 19.) Ms. Thomas selected the second, more straight-forward, approach of simply reflecting a 100% weighting of the Expected Bid Price, rather than adjusting the Generation Service Price to reflect the Expected Bid Price. (*Id.* at 20 and Exhibit LJT-3.)

It is also worthwhile to recognize that AEP Ohio has completed its first ESP and is proposing to institute its second consecutive ESP, which will cover the June 2012 through May 2015 period. In total this second ESP, if approved and implemented, will cover years four through six (actually years 4 ½ through 6 ½) since the date on which SB 221 was implemented. Arguably, the blending requirement of the MRO Price Test should be applied to this next ESP by blending the expected bid price (competitive benchmark price) at percentages applicable to the 4^{th}, 5^{th}, and 6^{th} years, (40%, 50%, and 60%) rather than starting over at the levels applicable to the 1st through 3^{rd} years (10%, 20%, and 30%). Conversely, the percentages of the current generation service price logically should be blending percentages applicable to the 4^{th}, 5^{th}, and 6^{th} years (60%, 50%, and 40%), levels rather than at the percentages applicable to the 1^{st} through 3^{rd} years (90%, 80%, and 70%).

When blending percentages are applied in that fashion, *i.e.*, using the percentages applicable to the 4^{th}, 5^{th}, and 6^{th} years, the result is a Modified ESP benefit that is substantially greater than what Company witness Thomas calculated using either the $355/MW-day capacity price in the CBP or the weighted two-tiered capacity prices in the CBP. Accordingly, it would be appropriate when evaluating the relative benefit of the Modified ESP, compared to the MRO alternative, to consider the impact of using the blending percentages applicable to the 4^{th}, 5^{th}, and 6^{th} years of an MRO alternative. Not doing so could frustrate the General Assembly's and Commission's purpose to move the electric utility industry to market because, conceivably, an electric utility could choose an ESP three or four times and, ten to twelve years after SB 221's enactment, still not be at market because the EDU would continually start again at 10% blending of market prices at the beginning of each ESP. Attached as Attachments B and C are revised Exhibits LJT-1, pages 2-3, and LJT-5 to Ms. Thomas's Direct Testimony that illustrate this impact on the MRO Price Test Comparison.

4. Results of the MRO Price Test

As shown in Exhibit LJT-1, page 2 of 3, to Ms. Thomas's Direct Testimony, the weighted average Proposed ESP Price ($63.62/MWH) is lower than the weighted average MRO Annual Price ($65.39/MWH), resulting in an MRO Price Test benefit from the Modified ESP of $256 million (Exhibit LJT-1, page 3 of 3, at line 15) or $1.77/MWH (Exhibit LJT-1, page 2 of 3, at line 15), as compared to the pricing that would result from an MRO.

5. The MRO Price Test using the tiered capacity charge

As explained above, Ms. Thomas presented the results of the MRO Price Test in Exhibit LJT-1, pages 2 and 3, of her Direct Testimony based on the use of the Company's full capacity cost of $355.72/MW-day in the development of the capacity component of the Competitive Benchmark prices. However, Ms. Thomas also provided a view of the MRO Price Test using the two-tiered discounted capacity that the Company has offered to make available to CRES providers as part of the modified proposed ESP in Exhibit LJT-5 of her Direct Testimony, AEP Ohio Ex. 114.

Exhibit LJT-5 shows that the "benefits" of the ESP are reduced to $81 million when the two-tiered discounted capacity is reflected in the Expected Bid Price (based on the appropriate percentages of load to which the discounted capacity is applicable). However, Ms. Thomas explained that these results are purely the mathematical results of an MRO test that is not designed to capture the benefits of offering reduced capacity prices to CRES providers during the period of the Company's FRR obligation. (AEP Ohio Ex. 114 at 22.) Ms. Thomas further observed that the Company's proposed ESP should not be deemed less beneficial when it is offering a benefit to CRES providers which, in turn, should result in benefits to consumers. Ms. Thomas concluded that the more proper approach for determining the benefits that the proposed Modified ESP provides is to use an MRO Price Test that utilizes Competitive Benchmark pricing and relies upon the Company's full, undiscounted, capacity costs. (*Id.*)

B. Price And Non-Price Quantifiable Net Benefits Of The Modified ESP

While the MRO Price Test is one element of the MRO/ESP, it does not account for all of the benefits of the modified proposed ESP. As explained below, the proposed Modified ESP provides additional quantifiable net benefits, not available under an MRO, that further demonstrate that the proposed ESP is substantially more beneficial than the expected results of an MRO.

Ms. Thomas listed at page 1 of Exhibit LJT-1 to her Direct Testimony the other non-price quantifiable net benefits of the proposed ESP, which Company witness Allen quantifies. First, Mr. Allen explained that under the proposed Modified ESP the Company is willing to supply capacity to CRES providers at reduced two-tiered prices, which are at a significant discount to the Company's cost of providing that capacity. Mr. Allen testified that the value of the discounted capacity provided to CRES providers is $989 million. (AEP Ohio Ex. 116 at 8-9, Ex. WAA-4 page 1.)

Mr. Allen also quantified the cost of the Retail Stability Rider (RSR), which enables the Company to offer the benefits of the proposed Modified ESP (assuming the acceptance of the proposal for the two-tiered discounted capacity pricing) to be $284 million over the term of the ESP. (*Id.* at 13-14, Ex. WAA-6.)

Ms. Thomas explained that the total quantifiable benefits of the ESP, including the benefits quantified by the MRO Price Test ($256 million), the value of the discounted, tiered capacity pricing for CRES providers ($989 million) and the cost of the RSR ($284 million) is in excess of $960 million. (AEP Ohio Ex. 114 at 6, Ex. LJT-1 page 1.)[25]

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[25] Ms. Thomas's Direct Testimony, at Exhibit LJT-1, page 1 of 3, appropriately assigns a zero net cost to the ESP from the Generation Resource Rider (GRR) during the ESP. In response to a directive in the Commission's April 25, 2012 Entry, the Company provided updated information regarding potential costs arising from the Turning Point Solar (TPS) project. Company witnesses Nelson and Roush sponsored supplemental testimony detailing potential costs of and resulting GRR rate impacts of the TPS project. (AEP Ohio Ex. 104, 112.) Ms. Thomas incorporated the information provided by Mr. Nelson and Mr. Roush into her presentation of the potential impacts of the TPS project on the GRR, in the event that the project were to go forward during the ESP term. (AEP Ohio Ex. 115.) Because the GRR is available under either an ESP or an MRO (*see* Tr. IV at 1310-11; Tr. XVI at 4627-4629), the impact of the TPS project on the Aggregate MRO Test is always going to be zero because that test captures the difference between what would exist under an ESP and what would exist under an MRO. In any event, Ms. Thomas reported that, even if the GRR were available only under an ESP, and if the TPS project were certain to go forward during the ESP, its maximum impact would be an additional cost of only approximately $8 million, and the total quantifiable net benefits of the proposed ESP would be reduced from $960 million to $952 million. (*Id.* at 2-3.)

C. Qualitative Benefits Of The Modified ESP

Ms. Thomas also listed the substantial benefits that the proposed Modified ESP provides that are not as readily susceptible to quantification as those discussed above. She explained that consideration of these qualitative benefits must be included in the evaluation of whether the ESP in the aggregate is more beneficial than an MRO. There are a number of such benefits that the Modified ESP provides, compared to what an MRO would provide, and they are significant. Ms. Thomas observed that, as one example, for those customers (and marketers and suppliers) that want market-based generation prices sooner, rather than later, the ESP provides an earlier transition to fully market-based prices (about three years) than would be possible through an MRO, which requires a significantly longer period for the transition (at least six years). (AEP Ohio Ex. 114. at Exhibit LJT-1, page 1 of 3.) *See also* Section V.K.6, *supra.* No party disputed this point, and Staff witness Fortney agreed with it. (Staff Ex. 110 at 6-7.) Moreover, as discussed in detail elsewhere in this brief, the Modified ESP advances numerous important state policies. *See* Section V.K, *supra*. The advancement of those state policies is an important benefit of the ESP.

Second, the ESP provides for no non-fuel generation rate increases, and the Company assumes the risk of increased environmental compliance costs for its generation assets through the elimination of the EICCR. Accordingly, the ESP provides substantial price certainty for SSO customers over its term. (AEP Ohio Ex. 114 at Ex. LJT-1 page 1; AEP Ohio Ex. 118 at 9; Staff Ex. 110 at 6-7.) *See also* Section V.A.1, *supra*.

In addition, AEP Ohio is proposing to unify the FAC rates for each rate zone (applicable to the former CSP and OPCo service territories) in June 2013 at the same time that it is proposing to implement the PIRR, also on a merged basis. Merging the FAC increases rates for

OPCo rate zone customers and reduces rates for CSP rate zone customers. Conversely, merging the PIRR reduces rates for OPCo rate zone customers and increases rates for CSP rate zone customers. Company witness Roush explained that merging the FAC at the same time that the PIRR is implemented on a merged basis limits the impact on both CSP and OPCo rate zone customers and is a significant benefit of AEP Ohio's proposed ESP. (AEP Ohio Ex. 111 at 5-6.) Unification of the PIRR and the FAC for the CSP and OPCo rate zones will allow for the better management of customer bill impacts during the ESP. (AEP Ohio Ex. 114 at Exhibit LJT-1, page 1of 3.)

As discussed in the testimony of Company witnesses Powers and Dias, the Company's Modified ESP proposal also includes an early 5% energy auction. (*See* AEP Ohio Ex. 101 at 21, Ex. RPP-1 page 1 of 3; AEP Ohio Ex. 119 at 8.) This benefit is in addition to the aggregate benefits of the Company's Modified ESP. It will have a moderating impact on the cost of the Modified ESP because it will substitute a price lower than the ESP price for 5% of the SSO load and, therefore, it will increase the benefits summarized in Ms. Thomas' testimony. (*See* AEP Ohio Ex. 114 at Ex. LJT-1 page 1.)

Finally, as discussed in detail elsewhere in this brief, the Modified ESP's distribution-related provisions include a number of non-quantifiable but important benefits. (*See id.*). *See also* Section V.D, *supra.* Ms. Thomas concluded that the ESP that results from the Stipulation is substantially more favorable than an MRO, in the aggregate, with regard to its pricing, its other quantifiable benefits, and its other less-quantifiable benefits.

D. The Commission Has The Responsibility And The Means To Ensure That The Aggregate MRO Test And, In Particular, The MRO Price Test, Are Not Used To Cause Financial Injury To AEP Ohio.

The process of reviewing, modifying, and approving an ESP is not intended to produce results injurious to the EDU. In particular, the process may not result in adverse financial impacts to the EDU that would cause a financial emergency, threaten the utility's financial integrity or result, directly or indirectly, in a taking of the EDU's property without compensation. This is made clear by § 4928.142(D), Ohio Revised Code. Division (D) explains how the competitively bid price shall be blended with the EDU's most recent generation standard service offer price to develop the MRO price that is then compared with proposed ESP price, which the Commission then uses as an element in either approving the proposed ESP or making modifications to the ESP before approving a Modified ESP. Division (D) specifically provides that, when determining the blended MRO price:

> The Commission may adjust the electric distribution utility's most recent standard service offer price by such just and reasonable amount that the commission determines necessary to address any emergency that threatens the utility's financial integrity or to ensure that the resulting revenue available to the utility for providing the standard service offer is not so inadequate as to result, directly or indirectly, in a taking of property without compensation pursuant to Section 19 of Article I, Ohio Constitution.

The clear and unambiguous message of this provision is that the blended MRO Price Test comparison and the Aggregate MRO Test may not be applied in a manner that injures the EDU. Indeed, the message of § 4928.142(D) is that the Commission should make adjustments necessary to avoid causing financial injury to the EDU.

In this case, the record is clear that imposing the results that many of the parties advocate, including pricing capacity to CRES providers below the Company's costs at RPM levels without any offsetting revenue stabilizing mechanism (such as the RSR mechanism that the Company has recommended) would lead to severe adverse financial impacts. As demonstrated in the record, the Commission should reject the Staff and intervenor recommendations that cause harmful financial impacts to the Company, because: (i) in the short run, such recommendations result in confiscatory taking of property and would cause unreasonably low earnings that are unacceptable and dangerous; and (ii) AEP Ohio's credit rating is two notches from being a high risk "junk bond" investment and could be downgraded if the Commission entertains the recommendations of Staff and intervenors, which downgrade would impact the vertically-integrated utility and cause wires services to be more expensive in the long run. (See, *supra*, at Section V.A.6.ii.) The RSR and other features of the Modified ESP have high qualitative value in avoiding such deleterious impacts and maintaining a healthy vertically-integrated utility going into corporate separation.

E. Criticisms By Opponents That The Modified ESP Is Not More Favorable Than An MRO Are Without Merit.

Staff and Intervenors critique the Modified ESP on several grounds pertaining to the ESP/MRO test that Company witness Thomas sponsors in her testimony. Several witnesses, for example, challenge the capacity cost that Ms. Thomas includes as one of the components of the Competitive Benchmark Price. IEU witness Murray suggests, wrongly, that FirstEnergy auction prices are a valid proxy for AEP Ohio's expected market prices. Mr. Murray also unfairly criticizes Ms. Thomas's MRO price test for failing to include the auction period of June 2015-May 2016, which clearly falls outside the period of the Modified ESP. Mr. Murray, Mr. Schnitzer (FES), and OCC witness Hixon all raise misplaced objections to the GRR placeholder rider, and still others object to AEP Ohio's MRO price test on various other, miscellaneous grounds. As the following discussion will show, however, these criticisms lack merit. As Ms.

Thomas testified, the Modified ESP is indeed more favorable in the aggregate than the expected results of an MRO and, therefore, the Commission should approve it as proposed.

1. Capacity costs

Staff and Intervenors challenged the cost-based capacity charge of $355 per MW-Day that Company witness Thomas included as a component of the Competitive Benchmark Price. Staff witness Johnson testified, for example, that although the MRO retail pricing construct offered by AEP witness Thomas "reasonably predicted, or 'backcasted,' the actual results of the FirstEnergy SSO auctions and Duke Energy Ohio SSO auctions," he "substituted more appropriate values" provided by witness Choueiki for the capacity component of the MRO price projection. (Staff Ex. 102 at 26-27.) Mr. Johnson projected three MRO values using different capacity prices for each. The first set of capacity values was based upon the PJM RPM Base Residual Auctions for the appropriate PJM delivery periods. (*Id.* at 27-28.) The second capacity value Johnson utilized ($146.41 per MW-day) was based upon the recommendation of Staff witness Emily Medine in the capacity charge proceeding. (*Id.* at 28.) The third value ($255/MW-day) was based on the tier-two rate for customers established by the Commission in its March 7, 2012 Order in the capacity case. (*Id.*) Mr. Johnson's testimony includes predictions of three sets of prices corresponding to these three capacity values. (*Id.* at 32; *see also id.* at DRJ-4, 5 and 6.)

OCC witness Hixon also took issue with the assumption of a $355.72/MW-Day capacity charge reflected in AEP witness Thomas's MRO price projection. She testified that "[i]f the Commission determines in the capacity charge case the levels of capacity charges that will be in effect during the term of the Modified ESP, those capacity charges (instead of the assumed

$355.72/MW-Day) should be reflected in the bid price to determine the blended MRO price for the statutory test of the Modified ESP." (OCC Ex. 114 at 10.)

DERS witness North also testified in support of different capacity prices than those assumed by AEP witness Thomas, asserting that "current market prices must be used for capacity and not the significantly higher costs that AEP Ohio seeks to impose upon shopping customers, via charges to CRES providers." (DERS Ex. 102 at 4.) These substitutions proposed by Mr. North would result in capacity prices of $16.73/MW-Day, $27.86/MW-Day, and $125.99/MW-Day being incorporated into the bid price. (*Id.*)

FES witnesses Schnitzer and Stoddard testified similarly that the RPM price of capacity should be used to develop the competitive benchmark price. (FES Ex. 104 at 22.) IEU witness Murray testified that because AEP witness Thomas assumed a cost-based capacity charge of $355 per MW-Day, "[t]he resulting capacity prices that Ms. Thomas applies to calculate the results of a [competitive benchmark price] used on the MRO option grossly overstates the capacity price that would apply to the CBP associated with the MRO option." (IEU Ex. 125 at 55.)

These challenges to the capacity cost that AEP Ohio witness Thomas utilized in the Competitive Benchmark Price all lack merit. As Ms. Thomas explained in her testimony, the capacity component of the Competitive Benchmark Price includes the capacity cost that a supplier (either a CRES provider or winning bidder in an auction) would incur in order to serve a retail customer in AEP Ohio's service territory. (AEP Ohio Ex. 114 at 15.) During the three years at issue in the Modified ESP, the Company will be operating under its FRR obligation in PJM. (*Id.*) As such, it must provide capacity for its customers during that period. (*Id.*) AEP Ohio's capacity will be used for customers taking service from a CRES provider as well as SSO customers, regardless of whether AEP Ohio is the supplier or if winning bidders through a competitive bidding process are the suppliers to AEP for SSO customer load. (*Id.*) Thus, the Competitive Benchmark Price should reflect that capacity obligation. (*Id.*)

The capacity cost rate for AEP Ohio during the ESP period, when the Company has the FRR obligation, is $343.98/MW-Day (before capacity losses) and $355.72/MW-Day (after capacity losses), as AEP witness Pearce testified in Case No. 10-2929-EL-UNC. (*Id.*) That is why Company witness Thomas properly used this capacity cost value in calculating the Competitive Benchmark Prices for each planning year of the Modified ESP. (*Id.* at 16; *see also id.* at LJT-2.) Although Thomas's Exhibit LJT-5 reflects that the "benefits" of the ESP are reduced to $81 Million when discounted capacity is reflected in the Expected Bid Price, such results are purely the mathematical results of a MRO test that is not designed to capture the benefits of offering reduced capacity prices to CRES providers during the period of the Company's FRR obligation. (AEP Ohio Ex. 114 at 21-22.) The more proper method is to use a MRO test and Competitive Benchmark pricing with the full capacity cost that details the discounted capacity and other benefits as shown in Thomas's primary exhibit, LJT-1. (*Id.* at 22.) As Ms. Thomas explained, "[i]t is appropriate to use the full capacity cost Competitive Benchmark prices because outside of this proposed ESP where discounted capacity is offered to CRES providers, it is the full capacity cost that would apply." (*Id.*) Ms. Thomas confirmed this point on cross-examination, testifying that "[i]t's appropriate to use because *** during the period when the Company is in FRR, that would be the cost of capacity that it supplies to serve the customers regardless of who is actually serving the customers [--] the company is providing the capacity." (Tr. IV at 1281.) It is entirely reasonable for the Commission to conclude that the full capacity cost of $355.72/MW-Day should be utilized to establish the capacity component of the Competitive Benchmark price.

2. Staff's approach to calculating the capacity and energy components of the CBP is flawed and should not be adopted.

An additional very significant flaw in the Staff's implementation of the MRO Price Test and, thus, its Aggregate MRO Test is the fundamental internal inconsistency in its calculation of the competitive benchmark price for the scenario that relies upon its $146.41/MW-day cost-based capacity price. Staff witness Fortney provides his ESP/MRO comparison for the $146.41/MW-day capacity pricing scenario in Attachment B to his Direct Testimony (Staff Ex. 110, Attachment B). Mr. Fortney relies upon Staff witness Johnson's calculations of the competitive benchmark price, provided at Attachment DRJ-5 to Mr. Johnson's Direct Testimony. (Staff Ex. 102.)[26] In this scenario, Mr. Johnson relies upon the embedded cost calculation that Staff presented in Case No. 10-2929-EL-UNC that Staff witnesses Smith, Harter and Medine sponsored in that case. (*Id.* at 28.) In that proceeding the Staff's embedded cost of capacity was composed of a full embedded cost estimate that Mr. Smith sponsored, offset by an energy credit that Mr. Harter and Ms. Medine sponsored. (Staff Ex. 103, Case No. 10-2929-EL-UNC, at 7-9.) The energy credit was based upon a forecast of energy prices during the proposed term of the ESP that Mr. Harter and Ms. Medine modeled. Mr. Harter and Ms. Medine's energy credit would have been significantly smaller and the net embedded cost capacity price that they and Mr. Smith sponsored would have been significantly larger if Mr. Harter and Ms. Medine had used forward energy prices as their measure of future energy costs for the energy credit, instead of the modeled forecasted values. (*See generally* Ohio Power Company's Initial Post-Hearing

[26] Mr. Fortney refers to the competitive benchmark price as the "Staff Projected MRO" and Mr. Johnson refers to it as the "Staff MRO Price."

Brief in Case No. 10-2929-EL-UNC at 53-57; *see also* AEP Ohio Ex. 144, Case No. 10-2929-EL-UNC, at 14-15, 26-27.)

While Mr. Johnson used a capacity component in this scenario, for his competitive benchmark price (the Staff MRO price) that was based in part upon forecasted modeled energy prices, for the energy component of his CBP Mr. Johnson used simple swap values, i.e., available forward prices. Ironically, and detrimentally to AEP Ohio, the Staff refused to use forward energy prices in the development of the energy credit offset and, thus, the net embedded cost capacity price in Case No. 10-2929-EL-UNC.

The Staff's inconsistent approach to valuing the cost of energy during the ESP in the capacity component of its CBP, on the one hand, and the energy component of the CBP, on the other hand appears calculated to minimize the result of its CBP that utilizes embedded cost-based capacity pricing. It is neither rational nor defensible. The Commission must correct the inconsistency. The most straightforward way to achieve consistency would be to substitute the publicly available forward energy prices that Mr. Johnson used for the forecasted modeled energy values included in the energy credit offset to the Staff's embedded cost calculation of capacity.

Another flaw in the Staff's approach to the MRO Price Test and, consequently, the Aggregate MRO Test is that the Staff does not adjust the capacity components of its CBPs to reflect the impacts of the scaling factor, Forecast Pool Requirement, and losses, all of which must be applied when RPM auction capacity prices are used. Staff witness Choueiki claimed that the impacts of these factors should be reflected in adjustments to the billing *quantities* of capacity provided to CRES providers, but he did not make any such adjustment. (Tr. VIII at 2417-2418.) Likewise, Mr. Johnson did not make any such adjustments to his calculations. (*See* *generally* Staff Ex. 102; *see also* Tr. VIII at 2475.) He simply used the unadjusted RPM prices that Dr. Choueiki recommended. Nor did Mr. Fortney make any adjustments, either to billing quantities or prices in any of his calculations in his testimony and exhibits.[27] While Dr. Choueiki conceded that the impacts of the three factors needed to be considered, neither he nor the other Staff witnesses took them into account. As a result, the capacity prices used by Staff under this scenario are understated by at least 20%.

3. FirstEnergy auction prices are not a valid proxy for AEP Ohio expected market prices.

As another basis for critiquing Company witness Thomas's Competitive Benchmark analysis, IEU witness Murray complains that "[i]t is not reasonable to rely exclusively upon administratively-determined estimates of competitive power prices *** when actual auction results for Ohio SSO load are readily available and more reliable." (IEU Ex. 125 at 58; *see also id.* at 54.) Mr. Murray contends that prices from prior auctions conducted by FirstEnergy's EDUs should be used, instead of Competitive Benchmark prices, to establish expected market prices for AEP Ohio. (*Id.*) Accordingly, for the purpose of his MRO Price Test, Mr. Murray "selected a price of $44.76 per MWH as an appropriate market price estimate for the June 2012 to May 2014 delivery period." (IEU Ex. 125 at 65 & Ex. KMM-19.) He obtained this figure from the FirstEnergy SSO auction held January 24, 2012 for the two-year delivery period of June 1, 2012 through May 31, 2014. (*Id.* at 61.) This is an incorrect approach. Mr. Murray fails to recognize the reasons that these "real results" from FE's auction are not applicable to AEP Ohio. There are three primary reasons why IEU's focus on FirstEnergy auction prices is misplaced.

[27] Mr. Fortney did attempt to orally correct the deficiency during cross-examination (Tr. XVI at 4646-4648), but provided no explanation of how he arrived at the corrections except to state that Dr. Choueiki belatedly offered them to him. (*Id.* at 4648 ("I only had the new value that I was provided. I don't have the workpaper that show me how that – how Mr. Choueiki utilized those factors.").)

First, there is an "apples to oranges" problem with Mr. Murray's approach given the many differences – both quantifiable and non-quantifiable – between the auctions in the different PJM zones occupied by FE and AEP Ohio. Staff witness Johnson recognized in his analysis the many differences that must be accounted for, including the zonal difference. (*See* Staff Ex. 102 at 23-24.) Mr. Murray failed to account for these differences. Next, as Mr. Johnson confirmed when testing the validity of the AEP Ohio retail pricing construct (using the exact same set of price components that Ms. Thomas used), the MRO retail pricing construct offered by Ms. Thomas reasonably predicted, or "backcasted," the actual results of the FirstEnergy SSO auctions and the Duke Energy Ohio SSO auctions, "and is therefore valid for forecasting the values of future procurements." (Staff Ex. 102 at 26.) Third, the most recent auctions for FirstEnergy (for the 2015-16 planning year) resulted in prices far different from those in the non-ATSI zone – another indication that it is improper to apply auction bids from another zone as a substitute for the "administratively-determined estimates" that are unfairly criticized by Mr. Murray.

On the "apples to oranges" point, Company witness Thomas discussed this very issue in her rebuttal testimony filed October 21, 2011. (AEP Ohio Ex. 23 at 5-9.) She explained that there are numerous reasons, both quantifiable and non-quantifiable, why FE's auction results are not applicable to AEP Ohio. For one, the delivery period for the FE auctions and the applicable period of the ESP are not the same, and it would be inappropriate to assume that prices for two different delivery periods would be the same. (AEP Ohio Ex. 23 at 5 and Table 5.) A table included in Ms. Thomas's rebuttal testimony depicted how price movement over time is another reason why the FE auction price would not be applicable to AEP Ohio. (*Id.* at 6-7 & Table 2.) Ms. Thomas went on to list three other components (excluding capacity) where the differences between FE and AEP Ohio are easily quantifiable, and would have a quantified impact on auction prices. (*Id.* at 7-8.) First, Ms. Thomas noted that "FE and AEP Ohio are in different zones within PJM and prices can be different between those zones." (*Id.* at 7.) Second, Ms. Thomas noted that the FE auction did not include costs to meet Ohio alternative energy requirements. (*Id.* at 8.) Third, FE auction prices do not include losses because the prices apply to loss adjusted MWhs, whereas AEP Ohio's Competitive Benchmark price applies to metered MWhs (including losses in the price). (*Id.*) Taken in conjunction with the differences in capacity pricing between FE and AEP Ohio, as well as additional competitive benchmark components that differ as between FE and AEP Ohio (which cannot be quantified, but would surely impact pricing), these factors illustrate why FE auction prices are not a valid proxy for AEP Ohio expected market prices. (*Id.* at 8-10.) As Ms. Thomas explained, when properly adjusted for just some of the known differences between the circumstances of the FE auctions and those that would apply to AEP Ohio, it becomes evident that the Competitive Benchmark prices (and, therefore, the Expected Bid Price) that Ms. Thomas has calculated provide a reasonable estimate of expected market prices. *Id.* at 10, Table 3.)

Staff's own witness Johnson confirmed this in his testimony here in the Modified ESP proceeding. (Staff Ex. 102.) He tested the validity of the AEP Ohio retail pricing construct, using the exact same set of price components that Ms. Thomas used, and confirmed that the MRO retail pricing construct offered by Ms. Thomas reasonably predicted, or "backcasted," the actual results of both the FirstEnergy SSO auctions and the Duke Energy Ohio SSO auctions, making Ms. Thomas's approach "valid for forecasting the values of future procurements." (Staff Ex. 102 at 26.) Mr. Johnson properly accounted for the differences that must be recognized when comparing auction results to the CBP.

And as Mr. Murray conceded on cross-examination here in the Modified ESP proceeding, FirstEnergy's auction clearing price is not the full SSO generation rate paid by its SSO customers – it does not include the alternative energy resource component of pricing. (Tr. XII at 3434.) He also testified that the FirstEnergy current SSO price is a result of the blending of several auction results, and that SSO customers in FirstEnergy's service territory actually pay a higher price than the auction price that he included in his testimony. (Tr. XII at 3434-35.) He conceded that prices can and often do differ between the zones occupied by FirstEnergy and AEP Ohio within PJM, and that he did not "explicitly" account for the basis differential for energy between the AEP zone and the ATSI zone when performing his calculations . (Tr. XII at 3437-38.) Mr. Murray also admitted that he did not include other elements of generation SSO pricing for FE, such as generation-related uncollectibles and FE's Rider GCR. (*Id.* at 3437.) Accordingly, the FirstEnergy auction prices are not a valid proxy for the expected market prices that AEP Ohio witness Thomas testified about, which she derived based on the factors specified in R.C. 4929.20(J). (AEP Ohio Ex. 114 at 10.) The Company used verifiable, publicly available information for each of the ten distinct components upon which the Competitive Benchmark prices were based, and the Commission should not look to the FirstEnergy auction prices (which are distinguishable and inapplicable for many reasons) as a substitute for the components to which Ms. Thomas testified. (*Id.* at 12.)

4. It is not appropriate to include the post-ESP auction year (June 2015 through May 2016) in the MRO price test.

Table 3 of Company witness Thomas's testimony depicts the weighted average Competitive Benchmark prices for each of the Planning Years at issue in this ESP, through May 2015. (AEP Ohio Ex. 114 at 21.) IEU witness Murray includes in his testimony results of the ESP versus MRO for an additional twelve-month period – the period from June 2015 through

May 2016 – saying "[f]or the June 2015 through May 2016 delivery year, the Modified ESP is less favorable than an MRO by $1.89 per MWH. Assuming the same SSO volumes as the prior delivery year, the Modified ESP costs $26 million more than the MRO." (IEU Ex. 125 at 70.) Murray testifies that "it is reasonable and appropriate for the Commission to consider the likely results of a 100% CBP process for SSO generation for the June 2015 through May 2016 delivery period as part of its consideration of the Modified ESP." (*Id.* at 79.)

But it is not appropriate for the Commission to include the competitive auction year of June 2015 through May 2016 in the MRO price test, for the simple reason that this goes beyond the planning period at issue in this ESP. Moreover, Mr. Murray acknowledged on cross-examination that he did not account for various adjustments in using the FE auction prices. (Tr. XII at 3435-39 (acknowledging differences in AER, difference in basis, and that his rate was lower than rates in the FE GEN tariff.) He conceded on cross-examination that in this calculation, he used the RPM price for the 2014-2015 delivery year on the MRO side of this test because more recent auction clearing prices – which were *higher* for the 2015-2016 delivery year than they were for the 2014-2015 year—were not yet known at the time when Mr. Murray prepared his testimony. (Tr. XII at 3440-41.) They are known now, and Mr. Murray conceded that the result of his analysis would change based on the 2015-2016 auction results, saying "[d]irectionally, it would move the market rate offer higher, all other things being equal." (Tr. XII at 3441.) The Commission should reject Mr. Murray's inappropriate and admittedly outdated calculation of the ESP versus MRO analysis for the June 2015-May 2016 competitive auction year.

5. The GRR placeholder rider is a zero net cost of the ESP.

As Company witness Thomas testified, GRR supported by Company witness Nelson is a "placeholder" rider that contains "no costs proposed for recovery in this ESP at this time." (AEP Ohio Ex. 114 at 8.) The Company is not certain as to what costs, if any, may ultimately be recovered through this rider, and any costs would be subject to Commission approval in another proceeding. (*Id.*) Thus, although itemized as part of the ESP, "there are no revenues or costs to include in either the Aggregate MRO Test or the MRO Price Test." (*Id.*) Ms. Thomas's exhibit LJT-1 thus properly assigns a "zero" dollar value to the GRR for these reasons. (*Id.* at Ex. LJT-1.)

IEU witness Murray testifies that, based on what he heard from counsel, neither Ohio Power nor Columbus Southern Power could include this "placeholder" rider under an MRO, and that even if it could be includable under the MRO option, it could not be included as a non-bypassable charge. (IEU Ex. 125 at 56.) He testifies that it is "improper and unreasonable to omit the potential effect of the GRR for the purpose of comparing the Modified ESP to the MRO, and that the Commission previously found that the projected effect of the GRR had to be quantified in order to properly perform the ESP versus MRO test. (*Id.*, quoting the Commission's December 14, 2011 Opinion and Order at 30.) Noting that Company witness Nelson provided supplemental testimony on the projected revenue requirement for the Turning Point Solar project, Murray complains that "Ms. Thomas does not address or recognize the costs associated with the GRR in her ESP versus MRO analysis, disregarding the Commission's prior guidance on this issue *** [.]" (*Id.* at 68.)

FES witness Schnitzer similarly complains that AEP Ohio understates the Modified ESP price by omitting the GRR. (FES Ex. 104 at 18.) He "relied on the Company's forecast of the Turning Point Solar Project revenue requirements and included the GRR cost in the Modified

ESP Price." (*Id.* at 19.) In Mr. Schnitzer's table of "Corrections to the Modified ESP Price," he included an "Estimate of GRR" costs for periods June 2013-May 2014, June 2014-December 2014, and January 2015-May 2015. (*Id.* at MMS-3.) He does so to "account for the fact that switched load will be charged the RSR and GRR non-bypassable riders proposed under the Modified ESP. (*Id.* at 19.) He complains that Ms. Thomas's Modified ESP Price is "too low because it omits the costs and risks that customers would face related to the *** GRR. *** under the Modified ESP." (*Id.* at 25.)

OCC witness Hixon also testifies that "the estimated revenues to be collected from customers through the GRR for Turning Point should be considered in the statutory test." (OCC Ex. 114 at 15.) She goes on to testify that "[t]o assume that there is $0 costs that will result from approval of the GRR significantly understates the costs associated with the Modified ESP." (*Id.*) Based on information that the Company provided at the direction of the Commission, Ms. Hixon presented, for purposes of the statutory test of the Modified ESP, an estimated net revenue requirement of $8.4 million for Turning Point as costs to AEP Ohio customers during the ESP. (*Id.* at 17.) She also presented the remaining Turning Point revenue requirement of $346.4 million as future GRR costs to customers. (*Id.* at 18.)

There are at least three fundamental points to be made in response to Intervenors' objections about the GRR. First, because the GRR is available under either an ESP or an MRO, as Ms. Thomas confirmed on cross-examination (Tr. IV at 1310-11), the impact of the Turning Point project on the Aggregate MRO Test is always going to be zero. That test, after all, captures the difference between what would exist under an ESP and what would exist under an MRO. (AEP Ohio Ex. 115 at 2 (Company witness Thomas testifying that "the benefit or difference to be captured under the Aggregate MRO Test for the TPS Project is zero because the aggregate test captures the difference between what would exist under an ESP and what would exist under an MRO").) For this reason, as Ms. Thomas explained, "regardless of what the Commission decides regarding the need for the TPS project *** there is no impact on the Aggregate Market Test for this Modified ESP. This does not change the zero impact of Rider GRR in Item 4 as shown in Exhibit LJT-1, Page 1 of my direct testimony." (*Id.*) Staff witness Fortney readily agreed with Ms. Thomas' conclusions in this respect. (*See* Tr. XVI at 4627-4629.) He testified that, in his opinion, once the Commission has given the authority to an EDU to recover generation investment costs through a mechanism like the GRR, that recovery would be permissible even if the EDU subsequently chose to pursue an MRO. (*Id.*)

Second, it is entirely speculative to suggest that any costs (above the zero dollar value assigned by Company witness Thomas) will actually be collected through the GRR during the ESP period, given that there is no guarantee that the Turning Point project will be approved by the Commission and/or move forward during that time. As Company witness Roush testified in his Supplemental Commission-Ordered Testimony, "[t]he need for the TPS Project is being evaluated as part of an on-going proceeding before the Commission * * * [.] Should the need be approved in those proceedings, the Company will seek approval of the TPS Project and specific GRR rates for the TPS Project in a later proceeding." (AEP Ohio Ex. 112 at 3.) As Mr. Roush explained on cross-examination, "since the design of the GRR won't be addressed until, first, the need for Turning Point's approved, second the GRR's approved in this ESP, and then, third, another proceeding is held regarding the inclusion of Turning Point in the GRR, * * * I didn't want to prejudge any particular rate design in this proceeding because I have no clue. There's too many other conditions precedent, I guess." (Tr. IV at 1098.)

Finally, even if the GRR were available only under an ESP, and even if the Turning Point project were certain to move forward during the ESP period, its maximum impact would be an additional cost of just over $8 million, reducing (only very modestly) the quantifiable net benefits of the proposed ESP from $960 million to $952 million. Company witness Thomas explained this potential impact of the TPS Project on the MRO Test in her Supplemental Commission-Ordered Testimony, informed by inputs she received from witnesses Nelson and Roush. (AEP Ohio Ex. 115 at 3.) She testified:

> If the Commission determines that the GRR would only exist under an ESP, then applying the TPS project cost included in the supplemental Commission-ordered testimony of Company witnesses Nelson and Roush would result in a change of approximately $8 million to Item 4 of Exhibit LJT-1, Page 1 of my direct testimony.

(*Id.*) For these reasons, the GRR simply has no meaningful impact on the MRO test sponsored by the Company, no matter what transpires.

On cross-examination, the witnesses criticizing the Company's treatment of the GRR conceded some significant points. Ms. Hixon, for example, acknowledged that the Company has not requested a value to recover any portion of the $8.4 million in costs estimated to be incurred during the Modified ESP period. (Tr. XII at 3298-99.) "By definition, the placeholder creates the mechanism, but does not set a rate." (*Id.* at 3308.) When asked on cross-examination whether she believed that the Company should estimate the future costs associated from other riders, and treat them as costs of the current ESP (to be consistent with her approach to the GRR), Ms. Hixon was unable to answer. (*Id.* at 3310-11.) Assuming *arguendo* that the costs of the TPS project should be included in the consideration of whether to approve the GRR in this case, it would be appropriate to consider only those project costs expected to be incurred during the term of this ESP, not the total costs to be incurred over the 25 year life of the project, as OCC witness Hixon admitted she had done in her ESP v. MRO comparison. (Tr. XII at 3298).

Mr. Murray took the Company to task in his pre-filed testimony for allegedly failing to abide by the Commission's December 2011 Entry on the subject of the GRR. (IEU Ex. 125 at 56.) In that Entry, the Commission stated that Ms. Thomas "'erred by failing to include a cost for the GRR in her price comparison *** as AEP-Ohio has produced a revenue requirement for the Turning Point Project, *and AEP-Ohio has claimed the Turning Point project as a benefit of the proposed ESP*.'" (*Id.* at n. 16, quoting the Commission's Entry , p. 30 (emphasis added).) On cross-examination, however, when asked if the Company was claiming the Turning Point Solar Project as a benefit of *this* Modified ESP, Mr. Murray testified that he did not recall. (Tr. XII at 3432-33.)

Notably, Staff witness Fortney agreed on cross-examination that it would be inappropriate to consider any costs associated with the TPS project in this proceeding, especially costs to be incurred beyond 2015, because "whether or how much the Commission will allow [the Company] to recover for [*sic*] in the GRR rider is the subject of another hearing at a future time, future unknown time, and [the Company] will be applying for future unknown costs, and I just did not believe it was a valid cost to include as part of the ESP because it's unknown." (Tr. XVI at 4589). Mr. Fortney testified in support of the GRR, noting the state policy goals achieved through the rider: "if there is an established need for additional generation in the future, the GRR provides a mechanism to enable the Commission to allow for the construction of generation facilities, while committing to the diversity of state supply, and allowing the applicant to fulfill its REC obligations." (Staff Ex. 110 at 7). For all of these reasons, and particularly given Staff's support of the GRR, Intervenors' criticisms of the placeholder rider are baseless.

VII. CONCLUSION

For the foregoing reasons, Ohio Power Company respectfully requests that the Commission approve the Modified ESP without modification.

Respectfully submitted,

//s/ Steven T. Nourse

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ATTACHMENT A

PENNSYLVANIA PUBLIC UTILITY COMMISSION
HARRISBURG, PENNSYLVANIA 17105-3265

Joint Application of West Penn Power Company d/b/a Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience under Section 1102(a)(3) of the Public Utility Code approving a change of control of West Penn Power Company And Trans-Allegheny Interstate Line Company

PUBLIC MEETING: February 24, 2011
2176520-OSA

Docket No. A-2010-2176520
Docket No. A-2010-2176732

DISSENTING STATEMENT OF CHAIRMAN JAMES H. CAWLEY

Before us is a proposed merger of four of Pennsylvania's electric distribution companies ("EDCs") which, if approved, will impact the electricity service provided to more than one-third of Pennsylvania's electric customers in a combined service territory covering approximately 70 percent of the Commonwealth. In this proceeding, FirstEnergy Corporation ("FirstEnergy") – which consists of Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power"), and Metropolitan Edison Co. ("MetEd") – proposes to acquire West Penn Power Company d/b/a Allegheny Power ("Allegheny") and Trans-Allegheny Interstate Line Company ("TrAILCo") (collectively "Joint Applicants").

Given the significance of this merger and the record developed in this proceeding demonstrating that anticompetitive and/or discriminatory conduct is virtually certain to occur if this merger is approved without the imposition of significant conditions, this merger, as modified by the Joint Petition for Partial Settlement ("Partial Settlement"), should not be approved. Rather, the Partial Settlement must be substantially augmented to mitigate the likelihood of anticompetitive or discriminatory conduct post-merger. Additional conditions are necessary so as to foster development of a properly functioning competitive market with the goal of delivering competitive benefits to customers, including lower, more competitive prices and innovative services.

Statutory Standards

Before the Commission can approve this proposed change in control, it must find that the merger is "necessary or proper for the service, accommodation, convenience, or safety of the public." 66 Pa.C.S. § 1103(a). To satisfy this standard, the merger must be shown to produce "affirmative public benefits." *City of York v. Pa. Pub. Util. Comm'n*, 449 Pa. 136, 295 A.2d 825 (1972). Also, because the merger involves EDCs, the Commission must determine whether the merger is likely to result in anticompetitive or discriminatory conduct, including the unlawful exercise of market power, which will prevent customers from enjoying the benefits of a properly functioning and workable competitive retail electricity market. 66 Pa.C.S. § 2811(e)(1). If the Commission finds that the merger is not necessary or proper and/or that the merger is likely to result in anticompetitive or discriminatory conduct that will result in a market that is not workably competitive, then the Commission must either reject the merger or impose appropriate conditions on the merger to cure the projected deficiencies. *Id.,* § 2811(e)(2).

Non-Unanimous Settlement

The Administrative Law Judges ("ALJs") recommend approval of the merger as modified by a Partial Settlement. While many of the parties to the proceeding supported the Partial Settlement, it was not unanimous. Significantly, the Office of Small Business Advocate ("OSBA"), the Retail Energy Supply Association ("RESA"), Direct Energy Services, LLC ("Direct Energy"), and Citizens Power all opposed the Partial Settlement. All non-settling parties concluded that the Joint Applicants failed to meet their burden of proving that the merger should be approved pursuant to the statutory requirements of sections 1103(a) and 2811(e).

The Relevant Inquiry

Initially, because the settlement is not unanimous, the relevant inquiry is not whether the Partial Settlement is in the public interest. Rather, we are compelled to review the record as we would in a fully contested proceeding and make a determination of whether the merger, as modified by the concessions offered by the Joint Applicants in the Partial Settlement, satisfies the applicable standards discussed above. While Citizen Power recommended that the merger be rejected, OSBA, Direct Energy, and RESA offered conditions that, if imposed, would satisfy the statutory standards and the Commission's obligations. As discussed below, these parties correctly alleged that the merger – even as modified by the Partial Settlement – does not meet the statutory merger standards. Additional conditions are needed for approval of the merger, in addition to those concessions offered by the Joint Applicants and the measures proposed by my colleagues.

Inadequacy of the Partial Settlement

The concessions agreed to by the Joint Applicants in their original filing, as well as in the Partial Settlement, address to some extent the legal requirement that the merger produce general "affirmative public benefits," and minimally address widespread concerns about job loss and loss of Allegheny's corporate presence in the Commonwealth. These concessions also provide modest rate decreases to customers, without which it would be difficult to conclude that the merger affirmatively benefited the public interest. They should, therefore, be required as a condition for approval by this Commission, not because they were part of a less than unanimous settlement, but because, without them, the merger would fail even the "affirmative public benefits" test.

However, the concessions offered by the Joint Applicants do not adequately address the concomitant obligation to show that the merger will not create competitive concerns, as required by section 2811(e). This facet of merger review is particularly important here because what is proposed is the merger of four major EDCs after the termination of the generation "price caps" that have kept retail competition development on hold throughout Pennsylvania. In this posture, it is crucially important that, if this merger is to go forward, the merger must not frustrate the development of a workably competitive wholesale and retail market.

Unfortunately, the record does not permit a conclusion that a workable competitive market will likely result if the merger is approved with only the competitive conditions proposed in the Partial Settlement and the proposed conditions offered by my colleagues. In a related context, the Commission has found that a workable, or effectively competitive market is one in which there is:

- Participation in the market by many sellers so that an individual seller is not able to influence significantly the price of the commodity.
- Participation in the market by many buyers.
- Lack of substantial barriers to supplier entry and participation in the market.
- Lack of substantial barriers that may discourage customer participation in the market.
- Sellers offering buyers a variety of products and services.[1]

A review of the evidence leads to the conclusion that the merger will likely prevent a market with these characteristics from developing. The principal reason for this is FirstEnergy's proposed acquisition of Allegheny's substantial generation and transmission assets, and particularly Allegheny's substantial generating fleet which is capable of serving its Pennsylvania service territories in a highly economic manner. Access to these assets, together with FirstEnergy's existing capacity, will put the merged company in a position to dominate the Pennsylvania market. In consequence, no real competition will exist and result in customers paying higher prices than if real competition were able to develop.

Ohio All Over Again

The evidence shows that the acquisition of Allegheny's assets will permit FirstEnergy to deploy a "retail marketing strategy" in the Commonwealth that will result in most residential and small business customers taking service from

[1] Investigation into the Natural Gas Supply Market: Report on Stakeholders' Working Group (SEARCH), Docket No. I-00040103F0002 (Sept. 11, 2008).

FirstEnergy's default service or from FirstEnergy's electric generation supplier affiliate, FirstEnergy Solutions. FirstEnergy intends to accomplish this by utilizing Allegheny's generation fleet to aggressively market at the retail level through three sales channels – (1) municipal aggregation; (2) direct sales to customers through its affiliated electric generation supplier (EGS); and, (3) indirectly to customers through the default service of affiliated EDCs (with power supplied by the affiliated-EGS which controls the FirstEnergy generation assets). FirstEnergy's "retail marketing strategy," enabled by its newly acquired assets, will result in the stifling of competition throughout the FirstEnergy service territory. The result will be higher prices and fewer choices for customers than if a fully competitive market was able to develop—the opposite of what the General Assembly intended when it enacted the Electricity Generation Customer Choice and Competition Act.

As FirstEnergy Corporation's Fourth Quarter 2010 Earnings Report makes plain, this generation-backed retail marketing strategy has been highly successful for FirstEnergy in Ohio, where, the record establishes, it serves approximately 81.4 percent of the retail customers, either through the competitive market, municipal aggregation, or default service.[2] Indeed, FirstEnergy made clear during the hearings that it fully intended to utilize the same three-pronged business strategy

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[2] "FirstEnergy Solutions Increases Share of Sales at Affiliated Ohio Utilities to 81.4% February 17, 2011

"FirstEnergy Solutions increased its share of sales in its affiliated franchised utility territories in Ohio to 81.4%, FirstEnergy Corp. disclosed in reporting fourth-quarter earnings.

"The 81.4% share for the quarter ending December 31, 2010, which includes POLR, aggregation and direct retail sales, compares to 80.7% during the quarter ending September 30, 2010, and 72.1% for the quarter ending December 31, 2009.
Through a combination of POLR, opt-out government aggregation, and direct sales to end users, FirstEnergy Solutions supplied 10,546 GWh of the total 12,950 GWh used by customers at its affiliated Ohio distribution companies.

"The breakdown was 2,959 GWh POLR sales, 3,475 GWh aggregation sales, and 4,112 GWh direct retail sales.

"Non-affiliated third parties accounted for only 2,404 GWh of supply at the FirstEnergy Ohio distribution companies, with such third-party supply split almost evenly between POLR sales and competitive retail sales.

"FirstEnergy Solutions also reported that, during the fourth quarter, it served 990 GWh of non-aggregation, non-POLR retail sales in Ohio outside of its affiliated service areas. In Pennsylvania, FirstEnergy Solutions served 561 GWh of direct retail sales in its affiliated service areas, and 812 GWh of direct retail sales outside of its affiliated service areas.

"FirstEnergy Solutions' current customer count is 1.5 million, versus 1.2 million as of late October 2010.

"FirstEnergy Solutions said that it continues to expand direct retail sales in Illinois, Michigan and Maryland, in addition to recently entered non-affiliate territories in Pennsylvania and southern Ohio.

"In 2010, FirstEnergy Solutions doubled its sales outside of Ohio."
http://www.energychoicematters.com/stories/20110217d.html

in Pennsylvania to achieve comparable results achieved in Ohio, through the acquisition of Allegheny's generating supply.[3]

With approval of this merger, several rural Pennsylvania towns will soon be offered "deals" similar to the one New Middletown, Ohio (just across the border from New Castle, Pennsylvania), recently received, as reported in the local online news source:

> Also Monday, council advanced to a first reading legislation to accept a proposal from First Energy Solutions for a nine-year contract under electrical aggregation approved by village voters.
>
> The village would agree to a fixed nine-year electric rate and First Energy would provide the village with a $40,000 lump sum payment and would give residential and commercial customers in the village six and four percent discounts, respectively. Council would like public input and the measure needs two more readings.[4]

One is left to wonder how any Electric Generation Supplier, without a crystal ball accurately predicting generation costs far into the future, can offer anyone a fixed-price rate for nine years. FirstEnergy's affiliate EGS can do so (and will do so) because of its parent's existing generating assets and those it will acquire from Allegheny Power. And will competing EGSs be able to match the off-contract $40,000 sweetener, or perhaps next time FES's offer of a new fire truck or municipal swimming pool? Finally, will it be fair to the residents and businesses in Pennsylvania towns to offer them 4% and 6% discounts, respectively, when EGSs who have been able to compete in other Pennsylvania electric distribution companies' territories routinely offer 10% - 15% discounts to residential customers (with a variety of products and inducements) and a whole panoply of tailored products and prices to businesses? But, of course, with the approval of the Partial Settlement without effective additional protections, there won't be any competing EGSs because none will be able to acquire sufficient customers to make the effort worthwhile, even if they could obtain supply in the wholesale market at a price comparable to that which FES can obtain from its parent's generation arm (which is highly unlikely).

Adverse Effects on the Wholesale Market

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[3] Tr. at 213-218 & Direct Energy Cross Examination Exh. 1 (FE-4(c)-19). The exhibit shows retail market "Take Rates" of 65% that Booz and Co. on March 22, 2010, projected could be achieved by Joint Applicants in the Penelec, Met-Ed, and Duquesne Light Co. service territories (65%-70% in the West Penn service territory). This colloquy occurred at page 218 of the hearing transcript: Q. "So we are in agreement that your goal for the FE and Allegheny service territories if the merger is consummated is to try to achieve these kind of take shares through your three pronged retail marketing channels? A. (Alexander): Absolutely."

[4] http://www.vindy.com/news/2011/feb/16/trustee-why-the-animosity/.

It is also very concerning that FirstEnergy's acquisition of Allegheny's generation will give the merged company the ability to raise prices in the wholesale market, which, in turn, will affect retail competition and wholesale pricing. While the merger has been approved by the Federal Energy Regulatory Commission ("FERC") on the basis of its standard horizontal merger guidelines and the "delivered price test," the Joint Applicants' own FERC analysis showed that the merger resulted in several "screen failures" and near failures in both on and off peak periods. These screen failures occurred even with the exclusion of 2,700 MW[5] of potential future capacity which FirstEnergy has announced its intention to develop. Furthermore, the Pennsylvania Office of Consumer Advocate ("OCA") raised valid concerns about the Joint Applicants' market power studies, mainly that they failed to adequately address relevant market definition concerns.

In making its determinations regarding market power, FERC uses the Herfindahl-Hirschman Index (HHI). The HHI is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in the market and summing the results. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases. Markets in which the HHI is less than 1,000 points are considered to be unconcentrated; markets in which the HHI is greater than or equal to 1,000 but less than 1,800 points are considered to be moderately concentrated; and markets in which the HHI is greater than or equal to 1,800 points are considered to be highly concentrated. The Commission has adopted the Federal Trade Commission/Department of Justice Horizontal Merger Guidelines, which state that, in a horizontal merger, an increase of more than 50 HHI points in a highly concentrated market or an increase of 100 HHI points in a moderately concentrated market fails its screen and warrants further review.

In the FERC proceeding, FERC admitted that the post merger HHIs for the summer off-peak, winter off-peak, and shoulder off-peak periods were 1,054, 1,000, and 1,014, with HHI increases of 111, 111, and 110, respectively. These screen failures exceed the criteria used to detect potential market power. OCA argued before the FERC that the Joint Applicants would have the ability and incentive to withhold coal unit generation during off-peak periods. Specifically, OCA noted that Allegheny has eight coal plants that are located on the flat portion of the supply curve which are candidates for withholding. OCA argued that the Joint Applicants could increase their net energy revenues by approximately $100,000 per hour by withholding the plants in question. OCA further argued that economic withholding of these plants in the form of high bid prices could be detected by the Independent Market Monitor (IMM), but other forms of withholding, such as premature retirement, are beyond the purview of the IMM and the RTO, unless the units are necessary for regional reliability. Rather than investigating these marketing concerns, FERC opted to place the burden on OCA to prove these market power

[5] The Norton Energy Storage Project.

impacts, and further refused to institute an evidentiary proceeding to evaluate such market power impacts. Instead of addressing these concerns, FERC was content to rely on the IMM to ensure that economic withholding does not incur, rather than on a truly competitive generation market to force competitive outcomes in the marketplace.

Similarly, OCA argued that the Joint Applicants' analysis was incomplete because it failed to analyze all the appropriate geographic and product markets. OCA contended that PJM West is one appropriate geographic market that the Joint Applicants overlooked. FERC dismissed OCA's concerns, finding once again that OCA failed to justify why PJM West should be treated as a separate submarket based on this standard. FERC stated that OCA did not cite any evidence, such as binding transmission constraints or price separation data, to support the existence of a separate PJM West submarket. Once again, FERC shifted the burden of proof to OCA and refused to hold an evidentiary hearing on this important issue of fact.

As to default service supply market power, OCA appropriately noted that generation market power is not the same as default service market power. A default service supplier must often provide a number of services, including energy, capacity, ancillary, and alternative energy acquisition services. To put this in perspective, while there are approximately 1,340 generation plants in PJM, there were only 8 winning bidders in Penelec's auctions, with 3 bidders accounting for over 77% of the supply. Similarly, there were approximately a dozen bidders in all of Allegheny's default service auctions, but only 4 winning bidders. Without revealing too much detail because of the potential confidential nature of these requests for proposals and auctions, FirstEnergy and Allegheny Energy Services were substantive competitors – competition that will be lost in this merger to the detriment of Penelec and Allegheny default service customers. OCA, before FERC, raised this same issue—that, because the Joint Applicants each control significant amounts of low cost generation, the Joint Applicants should have been required to analyze the market in relation to competitive procurement of power in Pennsylvania and other restructured PJM states. It is not apparent from the FERC Order that FERC even addressed this concern at all.

If FERC had taken the time to address product markets associated with default service bidding, market power screens for such markets would have consistently failed. In fact, all default service markets are highly concentrated. In the case of Penelec, the calculated HHI index for the residential and small commercial default service market, combined, would have been approximately 2800 pre-merger and over 4600 post merger, an HHI increase of over 1800. In the case of West Penn Power, individual default service class HHI indices were all approximately 4000 or higher, the combined residential and small commercial (rate class C-20) HHI index increased from approximately 3400 to 4200, and, combining all rate class procurement markets, the HHI index increased from approximately 2400 to 3000. These statistics clearly indicate that, if this merger is approved without the conditions proposed herein, it will be necessary for this Commission to significantly modify the provision of default service in the FirstEnergy companies' service territories.

The Joint Applicants' analysis also failed to take into account the evidence of existing structural deficiencies in several aspects of the PJM market, specifically, the energy, reserve, and capacity markets where PJM's own Independent Market Monitor could not say without exception that no participant had the power to affect prices. While this Commission has looked to the FERC analysis as an initial starting point in determining whether a merger would give the merged company wholesale market power, this Commission must go farther and review these data from the standpoint of Pennsylvania's unique statutory requirement: whether it is likely that the merged company will be able to engage in anticompetitive or discriminatory conduct that would harm retail competition. 66 Pa.C.S. § 2811(e)(2).

The Joint Applicants have not sufficiently responded to the potential that they could withhold generation, and thus raise prices in the wholesale energy, reserve, or capacity markets by exploiting the acknowledged existing structural deficiencies in the PJM market to the detriment of competitors and customers. Evidence provided in this proceeding clearly indicates that consumers must rely on the IMM and PJM's tariff to mitigate market prices, instead of relying on real competition. For example, the IMM has already noted that capacity markets are highly concentrated, leading the IMM to impose bid caps in all zones.[6] This merger will only increase the concentration of generating capacity in the PJM market, and worsen the potential market power problems in the capacity market.[7] Offer caps in the capacity market were applied to all sell offers. Morey next noted that the IMM found the reserve markets are highly concentrated, leading to serious market power problems.[8] Thus, while many of these structural problems are well documented in the PJM market, approval of this merger without any mitigation will only aggravate an already highly concentrated market.

Adverse Effect on Default Service

In fact, the Joint Applicants' ability to control the market will be enhanced by FirstEnergy's status as default service provider throughout its service territory. While there has been a reasonable amount of switching in certain service territories (e.g., that of PPL Electric Utilities), the existing default service rules and structure will continue to make it more difficult for EGSs to make meaningful headway in persuading a majority of residential and small commercial customers to switch to competitive alternatives. It is the application of this default service structure (a structure that we have approved for use by all of the major Pennsylvania EDCs) *combined with* FirstEnergy's ability and intent to exploit that structure by coupling

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[6] Morey Stmt. 1 at 27.
[7] *Id.*
[8] *Id.* at 29.

its sales with its newly expanded generation fleet and to have its EGS take advantage of its status as an affiliate of the longstanding "electric service provider" that ensures that the statutory merger standards will not be met.

Further, while there may be other EGSs making offers in the Met-Ed, Penelec, Penn Power, and Allegheny service territories, it will be very difficult for these competitors to have anything other than marginal success under the proposed merger and Partial Settlement. Without meaningful conditions, FirstEnergy will be able to exploit this tendency of smaller customers to do nothing or to remain with their longstanding "electric company," resulting in a large portion of the market staying with either the incumbent utility or an affiliate of the incumbent (especially if it enjoys the incumbent's brand name). The result will not be a market with many sellers and many buyers. Moreover, FirstEnergy's generation advantage constitutes a significant barrier to entry such that non-affiliated competitors will find it difficult to develop the level of market share and presence that would make it worthwhile for them to offer attractive "value added" products, services, and promotions that are the hallmark of a workably competitive market. The evidence of record requires the conclusion that, if the merger is approved as presented, the retail market in the territories of Met-Ed, Penelec, Penn Power, and Allegheny will not result in a workably competitive market, as is required by 66 Pa.C.S. § 2811.

Despite the record evidence of serious problems that will detrimentally affect the competitive market post-merger, the Joint Applicants presented nothing to remedy these concerns. The Partial Settlement does not address the competitive retail market concerns resulting from this merger in any meaningful way.

Conditions That Should Have Been Imposed

In order to mitigate the competitive retail and wholesale competitive concerns, approval should have been conditioned upon the Joint Applicants' acceptance of all of the conditions set forth in the Partial Settlement, the conditions imposed by the Commission pursuant to today's approved motions, as well as the following appropriate and reasonable conditions. All of these conditions are intended to break the inherent bias in favor of FirstEnergy's default service, to mitigate FirstEnergy Solution's post-merger retail market power, and to bring a sufficient number of non-affiliated EGSs into the market to reduce the merged company's ability to dominate the market. This result would have been in the public interest because it fulfills our statutory duty to assure not only that affirmative public benefits will result from a merger, but also that the environment post-merger will produce a fully functional and competitive retail and wholesale market wherein consumers are presented with a variety of competitive options for generation service as well as innovative, value added products.

Accordingly, the Commission should have imposed the following conditions on the merger, in addition to those agreed to by the Joint Applicants in the Partial Settlement:

First, the Joint Applicants should have agreed to exit the default service provider function. To accomplish this goal, the Commission could initiate a separate proceeding to select an alternative default service provider or providers. The Commission could convene a proceeding to determine the procedures and criteria for selecting an alternative default service provider or providers through the establishment of a competitive bidding process for all of the EDC affiliates of the Joint Applicants in Pennsylvania. This proceeding could examine the feasibility of designing a competitive bidding process (perhaps along the lines of FirstEnergy's wholesale default service declining block auction) to select one or more alternative default service providers through the auctioning of blocks of residential and small commercial customers at the lowest cleared auction price. This proceeding could include a determination of the appropriate levels of market share caps applied to First Energy affiliates, and appropriate contingency plans for the various auctions and suppliers. At the conclusion of this proceeding, Joint Applicants could hold the competitive auction consistent with the approved bid process. To address the requirement in Act 129 of 2008 that power procured by default service providers include a prudent mix of supplies, parties could propose modifications to Direct Energy's proposal which called for the alternative default supplier to procure power on the spot market. The alternative default supply provider or providers ultimately selected would ideally not take over responsibility for providing default service in the FirstEnergy-affiliated EDC service territory until the completion of the existing default service procurement period for the EDC affiliate, but no later than June 1, 2013.

Second, while we need not require FirstEnergy to establish a new unbundled affiliated entity to provide the billing, collections, call center, electronic data interchange (EDI) and other related customer service functions on a competitively neutral basis at this time, we should have required FirstEnergy to participate in the efforts of PPL Electric Utilities to design and implement an EGS consolidated billing process. It is not clear that such a billing affiliate would be any more responsive to EGS' needs. Instead, under EGS consolidated billing, EGSs could optimally address their desire to provide billing services that best meet the product and marketing needs of themselves and their customers. The Committee Handling Activities for Retail Growth in Electricity (CHARGE), or a separate working group established under CHARGE, should have been required to establish an appropriate process and timeline to establish standards for this billing mechanism. FirstEnergy should have been directed to accommodate EGS consolidated billing on a manual basis when requested initially, to develop statewide EDI-based EGS consolidated billing standards, and to implement these standards when economically efficient to do so.

Third, given the evidence of the potential for FirstEnergy to exploit existing PJM market deficiencies to exercise wholesale market power, FirstEnergy should have been required to divest generation assets in such a fashion as to mitigate any increase in the HHI in PJM markets. Joint Applicants should have been required to file with the Commission a proposed generation divestiture plan within 90 days of the effective date of this Order. FirstEnergy should not have been permitted to close the merger until the Commission had made a determination on the compliance with a filed divestiture compliance plan. The prohibition against divestiture of facilities in section 2804(5), applicable to electric restructuring, is inapplicable to a merger proceeding where sections 1103(a) and 2811(e) are paramount.

In retrospect, this Commission should likely have requested the IMM to perform an independent market power study of this merger. For example, studies were prepared for the proposed Exelon Corporation-Public Service Electric and Gas Merger in 2005 at the request of the New Jersey Board of Public Utilities. That study identified market power concerns, and ultimately the merger was abandoned.

A $22 Million Net Benefit?

Given the lack of this market study, lack of evidentiary support in the FERC docket for this merger, and clear evidence that the default service bidding markets are extremely concentrated as defined by existing market power indices, the net benefits of this merger are lacking. The Partial Settlement provides quantitative benefits of slightly less than $22 million. In contrast to this, Allegheny Power shareholders would receive a $1.2 billion premium on their investment if they cash out today, Allegheny Power senior executives will be paid $43 million in change-of-control payments, and lawyers, investment bankers, and consultants will be paid $58 million.

Additionally, when the merger was announced, FirstEnergy's S&P's rating was downgraded to BBB- from BBB, while FirstEnergy's senior unsecured rating was changed to BB+ from BBB-. Moody's and Fitch's ratings were unchanged after the announcement.[9] It is important to note that, even though FirstEnergy's regulated subsidiaries maintain their own debt independent of the holding company, S & P downgraded the credit rating of all FirstEnergy subsidiary companies by one notch upon the announcement of the merger, in addition to the downgrade of the rating of the parent company. Such a downgrading can result in approximately a 25 basis point debt premium which could result in roughly $40 million in net-present valued additional interest cost over a 15-year period when applied to the three FirstEnergy operating companies.[10]

[9] OCA St.1 at 9.

[10] This reflects net present cost at 8%, assuming scheduled debt retirements and annual capital programs for Met-Ed, Penelec, and Penn Power of $100 million, $132.5 million, and $27.5 million, respectively, escalated at 3%, and debt coverage of these capital programs of only 40%, 53.6%, and 40%, respectively.

As to the potential for higher default service premiums being imposed on consumers due to the highly concentrated nature of default service supplier markets, a mere $1 per MWH increase in default service costs translates into roughly $68 million and $86 million when net present valued over a 15 year period for the Penelec and West Penn Power service territories, respectively.[11] If, on the other hand, FirstEnergy uses its expanded generation fleet to increase overall wholesale market prices only $1 per MWH in its four Pennsylvania service territories, the net present value cost to consumers over a 15-year period explodes to roughly $465 million.[12]

It should come as no shock that these costs are in line with the premium paid and the costs incurred by FirstEnergy to gain approval of this merger. How then, do we justify approval of such a merger in light of the miniscule guaranteed merger savings, relative to the enormous potential costs to consumers associated with higher energy costs? Only through further mitigation, as proposed herein, does this merger make any logical sense.

Kudos to Allegheny Power's Management and Employees

Mergers of distribution companies do have some credibility. The efficiencies gained through adjacent service territories can result in lower costs to customers if implemented efficiently. Here, however, there are again grave doubts as to such benefits. For example, in most categories of performance, Allegheny Power has often excelled, or performed at least as admirably as FirstEnergy. Complaint rates and call center performance are roughly similar, with Allegheny performing slightly better in some categories and slightly worse in other categories. In terms of the most important performance criteria—reliability—Allegheny is in compliance with our 3-year metrics, while FirstEnergy's Met-Ed subsidiary is again not meeting its 3-year performance standards. In other words, the evidence does not lead one to believe that "best practices" are going to lead to substantial customer benefits. As is typical of these types of mergers, the acquiring company will overshadow the acquired company, therefore leading to continued concerns about FirstEnergy reliability performance.

Allegheny Power has also demonstrated superior performance in managing bad debt and effectively managing universal service program (USP) costs. While the introduction of USP cost riders by FirstEnergy companies has been accompanied by the explosion of USP costs paid by FirstEnergy ratepayers, Allegheny Power has continued to manage these costs effectively within the context of its existing base rates. While the 2010 costs are still not in, which would likely further magnify the difference in cost management between these two companies,

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[11] This assumes 80% customer retention of residential and commercial customers under default service, 0.8% annual market growth for Penelec, and 0.9% annual growth for West Penn Power.
[12] This assumes annual market growth for Met-Ed and Penn Power of 2.1% and 1.5%, respectively, applicable to all customer classes, present valued at 8%.

in 2009, Allegheny Power out performed its FirstEnergy counterparts in all cost management statistics: USP annual spending per residential customer ($15.07 vs. $56.53) and average gross program annual cost per CAP customer ($398 vs. $911). Furthermore, while managing costs, Allegheny Power simultaneously performed far better in managing its bad debt. For example, 2.2% of Allegheny Power customers are in debt, while 5.24% of FirstEnergy customers are in debt. The weighted average arrearage of Allegheny Power is 1.51, while the FirstEnergy rate is 3.23. Similarly, bad debt write-offs are higher for FirstEnergy than for Allegheny Power for both residential customers and low-income customers.

Conclusion

In short, I cannot support this merger without significant conditions over and above those in the Partial Settlement. I do support the additional conditions imposed by my colleagues. These conditions may help, in a small degree, in mitigating some of the impacts of this merger, but, unfortunately, these additional conditions fall far short of mitigating the biggest cost effects – retail and wholesale price impacts. It seems we increasingly rely on the IMM to mitigate a moderately concentrated wholesale market, instead of taking needed steps to make the market effectively competitive, as the Electric Choice Act contemplated.

There will be no retail electric choice in most of Pennsylvania as a result of this merger. FirstEnergy's clever strategy of professing to countenance the competitive protections advocated by the non-settling parties while urging that they be applied, not just to FirstEnergy, but "generically" to all EDCs was designed to gain allies of those EDCs who, unlike FirstEnergy, are actively promoting electric choice and therefore will oppose the need for universal application of measures that are only needed in the FirstEnergy service territories. Once this merger closes, FirstEnergy will never countenance any interference with its three-pronged business strategy, and this Commission will have lost forever its ability to ensure robust electric choice in the FirstEnergy service territories. We are taking a *huge* step backward by approving this merger.

Thanks go to the hard working Allegheny Power employees. As noted, their performance has in many respects been outstanding. Many of these employees have performed admirably, and, in some circumstances, superior to their FirstEnergy counterparts. Regrettably, rather than rewarding this performance by expanding its presence in Pennsylvania, FirstEnergy has chosen only a few Allegheny Power managers to lead the merged entity while reducing its workforce in Pennsylvania.

In sum, rather than net benefits for Pennsylvania and its citizens from this merger, I see mostly negatives. The effects on retail electric choice will be devastating for most rural Pennsylvanians who will soon be given cause to wonder where we were when we were needed.

James H. Cawley, Chairman

Dated: February 24, 2011

ATTACHMENT B

AEP Ohio
Electric Security Plan
Aggregate Market Rate Offer Test

Market Rate Offer Price Test *
(modified bid price weightings)

		PY 2012/2013	PY 2013/2014	PY 2014/2015 Jun-Dec 2014	PY 2014/2015 Jan-May 2015	Wtd Average (5) = weighted (1) through (4)
	Generation Service Price	(1)	(2)	(3)	(4)	
1	Current Base ESP 'g' Rate	21.26	21.26	21.28	21.22	21.26
2	Current TCCR 'g' component	2.95	2.95	2.95	2.94	2.95
3	Current EICCR	1.60	1.60	1.61	1.60	1.60
4	Market Comparable Base 'g'	25.81	25.81	25.84	25.76	25.81
5	Current Fuel Factor	36.35	36.36	36.39	36.32	36.36
6	Total Generation Service Price	62.16	62.17	62.23	62.08	62.17
	Expected Bid Price					
7	Competitive Benchmark (at $355/MW-Day)	69.36	71.09	74.34	74.34	71.60
	MRO Pricing					
8	Generation Service Price	62.16	62.17	62.23	62.08	62.17
9	Generation Service Weight	60%	50%	40%	0%	
10	Expected Bid Price	69.36	71.09	74.34	74.34	71.60
11	Expected Bid Weight	40%	50%	60%	100%	
12	MRO Annual Price	65.04	66.63	69.50	74.34	67.72
	MRO - ESP Price Comparison					
13	Proposed ESP Price	62.12	61.79	61.82	74.34	63.62
14	MRO Annual Price	65.04	66.63	69.50	74.34	67.72
15	Modified ESP Benefit**	2.92	4.84	7.68	0.00	4.10

* One part of the test "in the aggregate"
** Does not include all ESP Benefits shown on Page 1

Market Rate Offer Price Test *

		PY 2012/2013	PY 2013/2014	PY 2012/2013 Jun-Dec 2014	PY 2012/2013 Jan-May 2015	Wtd Average (5) = weighted (1) through (4)
	Generation Service Price	(1)	(2)	(3)	(4)	
1	Current Base ESP 'g' Rate	1,024,623,306	1,026,026,251	605,071,259	418,841,336	3,074,562,152
2	Current TCCR 'G' component	142,174,918	142,369,588	83,879,709	58,029,855	426,454,070
3	Current EICCR	77,111,820	77,217,404	45,778,418	31,580,874	231,688,516
4	Market Comparable Base 'g'	1,243,910,044	1,245,613,243	734,729,386	508,452,065	3,732,704,738
5	Current Fuel Factor	1,751,884,157	1,754,765,497	1,034,705,973	716,885,831	5,258,241,458
6	Total Generation Service Price	2,995,794,201	3,000,378,740	1,769,435,359	1,225,337,896	8,990,946,196
	Expected Bid Price					
7	Competitive Benchmark (at $355/MW-Day)	3,342,797,391	3,430,865,764	2,113,768,674	1,467,326,339	10,354,758,168
	MRO Pricing					
8	Generation Service Price	2,995,794,201	3,000,378,740	1,769,435,359	1,225,337,896	8,990,946,196
9	Generation Service Weight	60%	50%	40%	0%	
10	Expected Bid Price	3,342,797,391	3,430,865,764	2,113,768,674	1,467,326,339	10,354,758,168
11	Expected Bid Weight	40%	50%	60%	100%	
12	MRO Annual Price	3,134,595,477	3,215,622,252	1,976,035,348	1,467,326,339	9,793,579,416
	MRO - ESP Price Comparison					
13	Proposed ESP Price	2,993,866,406	2,982,039,606	1,757,777,501	1,467,326,339	9,201,009,852
14	MRO Annual Price	3,134,595,477	3,215,622,252	1,976,035,348	1,467,326,339	9,793,579,416
15	Modified ESP Benefit**	140,729,071	233,582,646	218,257,847	0	592,569,564

* One part of the test "in the aggregate"
** Does not include all ESP Benefits shown on Page 1

Connected Load (kWh)	48,194,887,407	48,260,877,259	28,433,799,761	19,738,045,996	144,627,610,423

ATTACHMENT C

Alternative Market Rate Offer Price Test *
(modified bid price weightings)

		PY 2012/2013	PY 2013/2014	PY 2014/2015 Jun-Dec 2014	PY 2014/2015 Jan-May 2015	Wtd Average (5) = weighted (1) through (4)
	Generation Service Price	(1)	(2)	(3)	(4)	
1	Current Base ESP 'g' Rate	21.26	21.26	21.28	21.22	21.26
2	Current TCCR 'G' component	2.95	2.95	2.95	2.94	2.95
3	Current EICCR	1.60	1.60	1.61	1.60	1.60
4	Market Comparable Base 'g'	25.81	25.81	25.84	25.76	25.81
5	Current Fuel Factor	36.35	36.36	36.39	36.32	36.36
6	Total Generation Service Price	62.16	62.17	62.23	62.08	62.17
	Expected Bid Price					
7	Competitive Benchmark-Shopping Weighted	62.39	63.56	66.26	64.28	63.80
	MRO Pricing					
8	Generation Service Price	62.16	62.17	62.23	62.08	62.17
9	Generation Service Weight	60%	50%	40%	0%	
10	Expected Bid Price	62.39	63.56	66.26	64.28	63.80
11	Expected Bid Weight	40%	50%	60%	100%	
12	MRO Annual Price	62.25	62.87	64.65	64.28	63.20
	MRO - ESP Price Comparison					
13	Proposed ESP Price	62.12	61.79	61.82	64.28	62.25
14	MRO Annual Price	62.25	62.87	64.65	64.28	63.20
15	Modified ESP Benefit**	0.13	1.08	2.83	0.00	0.96

* One part of the test "in the aggregate"
** Does not include all ESP Benefits shown on Page 1

Alternative Market Rate Offer Price Test *

		PY 2012/2013	PY 2013/2014	PY 2012/2013 Jun-Dec 2014	Jan-May 2015	Wtd Average (5) = weighted (1) through (4)
	Generation Service Price	(1)	(2)	(3)	(4)	
1	Current Base ESP 'g' Rate	1,024,623,306	1,026,026,251	605,071,259	418,841,336	3,074,562,152
2	Current TCCR 'G' component	142,174,918	142,369,588	83,879,709	58,029,855	426,454,070
3	Current EICCR	77,111,820	77,217,404	45,778,418	31,580,874	231,688,516
4	Market Comparable Base 'g'	1,243,910,044	1,245,613,243	734,729,386	508,452,065	3,732,704,738
5	Current Fuel Factor	1,751,884,157	1,754,765,497	1,034,705,973	716,885,831	5,258,241,458
6	Total Generation Service Price	2,995,794,201	3,000,378,740	1,769,435,359	1,225,337,896	8,990,946,196
	Expected Bid Price					
7	Competitive Benchmark-Shopping Weighted	3,006,879,025	3,067,461,359	1,884,023,572	1,268,761,597	9,227,125,553
	MRO Pricing					
8	Generation Service Price	2,995,794,201	3,000,378,740	1,769,435,359	1,225,337,896	8,990,946,196
9	Generation Service Weight	60%	50%	40%	0%	
10	Expected Bid Price	3,006,879,025	3,067,461,359	1,884,023,572	1,268,761,597	9,227,125,553
11	Expected Bid Weight	40%	50%	60%	100%	
12	MRO Annual Price	3,000,228,131	3,033,920,050	1,838,188,287	1,268,761,597	9,141,098,064
	MRO - ESP Price Comparison					
13	Proposed ESP Price	2,993,866,406	2,982,039,606	1,757,777,501	1,268,761,597	9,002,445,110
14	MRO Annual Price	3,000,228,131	3,033,920,050	1,838,188,287	1,268,761,597	9,141,098,064
15	Modified ESP Benefit**	6,361,725	51,880,444	80,410,786	0	138,652,954

* One part of the test "in the aggregate"
** Does not include all ESP Benefits shown on Page 1

	Connected Load (kWh)	48,194,887,407	48,260,877,259	28,433,799,761	19,738,045,996	144,627,610,423

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 29th day of June, 2012.

//s/ Steven T. Nourse
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