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**The**
**SUPREME COURT OF OHIO**

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| The Kroger Company, *et al.*,<br><br>Appellants,<br><br>v.<br><br>Public Utilities Commission of Ohio,<br><br>Appellee,<br><br>and<br><br>Ohio Power Company,<br><br>Cross-Appellant. | : | Case No. 13-521<br><br>On appeal from the Public Utilities Commission of Ohio, Case Nos. 11-346-EL-SSO, Case No. 11-348-EL-SSO, Case No. 11-349-EL-AAM, and 11-350-EL-AAM, *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, et al.* |

# SECOND MERIT BRIEF
## SUBMITTED ON BEHALF OF APPELLEE, THE PUBLIC UTILITIES COMMISSION OF OHIO


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**SECOND MERIT BRIEF**
**SUBMITTED ON BEHALF OF APPELLEE,**
**THE PUBLIC UTILITIES COMMISSION OF OHIO**

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## INTRODUCTION

Senate Bill 3, enacted in 1999 to restructure Ohio's electric industry by changing the way customers shop for electricity, provided for a five-year market development period. During this time, electric rates were frozen to allow a competitive retail market to develop. The market did not develop within those five years, nor has it yet fully developed. As the end of S.B. 3's market development period neared, there was a growing concern that an immediate shift to market-based rates in 2006 would not be in the best interest of customers. To minimize the effects of rate "sticker shock" and transition customers to market-based rates, the Public Utilities Commission of Ohio ("Commission") worked with Ohio's electric utilities to develop rate stabilization plans. The rate stabilization plans eliminated market uncertainty and provided customers with stable rates. Most of these plans expired at the end of 2008.

In 2008, the Ohio General Assembly passed Senate Bill 221 to keep electric rates stable going forward, create jobs, implement energy efficiency, and expand Ohio's alternative energy industry. S.B. 221 outlined alternative paths for electric utilities to implement different forms of market-based pricing.

This is AEP Ohio's second Electric Security Plan ("ESP") case. The Commission approved the proposed ESP, with modifications, finding that the plan provides rate stability for customers, revenue certainty for the Company, and facilitates a transition to market. This plan marks a significant milestone in the ongoing transition to market, and should be affirmed.

## STATEMENT OF THE FACTS AND CASE

The facts and procedural state of the case have been adequately set forth in the multiple other statements filed in this case. The Commission specifically adopts the Statement of Facts as set forth by Cross-Appellant/Appellee AEP Ohio.

## ARGUMENT

**Proposition of Law No. I:**

> **When considering whether an ESP is more favorable than an MRO, the Commission is not bound to a "strict price comparison" and "must consider more than price" in determining whether the ESP should be approved. *In re Columbus S. Power Co.*, 128 Ohio St.3d 402, 2011-Ohio-958, ¶ 27; R.C. 4928.143(C)(1), App. at 22.[1]**

### A. The record shows that the ESP was more favorable in the aggregate than the MRO. [FES 1(1)]

When examining a proposed ESP, the Commission must consider all the potential benefits of the plan, both quantitative and qualitative. *In re Columbus S. Power Co.*, 128 Ohio St.3d 402, 2011-Ohio-958, ¶ 27 ("[I]n evaluating the favorability of a plan, the statute instructs the commission to consider 'pricing and all other terms and conditions.' Thus, the commission *must consider more than price in determining whether an electric security plan should be modified.*") citing R.C. 4928.143(C)(1) (emphasis added). Quantitative benefits relate to "pricing" or the "costs" of the plan and can be assigned a specific dollar value. Qualitative benefits, by their very nature, cannot. The Commission

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1 References to appellee's appendix attached to this brief are denoted "App. at ___" references to appellee's supplement are denoted "Supp. at ___;" references to the appendix of appellant Industrial Energy Users-Ohio (filed August 12, 2013) are denoted "IEU App. at ___;" references to the Supplement to the merit brief of appellant Industrial Energy Users-Ohio (filed August 12, 2013) are denoted IEU "Supp. at ___."

*must* consider whether certain aspects of the ESP are valuable and help further the policy goals of R.C. 4928.02, even if these aspects cannot be quantified.[2]

In this case, the ESP was found to be more favorable in the aggregate than a Market-Rate Offer ("MRO"). *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 Nos. 11-346-EL-SSO, *et al.* ("*ESP 2 Case*") (Opinion and Order at 77) (Aug. 8, 2012), IEU App. at 100. The ESP had numerous qualitative benefits that furthered the goals of R.C. 4928.02. *Id.* at 75-77, IEU App. at 98-100; *ESP 2 Case* (Entry on Rehearing at 9-12) (Jan. 30, 2013), IEU App. at 115-118. The qualitative benefits of the ESP, which are not available under an MRO, include:

- Meeting the General Assembly's goal of moving AEP Ohio to competitive market-based prices within just two and a half years. *ESP 2 Case* (Opinion and Order at 76) (Aug. 8, 2012), IEU App. at 99; *see* R.C. 4928.02(B), (C), (G), App. at 12, 12, 13.

- Accelerating AEP Ohio's energy-only auctions that enable customers to take advantage of competitive market-based energy prices more quickly than customers would be able to under an MRO. *ESP 2 Case* (Opinion and Order at 76) (Aug. 8, 2012); IEU App. at 99; *see* R.C. 4928.02 (B), (C), (G) , App. at 12, 12, 13.

- Ensuring that AEP Ohio will continue successful distribution-related programs that have improved service, safety and reliability on AEP Ohio's system and

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2 The Commission stated that its decision was "guided by the policies established by the General Assembly in Section 4928.02, Revised Code…" *ESP 2 Case* (Opinion and Order at 13) (Aug. 8, 2012), IEU App. at 36; *see also* R.C. 4928.06 ("Beginning on the starting date of competitive retail electric service, the public utilities commission shall ensure that the policy specified in section 4928.02 of the Revised Code is effectuated."), .

helped modernize its system. *ESP 2 Case* (Opinion and Order at 76) (Aug. 8, 2012); IEU App. at 99; *see* R.C. 4928.02(A), (D), App. at 12, 12.

- Providing price certainty for customers by freezing base generation rates until rates are established through a competitive bidding process. *ESP 2 Case* (Opinion and Order at 7, 15-16, 76) (Aug. 8, 2012) , IEU App. at 30, 38-39, 99; *ESP 2 Case* (Entry on Rehearing at 36-37) (Jan. 30, 2013), IEU App. at 142-143; *see* R.C. 4928.02(A), App. at 12.

- Reducing the impacts of potential rate increases by establishing a 12% cap on customer rate increases. *ESP 2 Case* (Opinion and Order at 70) (Aug. 8, 2012), IEU App. at 9.; *ESP 2 Case* (Entry on Rehearing at 11, 40) (Jan. 30, 2013), IEU App. at 117146; *see* R.C. 4928.02(A), App. at 12.

FES and IEU dispute whether the record supports the Commission's determination that these qualitative benefits of the ESP make it more favorable than an MRO. This is a question of fact. This Court has stated on numerous occasions that it "will not second-guess the Commission on questions of fact absent" a showing that "the Commission's findings...are manifestly against the weight of evidence." *Consumers' Counsel v. Pub. Util. Comm'n*, 114 Ohio St.3d 340, 2007-Ohio-4276, ¶ 29; and *New Par v. Pub. Util. Comm'n,* 98 Ohio St.3d 277, 2002-Ohio-7245, ¶17 ("[A]ppellants are requesting that the court examine and weigh the evidence contained in a record of over 1100 pages of testimony and thousands of pages of exhibits. It is clear from the order that the commission carefully and thoroughly considered the evidence before it. We hereby decline to review and weigh that evidence anew…").

The Commission fully explained why it believed the qualitative benefits of the ESP made it more favorable than the MRO in its decision. *ESP 2 Case* (Opinion and Order at 75-77) (Aug. 8, 2012), IEU App. at 98-100; *ESP 2 Case* (Entry on Rehearing at

9-12) (Jan. 30, 2013), IEU App. at 115-118. The record shows that the Commission's decision comports with R.C. 4928.143(C)(1) and that the qualitative benefits of the ESP further the policy goals of R.C. 4928.02. *Consumers' Counsel v. Pub. Util. Comm'n*, 125 Ohio St.3d 57, 2010-Ohio-134, ¶ 39-40 ("The General Assembly left it to the commission to determine how best to carry out the state's policy goals...").

### B. The ESP will allow AEP Ohio to quickly move to competitive market-based pricing, which is a goal of the General Assembly.

#### 1. Various parties, including FES, supported moving AEP Ohio to competitive market-based pricing faster. [FES 1(2)(b)]

One of the most significant qualitative benefits of the ESP is AEP Ohio's expedited move to market-based pricing. *ESP 2 Case* (Opinion and Order at 38-40, 76) (Aug. 8, 2012), IEU App. at 61-63; *ESP 2 Case* (Entry on Rehearing at 10-12) (Jan. 30, 2013), IEU App. at 116-118. The General Assembly has mandated competition and AEP Ohio agreed to shift its business structure towards fully competitive, market-based generation prices within an expedited two-and-a-half year period. *ESP 2 Case* (Opinion and Order at 38) (Aug. 8, 2012), IEU App. at 61. A number of parties, including FES, testified that allowing AEP Ohio to move to market more quickly was a plus.[3] AEP Ohio agreed to

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[3] *ESP 2 Case* (Direct Testimony of Rodney Frame at 3, 32) (May 4, 2012) ("Frame Testimony"), Supp. at 35, 38; *Id.* (Direct Testimony of Teresa Ringenbach at 3) (May 4, 2012), Supp. at 40; *Id.* (Direct Testimony of David Fein at 8, 14-15) (May 4, 2012), Supp. at 31, 32-33; *Id.* (Direct Testimony of Salil Pradhan at 3) (May 4, 2012), Supp. at 40; *ESP 2 Case* (Opinion and Order at 38-39) (Aug. 8, 2012), IEU App. at 61-62.

make several major, complex structural changes – such as transferring ownership of its generation assets and terminating its Pool Agreement[4] – in order to move to 100% market-based generation prices. *Id.* at 7, 38, IEU App. at 30, 61. AEP Ohio's agreement to move to full competition in two and a half years was voluntary and could only happen in an ESP. *Id.* at 38-40, 76, IEU app. at 61-63, 99.

### 2. AEP Ohio's expected move to market-based prices would not be possible under an MRO. [FES 1(2)(b), IEU 1(2)(b)]

FES claims that moving AEP Ohio to market in just two and a half years is not a benefit of the ESP. IEU Merit Brief at 11-12. FES is wrong. Under an MRO, this move would take at least six years except in certain rare circumstances, none of which are present here.[5] Although FES claims that AEP Ohio could "be at 100% market prices by 2015" under an MRO, this argument is based upon an incorrect premise. FES Merit Brief at 12. FES bases this argument on AEP Ohio witness Thomas' testimony. *Id.* But the Commission stated in its Opinion and Order that it was applying the MRO blending percentages specified in R.C. 4928.142(D) and *not* those proposed by AEP Ohio witness

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4 The Pool Agreement is an agreement among AEP Ohio and some of its affiliate utilities that governs generation sales and interconnected operations between AEP Ohio and its affiliates for decades. Frame Testimony at 4-5, Supp. at 36-37.

5 R.C. 4928.142(D) describes the blending percentages required under an MRO. Under R.C 4928.142(E), the Commission may alter the blending percentages after the second year of an MRO only if it needs to "mitigate any effect of an abrupt or significant price change in the electric distribution utility's standard service offer…." *ESP 2 Case* (Entry on Rehearing at 12) (Jan. 30, 2013), IEU App. at 118.

Thomas. *ESP 2 Case* (Opinion and Order at 75) (Aug. 8, 2012), IEU App. at 98; *Consumers' Counsel v. Pub. Util. Comm.*, 111 Ohio St.3d 300, 2006-Ohio-5789, ¶ 69 ("Due deference should be given to statutory interpretations by an agency that has accumulated substantial expertise and to which the General Assembly has delegated enforcement responsibility."). Under an MRO, it would take AEP Ohio at least six years to move to fully market-based prices. R.C. 4928.142(D), App. at 18. Under the ESP, this will only take two and a half years. In addition, AEP Ohio will competitively bid 60% of its SSO load in the second year of the ESP in an energy-only auction. By contrast, under an MRO AEP Ohio would only be required to competitively bid 20% of its SSO load by the second year. A comparison of the ESP and MRO blending percentages shows that the ESP moves AEP Ohio to market much faster than an MRO. In addition, although FES claims corporate separation is the true reason AEP Ohio can move to market faster and not the ESP, FES ignores the fact that corporate separation is an integral part of the overall ESP package.[6]

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6 *ESP 2 Case* (Direct Testimony of Robert Powers at 10-12) (Mar. 30, 2012), IEU Supp. at 528-530; *Id.* (Direct Testimony Philip Nelson at 4-6) (May 2, 2012) ("Nelson Testimony"), IEU Supp. at 62-64; *Id.* (Ohio Power Company's Modified Electric Security Plan) (Mar. 30, 2012), IEU Supp. at 1. Although the details of AEP Ohio's corporate separation were addressed in a separate proceeding, the Commission found in the *ESP 2 Case* that corporate separation will facilitate AEP Ohio's move to a fully competitive market. *ESP 2 Case* (Opinion and Order at 59) (Aug. 8, 2012), IEU App. at 82.

While AEP Ohio's move to market has quantitative benefits,[7] it also has qualitative benefits that go beyond mere price terms. It will help promote the development of a fully competitive electric marketplace in Ohio. Because many of the benefits of a fully competitive market will occur in the future, *no one* can accurately quantify this potential today. However, the development of market-based pricing in AEP Ohio's territory fosters competition and meets the policy goals of R.C. 4928.02(B), (C) and (G). Therefore, AEP Ohio's expedited move to market is indeed a qualitative benefit that the Commission properly considered in its ESP v. MRO analysis. *ESP 2 Case* (Opinion and Order at 76) (Aug. 8, 2012), IEU App. at 99.

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7 IEU criticizes the Commission for its quantification of the costs of the "the energy-only" auctions. IEU Merit Brief at 15. The Commission considered IEU's testimony regarding this issue and determined that it was speculative and "conclusory in nature." *ESP 2 Case* (Entry on Rehearing at 11) (Jan. 30, 2013), IEU App. at 117. Although IEU disagrees with the Commission's conclusion, the Commission's decision to exclude speculative costs from the ESP v. MRO analysis was a reasonable factual determination.

### 3. The Commission correctly determined that distribution riders are a qualitative benefit of an ESP. [FES 1(2)(a)]

The Distribution Investment Rider ("DIR"),[8] gridSMART,[9] and Enhanced Service Reliability Rider ("ESRR")[10] riders will lead to qualitative benefits that make the ESP more favorable than the MRO. *ESP 2 Case* (Opinion and Order at 75-76) (Aug. 8, 2012), IEU App. at 98-99. These riders relate to AEP Ohio's distribution system as opposed to generation assets. Because the programs funded through these distribution riders are not currently quantifiable, the Commission could not consider the costs of the programs in its analysis. *Id.* The Commission did, however, consider the qualitative benefits of the programs funded by these riders. This is consistent with the Commission's action in *In re First Energy Ohio,* which FES cites in its brief. FES Merit Brief at 10. For example, in *In re First Energy Ohio*, the Commission noted that the "continuation of the distribution

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8 DIR allows AEP Ohio to proactively make needed investments in its distribution system without the regulatory lag associated with a distribution base rate case. *ESP 2 Case* (Opinion and Order at 46) (Aug. 8, 2012), IEU App. at 69. In addition, AEP Ohio agreed to a distribution rate freeze as a condition of the DIR, and also agreed to annual revenue caps, which are benefits that would not be available in an MRO. *Id.* at 43, IEU App. at 66.

9 gridSMART is pilot program that explores new technologies that modernize AEP Ohio's distribution system. *ESP 2 Case* (Testimony of Thomas L. Kirkpatrick at 9-10) (Mar. 30, 2012) ("Kirkpatrick Testimony"), Supp. at 14-15. The experimental nature of the gridSMART program is why AEP Ohio is allowed to recover investment on "as spent" basis, subject to annual audits, as opposed to a traditional distribution base rate case.

10 The ESRR continues AEP Ohio's comprehensive vegetative management program, which reduced tree-caused outages and improved reliability. Kirkpatrick Testimony at 5-7, Supp. at 7-9.

rate increase 'stay-out' for an additional two years [] provide[d] rate certainty, predictability, and stability for customers." *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case No. 12-1230-EL-SSO (Opinion and Order) (Jul. 18, 2012) ("*In re FirstEnergy Ohio*"), App. at 51-115. Further, the Commission recognized that the ESP "supports reliable service through the continuation of the [distribution rider]." *Id.*

In the *ESP 2 Case*, the Commission recognized the qualitative benefits of these distribution programs because these programs and accompanying benefits would not necessarily occur through a distribution rate case. For example, the DIR freezes distribution base rates and establishes annual caps on the amount of distribution investment AEP Ohio can recover from customers.[11] These benefits would not occur in a distribution rate case. More importantly, AEP Ohio has committed to continue these programs although it is under no obligation to do so. Because these programs are important, albeit not currently quantifiable, the Commission reasonably decided to continue the distribution programs and recognize the qualitative value of these programs in its "more favorable than" analysis.

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11 *ESP 2 Case* (Direct Testimony of William A. Allen at 11-12) (Mar. 30, 2012) ("Allen Testimony), IEU Supp. at 35-36.

**C. The Commission's factual determination regarding the various quantitative aspects of the ESP was reasonable and supported by the record.**

**1. The Commission's decision to use the $188.88/MW-day capacity price to determine the quantitative costs of the MRO was reasonable and consistent with its ruling in the Capacity Case. [IEU 1(2)(a)]**

The Commission's decision to use $188.88/MW-day is reasonable and consistent with the Commission's decision in the Capacity Case. *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC (Opinion and Order at 33-36) (Jul. 2, 2012) ("*Capacity Case*"), IEU App. at 56-59. Because AEP Ohio is contractually obligated to remain a Fixed Resource Requirement ("FRR") entity until May 31, 2015, its obligation to supply capacity for all customers – both SSO customers and customers taking service through a CRES provider – also remains until May 31, 2015. Therefore, AEP Ohio's cost of capacity would be the same under an ESP or MRO. *ESP 2 Case* (Opinion and Order at 74) (Aug. 8, 2012), IEU App. at 97.

**2. The Commission accurately determined that the potential cost of the Generation Resource Rider during the ESP period was approximately $8 million. [IEU 1(2)(b)]**

IEU takes issue with the quantitative value the Commission gave the Generation Resource Rider ("GRR"). The GRR was merely a placeholder and set it at $0. However, because AEP Ohio provided an estimate of $8 million[12] in potential costs that may eventually be included in the GRR over the approximately two-year ESP period, the Commission included $8 million in the ESP v. MRO analysis. *ESP 2 Case* (Opinion and Order at 75) (Aug. 8, 2012), IEU App. at 98. The Commission's decision to include only the GRR costs that would occur during the ESP term was reasonable and consistent with its analysis of other quantifiable costs of the ESP. Although IEU disagrees with the Commission's decision, the Commission ultimately determined that there is currently no need for the Turning Point facility as discussed below in Proposition of Law No. IV. *ESP 2 Case* (Entry on Rehearing at 8) (Jan. 30, 2013), IEU App. at 114. Consequently, the Commission potentially overstated the ESP costs by $8 million by including the costs of Turning Point facility. IEU has therefore suffered no prejudice. *Id.*

**3. The Commission's decision to exclude the costs of the Pool Termination Rider was reasonable because these costs are highly speculative and may never occur. [IEU 1(2)(b)]**

The Commission established another placeholder rider, the pool termination rider ("PTR"), that was also set at $0. *ESP 2 Case* (Opinion and Order at 49) (Aug. 8, 2012), IEU App. at 72. AEP Ohio can only seek recovery through the PTR if the Commission modifies provisions of AEP Ohio's corporate separation plan that relate to divestiture of

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12 The $8 million related to the potential costs of the proposed Turning Point solar facility project that would, if approved, occur during the two-year ESP period. IEU wanted the Commission to include an estimate of the 25-year lifetime costs of the facility.

AEP Ohio's generation assets. *Id.* In addition, even if the Commission modified AEP Ohio's corporate separation plan, a number of preconditions must be met before AEP Ohio can recover any funds through the PTR.[13] Because it was impossible to know when or if AEP Ohio will ever recover any funds through the PTR, the Commission logically excluded the speculative costs related to the PTR in its quantitative analysis.

**4. The Commission's decision to exclude the capacity deferral was reasonable because these costs are unknown and depend on the amount of shopping that will occur over the term of the ESP. [IEU 1(2)(b)]**

The Commission excluded the amount of the deferral created in the *Capacity Case* from its ESP v. MRO analysis. It is impossible to know what the deferral amount will actually be because it depends on the amount of customer shopping that occurs during the ESP term. *ESP 2 Case* (Opinion and Order at 36, 76) (Aug. 8, 2012), IEU App. at 59, 99; *Id.* (Entry on Rehearing at 8-9) (Jan. 30, 2013), IEU App. at 114-115. Although one could speculate about this amount, the Commission rightfully refused to do so.

Further, excluding the $144 million set-aside from the RSR was consistent with the Commission's decision in the *Capacity Case*. The deferral arises from the $188.88/MW-day capacity charge the Commission established in the *Capacity Case*. As

13 The Commission stated that if AEP Ohio seeks recovery under the PTR, it must (1) "demonstrate the extent to which the Pool Agreement benefitted Ohio ratepayers over the long-term and the extent to which the costs and/or revenues should be allocated to Ohio ratepayers" and (2) "demonstrate to the Commission that any recovery it seeks under the PTR is based upon costs which were prudently incurred and are reasonable." *ESP 2 Case* (Opinion and Order at 49) (Aug. 8, 2012), IEU App. at 72.

discussed above, because the same capacity costs would apply under both the ESP and the MRO, it was reasonable for the Commission to apply the portion of the RSR that is being deferred to pay the $188.88/MW-day capacity costs to both the ESP and the MRO.

### 5. The Commission's decision to apply the ESP v. MRO price test for the period between June 1, 2013 and May 31, 2015 was reasonable. [IEU 1(2)(b)]

To accurately compare the ESP to the results of an MRO, the Commission set the time period of the statutory price test as June 1, 2013 through May 31, 2015. *ESP 2 Case* (Opinion and Order at 73-74) (Aug. 8, 2012), IEU App. at 96-97. The Commission based this decision upon the language of R.C. 4928.143(A)(1), which states that the ESP must be "compared to the expected results that would otherwise apply under Section 4928.142 of the Revised Code [the MRO statute]." *Id.* Under an MRO, AEP Ohio would need to implement a competitive bidding process, which would take approximately 10 months. *Id.* at 74, IEU App. at 97. Because June 1, 2013 was a realistic target date for an auction, the Commission decided to start the statutory price comparison on June 1, 2013. This resulted in a more realistic and accurate ESP v. MRO comparison.

IEU argues that the Commission should have used potential MRO results from a time period that had already elapsed when the Commission issued its order. IEU Merit Brief at 19-20. This would have resulted in a less reliable price comparison by including MRO market results from dates that had already passed. The Commission's decision was reasonable based upon its interpretation of R.C. 4928.143(C)(1) and R.C. 4928.142(A)(1). *Consumers' Counsel v. Pub. Util. Comm.*, 111 Ohio St.3d 300, 2006-Ohio-5789, ¶ 69. IEU, on the other hand, merely provides a conclusory opinion that the Commission should have done it another way. IEU cites no statute or case law suggesting that the Commission's decision was unlawful. Without more, IEU's argument must fail.

### D. The Commission met the requirements of R.C. 4903.09 by identifying the qualitative benefits of the ESP and discussing why these benefits made the ESP more favorable than the MRO. [IEU 1(1)]

The purpose of R.C. 4903.09 is "to enable th[e] court to review the action of the commission without reading the voluminous records" involved with Commission cases. *MCI Telecommunications Corp. v. Pub. Util. Comm.*, 32 Ohio St.3d 306, 311, 513 N.E.2d 337 (1987) quoting *Commercial Motor Freight, Inc. v. Pub. Util. Comm.*, 156 Ohio St. 360, 363, 102 N.E.2d 842, 844-845 (1951). The Court has stated that strict compliance with the terms of the statute is not required. *Tongren v. Pub. Util. Comm.*, 85 Ohio St.3d 87, 89, 706 N.E.2d 1255, 1257 (1999); *Payphone Ass'n v. Pub. Util. Comm.*, 109 Ohio St.3d 45, 2006-Ohio-2988, ¶ 32 ("The detail need be sufficient only for th[e] court to determine the basis of the PUCO's reasoning."). R.C. 4903.09 simply requires that the Commission provide "some factual basis and reasoning based thereon in reaching its conclusion." *Tongren v. Pub. Util. Comm.*, 85 Ohio St.3d 87, 89, 706 N.E.2d 1255, 1257 (1999); *Payphone Ass'n v. Pub. Util. Comm.*, 109 Ohio St.3d 45, 2006-Ohio-2988, ¶ 32.

In this case, the Commission properly considered and discussed the "non-quantitative" benefits that make the ESP more favorable than the MRO. *ESP 2 Case* (Opinion and Order at 75-77) (Aug. 8, 2012), IEU App. at 98-100; *Id.* (Entry on Rehearing at 9-12) (Jan. 30, 2013), IEU App. at 115-118. The Commission is not required to "explain its math" regarding "non-quantitative benefits" because, as the name suggests, these benefits cannot be quantified. That does not mean, however, that these benefits are not valuable. The Commission identified the qualitative benefits of the ESP and the evidence it relied upon. It explained why it believed these benefits were valuable. FES and IEU may disagree with the Commission's conclusion but the General Assembly has authorized the Commission to consider benefits that cannot be measured "mathematically" or evaluated simply using strict price comparisons. This is exactly why R.C. 4928.143(C)(1) allows the Commission to consider "pricing and *all other terms and conditions*" of the ESP. *In re Columbus S. Power Co.*, 128 Ohio St.3d 402, 2011-Ohio-958, ¶ 27.

**Proposition of Law No. II:**

> **The Commission's decision approving the Rate Stability Rider (RSR) was reasonable, lawful, and adequately supported by the evidence of record.**

**A. The Retail Stability Rider is authorized by R.C. 4928.143(B)(2)(d). [FES 2(1), IEU 2(2), OCC 3]**

The Commission found that the Rate Stability Rider (RSR) satisfied the provisions of R.C. 4928.143(B)(2)(d), which provides that an ESP may provide for:

> 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.

The statutory language is extremely broad, and affords the Commission considerable latitude in authorizing allowable charges. The statute requires three distinct inquiries, and the Commission found, as a matter of fact, that all three were met.

First, the RSR must be a term, condition, or charge. The Commission found that "the RSR is indeed a charge, meeting the first component of the statute." *ESP 2 Case* (Entry on Rehearing at 15) (Jan. 30, 2013), IEU App. at 121.

Second, it must relate 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." The Commission found that, because the "SSO is the default service plan for AEP Ohio customers who choose not to shop, the RSR meets the second inquiry of the statute as it provides a charge related to default service." *Id.*

OCC argues that "default service" is legislatively defined in R.C. 4928.14 as "the provision of service by the utility where the non-utility supplier (marketer) fails to provide service to customers." OCC Merit Brief at 22. A simple reading of R.C. 4928.14, however, demonstrates that the phrase "default service" does not, in fact, even appear there.[14] The Commission acknowledges that default service certainly relates to a utility's obligation to serve as the provider of last resort (POLR). But that is not the same as saying that charges intended to provide financial stability must be justified as actual costs to serve as the provider of last resort. These are not POLR costs.[15]

OCC's argument that "[d]efault service does not mean standard service" is without basis. OCC Merit Brief at 24. A standard service offer is a default service that must be offered to current and future non-shopping customers during the entire ESP term. The RSR clearly relates to default service.

The argument that any charge that relates to standard service could then be included in an SSO is also without merit. The statute requires that any such charge must "have the effect of stabilizing or providing certainty regarding retail electric service." R.C. 4928.143(B)(2)(d), App. at 21. The Commission found, as a matter of fact, that the RSR promotes retail stability and certainty "by stabilizing base generation costs at their current rates, ensuring customers have certain and fixed rates going forward." *ESP 2 Case* (Entry on Rehearing at 16) (Jan. 30, 2013), IEU App. at 122.

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14 R.C. 4928.14 defines when a supplier can be deemed to have failed to provide retail electric generation service. The statute merely states that such failure "shall result in the supplier's customer . . . defaulting to the utility's standard service offer." R.C. 4928.14, App. at 15-16. It could hardly be clearer that the General Assembly intended that the SSO be the "default service" referenced in R.C. 4928.143(B)(2)(d).

15 IEU also argues the Commission essentially treats the RSR as a POLR charge, but that it does not satisfy the Court's requirements for such a charge. Even IEU acknowledges, however, that the RSR does not recover AEP Ohio's cost of satisfying a POLR obligation. IEU Merit Brief at 28.

The RSR freezes any non-fuel generation rate increase that might not otherwise occur absent the RSR, allowing current customer rates to remain stable throughout the term of the modified ESP. *ESP 2 Case* (Opinion and Order at 31) (Aug. 8, 2012), IEU App. at 54. The ability for all customers to have the option to return to AEP Ohio's certain and fixed rates allows customers to explore shopping opportunities. *ESP 2 Case* (Opinion and Order at 32) (Aug. 8, 2012), IEU App. at 55. Most importantly, inclusion of the RSR guarantees that pricing will be based on energy and capacity auctions in less than three years. *Id.* All of these factors were relied on by the Commission in making its determination.

IEU argues that the Commission's rationale was limited to *rate* stability rather than *service* stability, and that the rider was therefore improperly approved.[16] IEU Merit Brief at 25. But there is no justification for the claim that the "the General Assembly made clear that the charges that could be authorized under R.C. 4928.143(B)(2)(d) were to assure that *physical supply* of electricity would be made *more* stable and certain." *Id.* at 26. The statute does not limit stability or certainty to physical delivery. Indeed, the statute specifies that carrying charges, amortization periods, and accounting deferrals can all have the effect of providing stability and certainty. Since none of these have anything

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16 FES argues precisely the opposite. FES argues that the very fact that the RSR increases *rates* indicates that it does not provide stability. FES Merit Brief at 16. The Commission found that such increases, however, could be mitigated by increase shopping opportunities. *ESP 2 Case* (Opinion and Order at 31) (Aug. 8, 2012), IEU App. at 54. While FES disagrees, the Commission's factual finding is entitled to considerable deference.

to do with the physical supply of service, IEU's interpretation is too restrictive. Price and rate stability both affect the certainty of retail service. To read the statute otherwise would render it meaningless.

Nor does R.C. 4928.143(B)(2)(d) require that charges make retail electric service *more* stable or certain. The statute authorizes charges that "would have the effect of" stabilizing or providing certainty regarding retail electric service. R.C. 4928.143(B)(2)(d), App. at 21. Charges may have the effect of stabilizing or providing certainty regarding service without making the service more certain or probable. IEU asks the Court to require a threshold that the General Assembly simply did not mandate under R.C. 4928.143(B)(2)(d).

OCC's claim that any such benefits must be provided directly by virtue of the charge, and not indirectly is equally without merit. Since the Commission's analysis hinges on the indirect effect that the RSR has on the ESP as a whole, asserts OCC, the statutory test is not met. The statute, of course, does not specify that the effect stabilizing or providing certainty must occur *directly*. As the Commission noted that many of the benefits of the ESP could not be realized absent the RSR, the RSR has the effect of stabilizing or providing certainty regarding retail electric service. That is all the statute requires.

### B. The inclusion of *Capacity Case* deferral costs in the RSR is permitted by statute, and facilitates state policy. [IEU 2(5), IEU 2(4), IEU 4, OEG 1]

The issue of whether the Commission had such authority to determine AEP Ohio's capacity costs is the subject of another case[17] pending before this Court, and the Commission has fully set forth its position in that case. That issue is not properly before the Court here.

IEU argues that the collection of deferred capacity costs is unlawful because the Commission lacked authority to determine those costs in the first instance. Because the Commission has argued that it had the authority to determine capacity costs properly recoverable by AEP Ohio, it logically follows that it had the authority to permit the recovery of those revenues deferred to the ESP case.

The Commission determined, as a matter of fact, that:

> The inclusion of the deferral, which is justified by Section 4909.15, Revised Code, within the RSR is permissible by Section 4928.143, Revised Code, as it has the effect of providing certainty for retail electric service by allowing CRES suppliers to purchase capacity at market prices while allowing AEP Ohio to continue to offer reasonably priced electric service to customers who choose not to shop.

*ESP 2 Case* (Entry on Rehearing at 17) (Jan. 30, 2013), IEU App. at 123. The Commission further determined that it was appropriate, given the importance of developing com-

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17 Industrial Energy Users-Ohio v. Pub. Util. Comm., Case Nos. 2013-0228, 2012-2098.

petitive electric markets, to begin recovery of deferred capacity costs as part of the RSR mechanism. *ESP 2 Case* (Opinion and Order at 36) (Aug. 8, 2012), IEU App. at 59.

IEU further argues that the capacity charge is not authorized under sections 4928.141 to 4928.143, and that only such charges can be phased in under R.C. 4928.144. The Commission has demonstrated above that it had the authority to adopt the RSR pursuant to R.C. 4928.143(B)(2)(d). Because the RSR is permitted under the ESP statute, the Court should reject this argument on the same grounds.

Nor is there merit to OEG's assertion that the Commission lacked authority to approve recovery of wholesale costs from retail customers. OEG Merit Brief at 12. Even though the capacity deferrals relate to a wholesale service, and regardless of whether the service is considered competitive or noncompetitive, the capacity deferrals can be recovered through a retail charge adopted in an ESP. Wholesale costs are routinely, and indeed must be, recovered through retail rates. FERC-approved cost recovery, for example, must be recognized in retail rates. See e.g., *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 966 (1986); *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982). AEP Ohio's Fuel Adjustment Clause, which recovers the cost of fuel and purchased power, includes wholesale costs. There is simply no basis to assert that ESP rates cannot include wholesale costs. Deferring recovery of wholesale costs under R.C. 4928.144 is entirely permissible.

### C. The RSR is not unduly discriminatory and does not constitute an unlawful or unreasonable subsidy.

The Commission found that the RSR is not discriminatory and is permissible under 4928.143(B)(2)(d). Furthermore, it found that all customers benefit, whether they shop or not. *ESP 2 Case* (Opinion and Order at 37) (Aug. 8, 2012), IEU App. at 60; *Id.* (Entry on Rehearing at 19) (Jan. 30, 2013), IEU App. at 125.

#### 1. Because the Commission's order benefits both shopping and non-shopping customers while appropriately compensating AEP Ohio, it was appropriate to approve the RSR as a non-bypassable charge [FES 1(2)(c), IEU 2(1), IEU 2(5), IEU 5, OCC 1, OEG 1]

The Commission found that all customers, both shopping and non-shopping, would benefit from the RSR, and that it was therefore appropriate to make it non-bypassable. For non-shopping customers, the order provides rate stability and certainty, and ensures all SSO rates will be market-based by June 2015. *ESP 2 Case* (Opinion and Order at 37) (Aug. 8, 2012), IEU App. at 60. For shopping customers, the order makes available reasonably-priced SSO[18], even in the event market prices increase, and it also enables CRES providers to provide offers tied to current market prices, which is a benefit for shopping customers. *Id.* All customers have the ability to shop and return at fixed base generation rates. *Id.* at 36, IEU App. at 59. Stable rates throughout the ESP period, while accelerating the final movement to a competitive market, will allow all customers

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18 The SSO provides market discipline for the kinds of offers that competitors put forward.

to realize savings that may otherwise not have been available. *Id.* at 36-37, IEU App. at 59-60. Because all customers will benefit, the Commission determined that all customers should share in the charge, and approved the RSR as a non-bypassable rider. *Id.* at 37, IEU App. at 60.

IEU claims that R.C. 4928.143(B)(2) only permits non-bypassable charges in two instances: paragraphs (b) and (c). Since paragraph (d) does not include such a specific provision, it argues, the Commission may not approve a rider under that subsection as non-bypassable. IEU Merit Brief at 24. But nothing in R.C. 4928.143(B)(2)(d), nor in any other provision in Chapter 4928, prohibits the Commission from approving the RSR on a non-bypassable basis. This is not a situation where the doctrine of *inclusio unius est exclusion alterius* applies. Both paragraph (b) and (c) *require*, rather than merely permit, the surcharges authorized by those subsections to be non-bypassable. There is neither proscription nor restriction contained in paragraph (d), and the Commission properly determined that non-bypassability was appropriate.[19]

This Court has frequently acknowledged that decisions about how rates are designed – including which customers pay and under what circumstances – are matters within the discretion of the Commission. *Green Cove Resort Owners' Ass'n. v. Pub. Util. Comm.*, 103 Ohio St.3d 125, 2004-Ohio-4774, ¶ 21 (recognizing the Commission's

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19 It also claims that making these charges nonbypassable violates state policy, as interpreted by the Commission, relying on a Commission order holding that R.C. 4928.02 (H) prohibits non-bypassable charges that are designed to collect generation-related costs. IEU's reliance is misplaced. The Commission's decision in this case was made on the basis of R.C. 4928.02(B)(2)(d), not R.C. 4928.02(H).

"unique rate design expertise"); *Citywide Coalition for Util. Reform v. Pub. Util. Comm.*, 67 38 Ohio St.3d 531, 533 (1993) (the Court affords the Commission "considerable discretion" in matters of rate design). R.C. 4928.143(B)(2)(d) allows for the establishment of terms, conditions, or charges relating to limitations on customer shopping for retail generation service, as well as accounting or deferrals, so long as they would have the effect of stabilizing or providing certainty regarding retail electric service.

Appellants' claims that the RSR over-compensates AEP Ohio fail to consider the actual construct of the $188.88/MW-day capacity price, as the deferral established in the *Capacity Case* will not be booked as a revenue during the deferral period. *ESP 2 Case* (Entry on Rehearing at 22-23) (Jan. 30, 2013), IEU App. at 128-129, citing, *Capacity Case* (Opinion and Order) (Jul. 2, 2012), IEU Supp. at 234-278. But the revenue that AEP Ohio will collect for capacity is limited to only the RPM price of capacity. *ESP 2 Case* (Entry on Rehearing at 23) (Jan. 30, 2013), IEU App. at 129. Therefore, all assertions made about AEP Ohio receiving sufficient revenue from the capacity deferral alone are wrong. *Id.* The RSR provides for stability and certainty for AEP Ohio's non-shopping customer prices, while the deferral relates to capacity for which customers only pay once. *Id.*

Furthermore, the $188.88-RPM differential from AEP Ohio's costs is funded by all customers because all customers benefit from the opportunity to shop afforded by RPM-priced capacity. *Capacity Case* (Opinion and Order at 23) (Jul. 2, 2012), IEU Supp. at 256. And it is reasonable for all customers, whether they shop or not, to fund the

$188.88/RPM differential because all customers are benefiting from the associated capacity.

The Commission found that "as a result of the Capacity Case, customers may be able to lower their bill impacts by taking advantage of CRES offers allowing customers to realize savings that may not have otherwise occurred without the development of a competitive market." *ESP 2 Case* (Opinion and Order at 76) (Aug. 8, 2012), IEU App. at 99. The Commission further determined that the RSR, including the capacity deferrals, enabled all of AEP Ohio's customers to receive substantial and valuable benefits that would not otherwise be achieved:

> [W]hile the RSR and the inclusion of the deferral within the RSR are the most significant cost associated with the modified ESP, but for the RSR it would be impossible for AEP Ohio to completely participate in full energy and capacity based auctions beginning in June 1, 2015. Although the decision for AEP Ohio to transition towards competitive market pricing is something this Commission strongly supports and the General Assembly anticipated in enacting Senate Bill 221, the fact remains that the decision to move towards competitive market pricing is voluntary under the statute and in the event this ESP is withdrawn or even replaced with an MRO, there is no doubt that AEP Ohio would not be fully engaged in the competitive marketplace by June 1, 2015.

*Id.* at 76, IEU App. at 99. As the Commission has factually determined, the creation of the capacity deferrals is intended to benefit all AEP Ohio customers, not just shopping customers or CRES providers. Any claims of discriminatory treatment towards non-shopping customers are without merit.

OEG argues that capacity costs cannot be approved in an ESP. However, under R.C. 4928.143(B)(2)(d) the Commission is authorized to establish charges that would have the effect of stabilizing retail electric service. *ESP 2 Case* (Entry on Rehearing at 18) (Jan. 30, 2013), IEU App. at 124. The Commission has explicit statutory authority to include these costs in the RSR because the costs provide CRES providers access to capacity at market prices in order to provide competitive offers to AEP Ohio customers. *Id.* OEG's claim should be rejected.

### 2. Shopping customers, CRES providers, and non-shopping customers are not similarly situated. [IEU 5, OCC 1]

The Commission's order is not discriminatory. It is well established that Ohio law "does not prohibit rate discrimination *per se*; rather, it prohibits charging different rates when the utility is performing *** a like and contemporaneous service under substantially the same circumstances and conditions." *Consumers' Counsel v. Pub. Util. Comm.*, 109 Ohio St.3d 328, 2006- Ohio-2110, 847 N.E.2d 1184, ¶ 23, *quoting AK Steel Corp. v. Pub. Util. Comm.*, 95 Ohio St.3d 81, 86-87, 2002-Ohio-1735, 765 N.E.2d 862 and *Mahoning Cty. Twps. v. Pub. Util. Comm.*, 58 Ohio St.2d 40, 43-44, 388 N.E.2d 739 (1979). Discriminatory pricing is prohibited only for "like and contemporaneous service" rendered "under substantially the same circumstances and conditions." If, however, "the utility services rendered to customers are different or if they are rendered under different circumstances or conditions, differences in the prices charged and collected are not proscribed ...." *Weiss v. Pub. Util. Comm.*, 90 Ohio St.3d 15, 16, 734 NE 2d 775 (2000). Similarly, although a utility is prohibited from giving "undue or unreasonable" preference, Ohio law "does not prohibit all preferences, advantages, prejudices, or disadvantages – only those that are undue or unreasonable." *Id.* at 15-17. "Thus, a discriminatory classification is not prohibited if it is reasonable." *Id.* at 16. For example, if the utility services rendered to similarly situated customers are different, or if they are rendered under different circumstances or conditions, then differences in the prices charged and collected are not proscribed. *Id.*

In this case, both services are different – AEP Ohio supplies CRES providers in a *wholesale* transaction with capacity and it provides SSO base generation service that includes more than simply capacity to non-shopping customers in a *retail* transaction. The services are also rendered under different circumstances: to CRES providers for resale, on the one hand, versus to non-shopping customers as one component of a larger, negotiated, rate for electric service, on the other hand. In other words, CRES providers are not similarly situated with shopping and non-shopping retail customers. Appellants' claim that SSO base generation rates result in discriminatory pricing of capacity lacks merit.

#### 3. The Commission's order does not create cross-subsidies to AEP Ohio's generation affiliate (GenResources). [FES 4]

AEP Ohio, as an FRR entity, must provide adequate capacity to both its own customers and to CRES providers even after corporate separation. *ESP 2 Case* (Entry on Rehearing at 26) (Jan. 30, 2013), IEU App. at 132. For AEP Ohio to continue to meet its FRR obligations, it must be permitted to recover its actual cost of capacity through the RSR to enable AEP Ohio to begin paying off its capacity deferral. *Id.* AEP Ohio's generation affiliate is not receiving an improper subsidy. To the contrary, it receives only its actual cost of providing the service. *ESP 2 Case* (Opinion and Order at 60) (Aug. 8, 2012), IEU App. at 83. As explained above, actual costs were properly determined in the *Capacity Case*. The Commission must, under R.C. 4905.22, ensure that all charges for service are just and reasonable and in accord with orders of the Commission. *Capacity Case* (Entry on Rehearing at 28) (Oct. 17, 2012), App. at 40. The Commission has exclusive initial jurisdiction over a public utility's rates and charges. *State ex rel. Columbus S. Power Co. v. Fais*, 117 Ohio St.3d 340, 2008-Ohio-849.

Furthermore, there is a cost for AEP Ohio to provide capacity for shopping load. Evidence adduced in the *Capacity Case* showed that RPM pricing does not compensate AEP Ohio for its capacity. The State Compensation Mechanism ("SCM") approved by the Commission in the *Capacity Case* relieves AEP Ohio from providing the use of its assets at a rate below its costs, and avoids a confiscation issue.

#### 4. The RSR does not result in impermissible subsidies within customer classes. [Kroger 1]

Kroger's argument that the Commission failed to address its issue regarding whether the RSR should be structured as a demand charge for demand-billed customers is without merit. Kroger claims that customers with high load factors will subsidize low load factor customers.

In approving the rate design of the RSR, the Commission noted that all customers would benefit from the charge. Furthermore, the Commission found, as a matter of fact, that those benefits would be diminished if it adopted the rate design advocated by Kroger.

Specifically, the Commission found that "smaller commercial and industrial customers would face an undue burden of the RSR" if costs were recovered on a demand- rather than an energy-basis. *ESP 2 Case* (Entry on Rehearing at 25) (Jan. 30, 2013), IEU App. at 131. In the Commission's opinion, recovery on an energy-basis by customer class would appropriately spread costs among all customers, as all customers would benefit from the charge. *Id.* at 26, IEU App. at 132. The Court should not second-guess the Commission's expertise with respect to rate design matters. *See e.g. Consumers' Counsel v. Pub. Util. Comm.*, 125 Ohio St.3d 57, 2010-Ohio-134, ¶ 11; *AT&T Communications of Ohio v. Pub. Util. Comm.*, 51 Ohio St.3d 150, 154 (1990).

### D. The Commission has not authorized the receipt of transition revenues or any equivalent revenues by an electric utility except as expressly authorized in R.C. 4928.31 to 4928.40, and it has not done so. R.C. 4928.38, App. at 34. [IEU 3, OCC 2]

Appellants IEU and OCC claims that the Commission has authorized the collection of transition revenues in violation of R.C. 4928.38. Appellants are incorrect.

To the extent that Appellants' arguments claim that the costs determined in the *Capacity Case* constitute transition costs, that issue was dealt with in that earlier case, and was raised in that appeal, currently pending before the Court.[20] The Commission's analysis in that case is, however, equally applicable here.

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20 Industrial Energy Users-Ohio v. Pub. Util. Comm., Case Nos. 2013-0228, 2012-2098.

Transition revenues were a facet of the restructuring that occurred in 2000 when electricity competition was first permitted in Ohio. The then-existing rates were to be broken up, "unbundled", into components: transmission, distribution, and generation. R.C. 4928.34(A), App. at 28. Customers who chose to purchase power from an alternative supplier would no longer pay the generation component of their bill to the electric distribution utility ("EDU").

The General Assembly recognized that this system would allow shopping customers to avoid paying what were termed "stranded costs." These were the amounts invested by the EDUs in reliance upon the continuation of a regulated market for electricity which the EDUs would not be able to recoup from retail customers in the new, unregulated electricity market. To remedy this problem, the General Assembly authorized the Commission to identify amounts that might be stranded, terming them "transition costs," and allowing the imposition of "transition charges" on retail customers to collect them. R.C. 4928.37, 4928.39, App. at 32-34, 34-35. 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. Thus, the EDU's investment would not be stranded and it would have an "...opportunity to receive transition revenues that may assist it in making the transition to a fully competitive retail electric generation market." R.C. 4928.37(A), App. at 32-33. The end result was that a shopping customer would avoid paying the generation charge but would see a portion of this back in the form of a transition charge.

None of the above had anything to do with AEP Ohio, either then or now. The AEP Ohio EDUs[21] neither sought, nor received, authorization to impose a transition charge during the restructuring process.[22]

Nor has AEP Ohio made any claim that it has not or could not recover its stranded costs during or since the market development period. The Commission specifically noted that AEP Ohio had not argued that its Electric Transition Plan ("ETP") did not provide it with sufficient revenues. *ESP 2 Case* (Opinion and Order at 32) (Aug. 8, 2012), IEU App. at 55.

The proceeding below involved a 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. The ETP cases were retail rate-making cases, and have no bearing on a wholesale capacity rate charged to CRES providers. 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.

The Commission rejected the claim that the RSR allows for the collection of inappropriate transition revenues or stranded costs that should have been collected prior to

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21 There were two at the time, Ohio Power Company and the Columbus Southern Power Company. These have subsequently been merged.

22 Per statute, transition charges were tacitly included in the unbundled rates that the non-shopping customers continued to pay. R.C. 4928.37(A)(1)(b), App. at 33. This had little meaning for the non-shopping customers as their overall rates did not change.

December 2010 pursuant to SB 3. It found that AEP Ohio did not seek transition revenues below, and that costs associated with the RSR are permissible in light of AEP Ohio's status as an FRR entity. *ESP 2 Case* (Entry on Rehearing at 21) (Jan. 30, 2013), IEU App. at 127. The case below had nothing to do with transition costs. As the Commission stated in the *Capacity Case*:

> As previously discussed, the Commission does not believe that AEP Ohio's capacity costs fall within the category of transition costs. Section 4928.39, Revised Code, defines transition costs as costs that, among meeting other criteria, are directly assignable or allocable to retail electric generation service provided to electric consumers in this state. As we have determined, AEP Ohio's provision of capacity to CRES providers is not a retail electric service as defined by Section 4928.01(A)(27), Revised Code. It is a wholesale transaction between AEP Ohio and CRES providers.

*Capacity Case* (Entry on Rehearing at 56-57) (Oct. 17, 2012), App. at 45-46. The claim that the charges set below are "transition charges" has no basis whatsoever.

### E. The calculation of the RSR is adequately supported by the record [FES 2(3)]

The Commission did not adopt the Companies' RSR as proposed. It found that the Companies failed to adequately justify the revenue targets that the RSR was intended to reach. Instead, the Commission significantly reduced the levels requested by the Companies, but found that its determined levels were adequate to ensure that AEP Ohio could keep its base generation rates frozen, and still maintain its financial health. *ESP 2 Case* (Opinion and Order at 32-33) (Aug. 8, 2012), IEU App. at 55-56.

FES argues that there is insufficient evidence to support the revenue target. It argues that there is no evidence that AEP Ohio needs revenue to protect its financial integrity, or that the RSR level determined by the Commission is the minimum amount required to do so. FES Merit Brief at 22-23.

The Court stated that it "will not reverse or modify a determination unless it is manifestly against the weight of the evidence and so clearly unsupported by the record as to show misapprehension, mistake, or willful disregard of duty." *Ohio Partners for Affordable Energy v. Pub. Util. Comm.*, 115 Ohio St.3d 208, 210, 2007-Ohio-4790, 874 N.E.2d 764, 767, ¶ 10; *Monongahela Power Co. v. Pub. Util. Comm.*, 104 Ohio St.3d 571, 577-578, 2004-Ohio-6896, 820 N.E.2d 921, 927, ¶ 29. The appellant bears the burden of demonstrating that the Commission's decision is against the manifest weight of the evidence or is clearly unsupported by the record. *AK Steel Corp. v. Pub. Util. Comm'n*, 95 Ohio St.3d 81, 2002-Ohio-1735, 765 N.E.2d 862, 867. FES has not met that burden in this appeal.

The Commission relied on evidence that included reasonable rates of return, anticipated levels of customer shopping, and anticipated revenues from capacity and off-system sales to establish a revenue benchmark – not an earnings guarantee – for the RSR. *ESP 2 Case* (Opinion and Order at 32-33) (Aug. 8, 2012), IEU App. at 55-56. Specifically, the Commission analyzed the testimony of three expert witnesses, representing three different parties, exploring how an appropriate revenue target for the RSR should be established. Finding all three credible, the Commission defined a "zone of reasonableness," and established the midpoint as a benchmark. It then adjusted that figure to account for projected shopping levels offered both by a Company witness and several FES exhibits, among other factors, to arrive at an appropriate RSR target. *Id.* The calculation made by the Commission is reasonable and amply supported by the evidence of record, and should not be disturbed.

**Proposition of Law No. III:**

> **IEU rehashes its arguments from the *Capacity Case* appeal by challenging the Commission's decision to approve a cost-based capacity rate. IEU Merit Brief at 38; *see also,* Ohio Supreme Court Case No. 2013-0228 (IEU First Merit Brief filed July 15, 2013). The Commission's decision in the *Capacity Case* was lawful.**

The Commission initiated the capacity investigation pursuant to R.C. 4905.26 to review and determine if AEP Ohio's proposed change to its capacity charge was reasonable, assess its impact on CRES providers and retail competition, and adopt a state compensation mechanism (SCM). *Capacity Case* (Entry on Rehearing at 9, 28-29, 32) (Oct. 17, 2012), App. at 39, 40-41, 42. This Court has repeatedly held that the Commission has considerable authority under R.C. 4905.26, without compelling the affected utility to apply for a rate increase under R.C. 4909.18, to initiate proceedings to investigate the reasonableness of any rate or charge and impose new utility rates or change existing rates of a public utility. *Consumers' Counsel v. Pub. Util. Comm.*, 110 Ohio St.3d 394, 2006-Ohio-4706, ¶¶ 29, 32; see, e.g., *Lucas Cty. Commrs. v. Pub. Util. Comm.*, 80 Ohio St.3d 344, 347, 686 N.E. 2d 501 (1997). The Commission held a hearing and established a capacity rate that has a wholesale and a retail component, appropriately balancing the Commission's objectives of enabling AEP Ohio to fully recover its capacity costs incurred from carrying out its FRR obligations, while encouraging retail competition in the Company's service territory. *Capacity Case* (Entry on Rehearing at 38-39) (Oct. 17, 2012), App. at 43-44.

The Commission found that it had jurisdiction to establish an SCM pursuant to its general supervisory authority found in R.C. Sections 4905.04, 4905.05, and 4905.06. *Capacity Case* (Opinion and Order at 22) (Jul. 2, 2012), IEU Supp. at 255. Neither R.C. Chapter 4905 nor R.C. 4905.26 prohibits the Commission from initiating a review of a wholesale rate, and the Commission so found. *Capacity Case* (Entry on Rehearing at 9) (Dec. 12, 2012), App. at 39.[23] Further, the Commission can authorize accounting deferrals with carrying charges under R.C. 4905.13 as part of its general jurisdiction over utilities. The Commission has broad supervisory authority under R.C. 4905.13 to authorize both the deferrals and the associated carrying costs.

AEP Ohio's provision of capacity to CRES providers is not a retail service as defined by R.C. 4928.01(A)(27), and it is also noncompetitive. The Commission has jurisdiction to establish a cost-based rate for a noncompetitive capacity service that is provided only within the service territory of AEP Ohio, and only rendered by AEP Ohio, a utility regulated by the Commission.

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23 Any limitation on the Commission's ability to review wholesale rates would arise from federal pre-emption but there is no pre-emption. The FERC has examined the Commission's action and adopted that action as its own. In the event the Court decides that the Commission's decision in the *Capacity Case* is properly a subject of this appeal, the Commission incorporates by reference the relevant portions of its September 23, 2013 merit brief in Case Nos. 2012-2098 as if set forth fully herein.

The Commission's adoption of a SCM is not preempted by federal law. Based on R.C. Chapter 4905, in combination with the Commission exercising an option FERC authorized in the Reliability Assurance Agreement ("RAA") for it to adopt an SCM, the Commission had authority, not preempted by federal law, to create a hybrid mechanism to reasonably compensate AEP Ohio for its capacity resources. The Commission's sole purpose in exercising jurisdiction in this case was to establish an appropriate SCM. *Capacity Case* (Opinion and Order at 13) (Jul. 2, 2012), IEU App. at 36; *Id.* (Entry on Rehearing at 28) (Oct. 17, 2 012), App. at 40. The Commission's adoption of an SCM for AEP Ohio was well within the bounds of its broad authority pursuant to R.C. 4905.04, 4905.05, and 4905.06. *Capacity Case* (Entry on Rehearing at 9) (Oct. 17, 2012), App. at 39.

Further, R.C. 4928.143(B)(2)(d) allows for the establishment of terms, conditions, or charges relating to limitations on customer shopping for retail generation service, as well as accounting or deferrals, so long as they would have the effect of stabilizing or providing certainty regarding retail electric service. Therefore, the inclusion of the deferral, which is justified by R.C. 4905.13, within the RSR is permissible by R.C. 4928.143 as it has the effect of providing certainty for retail electric service by allowing CRES suppliers to purchase capacity at market prices while allowing AEP Ohio to continue to offer reasonably priced electric service to customers who choose not to shop.

**Proposition of Law No. IV:**

> **The Commission is authorized to establish a non-bypassable charge for recovery of costs of a generating plant owned by an EDU. R.C. 4928.143(B)(2)(c), App. at 21. [FES 3, IEU 2(3)]**

The General Assembly has authorized the Commission to approve ESPs that establish non-bypassable charges related to EDU generating assets where certain statutory criteria are met. R.C. 4928.143(B)((2)(c), App. at 21. The Generation Recovery Rider ("GRR") does exactly this. As there were no plants which met the statutory criteria, the GRR rate is $0. *ESP 2 Case* (Opinion and Order at 23-25) (Aug. 8, 2012), IEU App. at 46-48. In the event that AEP Ohio believes it has generating plant that would meet the statutory criteria for inclusion in the GRR at some point in the future, it can apply to the Commission and there will then be a proceeding to determine whether those criteria have been met and an actual charge should be imposed. This is exactly as it should be. A GRR can only be established as part of an ESP, and it has been here. It will be available should the need arise. All interested parties will have the opportunity to participate in a proceeding to determine whether the there is a plant which meets the statutory criteria. The interests of all parties are protected and the statutes have been fulfilled.

IEU is adamantly opposed to an AEP Ohio generating project called Turning Point. The Commission did not approve, indeed it was not even asked to approve, Turning Point in this case. *Id.* IEU wants this Court to pre-judge a future, hypothetical application for the Turning Point project. If such an application is filed, IEU will have its hearing. If the Commission authorizes an actual amount to be charged through the GRR after that proceeding, parties will be able to bring an actual controversy to this Court. At this time Turning Point has not been approved, the charge is $0 and, thus, IEU is seeking a purely advisory opinion about what the Commission should do with a future, hypothetical application. This Court does not issue advisory opinions and IEU cannot be harmed as the charge is $0. Appeal lies only on behalf of a party aggrieved by the final order appealed from. Appeals are not allowed for the purpose of settling abstract questions, but only to correct errors injuriously affecting the appellant. *Ohio Contract Carriers Ass'n v. Pub. Util. Comm.,* 140 Ohio St. 160, 42 N.E. 2d 758 (1942).[24] The Commission order approving the GRR should be affirmed.

**Proposition of Law No. V:**

> **The Commission's order does not create cross-subsidies to AEP Ohio's generation affiliate (GenResources). [FES 4]**

The Commission must ensure effective competition in the provision of retail service and protect consumers against a utility company acquiring market power under R.C. 4928.02(H) and (I). The Commission is obligated under R.C. 4928.06 to ensure that the policy specified in R.C. 4928.02 is effectuated. The decision below advances competition in AEP Ohio's service territory and FES' claims of anti-competitive cross-subsidy are misguided.

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24 This reasoning applies equally to another rider established in the order, the PTR. This rider is intended to capture costs, if any, associated with the unraveling of AEP's pooling agreement. It has been set at $0 currently. No one can be harmed by establishing a $0 rate. In the event that AEP Ohio makes a request to raise the rate, any interested party will be able to be heard at that point. Until then all that is sought is an advisory opinion and this Court does not issue advisory opinions.

The Court has "recognized the commission's duty and authority to enforce the competition-encouraging statutory scheme of S.B. 3, and we have accorded due deference in this regard to the commission's statutory interpretations and expertise in establishing and modifying rates." *Consumers' Counsel v. Pub. Util. Comm.*, 111 Ohio St.3d 300, 2006-Ohio-5789, 856 N.E.2d 213, ¶ 44, *citing Migden-Ostrander v. Pub. Util. Comm.*, 102 Ohio St.3d 451, 2004-Ohio-3924, 812 N.E.2d 955, ¶ 23. Furthermore, under R.C. 4928.06(E)(1), the Commission is authorized to resolve abuses of market power that interfere with effective competition in the provision of retail electric service.

### A. The Commission does not control the terms of AEP Ohio's future agreement with GenResources.

The specific pass-through costs targeted by FES – RSR revenues, generation-based new revenue, and revenues associated with sales to shopping customers[25] – were discussed in testimony and briefs below. But the contract for the wholesale sale of power between AEP Ohio and GenResources to support the SSO during the ESP term is ultimately subject to FERC approval. *AEP Generation Resources, Inc.*, Docket No. ER13-232-000; *ESP 2 Case* (Opinion and Order at 60) (Aug. 8, 2012), IEU App. at 83. The Commission does not have approval authority over the terms of that agreement and it made this clear when it stated that it did "not make, as part of our review of the Company's modified ESP application, any expressed or implied endorsement of the terms or

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25 Capacity costs were properly approved in the Capacity Case.

conditions of the AEP Ohio contract with GenResources, as presented in this case." *Id.* But the Commission did address AEP Ohio's testimony that detailed the plan for revenue pass-through given that GenResources was stepping into AEP Ohio's shoes to support the SSO during this brief transition period to full corporate separation:

> The Commission finds, that once corporate separation is effective and AEP-Ohio procures its generation from GenResources that it is appropriate and reasonable for certain revenue to pass-through AEP-Ohio to GenResources. Specifically, the revenues AEP-Ohio receives, after corporate separation is implemented, from the RSR which are not allocated to recovery of the deferral, revenue equivalent to the capacity charge [] authorized in Case No. 10-2929-EL-UNC, generation-based revenues from SSO customers, and revenue for energy sales to shopping customers, should flow to GenResources.

*Id.*; *see also ESP 2 Case* (Entry on Rehearing at 65) (Jan. 30, 2013), IEU App. at 171. Hence, the revenue pass-through is simply reimbursement for the services provided by GenResources to support the ESP – and GenResources is only receiving the same revenues approved for collection by AEP-Ohio for rendering those services.

FES' claim that the Commission's order improperly "transfers" these pass-through revenue streams is wrong. While the Commission addressed and resolved the cross-subsidy allegations, the contract between AEP Ohio and GenResources is subject to approval of the FERC and not the Commission.

### B. R.C. 4928.143(B)(2)(a) does not apply.

FES argues that after corporate separation AEP Ohio cannot simply pass through generation revenues it receives without evidence that the costs are prudent under

R.C. 4928.143(B)(2)(a). FES confuses pass-through costs with automatic recovery. R.C. 4928.143(B)(2)(a) applies only to instances of automatic recovery, and has no application to recovery of costs properly approved in an ESP Case or other rate-making/accounting proceedings. R.C. 4928.143(B)(2)(a) states:

> (a) *Automatic recovery of any of the following costs of the electric distribution utility*, provided the cost is prudently incurred: the cost of fuel used to generate the electricity supplied under the offer; the cost of purchased power supplied under the offer, including the cost of energy and capacity, and including purchased power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes;

R.C. 4928.143(B)(2)(a), App. at 20 (emphasis added). Automatic recovery only applies when costs must be reviewed and adjusted in future true-up proceedings. An example is fuel costs, which are adjusted and approved in separate annual true-up proceedings. R.C. 4928.143(B)(2)(a) does not apply to costs that have already been litigated and approved by the Commission. The prudency of the costs/revenue cited by FES – RSR revenues, generation-based new revenue, and revenues associated with sales to shopping customers – have already been reviewed and approved by the Commission. Energy costs were approved in the ESP 2 proceeding below and capacity costs were approved in the *Capacity Case*. *Capacity Case* (Opinion and Order) (Jul. 2, 2012), IEU Supp. at 234-278. Therefore, R.C. 4928.143(B)(2)(a) does not apply and FES' arguments have should be rejected.

**Proposition of Law No. VI:**

**The Commission has fully considered AEP Ohio's corporate separation plan in several cases and IEU was afforded ample opportunity to challenge that plan.**

IEU challenges various aspects of the Commission's authority regarding AEP Ohio's corporate separation in the ESP 2 proceeding.[26] The Commission found that:

> * * *sufficient information regarding the proposed generation asset divestiture and corporate separation, as reflected in more detail in the Corporate Separation Case, has been provided in this modified ESP case to allow the Commission to reasonably conclude that termination of the Pool Agreement and corporate separation facilitate AEP Ohio's transition to a competitive market in Ohio.

*ESP 2 Case* (Opinion and Order at 59) (Aug. 8, 2012), IEU App. at 82. The Commission on rehearing further stated:

> AEP Ohio did not request that the Corporate Separation Case and the ESP proceedings be consolidated. Therefore, as was noted in the Opinion and Order, the primary considerations in the ESP proceeding was how the divestiture of the generation assets and the agreement between AEP Ohio and its generation affiliate would impact SSO rates and customers. The requirements for corporate separation contained in Sections 4928.17 and 4928.18(B), Revised Code, and the applicable rules in Chapter 4901:1-37, O.A.C., were addressed in the Corporate Separation Case which was issued subsequent to the Opinion and Order in this matter. As the issues raised by

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26 AEP Ohio corporate separation is currently pending before this Court in a separate appeal. The lawfulness of the Commission's corporate separation order will be more fully addressed in the Commission's Merit Brief to be filed in Ohio Supreme Court Case No. 2013-1014.

> IEU have subsequently been addressed, we deny the request for rehearing.

*ESP 2 Case* (Entry on Rehearing at 62) (Jan. 30, 2013), IEU App. at 168.

The Commission had jurisdiction over AEP Ohio's corporate separation request in the *ESP 2 Case*. The Commission has authority under R.C. 4928.06 to ensure that the policies of 4928.02 are met. Corporate separation is necessary for AEP Ohio to transition to an auction-based SSO and is critical to the overall ESP package. Further, the Commission has jurisdiction under R.C. Sections 4928.141 through 4928.143, to evaluate the full corporate separation impact on SSO rates under the ESP. Thus, the Commission is completely within its jurisdiction and the Commission should reject IEU's jurisdictional claim.

AEP Ohio's separation plan promotes the public interest by paving the path to a competitively bid SSO and more competitive choices for electric service in Ohio. The proposed generating asset transfer fulfills the mandate of R.C. 4928.17 and terminates the interim plan of functional separation for AEP Ohio. Corporate separation will promote retail shopping in Ohio and is critical to facilitating an auction-based SSO similar to that of other electric utilities in Ohio. Contrary to IEU's concerns, this progression helps facilitate the competitive policies in Revised Code Chapter 4928 that the Commission is charged with ensuring.

IEU posits that AEP Ohio failed to provide the Commission with the net book and market value of the generation assets, the Commission to determine whether the transfer is just, reasonable, and in the public interest. The claim that market valuation is needed is meritless. R.C. 4928.17 requires corporate separation but does not require a market valuation. While Commission rules reflect a market valuation, the Commission properly granted waiver of Rule 4901:1-37-09(C)(4) in the corporate separation proceeding. This is consistent with a similar waiver granted to Duke Ohio in an analogous case. *In the Matter of the Application of Duke Energy Ohio for Approval of an Electric Security Plan; Amendment to Its Certified Supplier Tariff; and Amendment to its Corporate Separation Plan,* PUCO Case Nos. 11-3549-EL-SSO, *et al.* (Opinion and Order at 46) (Nov. 22, 2011), App. at 49. There is no requirement that generation assets be transferred at market value and there is no reason why AEP Ohio should not be permitted to transfer its assets at net book value.

IEU's belief that transferring assets at net book value somehow creates a profit is erroneous as there is no reason to believe that market value is above book value. Future transactions of the generation assets upon or after corporate separation from the electric distribution utilities (EDUs) are not matters of concern under R.C. 4928.17, or under the Commission's rules. The statute and the Commission's rules are concerned with the divestiture of generation assets from the EDU. The rules are not concerned with future performance of those assets, future environmental rules or market conditions that may affect the value of the assets, or whether there are subsequent transactions (known or unknown) that would alter the ownership or economic value of the assets.

Moreover, ratepayers have no ownership interest in an EDU's generating assets. Consequently, they are not affected by the valuation of these assets when they are transferred to an affiliate. Therefore, IEU cannot demonstrate prejudice, which is essential to obtain a reversal of a Commission order. *In re Complaint of Cameron Creek Apts. v. Columbia Gas of Ohio, Inc.*, 2013-Ohio-3705, ¶ 33; *In re Complaint of City of Reynoldsburg,* 134 Ohio St.3d 29, 2012-Ohio-5270, 979 N.E. 2d 1229, ¶ 58. This Court has recognized that "[a]ppeals are not allowed for the purpose of settling abstract questions, but only to correct errors injuriously affecting the appellant." *Ohio Domestic Violence Network v. Pub. Util. Comm.*, 65 Ohio St.3d 438, 439, 605 N.E. 2d 13, 14 (1992), quoting *Ohio Contract Carrier Ass'n v. Pub. Util. Comm.,* 140 Ohio St. 160, 42 N.E. 2d 758 (1942) syllabus. The Court should therefore decline IEU's invitation to explore an abstract question that has no tangible effect on the appellant.

Furthermore, the Commission did not simply approve the transfer and wash its hands of the matter. The Commission imposed a number of conditions to ensure that AEP Ohio does not gain a competitive advantage through the transfer:

- A requirement for an audit by the Commission Staff or an independent auditor to ensure that the generation affiliate has no competitive advantage due to its affiliation with AEP Ohio;
- Continuing access by the Commission Staff to all books, accounts, and records both AEP Ohio and the generation affiliate;
- Restrictions on financing arrangements that would benefit the generation affiliate; and
- A requirement that the generation affiliate not rely upon the credit rating of AEP Ohio.

*In the Matter of the Application of Ohio Power Company Energy Ohio for Approval of an Amendment to its Corporate Separation Plan,* Case No. 12-1126-EL-UNC (Finding and

Order at 15-18) (Oct. 17, 2012), App. at 117-120. These conditions prevent GenResources from gaining a competitive advantage through its relationship with AEP Ohio. The Commission also has the statutory authority and duty to resolve any abuses of market power. R.C. 4928.06(E)(1) states:

> Beginning on the starting date of competitive retail electric service, the commission has authority under Chapters 4901. to 4909. of the Revised Code, and shall exercise that authority, to resolve abuses of market power by any electric utility that interfere with effective competition in the provision of retail electric service.

R.C. 4928.06(E)(1), App. at 14-15. The Commission has both the power and the means to address any concerns about GenResources having an unfair advantage in the market for electric service. The Commission correctly applied all relevant statutes and its rules in approving AEP Ohio's corporate separation plan, and its determination should be upheld.

## CONCLUSION

The Commission's orders fully comply with Chapter 4928. Its reasoning is thoroughly set forth and more than adequately supported by the evidence of record. The decision to approve AEP Ohio's modified ESP was lawful and reasonable. Appropriate deference should be given to the Commission's statutory interpretations and factual findings, and the Commission's orders should be affirmed.

Respectfully submitted,


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## PROOF OF SERVICE

I hereby certify that a true copy of the foregoing Second Merit Brief, submitted on behalf of appellee, the Public Utilities Commission of Ohio, was served by regular U.S. mail, postage prepaid, or hand-delivered, upon the following parties of record, this 21st day of October, 2013.

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# APPENDIX

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**4903.09 Written opinions filed by commission in all contested cases.**

In all contested cases heard by the public utilities commission, a complete record of all of the proceedings shall be made, including a transcript of all testimony and of all exhibits, and the commission shall file, with the records of such cases, findings of fact and written opinions setting forth the reasons prompting the decisions arrived at, based upon said findings of fact.

**4905.04 Power to regulate public utilities and railroads.**

The public utilities commission is hereby vested with the power and jurisdiction to supervise and regulate public utilities and railroads, to require all public utilities to furnish their products and render all services exacted by the commission or by law, and to promulgate and enforce all orders relating to the protection, welfare, and safety of railroad employees and the traveling public, including the apportionment between railroads and the state and its political subdivisions of the cost of constructing protective devices at railroad grade crossings.

**4905.05 Scope of jurisdiction.**

The jurisdiction, supervision, powers, and duties of the public utilities commission extend to every public utility and railroad, the plant or property of which lies wholly within this state and when the property of a public utility or railroad lies partly within and partly without this state to that part of such plant or property which lies within this state; to the persons or companies owning, leasing, or operating such public utilities and railroads; to the records and accounts of the business thereof done within this state; and to the records and accounts of any companies which are part of an electric utility holding company system exempt under section 3(a)(1) or (2) of the "Public Utility Holding Company Act of 1935," 49 Stat. 803, 15 U.S.C. 79c, and the rules and regulations promulgated thereunder, insofar as such records and accounts may in any way affect or relate to the costs associated with the provision of electric utility service by any public utility operating in this state and part of such holding company system.

Nothing in this section, or section 4905.06 or 4905.46 of the Revised Code pertaining to regulation of holding companies, grants the public utilities commission authority to regulate a holding company or its subsidiaries which are organized under the laws of another state, render no public utility service in the state of Ohio, and are regulated as a public utility by the public utilities commission of another state or primarily by a federal regulatory commission, nor do these grants of authority apply to public utilities that are excepted from the definition of "public utility" under divisions (A)(1) to (3) of section 4905.02 of the Revised Code.

**4905.06 General supervision.**

The public utilities commission has general supervision over all public utilities within its jurisdiction as defined in section 4905.05 of the Revised Code, and may examine such public utilities and keep informed as to their general condition, capitalization, and franchises, and as to the manner in which their properties are leased, operated, managed, and conducted with respect to the adequacy or accommodation afforded by their service, the safety and security of the public and their employees, and their compliance with all laws, orders of the commission, franchises, and charter requirements. The commission has general supervision over all other companies referred to in section 4905.05 of the Revised Code to the extent of its jurisdiction as defined in that section, and may examine such companies and keep informed as to their general condition and capitalization, and as to the manner in which their properties are leased, operated, managed, and conducted with respect to the adequacy or accommodation afforded by their service, and their compliance with all laws and orders of the commission, insofar as any of such matters may relate to the costs associated with the provision of electric utility service by public utilities in this state which are affiliated or associated with such companies. The commission, through the public utilities commissioners or inspectors or employees of the commission authorized by it, may enter in or upon, for purposes of inspection, any property, equipment, building, plant, factory, office, apparatus, machinery, device, and lines of any public utility. The power to inspect includes the power to prescribe any rule or order that the commission finds necessary for protection of the public safety. In order to assist the commission in the performance of its duties under this chapter, authorized employees of the motor carrier enforcement unit, created under section 5503.34 of the Revised Code in the division of state highway patrol, of the department of public safety may enter in or upon, for inspection purposes, any motor vehicle of any motor carrier .

In order to inspect motor vehicles owned or operated by a motor carrier engaged in the transportation of persons, authorized employees of the motor carrier enforcement unit, division of state highway patrol, of the department of public safety may enter in or upon any property of any motor carrier engaged in the intrastate transportation of persons.

**4905.13 System of accounts for public utilities.**

The public utilities commission may establish a system of accounts to be kept by public utilities or railroads, including municipally owned or operated public utilities, or may classify said public utilities or railroads and establish a system of accounts for each class, and may prescribe the manner in which such accounts shall be kept. Such system shall, when practicable, conform to the system prescribed by the department of taxation. The commission may prescribe the forms of accounts, records, and memorandums to be kept by such public utilities or railroads, including the accounts, records, and memorandums of the movement of traffic as well as of the receipts and expenditure of moneys, and any other forms, records, and memorandums which are necessary to carry out Chapters 4901., 4903., 4905., 4907., 4909., 4921., and 4923. of the Revised Code. The system of accounts established by the commission and the forms of accounts, records, and memorandums prescribed by it shall not be inconsistent, in the case of corporations subject to the act of congress entitled "An act to regulate commerce" approved February 4, 1887, and the acts amendatory thereof and supplementary thereto, with the systems and forms established for such corporations by the interstate commerce commission. This section does not affect the power of the public utilities commission to prescribe forms of accounts, records, and memorandums covering information in addition to that required by the interstate commerce commission. The public utilities commission may, after hearing had upon its own motion or complaint, prescribe by order the accounts in which particular outlays and receipts shall be entered, charged, or credited. Where the public utilities commission has prescribed the forms of accounts, records, or memorandums to be kept by any public utility or railroad for any of its business, no such public utility or railroad shall keep any accounts, records, or memorandums for such business other than those so prescribed, or those prescribed by or under the authority of any other state or of the

United States, except such accounts, records, or memorandums as are explanatory of and supplemental to the accounts, records, or memorandums prescribed by the commission. The commission shall at all times have access to all accounts kept by such public utilities or railroads and may designate any of its officers or employees to inspect and examine any such accounts. The auditor or other chief accounting officer of any such public utility or railroad shall keep such accounts and make the reports provided for in sections 4905.14 and 4907.13 of the Revised Code. Any auditor or chief accounting officer who fails to comply with this section shall be subject to the penalty provided for in division (B) of section 4905.99 of the Revised Code. The attorney general shall enforce such section upon request of the public utilities commission by mandamus or other appropriate proceedings.

**4905.22 Service and facilities required - unreasonable charge prohibited.**

Every public utility shall furnish necessary and adequate service and facilities, and every public utility shall furnish and provide with respect to its business such instrumentalities and facilities, as are adequate and in all respects just and reasonable. All charges made or demanded for any service rendered, or to be rendered, shall be just, reasonable, and not more than the charges allowed by law or by order of the public utilities commission, and no unjust or unreasonable charge shall be made or demanded for, or in connection with, any service, or in excess of that allowed by law or by order of the commission.

**4905.26 Complaints as to service.**

Upon complaint in writing against any public utility by any person, firm, or corporation, or upon the initiative or complaint of the public utilities commission, that any rate, fare, charge, toll, rental, schedule, classification, or service, or any joint rate, fare, charge, toll, rental, schedule, classification, or service rendered, charged, demanded, exacted, or proposed to be rendered, charged, demanded, or exacted, is in any respect unjust, unreasonable, unjustly discriminatory, unjustly preferential, or in violation of law, or that any regulation, measurement, or practice affecting or relating to any service furnished by the public utility, or in connection with such service, is, or will be, in any respect unreasonable, unjust, insufficient, unjustly discriminatory, or unjustly preferential, or that any service is, or will be, inadequate or cannot be obtained, and, upon complaint of a public utility as to any matter affecting its own product or service, if it appears that reasonable grounds for complaint are stated, the commission shall fix a time for hearing and shall notify complainants and the public utility thereof. The notice shall be served not less than fifteen days before hearing and shall state the matters complained of. The commission may adjourn such hearing from time to time.

The parties to the complaint shall be entitled to be heard, represented by counsel, and to have process to enforce the attendance of witnesses.

**4909.18 Application to establish or change rate.**

Any public utility desiring to establish any rate, joint rate, toll, classification, charge, or rental, or to modify, amend, change, increase, or reduce any existing rate, joint rate, toll, classification, charge, or rental, or any regulation or practice affecting the same, shall file a written application with the public utilities commission. Except for actions under section 4909.16 of the Revised Code, no public utility may issue the notice of intent to file an application pursuant to division (B) of section 4909.43 of the Revised Code to increase any existing rate, joint rate, toll, classification, charge, or rental, until a final order under this section has been issued by the commission on any pending prior application to increase the same rate, joint rate, toll, classification, charge, or rental or until two hundred seventy-five days after filing such application, whichever is sooner. Such application shall be verified by the president or a vice-president and the secretary or treasurer of the applicant. Such application shall contain a schedule of the existing rate, joint rate, toll, classification, charge, or rental, or regulation or practice affecting the same, a schedule of the modification amendment, change, increase, or reduction sought to be established, and a statement of the facts and grounds upon which such application is based. If such application proposes a new service or the use of new equipment, or proposes the establishment or amendment of a regulation, the application shall fully describe the new service or equipment, or the regulation proposed to be established or amended, and shall explain how the proposed service or equipment differs from services or equipment presently offered or in use, or how the regulation proposed to be established or amended differs from regulations presently in effect. The application shall provide such additional information as the commission may require in its discretion. If the commission determines that such application is not for an increase in any rate, joint rate, toll, classification, charge, or rental, the commission may permit the filing of the schedule proposed in the application and fix the time when such schedule shall take effect. If it appears to the commission that the proposals in the application may be unjust or unreasonable, the commission shall set the matter for hearing and shall give notice of such hearing by sending written notice of the date set for the hearing to the public utility and publishing notice of the hearing one time in a newspaper of general circulation in each county in the service area affected by the application. At such hearing, the burden of proof to show that the proposals in the application are just and reasonable shall be upon the public utility. After such hearing, the commission shall, where practicable, issue an appropriate order within six months from the date the application was filed.

If the commission determines that said application is for an increase in any rate, joint rate, toll, classification, charge, or rental there shall also, unless otherwise ordered by the commission, be filed with the application in duplicate the following exhibits:

(A) A report of its property used and useful, or, with respect to a natural gas, water-works, or sewage disposal system company, projected to be used and useful as of the date certain, in rendering the service referred to in such application, as provided in section 4909.05 of the Revised Code;

(B) A complete operating statement of its last fiscal year, showing in detail all its receipts, revenues, and incomes from all sources, all of its operating costs and other expenditures, and any analysis such public utility deems applicable to the matter referred to in said application;

(C) A statement of the income and expense anticipated under the application filed;

(D) A statement of financial condition summarizing assets, liabilities, and net worth;

(E) Such other information as the commission may require in its discretion.

**4928.01 Competitive retail electric service definitions.**

(A) As used in this chapter:

(1) "Ancillary service" means any function necessary to the provision of electric transmission or distribution service to a retail customer and includes, but is not limited to, scheduling, system control, and dispatch services; reactive supply from generation resources and voltage control service; reactive supply from transmission resources service; regulation service; frequency response service; energy imbalance service; operating reserve-spinning reserve service; operating reserve-supplemental reserve service; load following; back-up supply service; real-power loss replacement service; dynamic scheduling; system black start capability; and network stability service.

(2) "Billing and collection agent" means a fully independent agent, not affiliated with or otherwise controlled by an electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code, to the extent that the agent is under contract with such utility, company, cooperative, or aggregator solely to provide billing and collection for retail electric service on behalf of the utility company, cooperative, or aggregator.

(3) "Certified territory" means the certified territory established for an electric supplier under sections 4933.81 to 4933.90 of the Revised Code.

(4) "Competitive retail electric service" means a component of retail electric service that is competitive as provided under division (B) of this section.

(5) "Electric cooperative" means a not-for-profit electric light company that both is or has been financed in whole or in part under the "Rural Electrification Act of 1936," 49 Stat. 1363, 7 U.S.C. 901, and owns or operates facilities in this state to generate, transmit, or distribute electricity, or a not-for-profit successor of such company.

(6) "Electric distribution utility" means an electric utility that supplies at least retail electric distribution service.

(7) "Electric light company" has the same meaning as in section 4905.03 of the Revised Code and includes an electric services company, but excludes any self-generator to the extent that it consumes electricity it so produces, sells that electricity for resale, or obtains electricity from a generating facility it hosts on its premises.

(8) "Electric load center" has the same meaning as in section 4933.81 of the Revised Code.

(9) "Electric services company" means an electric light company that is engaged on a for-profit or not-for-profit basis in the business of supplying or arranging for the supply of only a competitive retail electric service in this state. "Electric services company" includes a power marketer,

power broker, aggregator, or independent power producer but excludes an electric cooperative, municipal electric utility, governmental aggregator, or billing and collection agent.

(10) "Electric supplier" has the same meaning as in section 4933.81 of the Revised Code.

(11) "Electric utility" means an electric light company that has a certified territory and is engaged on a for-profit basis either in the business of supplying a noncompetitive retail electric service in this state or in the businesses of supplying both a noncompetitive and a competitive retail electric service in this state. "Electric utility" excludes a municipal electric utility or a billing and collection agent.

(12) "Firm electric service" means electric service other than nonfirm electric service.

(13) "Governmental aggregator" means a legislative authority of a municipal corporation, a board of township trustees, or a board of county commissioners acting as an aggregator for the provision of a competitive retail electric service under authority conferred under section 4928.20 of the Revised Code.

(14) A person acts "knowingly," regardless of the person's purpose, when the person is aware that the person's conduct will probably cause a certain result or will probably be of a certain nature. A person has knowledge of circumstances when the person is aware that such circumstances probably exist.

(15) "Level of funding for low-income customer energy efficiency programs provided through electric utility rates" means the level of funds specifically included in an electric utility's rates on October 5, 1999, pursuant to an order of the public utilities commission issued under Chapter 4905. or 4909. of the Revised Code and in effect on October 4, 1999, for the purpose of improving the energy efficiency of housing for the utility's low-income customers. The term excludes the level of any such funds committed to a specific nonprofit organization or organizations pursuant to a stipulation or contract.

(16) "Low-income customer assistance programs" means the percentage of income payment plan program, the home energy assistance program, the home weatherization assistance program, and the targeted energy efficiency and weatherization program.

(17) "Market development period" for an electric utility means the period of time beginning on the starting date of competitive retail electric service and ending on the applicable date for that utility as specified in section 4928.40 of the Revised Code, irrespective of whether the utility applies to receive transition revenues under this chapter.

(18) "Market power" means the ability to impose on customers a sustained price for a product or service above the price that would prevail in a competitive market.

(19) "Mercantile customer" means a commercial or industrial customer if the electricity consumed is for nonresidential use and the customer consumes more than seven hundred thousand

kilowatt hours per year or is part of a national account involving multiple facilities in one or more states.

(20) "Municipal electric utility" means a municipal corporation that owns or operates facilities to generate, transmit, or distribute electricity.

(21) "Noncompetitive retail electric service" means a component of retail electric service that is noncompetitive as provided under division (B) of this section.

(22) "Nonfirm electric service" means electric service provided pursuant to a schedule filed under section 4905.30 of the Revised Code or pursuant to an arrangement under section 4905.31 of the Revised Code, which schedule or arrangement includes conditions that may require the customer to curtail or interrupt electric usage during nonemergency circumstances upon notification by an electric utility.

(23) "Percentage of income payment plan arrears" means funds eligible for collection through the percentage of income payment plan rider, but uncollected as of July 1, 2000.

(24) "Person" has the same meaning as in section 1.59 of the Revised Code.

(25) "Advanced energy project" means any technologies, products, activities, or management practices or strategies that facilitate the generation or use of electricity or energy and that reduce or support the reduction of energy consumption or support the production of clean, renewable energy for industrial, distribution, commercial, institutional, governmental, research, not-for-profit, or residential energy users, including, but not limited to, advanced energy resources and renewable energy resources. "Advanced energy project" also includes any project described in division (A), (B), or (C) of section 4928.621 of the Revised Code.

(26) "Regulatory assets" means the unamortized net regulatory assets that are capitalized or deferred on the regulatory books of the electric utility, pursuant to an order or practice of the public utilities commission or pursuant to generally accepted accounting principles as a result of a prior commission rate-making decision, and that would otherwise have been charged to expense as incurred or would not have been capitalized or otherwise deferred for future regulatory consideration absent commission action. "Regulatory assets" includes, but is not limited to, all deferred demand-side management costs; all deferred percentage of income payment plan arrears; post-in-service capitalized charges and assets recognized in connection with statement of financial accounting standards no. 109 (receivables from customers for income taxes); future nuclear decommissioning costs and fuel disposal costs as those costs have been determined by the commission in the electric utility's most recent rate or accounting application proceeding addressing such costs; the undepreciated costs of safety and radiation control equipment on nuclear generating plants owned or leased by an electric utility; and fuel costs currently deferred pursuant to the terms of one or more settlement agreements approved by the commission.

(27) "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.

(28) "Starting date of competitive retail electric service" means January 1, 2001.

(29) "Customer-generator" means a user of a net metering system.

(30) "Net metering" means measuring the difference in an applicable billing period between the electricity supplied by an electric service provider and the electricity generated by a customer-generator that is fed back to the electric service provider.

(31) "Net metering system" means a facility for the production of electrical energy that does all of the following:

(a) Uses as its fuel either solar, wind, biomass, landfill gas, or hydropower, or uses a micro-turbine or a fuel cell;

(b) Is located on a customer-generator's premises;

(c) Operates in parallel with the electric utility's transmission and distribution facilities;

(d) Is intended primarily to offset part or all of the customer-generator's requirements for electricity.

(32) "Self-generator" means an entity in this state that owns or hosts on its premises an electric generation facility that produces electricity primarily for the owner's consumption and that may provide any such excess electricity to another entity, whether the facility is installed or operated by the owner or by an agent under a contract.

(33) "Rate plan" means the standard service offer in effect on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008.

(34) "Advanced energy resource" means any of the following:

(a) Any method or any modification or replacement of any property, process, device, structure, or equipment that increases the generation output of an electric generating facility to the extent such efficiency is achieved without additional carbon dioxide emissions by that facility;

(b) Any distributed generation system consisting of customer cogeneration technology;

(c) Clean coal technology that includes a carbon-based product that is chemically altered before combustion to demonstrate a reduction, as expressed as ash, in emissions of nitrous oxide, mercury, arsenic, chlorine, sulfur dioxide, or sulfur trioxide in accordance with the American society of testing and materials standard D1757A or a reduction of metal oxide emissions in accordance with standard D5142 of that society, or clean coal technology that includes the design capability to control or prevent the emission of carbon dioxide, which design capability the commission shall adopt by rule and shall be based on economically feasible best available technology or, in the absence of a determined best available technology, shall be of the highest level of economically feasible design capability for which there exists generally accepted scientific opinion;

(d) Advanced nuclear energy technology consisting of generation III technology as defined by the nuclear regulatory commission; other, later technology; or significant improvements to existing facilities;

(e) Any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell;

(f) Advanced solid waste or construction and demolition debris conversion technology, including, but not limited to, advanced stoker technology, and advanced fluidized bed gasification technology, that results in measurable greenhouse gas emissions reductions as calculated pursuant to the United States environmental protection agency's waste reduction model (WARM) ;

(g) Demand-side management and any energy efficiency improvement;

(h) Any new, retrofitted, refueled, or repowered generating facility located in Ohio, including a simple or combined-cycle natural gas generating facility or a generating facility that uses biomass, coal, modular nuclear, or any other fuel as its input;

(i) Any uprated capacity of an existing electric generating facility if the uprated capacity results from the deployment of advanced technology.

"Advanced energy resource" does not include a waste energy recovery system that is, or has been, included in an energy efficiency program of an electric distribution utility pursuant to requirements under section 4928.66 of the Revised Code.

(35) "Air contaminant source" has the same meaning as in section 3704.01 of the Revised Code.

(36) "Cogeneration technology" means technology that produces electricity and useful thermal output simultaneously.

(37)

(a) "Renewable energy resource" means any of the following:

(i) Solar photovoltaic or solar thermal energy ;

(ii) Wind energy ;

(iii) Power produced by a hydroelectric facility ;

(iv) Geothermal energy ;

(v) Fuel derived from solid wastes, as defined in section 3734.01 of the Revised Code, through fractionation, biological decomposition, or other process that does not principally involve combustion ;

(vi) Biomass energy ;

(vii) Energy produced by cogeneration technology that is placed into service on or before December 31, 2015, and for which more than ninety per cent of the total annual energy input is from combustion of a waste or byproduct gas from an air contaminant source in this state, which source has been in operation since on or before January 1, 1985, provided that the cogeneration technology is a part of a facility located in a county having a population of more than three hundred sixty-five thousand but less than three hundred seventy thousand according to the most recent federal decennial census ;

(viii) Biologically derived methane gas ;

(ix) Energy derived from nontreated by-products of the pulping process or wood manufacturing process, including bark, wood chips, sawdust, and lignin in spent pulping liquors.

"Renewable energy resource" includes, but is not limited to, any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell; wind turbine located in the state's territorial waters of Lake Erie; methane gas emitted from an abandoned coal mine; waste energy recovery system placed into service or retrofitted on or after the effective date of the amendment of this section by S.B. 315 of the 129th general assembly, except that a waste energy recovery system described in division (A)(38)(b) of this section may be included only if it was placed into service between January 1, 2002, and December 31, 2004; storage facility that will promote the better utilization of a renewable energy resource ; or distributed generation system used by a customer to generate electricity from any such energy.

"Renewable energy resource" does not include a waste energy recovery system that is, or was, on or after January 1, 2012, included in an energy efficiency program of an electric distribution utility pursuant to requirements under section 4928.66 of the Revised Code.

(b) As used in division (A)(37) of this section, "hydroelectric facility" means a hydroelectric generating facility that is located at a dam on a river, or on any water discharged to a river, that is within or bordering this state or within or bordering an adjoining state and meets all of the following standards:

(i) The facility provides for river flows that are not detrimental for fish, wildlife, and water quality, including seasonal flow fluctuations as defined by the applicable licensing agency for the facility.

(ii) The facility demonstrates that it complies with the water quality standards of this state, which compliance may consist of certification under Section 401 of the "Clean Water Act of 1977," 91 Stat. 1598, 1599, 33 U.S.C. 1341, and demonstrates that it has not contributed to a finding by this state that the river has impaired water quality under Section 303(d) of the "Clean Water Act of 1977," 114 Stat. 870, 33 U.S.C. 1313.

(iii) The facility complies with mandatory prescriptions regarding fish passage as required by the federal energy regulatory commission license issued for the project, regarding fish protection for riverine, anadromous, and catadromous fish.

(iv) The facility complies with the recommendations of the Ohio environmental protection agency and with the terms of its federal energy regulatory commission license regarding watershed protection, mitigation, or enhancement, to the extent of each agency's respective jurisdiction over the facility.

(v) The facility complies with provisions of the "Endangered Species Act of 1973," 87 Stat. 884, 16 U.S.C. 1531 to 1544, as amended.

(vi) The facility does not harm cultural resources of the area. This can be shown through compliance with the terms of its federal energy regulatory commission license or, if the facility is not regulated by that commission, through development of a plan approved by the Ohio historic preservation office, to the extent it has jurisdiction over the facility.

(vii) The facility complies with the terms of its federal energy regulatory commission license or exemption that are related to recreational access, accommodation, and facilities or, if the facility is not regulated by that commission, the facility complies with similar requirements as are recommended by resource agencies, to the extent they have jurisdiction over the facility; and the facility provides access to water to the public without fee or charge.

(viii) The facility is not recommended for removal by any federal agency or agency of any state, to the extent the particular agency has jurisdiction over the facility.

(38) "Waste energy recovery system" means either of the following:

(a) A facility that generates electricity through the conversion of energy from either of the following:

(i) Exhaust heat from engines or manufacturing, industrial, commercial, or institutional sites, except for exhaust heat from a facility whose primary purpose is the generation of electricity;

(ii) Reduction of pressure in gas pipelines before gas is distributed through the pipeline, provided that the conversion of energy to electricity is achieved without using additional fossil fuels.

(b) A facility at a state institution of higher education as defined in section 3345.011 of the Revised Code that recovers waste heat from electricity-producing engines or combustion turbines and that simultaneously uses the recovered heat to produce steam, provided that the facility was placed into service between January 1, 2002, and December 31, 2004.

(39) "Smart grid" means capital improvements to an electric distribution utility's distribution infrastructure that improve reliability, efficiency, resiliency, or reduce energy demand or use, including, but not limited to, advanced metering and automation of system functions.

(40) "Combined heat and power system" means the coproduction of electricity and useful thermal energy from the same fuel source designed to achieve thermal-efficiency levels of at least sixty per cent, with at least twenty per cent of the system's total useful energy in the form of thermal energy.

(B) For the purposes of this chapter, a retail electric service component shall be deemed a competitive retail electric service if the service component is competitive pursuant to a declaration by a provision of the Revised Code or pursuant to an order of the public utilities commission authorized under division (A) of section 4928.04 of the Revised Code. Otherwise, the service component shall be deemed a noncompetitive retail electric service.

**4928.02 State policy.**

It is the policy of this state to do the following throughout this state:

(A) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service;

(B) 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;

(C) 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;

(D) 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, waste energy recovery systems, smart grid programs, and implementation of advanced metering infrastructure;

(E) 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;

(F) Ensure that an electric utility's transmission and distribution systems are available to a customer-generator or owner of distributed generation, so that the customer-generator or owner can market and deliver the electricity it produces;

(G) Recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment;

(H) 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;

(I) Ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power;

(J) Provide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential environmental mandates;

(K) Encourage implementation of distributed generation across customer classes through regular review and updating of administrative rules governing critical issues such as, but not limited to, interconnection standards, standby charges, and net metering;

(L) Protect at-risk populations, including, but not limited to, when considering the implementation of any new advanced energy or renewable energy resource;

(M) 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;

(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.

**4928.06 Commission to ensure competitive retail electric service.**

(A) Beginning on the starting date of competitive retail electric service, the public utilities commission shall ensure that the policy specified in section 4928.02 of the Revised Code is effectuated. To the extent necessary, the commission shall adopt rules to carry out this chapter. Initial rules necessary for the commencement of the competitive retail electric service under this chapter shall be adopted within one hundred eighty days after the effective date of this section. Except as otherwise provided in this chapter, the proceedings and orders of the commission under the chapter shall be subject to and governed by Chapter 4903. of the Revised Code.

(B) If the commission determines, on or after the starting date of competitive retail electric service, that there is a decline or loss of effective competition with respect to a competitive retail electric service of an electric utility, which service was declared competitive by commission order issued pursuant to division (A) of section 4928.04 of the Revised Code, the commission shall ensure that that service is provided at compensatory, fair, and nondiscriminatory prices and terms and conditions.

(C) In addition to its authority under section 4928.04 of the Revised Code and divisions (A) and (B) of this section, the commission, on an ongoing basis, shall monitor and evaluate the provision of retail electric service in this state for the purpose of discerning any noncompetitive retail electric service that should be available on a competitive basis on or after the starting date of competitive retail electric service pursuant to a declaration in the Revised Code, and for the purpose of discerning any competitive retail electric service that is no longer subject to effective competition on or after that date. Upon such evaluation, the commission periodically shall report its findings and any recommendations for legislation to the standing committees of both houses of the general assembly that have primary jurisdiction regarding public utility legislation. Until 2008, the commission and the consumer's counsel also shall provide biennial reports to those standing committees, regarding the effectiveness of competition in the supply of competitive retail electric services in this state. In addition, until the end of all market development periods as determined by the commission under section 4928.40 of the Revised Code, those standing committees shall meet at least biennially to consider the effect on this state of electric service restructuring and to receive reports from the commission, consumers' counsel, and director of development.

(D) In determining, for purposes of division (B) or (C) of this section, whether there is effective competition in the provision of a retail electric service or reasonably available alternatives for that service, the commission shall consider factors including, but not limited to, all of the following:

(1) The number and size of alternative providers of that service;

(2) The extent to which the service is available from alternative suppliers in the relevant market;

(3) The ability of alternative suppliers to make functionally equivalent or substitute services readily available at competitive prices, terms, and conditions;

(4) Other indicators of market power, which may include market share, growth in market share, ease of entry, and the affiliation of suppliers of services. The burden of proof shall be on any entity requesting, under division (B) or (C) of this section, a determination by the commission of the existence of or a lack of effective competition or reasonably available alternatives.

(E)

(1) Beginning on the starting date of competitive retail electric service, the commission has authority under Chapters 4901. to 4909. of the Revised Code, and shall exercise that authority, to

resolve abuses of market power by any electric utility that interfere with effective competition in the provision of retail electric service.

(2) In addition to the commission's authority under division (E)(1) of this section, the commission, beginning the first year after the market development period of a particular electric utility and after reasonable notice and opportunity for hearing, may take such measures within a transmission constrained area in the utility's certified territory as are necessary to ensure that retail electric generation service is provided at reasonable rates within that area. The commission may exercise this authority only upon findings that an electric utility is or has engaged in the abuse of market power and that that abuse is not adequately mitigated by rules and practices of any independent transmission entity controlling the transmission facilities. Any such measure shall be taken only to the extent necessary to protect customers in the area from the particular abuse of market power and to the extent the commission's authority is not preempted by federal law. The measure shall remain the commission, after reasonable notice and opportunity for hearing, determines that the particular abuse of market power has been mitigated.

(F) An electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code shall provide the commission with such information, regarding a competitive retail electric service for which it is subject to certification, as the commission considers necessary to carry out this chapter. An electric utility shall provide the commission with such information as the commission considers necessary to carry out divisions (B) to (E) of this section. The commission shall take such measures as it considers necessary to protect the confidentiality of any such information. The commission shall require each electric utility to file with the commission on and after the starting date of competitive retail electric service an annual report of its intrastate gross receipts and sales of kilowatt hours of electricity, and shall require each electric services company, electric cooperative, and governmental aggregator subject to certification to file an annual report on and after that starting date of such receipts and sales from the provision of those retail electric services for which it is subject to certification. For the purpose of the reports, sales of kilowatt hours of electricity are deemed to occur at the meter of the retail customer.

**4928.14 Failure of supplier to provide service.**

The failure of a supplier to provide retail electric generation service to customers within the certified territory of an electric distribution utility shall result in the supplier's customers, after reasonable notice, defaulting to the utility's standard service offer under sections 4928.141, 4928.142, and 4928.143 of the Revised Code until the customer chooses an alternative supplier. A supplier is deemed under this section to have failed to provide such service if the commission finds, after reasonable notice and opportunity for hearing, that any of the following conditions are met:

(A) The supplier has defaulted on its contracts with customers, is in receivership, or has filed for bankruptcy.

(B) The supplier is no longer capable of providing the service.

(C) The supplier is unable to provide delivery to transmission or distribution facilities for such period of time as may be reasonably specified by commission rule adopted under division (A) of section 4928.06 of the Revised Code.

(D) The supplier's certification has been suspended, conditionally rescinded, or rescinded under division (D) of section 4928.08 of the Revised Code.

**4928.141 Distribution utility to provide standard service offer.**

(A) Beginning January 1, 2009, an electric distribution utility shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service. To that end, the electric distribution utility shall apply to the public utilities commission to establish the standard service offer in accordance with section 4928.142 or 4928.143 of the Revised Code and, at its discretion, may apply simultaneously under both sections, except that the utility's first standard service offer application at minimum shall include a filing under section 4928.143 of the Revised Code. Only a standard service offer authorized in accordance with section 4928.142 or 4928.143 of the Revised Code, shall serve as the utility's standard service offer for the purpose of compliance with this section; and that standard service offer shall serve as the utility's default standard service offer for the purpose of section 4928.14 of the Revised Code. Notwithstanding the foregoing provision, the rate plan of an electric distribution utility shall continue for the purpose of the utility's compliance with this division until a standard service offer is first authorized under section 4928.142 or 4928.143 of the Revised Code, and, as applicable, pursuant to division (D) of section 4928.143 of the Revised Code, any rate plan that extends beyond December 31, 2008, shall continue to be in effect for the subject electric distribution utility for the duration of the plan's term. A standard service offer under section 4928.142 or 4928.143 of the Revised Code shall exclude any previously authorized allowances for transition costs, with such exclusion being effective on and after the date that the allowance is scheduled to end under the utility's rate plan.

(B) The commission shall set the time for hearing of a filing under section 4928.142 or 4928.143 of the Revised Code, send written notice of the hearing to the electric distribution utility, and publish notice in a newspaper of general circulation in each county in the utility's certified territory. The commission shall adopt rules regarding filings under those sections.

**4928.142 Standard generation service offer price - competitive bidding.**

(A) For the purpose of complying with section 4928.141 of the Revised Code and subject to division (D) of this section and, as applicable, subject to the rate plan requirement of division (A) of section 4928.141 of the Revised Code, an electric distribution utility may establish a standard service offer price for retail electric generation service that is delivered to the utility under a market-rate offer.

(1) The market-rate offer shall be determined through a competitive bidding process that provides for all of the following:

(a) Open, fair, and transparent competitive solicitation;

(b) Clear product definition;

(c) Standardized bid evaluation criteria;

(d) Oversight by an independent third party that shall design the solicitation, administer the bidding, and ensure that the criteria specified in division (A)(1)(a) to (c) of this section are met;

(e) Evaluation of the submitted bids prior to the selection of the least-cost bid winner or winners. No generation supplier shall be prohibited from participating in the bidding process.

(2) The public utilities commission shall modify rules, or adopt new rules as necessary, concerning the conduct of the competitive bidding process and the qualifications of bidders, which rules shall foster supplier participation in the bidding process and shall be consistent with the requirements of division (A)(1) of this section.

(B) Prior to initiating a competitive bidding process for a market-rate offer under division (A) of this section, the electric distribution utility shall file an application with the commission. An electric distribution utility may file its application with the commission prior to the effective date of the commission rules required under division (A)(2) of this section, and, as the commission determines necessary, the utility shall immediately conform its filing to the rules upon their taking effect. An application under this division shall detail the electric distribution utility's proposed compliance with the requirements of division (A)(1) of this section and with commission rules under division (A)(2) of this section and demonstrate that all of the following requirements are met:

(1) The electric distribution utility or its transmission service affiliate belongs to at least one regional transmission organization that has been approved by the federal energy regulatory commission; or there otherwise is comparable and nondiscriminatory access to the electric transmission grid.

(2) Any such regional transmission organization has a market-monitor function and the ability to take actions to identify and mitigate market power or the electric distribution utility's market conduct; or a similar market monitoring function exists with commensurate ability to identify and monitor market conditions and mitigate conduct associated with the exercise of market power.

(3) A published source of information is available publicly or through subscription that identifies pricing information for traded electricity on- and off-peak energy products that are contracts for delivery beginning at least two years from the date of the publication and is updated on a regular basis. The commission shall initiate a proceeding and, within ninety days after the application's filing date, shall determine by order whether the electric distribution utility and its market-rate offer meet all of the foregoing requirements. If the finding is positive, the electric distribution utility may initiate its competitive bidding process. If the finding is negative as to one or more requirements, the commission in the order shall direct the electric distribution utility regarding

how any deficiency may be remedied in a timely manner to the commission's satisfaction; otherwise, the electric distribution utility shall withdraw the application. However, if such remedy is made and the subsequent finding is positive and also if the electric distribution utility made a simultaneous filing under this section and section 4928.143 of the Revised Code, the utility shall not initiate its competitive bid until at least one hundred fifty days after the filing date of those applications.

(C) Upon the completion of the competitive bidding process authorized by divisions (A) and (B) of this section, including for the purpose of division (D) of this section, the commission shall select the least-cost bid winner or winners of that process, and such selected bid or bids, as prescribed as retail rates by the commission, shall be the electric distribution utility's standard service offer unless the commission, by order issued before the third calendar day following the conclusion of the competitive bidding process for the market rate offer, determines that one or more of the following criteria were not met:

(1) Each portion of the bidding process was oversubscribed, such that the amount of supply bid upon was greater than the amount of the load bid out.

(2) There were four or more bidders.

(3) At least twenty-five per cent of the load is bid upon by one or more persons other than the electric distribution utility. All costs incurred by the electric distribution utility as a result of or related to the competitive bidding process or to procuring generation service to provide the standard service offer, including the costs of energy and capacity and the costs of all other products and services procured as a result of the competitive bidding process, shall be timely recovered through the standard service offer price, and, for that purpose, the commission shall approve a reconciliation mechanism, other recovery mechanism, or a combination of such mechanisms for the utility.

(D) The first application filed under this section by an electric distribution utility that, as of July 31, 2008, directly owns, in whole or in part, operating electric generating facilities that had been used and useful in this state shall require that a portion of that utility's standard service offer load for the first five years of the market rate offer be competitively bid under division (A) of this section as follows: ten per cent of the load in year one, not more than twenty per cent in year two, thirty per cent in year three, forty per cent in year four, and fifty per cent in year five. Consistent with those percentages, the commission shall determine the actual percentages for each year of years one through five. The standard service offer price for retail electric generation service under this first application shall be a proportionate blend of the bid price and the generation service price for the remaining standard service offer load, which latter price shall be equal to the electric distribution utility's most recent standard service offer price, adjusted upward or downward as the commission determines reasonable, relative to the jurisdictional portion of any known and measurable changes from the level of any one or more of the following costs as reflected in that most recent standard service offer price:

(1) The electric distribution utility's prudently incurred cost of fuel used to produce electricity;

(2) Its prudently incurred purchased power costs;

(3) Its prudently incurred costs of satisfying the supply and demand portfolio requirements of this state, including, but not limited to, renewable energy resource and energy efficiency requirements;

(4) Its costs prudently incurred to comply with environmental laws and regulations, with consideration of the derating of any facility associated with those costs. In making any adjustment to the most recent standard service offer price on the basis of costs described in division (D) of this section, the commission shall include the benefits that may become available to the electric distribution utility as a result of or in connection with the costs included in the adjustment, including, but not limited to, the utility's receipt of emissions credits or its receipt of tax benefits or of other benefits, and, accordingly, the commission may impose such conditions on the adjustment to ensure that any such benefits are properly aligned with the associated cost responsibility. The commission shall also determine how such adjustments will affect the electric distribution utility's return on common equity that may be achieved by those adjustments. The commission shall not apply its consideration of the return on common equity to reduce any adjustments authorized under this division unless the adjustments will cause the electric distribution utility to earn a return on common equity that is significantly in excess of the return on common equity that is earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. 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. The electric distribution utility has the burden of demonstrating that any adjustment to its most recent standard service offer price is proper in accordance with this division.

(E) Beginning in the second year of a blended price under division (D) of this section and notwithstanding any other requirement of this section, the commission may alter prospectively the proportions specified in that division to mitigate any effect of an abrupt or significant change in the electric distribution utility's standard service offer price that would otherwise result in general or with respect to any rate group or rate schedule but for such alteration. Any such alteration shall be made not more often than annually, and the commission shall not, by altering those proportions and in any event, including because of the length of time, as authorized under division (C) of this section, taken to approve the market rate offer, cause the duration of the blending period to exceed ten years as counted from the effective date of the approved market rate offer. Additionally, any such alteration shall be limited to an alteration affecting the prospective proportions used during the blending period and shall not affect any blending proportion previously approved and applied by the commission under this division.

(F) An electric distribution utility that has received commission approval of its first application under division (C) of this section shall not, nor ever shall be authorized or required by the commission to, file an application under section 4928.143 of the Revised Code.

**4928.143 Application for approval of electric security plan - testing.**

(A) For the purpose of complying with section 4928.141 of the Revised Code, an electric distribution utility may file an application for public utilities commission approval of an electric security plan as prescribed under division (B) of this section. The utility may file that application prior to the effective date of any rules the commission may adopt for the purpose of this section, and, as the commission determines necessary, the utility immediately shall conform its filing to those rules upon their taking effect.

(B) Notwithstanding any other provision of Title XLIX of the Revised Code to the contrary except division (D) of this section, divisions (I), (J), and (K) of section 4928.20, division (E) of section 4928.64, and section 4928.69 of the Revised Code:

(1) An electric security plan shall include provisions relating to the supply and pricing of electric generation service. In addition, if the proposed electric security plan has a term longer than three years, it may include provisions in the plan to permit the commission to test the plan pursuant to division (E) of this section and any transitional conditions that should be adopted by the commission if the commission terminates the plan as authorized under that division.

(2) The plan may provide for or include, without limitation, any of the following:

(a) Automatic recovery of any of the following costs of the electric distribution utility, provided the cost is prudently incurred: the cost of fuel used to generate the electricity supplied under the offer; the cost of purchased power supplied under the offer, including the cost of energy and capacity, and including purchased power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes;

(b) A reasonable allowance for construction work in progress for any of the electric distribution utility's cost of constructing an electric generating facility or for an environmental expenditure for any electric generating facility of the electric distribution utility, provided the cost is incurred or the expenditure occurs on or after January 1, 2009. Any such allowance shall be subject to the construction work in progress allowance limitations of division (A) of section 4909.15 of the Revised Code, except that the commission may authorize such an allowance upon the incurrence of the cost or occurrence of the expenditure. No such allowance for generating facility construction shall be authorized, however, unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Further, no such allowance shall be authorized unless the facility's construction was sourced through a competitive bid process, regarding which process the commission may adopt rules. An allowance approved under division (B)(2)(b) of this section shall be established as a nonbypassable surcharge for the life of the facility.

(c) The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division (C) of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements.

(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;

(e) Automatic increases or decreases in any component of the standard service offer price;

(f) Consistent with sections 4928.23 to 4928.2318 of the Revised Code, both of the following:

(i) Provisions for the electric distribution utility to securitize any phase-in, inclusive of carrying charges, of the utility's standard service offer price, which phase-in is authorized in accordance with section 4928.144 of the Revised Code;

(ii) Provisions for the recovery of the utility's cost of securitization.

(g) Provisions relating to transmission, ancillary, congestion, or any related service required for the standard service offer, including provisions for the recovery of any cost of such service that the electric distribution utility incurs on or after that date pursuant to the standard service offer;

(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.

(i) Provisions under which the electric distribution utility may implement economic development, job retention, and energy efficiency programs, which provisions may allocate program costs across all classes of customers of the utility and those of electric distribution utilities in the same holding company system.

(C)

(1) The burden of proof in the proceeding shall be on the electric distribution utility. The commission shall issue an order under this division for an initial application under this section not later than one hundred fifty days after the application's filing date and, for any subsequent application by the utility under this section, not later than two hundred seventy-five days after the application's filing date. Subject to division (D) of this section, 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 and any future recovery of 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. Additionally, if the commission so approves an application that contains a surcharge under division (B)(2)(b) or (c) of this section, the commission shall ensure that the benefits derived for any purpose for which the surcharge is established are reserved and made available to those that bear the surcharge. Otherwise, the commission by order shall disapprove the application.

(2)

(a) If the commission modifies and approves an application under division (C)(1) of this section, the electric distribution utility may withdraw the application, thereby terminating it, and may file a new standard service offer under this section or a standard service offer under section 4928.142 of the Revised Code.

(b) If the utility terminates an application pursuant to division (C)(2)(a) of this section or if the commission disapproves an application under division (C)(1) of this section, the commission shall issue such order as is necessary to continue the provisions, terms, and conditions of the utility's most recent standard service offer, along with any expected increases or decreases in fuel costs from those contained in that offer, until a subsequent offer is authorized pursuant to this section or section 4928.142 of the Revised Code, respectively.

(D) Regarding the rate plan requirement of division (A) of section 4928.141 of the Revised Code, if an electric distribution utility that has a rate plan that extends beyond December 31, 2008, files an application under this section for the purpose of its compliance with division (A) of section 4928.141 of the Revised Code, that rate plan and its terms and conditions are hereby incorporated into its proposed electric security plan and shall continue in effect until the date scheduled under the rate plan for its expiration, and that portion of the electric security plan shall not be subject to commission approval or disapproval under division (C) of this section, and the earnings test provided for in division (F) of this section shall not apply until after the expiration of the rate plan. However, that utility may include in its electric security plan under this section, and the commission may approve, modify and approve, or disapprove subject to division (C) of this section, provisions for the incremental recovery or the deferral of any costs that are not being recovered under the rate plan and that the utility incurs during that continuation period to comply with section 4928.141, division (B) of section 4928.64, or division (A) of section 4928.66 of the Revised Code.

(E) If an electric security plan approved under division (C) of this section, except one withdrawn by the utility as authorized under that division, has a term, exclusive of phase-ins or deferrals, that exceeds three years from the effective date of the plan, the commission shall test the plan in the fourth year, and if applicable, every fourth year thereafter, to determine whether the plan, including its then-existing pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, continues to be more favorable in the aggregate and during the remaining term of the plan as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. The commission shall also determine the prospective effect of the electric security plan to determine if that effect is substantially likely to provide the electric distribution utility with a return on common equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. If the test results are in the negative or the commission finds that continuation of the electric security plan will result in a return on equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that will face comparable business and financial risk, with such adjustments for capital structure as may be appropriate, during the balance of the plan, the commission may terminate the electric security plan, but not until it shall have provided interested parties with notice and an opportunity to be heard. The commission may impose such conditions on the plan's termination as it considers reasonable and necessary to accommodate the transition from an approved plan to the more advantageous alternative. In the event of an electric security plan's termination pursuant to this division, the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan.

(F) With regard to the provisions that are included in an electric security plan under this section, the commission shall consider, following the end of each annual period of the plan, if any such adjustments resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. Consideration also shall be given to the capital requirements of future committed investments in this state. The burden of proof for demonstrating that significantly excessive earnings did not occur shall be on the electric distribution utility. If the commission finds that such adjustments, in the aggregate, did result in significantly excessive earnings, it shall require the electric distribution utility to return to consumers the amount of the excess by prospective adjustments; provided that, upon making such prospective adjustments, the electric distribution utility shall have the right to terminate the plan and immediately file an application pursuant to section 4928.142 of the Revised Code. Upon termination of a plan under this division, rates shall be set on the same basis as specified in division (C)(2)(b) of this section, and the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan. In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expenses, or earnings of any affiliate or parent company.

**4928.144 Phase-in of electric distribution utility rate or price.**

The public utilities commission by order may authorize any just and reasonable phase-in of any electric distribution utility rate or price established under sections 4928.141 to 4928.143 of the Revised Code, and inclusive of carrying charges, as the commission considers necessary to ensure rate or price stability for consumers. If the commission's order includes such a phase-in, the order also shall provide for the creation of regulatory assets pursuant to generally accepted accounting principles, by authorizing the deferral of incurred costs equal to the amount not collected, plus carrying charges on that amount. Further, the order shall authorize the collection of those deferrals through a nonbypassable surcharge on any such rate or price so established for the electric distribution utility by the commission.

**4928.17 Corporate separation plans.**

(A) Except as otherwise provided in sections 4928.142 or 4928.143 or 4928.31 to 4928.40 of the Revised Code and beginning on the starting date of competitive retail electric service, no electric utility shall engage in this state, either directly or through an affiliate, in the businesses of supplying a noncompetitive retail electric service and supplying a competitive retail electric service, or in the businesses of supplying a noncompetitive retail electric service and supplying a product or service other than retail electric service, unless the utility implements and operates under a corporate separation plan that is approved by the public utilities commission under this section, is consistent with the policy specified in section 4928.02 of the Revised Code, and achieves all of the following:

(1) The plan provides, at minimum, for the provision of the competitive retail electric service or the nonelectric product or service through a fully separated affiliate of the utility, and the plan includes separate accounting requirements, the code of conduct as ordered by the commission pursuant to a rule it shall adopt under division (A) of section 4928.06 of the Revised Code, and such other measures as are necessary to effectuate the policy specified in section 4928.02 of the Revised Code.

(2) The plan satisfies the public interest in preventing unfair competitive advantage and preventing the abuse of market power.

(3) The plan is sufficient to ensure that the utility will not extend any undue preference or advantage to any affiliate, division, or part of its own business engaged in the business of supplying the competitive retail electric service or nonelectric product or service, including, but not

limited to, utility resources such as trucks, tools, office equipment, office space, supplies, customer and marketing information, advertising, billing and mailing systems, personnel, and training, without compensation based upon fully loaded embedded costs charged to the affiliate; and to ensure that any such affiliate, division, or part will not receive undue preference or advantage from any affiliate, division, or part of the business engaged in business of supplying the noncompetitive retail electric service. No such utility, affiliate, division, or part shall extend such undue preference. Notwithstanding any other division of this section, a utility's obligation under division (A)(3) of this section shall be effective January 1, 2000.

(B) The commission may approve, modify and approve, or disapprove a corporate separation plan filed with the commission under division (A) of this section. As part of the code of conduct required under division (A)(1) of this section, the commission shall adopt rules pursuant to division (A) of section 4928.06 of the Revised Code regarding corporate separation and procedures for plan filing and approval. The rules shall include limitations on affiliate practices solely for the purpose of maintaining a separation of the affiliate's business from the business of the utility to prevent unfair competitive advantage by virtue of that relationship. The rules also shall include an opportunity for any person having a real and substantial interest in the corporate separation plan to file specific objections to the plan and propose specific responses to issues raised in the objections, which objections and responses the commission shall address in its final order. Prior to commission approval of the plan, the commission shall afford a hearing upon those aspects of the plan that the commission determines reasonably require a hearing. The commission may reject and require refiling of a substantially inadequate plan under this section.

(C) The commission shall issue an order approving or modifying and approving a corporate separation plan under this section, to be effective on the date specified in the order, only upon findings that the plan reasonably complies with the requirements of division (A) of this section and will provide for ongoing compliance with the policy specified in section 4928.02 of the Revised Code. However, for good cause shown, the commission may issue an order approving or modifying and approving a corporate separation plan under this section that does not comply with division (A)(1) of this section but complies with such functional separation requirements as the commission authorizes to apply for an interim period prescribed in the order, upon a finding that such alternative plan will provide for ongoing compliance with the policy specified in section 4928.02 of the Revised Code.

(D) Any party may seek an amendment to a corporate separation plan approved under this section, and the commission, pursuant to a request from any party or on its own initiative, may order as it considers necessary the filing of an amended corporate separation plan to reflect changed circumstances.

(E) No electric distribution utility shall sell or transfer any generating asset it wholly or partly owns at any time without obtaining prior commission approval.

**4928.31 Transition plan.**

(A) Not later than ninety days after the effective date of this section, an electric utility supplying retail electric service in this state on that date shall file with the public utilities commission a plan for the utility's provision of retail electric service in this state during the market development period. This transition plan shall be in such form as the commission shall prescribe by rule adopted under division (A) of section 4928.06 of the Revised Code and shall include all of the following:

(1) A rate unbundling plan that specifies, consistent with divisions (A)(1) to (7) of section 4928.34 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code, the unbundles components for electric generation, transmission, and distribution service and such other unbundled service components as the commission requires, to be charged by the utility beginning on the starting date of competitive retail electric service and that includes information the commission requires to fix and determine those components;

(2) A corporate separation plan consistent with section 4928.17 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code;

(3) Such plan or plans as the commission requires to address operational support systems and any other technical implementation issues pertaining to competitive retail electric service consistent with any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code;

(4) An employee assistance plan for providing severance, retraining, early retirement, retention, outplacement, and other assistance for the utility's employees whose employment is affected by electric industry restructuring under this chapter;

(5) A consumer education plan consistent with former section 4928.42 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code. A transition plan under this section may include tariff terms and conditions to address reasonable requirements for changing suppliers, length of commitment by a customer for service, and such other matters as are necessary to accommodate electric restructuring. Additionally, a transition plan under this section may include an application for the opportunity to receive transition revenues as authorized under sections 4928.31 to 4928.40 of the Revised Code, which application shall be consistent with those sections and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code. The transition plan also may include a plan for the independent operation of the utility's transmission facilities consistent with section 4928.12 of the Revised Code, division (A)(13) of section 4928.34 of the Revised Code, and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code. The commission may reject and require refiling, in whole or in part, of any substantially inadequate transition plan.

(B) The electric utility shall provide public notice of its filing under division (A) of this section, in a form and manner that the commission shall prescribe by rule adopted under division (A) of section 4928.06 of the Revised Code. However, the adoption of rules regarding the public notice under this division, regarding the form of the transition plan under division (A) of this section, and regarding procedures for expedited discovery under division (A) of section 4928.32 of the Revised Code are not subject to division (D) of section 111.15 of the Revised Code.

**4928.32 Procedures for expedited discovery in proceeding initiated to consider transition plan.**

(A) The public utilities commission shall establish reasonable procedures for expedited discovery in any proceeding initiated to consider a transition plan filed under section 4928.31 of the Revised Code.

(B) Not later than forty-five days after the date on which an electric utility files a transition plan under section 4928.31 of the Revised Code, any person having a real and substantial interest in the transition plan may file with the commission preliminary objections to the transition plan, which shall identify with specificity issues pertaining to any aspect of the transition plan, and any such person may propose specific responses to those issues. The commission shall address those objections and responses in its final order. In addition, not later than ninety days after the plan's filing, the commission staff shall file with the commission a report of its recommendations with respect to the plan. Prior to commission approval of the plan, the commission shall afford a hearing upon those aspects of the plan that the commission determines reasonably require a hearing.

(C) The commission shall maintain a complete record of all proceedings relative to a transition plan filed under section 4928.31 of the Revised Code and shall issue and file with the record of the case findings of fact and written opinions setting forth the reasons for any modification to or its approval of a transition plan.

**4928.33 Transition plan approval.**

(A) Not later than two hundred seventy-five days after the date an electric utility files a transition plan under section 4928.31 of the Revised Code, but, in any event, not later than October 31, 2000, the public utilities commission shall issue a final order approving the transition plan as filed under section 4928.31 of the Revised Code or an order modifying and approving that plan. The order is subject to section 4903.15 of the Revised Code and is subject to review and appeal under Chapter 4903. of the Revised Code.

(B) If the commission fails to issue, by October 31, 2000, a final order approving a transition plan, or such a final order has been enjoined in whole or in part pending appeal to a court, the commission shall issue an interim order prescribing a transition plan, to have effect on an interim basis only, and containing the plan components required by division (A) of section 4928.31 of the Revised Code and providing for the opportunity for transition revenue receipt if such an application were included in the plan filed by the utility under that section. The interim order is subject to section 4903.15 of the Revised Code but is not subject to review and appeal under Chapter 4903. of the Revised Code. An interim plan prescribed under the interim order shall be effective for the electric utility beginning on the starting date of competitive retail electric service and shall continue in effect until such time as any other replacement transition plan takes effect pursuant to a final commission order or resolution of an appeal. Any interim plan so prescribed shall comply with the applicable provisions of section 4928.34 of the Revised Code. A final commission order shall provide for a reconciliation of those amounts determined in the final order relative to division (A) of section 4928.31 of the Revised Code as compared to the interim amounts as determined under this division.

(C) No electric utility required to file a transition plan under section 4928.31 of the Revised Code shall fail to implement a transition plan approved or prescribed for the utility by a commission order issued under division (A) or (B) of this section. No electric utility shall provide retail electric service in this state during the market development period except pursuant to such an approved or prescribed transition plan.

**4928.34 Determinations for approval or prescribing of plan.**

(A) The public utilities commission shall not approve or prescribe a transition plan under division (A) or (B) of section 4928.33 of the Revised Code unless the commission first makes all of the following determinations:

(1) The unbundled components for the electric transmission component of retail electric service, as specified in the utility's rate unbundling plan required by division (A)(1) of section 4928.31 of the Revised Code, equal the tariff rates determined by the federal energy regulatory commission that are in effect on the date of the approval of the transition plan under sections 4928.31 to 4928.40 of the Revised Code, as each such rate is determined applicable to each particular customer class and rate schedule by the commission. The unbundled transmission component shall include a sliding scale of charges under division (B) of section 4905.31 of the Revised Code to ensure that refunds determined or approved by the federal energy regulatory commission are flowed through to retail electric customers.

(2) The unbundled components for retail electric distribution service in the rate unbundling plan equal the difference between the costs attributable to the utility's transmission and distribution rates and charges under its schedule of rates and charges in effect on the effective date of this section, based upon the record in the most recent rate proceeding of the utility for which the utility's schedule was established, and the tariff rates for electric transmission service determined by the federal energy regulatory commission as described in division (A)(1) of this section.

(3) All other unbundled components required by the commission in the rate unbundling plan equal the costs attributable to the particular service as reflected in the utility's schedule of rates and charges in effect on the effective date of this section.

(4) The unbundled components for retail electric generation service in the rate unbundling plan equal the residual amount remaining after the determination of the transmission, distribution, and other unbundled components, and after any adjustments necessary to reflect the effects of the amendment of section 5727.111 of the Revised Code by Sub. S.B. No. 3 of the 123rd general assembly.

(5) All unbundled components in the rate unbundling plan have been adjusted to reflect any base rate reductions on file with the commission and as scheduled to be in effect by December 31, 2005, under rate settlements in effect on the effective date of this section. However, all earnings obligations, restrictions, or caps imposed on an electric utility in a commission order prior to the effective date of this section are void.

(6) Subject to division (A)(5) of this section, the total of all unbundled components in the rate unbundling plan are capped and shall equal during the market development period, except as specifically provided in this chapter, the total of all rates and charges in effect under the applicable bundled schedule of the electric utility pursuant to section 4905.30 of the Revised Code in effect on the day before the effective date of this section, including the transition charge determined under section 4928.40 of the Revised Code, adjusted for any changes in the taxation of electric utilities and retail electric service under Sub. S.B. No. 3 of the 123rd General Assembly, the universal service rider authorized by section 4928.51 of the Revised Code, and the temporary rider authorized by section 4928.61 of the Revised Code. For the purpose of this division, the rate cap applicable to a customer receiving electric service pursuant to an arrangement approved by the commission under section 4905.31 of the Revised Code is, for the term of the arrangement, the total of all rates and charges in effect under the arrangement. For any rate schedule filed pursuant to section 4905.30 of the Revised Code or any arrangement subject to approval pursuant to section 4905.31 of the Revised Code, the initial tax-related adjustment to the rate cap required by this division shall be equal to the rate of taxation specified in section 5727.81 of the Revised Code and applicable to the schedule or arrangement. To the extent such total annual amount of the tax-related adjustment is greater than or less than the comparable amount of the total annual tax reduction experienced by the electric utility as a result of the provisions of Sub. S.B. No. 3 of the 123rd general assembly, such difference shall be addressed by the commission through accounting procedures, refunds, or an annual surcharge or credit to customers, or through other appropriate means, to avoid placing the financial responsibility for the difference upon the electric utility or its shareholders. Any adjustments in the rate of taxation specified in 5727.81 of the Revised Code section shall not occur without a corresponding adjustment to the rate cap for each such rate schedule or arrangement. The department of taxation shall advise the commission and self-assessors under section 5727.81 of the Revised Code prior to the effective date of any change in the rate of taxation specified under that section, and the commission shall modify the rate cap to reflect that adjustment so that the rate cap adjustment is effective as of the effective date of the change in the rate of taxation. This division shall be applied, to the extent possible, to eliminate any increase in the price of electricity for customers that otherwise may occur as a result of establishing the taxes contemplated in section 5727.81 of the Revised Code.

(7) The rate unbundling plan complies with any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code.

(8) The corporate separation plan required by division (A)(2) of section 4928.31 of the Revised Code complies with section 4928.17 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code.

(9) Any plan or plans the commission requires to address operational support systems and any other technical implementation issues pertaining to competitive retail electric service comply

with any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code.

(10) The employee assistance plan required by division (A)(4) of section 4928.31 of the Revised Code sufficiently provides severance, retraining, early retirement, retention, outplacement, and other assistance for the utility's employees whose employment is affected by electric industry restructuring under this chapter.

(11) The consumer education plan required under division (A)(5) of section 4928.31 of the Revised Code complies with former section 4928.42 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code.

(12) The transition revenues for which an electric utility is authorized a revenue opportunity under sections 4928.31 to 4928.40 of the Revised Code are the allowable transition costs of the utility as such costs are determined by the commission pursuant to section 4928.39 of the Revised Code, and the transition charges for the customer classes and rate schedules of the utility are the charges determined pursuant to section 4928.40 of the Revised Code.

(13) Any independent transmission plan included in the transition plan filed under section 4928.31 of the Revised Code reasonably complies with section 4928.12 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code, unless the commission, for good cause shown, authorizes the utility to defer compliance until an order is issued under division (G) of section 4928.35 of the Revised Code.

(14) The utility is in compliance with sections 4928.01 to 4928.11 of the Revised Code and any rules or orders of the commission adopted or issued under those sections.

(15) All unbundled components in the rate unbundling plan have been adjusted to reflect the elimination of the tax on gross receipts imposed by section 5727.30 of the Revised Code. In addition, a transition plan approved by the commission under section 4928.33 of the Revised Code but not containing an approved independent transmission plan shall contain the express conditions that the utility will comply with an order issued under division (G) of section 4928.35 of the Revised Code.

(B) Subject to division (E) of section 4928.17 of the Revised Code, if the commission finds that any part of the transition plan would constitute an abandonment under sections 4905.20 and 4905.21 of the Revised Code, the commission shall not approve that part of the transition plan unless it makes the finding required for approval of an abandonment application under section 4905.21 of the Revised Code. Sections 4905.20 and 4905.21 of the Revised Code otherwise shall not apply to a transition plan under sections 4928.31 to 4928.40 of the Revised Code.

**4928.35 Schedules containing unbundled rate components set in approved plan.**

(A) Upon approval of its transition plan under sections 4928.31 to 4928.40 of the Revised Code, an electric utility shall file in accordance with section 4905.30 of the Revised Code schedules containing the unbundled rate components set in the approved plan in accordance with section

4928.34 of the Revised Code. The schedules shall be in effect for the duration of the utility's market development period, shall be subject to the cap specified in division (A)(6) of section 4928.34 of the Revised Code, and shall not be adjusted during that period by the public utilities commission except as otherwise authorized by division (B) of this section or as otherwise authorized by federal law or except to reflect any change in tax law or tax regulation that has a material effect on the electric utility.

(B) Efforts shall be made to reach agreements with electric utilities in matters of litigation regarding property valuation issues. Irrespective of those efforts, the unbundled components for an electric utility's retail electric generation service and distribution service, as provided in division (A) of this section, are not subject to adjustment for the utility's market development period, except that the commission shall order an equitable reduction in those components for all customer classes to reflect any refund a utility receives as a result of the resolution of utility personal property tax valuation litigation that is resolved on or after the effective date of this section and not later than December 31, 2005. Immediately upon the issuance of that order, the electric utility shall file revised rate schedules under section 4909.18 of the Revised Code to effect the order.

(C) The schedule under division (A) of this section containing the unbundled distribution components shall provide that electric distribution service under the schedule will be available to all retail electric service customers in the electric utility's certified territory and their suppliers on a nondiscriminatory and comparable basis on and after the starting date of competitive retail electric service. The schedule also shall include an obligation to build distribution facilities when necessary to provide adequate distribution service, provided that a customer requesting that service may be required to pay all or part of the reasonable incremental cost of the new facilities, in accordance with rules, policy, precedents, or orders of the commission.

(D) During the market development period, an electric distribution utility shall provide consumers on a comparable and nondiscriminatory basis within its certified territory a standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service priced in accordance with the schedule containing the utility's unbundled generation service component. Immediately upon approval of its transition plan, the utility shall file the standard service offer with the commission under section 4909.18 of the Revised Code, during the market development period. The failure of a supplier to deliver retail electric generation service shall result in the supplier's customers, after reasonable notice, defaulting to the utility's standard service offer filed under this division until the customer chooses an alternative supplier. A supplier is deemed under this section to have failed to deliver such service if any of the conditions specified in section 4928.14 of the Revised Code is met.

(E) An amendment of a corporate separation plan contained in a transition plan approved by the commission under section 4928.33 of the Revised Code shall be filed and approved as a corporate separation plan pursuant to section 4928.17 of the Revised Code.

(F) Any change to an electric utility's opportunity to receive transition revenues under a transition plan approved in accordance with section 4928.33 of the Revised Code shall be authorized only as provided in sections 4928.31 to 4928.40 of the Revised Code.

(G) The commission, by order, shall require each electric utility whose approved transition plan did not include an independent transmission plan as described in division (A)(13) of section 4928.34 of the Revised Code to be a member of, and transfer control of transmission facilities it owns or controls in this state to, one or more qualifying transmission entities, as described in division (B) of section 4928.12 of the Revised Code, that are planned to be operational on and after December 31, 2003. However, the commission may extend that date if, for reasons beyond the control of the utility, a qualifying transmission entity is not planned to be operational on that date. The commission's order may specify an earlier date on which the transmission entity or entities are planned to be operational if the commission considers it necessary to carry out the policy specified in section 4928.02 of the Revised Code or to encourage effective competition in retail electric service in this state. Upon the issuance of the order, each such utility shall file with the commission a plan for such independent operation of the utility's transmission facilities consistent with this division. The commission may reject and require refiling of any substantially inadequate plan submitted under this division. After reasonable notice and opportunity for hearing, the commission shall approve the plan upon a finding that the plan will result in the utility's compliance with the order, this division, and any rules adopted under division (A) of section 4928.06 of the Revised Code. The approved independent transmission plan shall be deemed a part of the utility's transition plan for purposes of sections 4928.31 to 4928.40 of the Revised Code.

**4928.36 Complaint concerning transition plan.**

The public utilities commission has jurisdiction under section 4905.26 of the Revised Code, upon complaint by any person or upon complaint or initiative of the commission on or after the starting date of competitive retail electric service, to determine whether an electric utility has failed to implement, in conformance with an order under section 4928.33 of the Revised Code or in ongoing compliance with applicable provisions of the policy specified in section 4928.02 of the Revised Code, a transition plan approved under section 4928.33 of the Revised Code. If, after reasonable notice and opportunity for hearing as provided in section 4905.26 of the Revised Code, the commission determines that the utility has failed to so comply, the commission, in addition to any other remedies provided by law, may use the remedies specified in divisions (C)(1) to (3) and (D)(1) and (2) of section 4928.18 of the Revised Code to enforce compliance.

**4928.37 Receiving transition revenues.**

(A)

(1) Sections 4928.31 to 4928.40 of the Revised Code provide an electric utility the opportunity to receive transition revenues that may assist it in making the transition to a fully competitive retail electric generation market. An electric utility for which transition revenues are approved pursuant to sections 4928.31 to 4928.40 of the Revised Code shall receive those revenues through both of the following mechanisms beginning on the starting date of competitive retail electric service

and ending on the expiration date of its market development period as determined under section 4928.40 of the Revised Code:

(a) Payment of unbundled rates for retail electric services by each customer that is supplied retail electric generation service during the market development period by the customer's electric distribution utility, which rates shall be specified in schedules filed under section 4928.35 of the Revised Code;

(b) Payment of a nonbypassable and competitively neutral transition charge by each customer that is supplied retail electric generation service during the market development period by an entity other than the customer's electric distribution utility, as such transition charge is determined under section 4928.40 of the Revised Code. The transition charge shall be payable by each such retail electric distribution service customer in the certified territory of the electric utility for which the transition revenues are approved and shall be billed on each kilowatt hour of electricity delivered to the customer by the electric distribution utility as registered on the customer's meter during the utility's market development period as kilowatt hour is defined in section 4909.161 of the Revised Code or, if no meter is used, as based on an estimate of kilowatt hours used or consumed by the customer. The transition charge for each customer class shall reflect the cost allocation to that class as provided under bundled rates and charges in effect on the day before the effective date of this section. Additionally, as reflected in section 4928.40 of the Revised Code, the transition charges shall be structured to provide shopping incentives to customers sufficient to encourage the development of effective competition in the supply of retail electric generation service. To the extent possible, the level and structure of the transition charge shall be designed to avoid revenue responsibility shifts among the utility's customer classes and rate schedules.

(2)

(a) Notwithstanding division (A)(1)(b) of this section, the transition charge shall not be payable on electricity supplied by a municipal electric utility to a retail electric distribution service customer in the certified territory of the electric utility for which the transition revenues are approved, if the municipal electric utility provides electric transmission or distribution service, or both services, through transmission or distribution facilities singly or jointly owned or operated by the municipal electric utility, and if the municipal electric utility was in existence, operating, and providing service as of January 1, 1999.

(b) The transition charge shall not be payable on electricity supplied or consumed in this state except such electricity as is delivered to a retail customer by an electric distribution utility and is registered on the customer's meter during the utility's market development period or, if no meter is used, is based on an estimate of kilowatt hours used or consumed by the customer. However, no transition charge shall be payable on electricity that is both produced and consumed in this state by a self-generator.

(3) The transition charge shall not be discounted by any party.

(4) Nothing prevents payment of all or part of the transition charge by another party on a customer's behalf if that payment does not contravene sections 4905.33 to 4905.35 of the Revised Code or this chapter.

(B) The electric utility shall separately itemize and disclose, or cause its billing and collection agent to separately itemize and disclose, the transition charge on the customer's bill in accordance with reasonable specifications the commission shall prescribe by rule under division (A) of section 4928.06 of the Revised Code.

**4928.38 Commencing and terminating transition revenues.**

Pursuant to a transition plan approved under section 4928.33 of the Revised Code, an electric utility in this state may receive transition revenues under sections 4928.31 to 4928.40 of the Revised Code, beginning on the starting date of competitive retail electric service. Except as provided in sections 4905.33 to 4905.35 of the Revised Code and this chapter, an electric utility that receives such transition revenues shall be wholly responsible for how to use those revenues and wholly responsible for whether it is in a competitive position after the market development period. The utility's receipt of transition revenues shall terminate at the end of the market development period. With the termination of that approved revenue source, the utility shall be fully on its own in the competitive market. The commission shall not authorize the receipt of transition revenues or any equivalent revenues by an electric utility except as expressly authorized in sections 4928.31 to 4928.40 of the Revised Code.

**4928.39 Determining total allowable transition costs.**

Upon the filing of an application by an electric utility under section 4928.31 of the Revised Code for the opportunity to receive transition revenues under sections 4928.31 to 4928.40 of the Revised Code, the public utilities commission, by order under section 4928.33 of the Revised Code, shall determine the total allowable amount of the transition costs of the utility to be received as transition revenues under those sections. Such amount shall be the just and reasonable transition costs of the utility, which costs the commission finds meet all of the following criteria:

(A) The costs were prudently incurred.

(B) The costs are legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state.

(C) The costs are unrecoverable in a competitive market.

(D) The utility would otherwise be entitled an opportunity to recover the costs. Transition costs under this section shall include the costs of employee assistance under the employee assistance plan included in the utility's approved transition plan under section 4928.33 of the Revised Code, which costs exceed those costs contemplated in labor contracts in effect on the effective date of this section. Further, the commission's order under this section shall separately identify regulatory assets of the utility that are a part of the total allowable amount of transition costs determined under this section and separately identify that portion of a transition charge determined under section 4928.40 of the Revised Code that is allocable to those assets, which portion of a transition charge shall be subject to adjustment only prospectively and after December 31, 2004, unless the commission authorizes an adjustment prospectively with an earlier date for any customer class based upon an earlier termination of the utility's market development period pursuant to division (B)(2) of section 4928.40 of the Revised Code. The electric utility shall have the burden of demonstrating allowable transition costs as authorized under this section. The commission may impose reasonable commitments upon the utility's collection of the transition revenues to ensure that those revenues are used to eliminate the allowable transition costs of the utility during the market development period and are not available for use by the utility to achieve an undue competitive advantage, or to impose an undue disadvantage, in the provision by the utility of regulated or unregulated products or services.

**4928.40 Establishing transition charge for each customer class.**

(A) Upon determining under section 4928.39 of the Revised Code the allowable transition costs of an electric utility authorized for collection as transition revenues under sections 4928.31 to 4928.40 of the Revised Code, the public utilities commission, by order under section 4928.33 of the Revised Code, shall establish the transition charge for each customer class of the electric utility and, to the extent possible, each rate schedule within each such customer class, with all such transition charges being collected as provided in division (A)(1)(b) of section 4928.37 of the Revised Code during a market development period for the utility, ending on such date as the commission shall reasonably prescribe. The market development period shall end on December 31, 2005, unless otherwise authorized under division (B)(2) of this section. However, the commission may set the utility's recovery of the revenue requirements associated with regulatory assets, as established pursuant to section 4928.39 of the Revised Code, to end not later than December 31, 2010. The commission shall not permit the creation or amortization of additional regulatory assets without notice and an opportunity to be heard through an evidentiary hearing and shall not increase the charge recovering such revenue requirements associated with regulatory assets. Factors the commission shall consider in prescribing the expiration date of the utility's market development period and the transition charge for each customer class and rate schedule of the utility include, but are not limited to, the total allowable amount of transition costs of the electric utility as determined under section 4928.39 of the Revised Code; the relevant market price for the delivered supply of electricity to customers in that customer class and, to the extent possible, in each rate schedule as determined by the commission; and such shopping incentives by customer class as are considered necessary to induce, at the minimum, a twenty per cent load switching rate by customer class halfway through the utility's market development period but not later than December 31, 2003. In no case shall the commission establish a shopping incentive in an amount exceeding the unbundled component for retail electric generation service set in the utility's approved transition plan under section 4928.33 of the Revised Code, and in no case shall the commission establish a transition charge in an amount less than zero.

(B)

(1) The commission may conduct a periodic review no more often than annually and, as it determines necessary, adjust the transition charges of the electric utility as initially established

under division (A) of this section or subsequently adjusted under this division. Any such adjustment shall be in accordance with division (A) of this section and may reflect changes in the relevant market.

(2) For purposes of this chapter, the market development period shall not end earlier than December 31, 2005, unless, upon application by an electric utility, the commission issues an order authorizing such earlier date for one or more customer classes as is specified in the order, upon a demonstration by the utility and a finding by the commission of either of the following:

(a) There is a twenty per cent switching rate of the utility's load by the customer class.

(b) Effective competition exists in the utility's certified territory.

(C) Notwithstanding any provision of this chapter, the commission shall issue an order under section 4928.33 of the Revised Code approving a transition plan for an electric utility that contains a rate reduction for residential customers of that utility, provided that the rate reduction shall not increase the rates or transition cost responsibility of any other customer class of the utility. The rate reduction shall be in effect only for such portion of the utility's market development period as the commission shall specify and shall be applied to the unbundled generation component for retail electric generation service as set in the utility's approved transition plan under section 4928.33 of the Revised Code subject to the price cap for residential customers required under division (A)(6) of section 4928.34 of the Revised Code. The amount of the rate reduction shall be five per cent of the amount of that unbundled generation component, but shall not unduly discourage market entry by alternative suppliers seeking to serve the residential market in this state. The commission, after reasonable notice and opportunity for hearing, may terminate the rate reduction by order upon a finding that the rate reduction is unduly discouraging market entry by such alternative suppliers. No such termination of the rate reduction shall take effect prior to the midpoint of the utility's market development period.

(D) Beginning on the starting date of competitive retail electric service, no electric utility in this state shall prohibit the resale of electric generation service or impose unreasonable or discriminatory conditions or limitations on the resale of electric generation service.

(E) Notwithstanding any provision of Title XLIX [49] of the Revised Code to the contrary, any customer that receives a noncompetitive retail electric service from an electric distribution utility shall be a retail electric distribution service customer, irrespective of the voltage level at which service is taken.

**4901:1-37-09 Sale or transfer of generating assets.**

(A) Consistent with division (E) of section 4928.17 of the Revised Code, an electric utility shall not sell or transfer any generating asset it wholly or partly owns without prior commission approval.

(B) An electric utility may apply for commission approval to sell or transfer its generating assets by filing an application to sell or transfer.

(C) An application to sell or transfer generating assets shall, at a minimum:

(1) Clearly set forth the object and purpose of the sale or transfer, and the terms and conditions of the same.

(2) Demonstrate how the sale or transfer will affect the current and future standard service offer established pursuant to section 4928.141 of the Revised Code.

(3) Demonstrate how the proposed sale or transfer will affect the public interest.

(4) State the fair market value and book value of all property to be transferred from the electric utility, and state how the fair market value was determined.

(D) Upon the filing of such application, the commission may fix a time and place for a hearing if the application appears to be unjust, unreasonable, or not in the public interest. The commission shall fix a time and place for a hearing with respect to any application that proposes to alter the jurisdiction of the commission over a generation asset.

(E) If, after such hearing or in the case that no hearing is required, the commission is satisfied that the sale or transfer is just, reasonable, and in the public interest, it shall issue an order approving the application to sell or transfer.

(F) Staff shall have access to all books, accounts, and/or other pertinent records maintained by the transferor and transferee as related to the application to sell or transfer generating assets and in accordance with rule 4901:1-37-07 of the Administrative Code.

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

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| In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company. | ) ) ) ) | Case No. 10-2929-EL-UNC |

ENTRY ON REHEARING

The Commission finds:

(1) On March 18, 2009, in Case No. 08-917-EL-SSO, *et al.*, the Commission issued its opinion and order regarding the application for an electric security plan (ESP) for Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Company),[1] pursuant to Section 4928.143, Revised Code (ESP 1 Order).[2] The ESP 1 Order was appealed to the Ohio Supreme Court and subsequently remanded to the Commission for further proceedings.

(2) On November 1, 2010, American Electric Power Service Corporation (AEPSC), on behalf of AEP-Ohio, filed an application with the Federal Energy Regulatory Commission (FERC) in FERC Docket No. ER11-1995. On November 24, 2010, at the direction of FERC, AEPSC refiled the application in FERC Docket No. ER11-2183 (FERC filing). The application proposed to change the basis for compensation for capacity costs to a cost-based mechanism, pursuant to Section 205 of the Federal Power Act and Section D.8 of Schedule 8.1 of the Reliability Assurance Agreement (RAA) for the regional transmission organization, PJM Interconnection, LLC (PJM), and included proposed formula rate templates under which AEP-Ohio would calculate its capacity costs.

1 By entry issued on March 7, 2012, the Commission approved and confirmed the merger of CSP into OP, effective December 31, 2011. *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals*, Case No. 10-2376-EL-UNC.

2 *In the Matter of the Application of Columbus Southern Power Company for Approval of an 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.

and approved as a distribution charge and distribution service is subject to the exclusive jurisdiction of the Commission, the Commission's determination as to what compensation is provided by the POLR charge raises no issue that is subject to FERC's jurisdiction. IEU-Ohio also notes that the Commission has previously rejected the argument that a specific grant of authority from the General Assembly is required before it can make a determination that has significance for purposes of implementing a requirement approved by FERC.

(26) FES argues that, pursuant to Section D.8 of Schedule 8.1 of the RAA, AEP-Ohio, as an FRR Entity, has no option to seek wholesale recovery of capacity costs associated with retail switching, if an SCM is in place. Additionally, FES asserts that the Commission has jurisdiction to review AEP-Ohio's rates. FES emphasizes that AEP-Ohio admits that the Commission has broad authority to investigate matters involving Ohio utilities and that the Commission may explore such matters even as an adjunct to its own participation in FERC proceedings.

(27) As stated in the Initial Entry, Sections 4905.04, 4905.05, and 4905.06, Revised Code, grant the Commission authority to supervise and regulate all public utilities within its jurisdiction. The Commission's explicit adoption of an SCM for AEP-Ohio was well within the bounds of this broad statutory authority. Additionally, we stated in the Initial Entry that, in light of AEPSC's FERC filing, a review was necessary to evaluate the impact of the proposed change to AEP-Ohio's existing capacity charge. Section 4905.26, Revised Code, provides the Commission with considerable authority to initiate proceedings to investigate the reasonableness of any rate or charge rendered or proposed to be rendered by a public utility, which the Ohio Supreme Court has affirmed on several occasions.[8] We therefore, grant rehearing for the limited purpose of clarifying that the investigation initiated by the Commission in this proceeding was consistent with Section

8 *See, e.g., Ohio Consumers' Counsel v. Pub. Util. Comm.*, 110 Ohio St.3d 394, 400 (2006); *Allnet Communications Services, Inc. v. Pub. Util. Comm.*, 32 Ohio St.3d 115, 117 (1987); *Ohio Utilities Co. v. Pub. Util. Comm.*, 58 Ohio St.2d 153, 156-158 (1979).

capacity service is limited to effectuating the state's energy policy found in Section 4928.02, Revised Code.

(71) In the Capacity Order, the Commission determined that it has authority pursuant to Sections 4905.04, 4905.05, and 4905.06, Revised Code, to establish the SCM. We determined that AEP-Ohio's provision of capacity to CRES providers is appropriately characterized as a wholesale transaction rather than a retail electric service. We noted that, although wholesale transactions are generally subject to the exclusive jurisdiction of FERC, our exercise of jurisdiction in this case was for the sole purpose of establishing an appropriate SCM and is consistent with Section D.8 of Schedule 8.1 of the FERC-approved RAA. Additionally, we noted that FERC had rejected AEPSC's proposed formula rate in light of the fact that the Commission had established an SCM in the Initial Entry.[19] The Commission further determined, within its discretion, that it was necessary and appropriate to establish a cost-based SCM for AEP-Ohio, pursuant to our regulatory authority under Chapter 4905, Revised Code, as well as Chapter 4909, Revised Code, which authorized the Commission to use its traditional regulatory authority to approve rates that are based on cost, such that the resulting rates are just and reasonable, in accordance with Section 4905.22, Revised Code. Because the capacity service at issue is a wholesale rather than retail electric service, we found that, although market-based pricing is contemplated in Chapter 4928, Revised Code, that chapter pertains solely to retail electric service and is thus inapplicable under the circumstances. The Commission concluded that we have an obligation under traditional rate regulation to ensure that the jurisdictional utilities receive just and reasonable compensation for the services that they render. However, rehearing is granted to clarify that the Commission is under no obligation with regard to the specific mechanism used to address capacity costs. Such costs may be addressed through an SCM that is specifically crafted to meet the stated needs of a particular utility or through a rider or other mechanism.

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19 *American Electric Power Service Corporation*, 134 FERC ¶ 61,039 (2011).

The Commission carefully considered the question of whether we have the requisite statutory authority in this matter. We affirm our findings in the Capacity Order that capacity service is a wholesale generation service between AEP-Ohio and CRES providers and that the provisions of Chapter 4928, Revised Code, that restrict the Commission's regulation of competitive retail electric services are inapplicable. The definition of retail electric service found in Section 4928.01(A)(27), Revised Code, is more narrow than IEU-Ohio would have it. As we discussed in the Capacity Order, retail electric service is "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." Because AEP-Ohio supplies the capacity service in question to CRES providers, rather than directly to retail customers, it is not a retail electric service, as IEU-Ohio appears to contend, or a deregulated service, as the Schools assert.

Additionally, as discussed above, we note that Section 4905.26, Revised Code, grants the Commission considerable authority to review rates[20] and authorizes our investigation in this case. The Commission properly initiated this proceeding, consistent with that statute, to examine AEP-Ohio's existing capacity charge for its FRR obligations and to establish an appropriate SCM upon completion of our review. We grant rehearing for the limited purpose of clarifying that the Capacity Order was issued in accordance with the Commission's authority found in Section 4905.26, Revised Code, as well as Sections 4905.04, 4905.05, and 4905.06, Revised Code.

Cost-Based SCM

(72) OCC argues that the Commission erred in adopting a cost-based SCM rather than finding that the SCM should be based on RPM pricing. Similarly, the Schools argue that the Commission failed to find that RPM-based capacity

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[20] *See, e.g., Ohio Consumers' Counsel v. Pub. Util. Comm.*, 110 Ohio St.3d 394, 400 (2006); *Allnet Communications Services, Inc. v. Pub. Util. Comm.*, 32 Ohio St.3d 115, 117 (1987); *Ohio Utilities Co. v. Pub. Util. Comm.*, 58 Ohio St.2d 153, 156-158 (1979).

suppliers in PJM. The Commission initiated this proceeding solely to review AEP-Ohio's capacity costs and determine an appropriate capacity charge for its FRR obligations. We have not considered the costs of any other capacity supplier subject to our jurisdiction nor do we find it appropriate to do so in this proceeding. Further, the Commission does not agree that the SCM that we have adopted is inconsistent with the RAA. Section D.8 of Schedule 8.1 of the RAA provides only that, where the state regulatory jurisdiction requires that the FRR Entity be compensated for its FRR capacity obligations, such SCM will prevail. There are no requirements or limitations for the SCM in that section or elsewhere in the RAA. Although Section D.8 of Schedule 8.1 of the RAA specifically contemplates that an SCM may be established by the state regulatory jurisdiction, neither that section nor any other addresses whether the SCM may provide for the recovery of embedded costs, nor would we expect it to do so, given that the FRR Entity's compensation is to be provided by way of a state mechanism. The Commission finds that we appropriately adopted an SCM that is consistent with Section D.8 of Schedule 8.1 of the RAA and state law and that nothing in the Capacity Order is otherwise contrary to the RAA.

<u>Energy Credit</u>

(78) AEP-Ohio raises numerous issues with respect to the energy credit recommended by Staff's consultant in this case, Energy Ventures Analysis, Inc. (EVA), which was adopted by the Commission in the Capacity Order. In its first assignment of error, AEP-Ohio contends that the Commission's adoption of an energy credit of \$147.41/MW-day was flawed, given that EVA assumed a static shopping level of 26.1 percent throughout the relevant timeframe. AEP-Ohio notes that, according to Staff's own witness, the energy credit should be lower based upon the established shopping level of thirty percent as of April 30, 2012. AEP-Ohio adds that the energy credit should be substantially lower based upon the increased levels of shopping that will occur with RPM-based capacity pricing. AEP-Ohio believes that there is an inconsistency

based capacity rate that the Commission determined was just and reasonable.

(88) In its memorandum contra, IEU-Ohio argues that AEP-Ohio assumes that the Commission may act beyond its statutory jurisdiction to set generation rates and that the Commission may unlawfully authorize the Company to collect transition revenue. IEU-Ohio adds that customer choice will be frustrated if the Commission grants the relief requested by AEP-Ohio in its application for rehearing.

(89) The Schools respond that AEP-Ohio should not complain that the Commission lacks authority to order a deferral, given that the Company has refused to accept the ratemaking formula and related process contained in Sections 4909.15, 4909.18, and 4909.19, Revised Code. The Schools add, however, that the Commission has wide discretion to issue accounting orders under Section 4905.13, Revised Code, in cases where the Commission is not setting rates pursuant to Section 4909.15, Revised Code.

(90) RESA and Direct Energy argue that the Commission's approach is consistent with Ohio's energy policy, supported by the record, and reasonable and lawful. RESA and Direct Energy believe that the Commission pragmatically balanced the various competing interests of the parties in establishing a just and reasonable SCM.

(91) Noting that nothing prohibits the Commission from bifurcating the means of recovery of a just and reasonable rate, Duke replies that AEP-Ohio's argument is not well founded, given that the Company will be made whole through the deferral mechanism to be established in the ESP 2 Case.

(92) In the Capacity Order, the Commission authorized AEP-Ohio to modify its accounting procedures to defer the incurred capacity costs not recovered from CRES providers and indicated that a recovery mechanism for the deferred capacity costs would be established in the ESP 2 Case. We find nothing unlawful or unreasonable in this approach. We continue to believe that it appropriately balances our objectives of enabling AEP-Ohio to fully recover its

capacity costs incurred in carrying out its FRR obligations, while encouraging retail competition in the Company's service territory.

The Commission finds no merit in the arguments that we lack the authority to order the deferral. As we noted in the Capacity Order, the Commission relied upon the authority granted to us by Section 4905.13, Revised Code, in directing AEP-Ohio to modify its accounting procedures to defer a portion of its capacity costs. Having found that the capacity service at issue is not a retail electric service and thus not a competitive retail electric service, IEU-Ohio's argument that the Commission may not rely on Section 4905.13, Revised Code, is unavailing. Neither do we find that authorization of the deferral was contrary to GAAP or prior Commission precedent, as IEU-Ohio contends. The requests for rehearing of IEU-Ohio and AEP-Ohio should, therefore, be denied.

<u>Competition</u>

(93) AEP-Ohio contends that it was unreasonable and unlawful for the Commission to require the Company to supply capacity to CRES providers at a below-cost rate to promote artificial, uneconomic, and subsidized competition that is unsustainable and likely to harm customers and the state economy, as well as the Company.

(94) Duke disagrees, noting that the evidence is to the contrary. Duke adds that the other Ohio utilities use RPM-based capacity pricing without causing a flood of unsustainable competition or damage to the economy in the state. FES responds that the deferral authorized by the Commission is an appropriate way to spur real competition and to prevent the chilling effect on competition that would result from above-market capacity pricing. FES contends that there is nothing artificial in allowing customers to purchase capacity from willing sellers at market rates. RESA and Direct Energy agree, noting that the Capacity Order will promote real competition among CRES providers to the benefit of customers.

(138) AEP-Ohio replies that it is noteworthy that neither the intervenors that are actually parties to the contracts nor OCC seeks rehearing on this issue. AEP-Ohio further notes that IEU-Ohio identifies no specific contract that has allegedly been unconstitutionally impaired. According to AEP-Ohio, the lack of any such contract in the record is fatal to IEU-Ohio's impairment claim. AEP-Ohio adds that customers and CRES providers have long been aware that the Commission was in the process of establishing an SCM that might be based on something other than RPM pricing. Finally, AEP-Ohio points out that IEU-Ohio makes no attempt to satisfy the test used to analyze impairment claims.

(139) The Commission agrees that it is the province of the courts, and not the Commission, to judge constitutional claims. As the Ohio Supreme Court is the appropriate forum for the constitutional challenges raised by AEP-Ohio and IEU-Ohio, they will not be considered here.

Transition Costs

(140) IEU contends that the Commission, in approving an above-market rate for generation capacity service, authorized AEP-Ohio to collect transition revenue or its equivalent, contrary to Section 4928.40, Revised Code, and the stipulation approved by the Commission in the Company's electric transition plan case. AEP-Ohio responds that this argument has already been considered and rejected by the Commission.

(141) As previously discussed, the Commission does not believe that AEP-Ohio's capacity costs fall within the category of transition costs. Section 4928.39, Revised Code, defines transition costs as costs that, among meeting other criteria, are directly assignable or allocable to retail electric generation service provided to electric consumers in this state. As we have determined, AEP-Ohio's provision of capacity to CRES providers is not a retail electric service as defined by Section 4928.01(A)(27), Revised Code. It is a wholesale transaction between AEP-Ohio and CRES

providers. IEU-Ohio's request for rehearing should thus be denied.

Peak Load Contribution (PLC)

(142) IEU-Ohio contends that the Commission unlawfully and unreasonably failed to ensure that AEP-Ohio's generation capacity service is charged in accordance with a customer's PLC factor that is the controlling billing determinant under the RAA. IEU-Ohio argues that AEP-Ohio should be required to disclose publicly the means by which the PLC is disaggregated from AEP East down to AEP-Ohio and then down to each customer of the Company. IEU-Ohio adds that calculation of the difference between RPM-based capacity pricing and $188.88/MW-day will require a transparent and proper identification of the PLC.

(143) The Commission notes that IEU-Ohio is the only party that has identified or even addressed the PLC factor as a potential issue requiring resolution in this proceeding. Additionally, the Commission finds that IEU-Ohio has not provided any indication that there are inconsistencies or errors in capacity billings. In the absence of anything other than IEU-Ohio's mere conclusion that the issue requires the Commission's attention, we find no basis upon which to consider the issue at this time. If IEU-Ohio believes that billing inaccuracies have occurred, it may file a complaint pursuant to Section 4905.26, Revised Code. Therefore, IEU-Ohio's request for rehearing should be denied.

Due Process

(144) IEU-Ohio argues that the totality of the Commission's actions during the course of this proceeding violated IEU-Ohio's due process rights under the Fourteenth Amendment. Specifically, IEU-Ohio believes that the Commission has repeatedly granted applications for rehearing, indefinitely tolling them to prevent parties from taking an unobstructed appeal to the Ohio Supreme Court; repeatedly granted AEP-Ohio authority to temporarily impose various forms of its two-tiered, shopping-blocking capacity charges without record support; failed to address

ORDERED, That a copy of this entry on rehearing be served upon all parties of record in this case.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

Lynn Slaby

SJP/sc

Entered in the Journal
OCT 17 2012

Barcy F. McNeal
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

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|---|---|---|
| In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications, and Tariffs for Generation Service. | ) | Case No. 11-3549-EL-SSO |
| In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20. | ) | Case No. 11-3550-EL-ATA |
| In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Amend its Corporate Separation Plan. | ) | Case No. 11-3551-EL-UNC |

OPINION AND ORDER

The Public Utilities Commission of Ohio, considering the above-entitled applications, the testimony, the applicable law, the proposed stipulation, and other evidence of record, and being otherwise fully advised, hereby issues its opinion and order.

APPEARANCES:

Amy B. Spiller, Elizabeth H. Watts, Rocco O. D'Ascenzo, and Jeanne W. Kingery, 2500 Atrium II, 139 East Fourth Street, Cincinnati, Ohio 45201, on behalf of Duke Energy Ohio, Inc.

Mike DeWine, Ohio Attorney General, by John H. Jones, Assistant Section Chief, and Steven L. Beeler and Devin D. Parram, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of Staff of the Commission.

Colleen L. Mooney, 231 West Lima Street, P.O. Box 1793, Findlay, Ohio 45839, on behalf of Ohio Partners for Affordable Energy.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff and Michael J. Settineri, 52 East Gay Street, Columbus, Ohio 43216, on behalf of Constellation New Energy, Inc., and Constellation Energy Commodities Group, Inc.

09(B) through (D), O.A.C., set forth the filing requirements and the procedures to be followed for an application requesting approval of the sale or transfer of generating assets.

Upon review of the stipulation, the Commission believes that the provisions contained therein provide the necessary safeguards to ensure that the statutory mandates pertaining to Duke's sale of generation assets and corporate separation are adhered to and the policy of the state is carried out. Therefore, we conclude that, to the extent necessary, Rule 4901:1-37-09(B) through (D), O.A.C., should be waived and Duke should be authorized to transfer title to all of its generation assets out of Duke, in accordance with the provisions of the stipulation. Furthermore, we conclude that Duke's full legal corporate separation and Third Amended CSP, as provided in the stipulation, are in compliance with Section 4928.17, Revised Code, and the rules contained in Chapter 4901:1-37, O.A.C., and should be approved.

E. Is the proposed ESP more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code?

The Commission must also consider the applicable statutory test for approval of an ESP. Section 4928.143(C)(1), Revised Code, provides that the Commission should approve, or modify and approve, an application for an ESP if it finds that the ESP, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under an MRO pursuant to Section 4928.142, Revised Code.

Staff witness Turkenton believes that the ESP provides a better framework than an MRO. According to Ms. Turkenton, the ESP should be judged as a comprehensive plan that promotes fully competitive markets, promotes energy efficiency, provides rate certainty and stability, promotes economic development by making specific tangible commitments to vital industrial and commercial enterprises, and supports low-income ratepayers. (Staff Ex. 1 at 8.)

In support of the ESP, Duke witness Janson explains that, under the ESP, Duke residential SSO customers will see an approximate 11 percent reduction from their current rates. In addition, customers will realize financial benefits that are not contemplated under MRO provisions, including: $1 million to support economic development efforts in Duke's service territory in 2012; $1.35 million for low-income weatherization programs; and $350,000 for a fuel fund administered by OPAE. These programs may be renewed for 2013 and 2014. (Duke Ex. 21 at 10-11.)

ORDERED, That a copy of this opinion and order be served upon each party of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Paul A. Centolella

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto — See Concurrence

CMTP/KLS/vrm

Entered in the Journal

NOV 22 2011

Betty McCauley

Betty McCauley
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

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| In the Matter of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan. | ) ) ) ) ) ) ) | Case No. 12-1230-EL-SSO |

OPINION AND ORDER

The Commission, considering the above-entitled application, hereby issues its opinion and order in this matter.

APPEARANCES:

James W. Burk, Arthur E. Korkosz, Kathy Kolich, and Carrie Dunn, FirstEnergy Service Company, 76 South Main Street, Akron, Ohio 44308; Calfee, Halter & Griswold LLP, by James F. Lang and Laura C. McBride, 1405 East Sixth Street, Cleveland, Ohio 44114; and Jones Day, by David A. Kutik, North Point, 901 Lakeside Avenue, Cleveland, Ohio 44114-1190, on behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company.

Mike DeWine, Ohio Attorney General, by Thomas W. McNamee, Assistant Attorney General, Public Utilities Section, 180 East Broad Street, 6th Floor, Columbus, Ohio 43215-3793, on behalf of the Staff of the Public Utilities Commission of Ohio.

Bruce J. Weston, Ohio Consumers' Counsel, by Larry Sauer, Melissa Yost, and Terry Etter, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215-3485, on behalf of the residential utility consumers of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company.

Kravitz, Brown & Dortch, LLC, by Michael D. Dortch, 65 East State Street, Suite 200, Columbus, Ohio, on behalf of AEP Retail Energy Partners, LLC.

Bricker & Eckler, LLP, by Matthew W. Warnock, 100 South Third Street, Columbus, Ohio 43215-4291, and Bricker & Eckler, LLP, by Glenn S. Krassen, 1001 Lakeside Avenue East, Suite 1350, Cleveland, Ohio 44114, on behalf of the Northeast Ohio Public Energy Council and the Ohio Schools Council.

Thomas Hays, 717 Cannons Park Road, Toledo, Ohio 43617, and Leslie A. Kovacik, City of Toledo, 420 Madison Avenue, Suite 100, Toledo, Ohio 43604-1219, on behalf of Northwest Ohio Aggregation Group.

Vorys, Sater, Seymour and Pease, LLP, by M. Howard Petricoff and Lija Kaleps-Clark, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, on behalf of the Retail Energy Supply Association, Exelon Generation Company, and Constellation NewEnergy, Inc.

Eimer, Stahl, Klevorn & Solberg, LLP, by David M. Stahl, 224 South Michigan Avenue, Suite 1100, Chicago, Illinois 60604, on behalf of Constellation NewEnergy and Exelon Generation Company, LLC.

Matthew J. Satterwhite, Steven T. Nourse, and Marilyn McConnell, American Electric Power Service Corporation, One Riverside Plaza, Columbus, Ohio 43215, on behalf of Ohio Power Company.

Joseph M. Clark, 6641 North High Street, Suite 200, Worthington, Ohio 43085, and Ice Miller LLP, by Asim Z. Haque, Christopher L. Miller, Gregory J. Dunn, and Alan G. Starkoff, 250 West Street, Columbus, Ohio 43215, on behalf of Direct Energy Services, LLC, and Direct Energy Business, LLC.

Craig I. Smith, 15700 Van Aken Boulevard, Shaker Heights, Ohio 44120, on behalf of the Material Sciences Corporation.

Boehm, Kurtz, & Lowry, by Michael L. Kurtz, David Boehm, and Jody Kyler, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202, on behalf of Ohio Energy Group.

Williams, Allwein & Moser, by Christopher J. Allwein, 1373 Grandview Avenue, Suite 212, Columbus, Ohio 43212, and Robb Kapla, 85 Second Street, Second Floor, San Francisco, California 94105-3459, on behalf of the Sierra Club.

Williams, Allwein & Moser, by Christopher J. Allwein, 1373 Grandview Avenue, Suite 212, Columbus, Ohio 43212, on behalf of Natural Resources Defense Council.

Gregory J. Poulos, 471 East Broad Street, Suite 1520, Columbus, Ohio 43215, on behalf of EnerNOC, Inc.

Jeanne W. Kingery, 155 East Broad Street, 21st Floor, Columbus, Ohio 43215, on behalf of Duke Energy Ohio, Inc.

Amy B. Spiller, 139 East Fourth Street, Cincinnati, Ohio 45202, on behalf of Duke Energy Retail Sales and Duke Energy Commercial Asset Management.

Bricker & Eckler, LLP, by Lisa McAlister and J. Thomas Siwo, 100 South Third Street, Columbus, Ohio 43215-4291, on behalf of Ohio Manufacturers Association.

Cathryn N. Loucas, 1207 Grandview Avenue, Suite 201, Columbus, Ohio 43212, on behalf of Ohio Environmental Council.

Colleen Mooney, 231 West Lima Street, Findlay, Ohio 45840, on behalf of Ohio Partners for Affordable Energy.

Theodore S. Robinson, 2121 Murray Avenue, Pittsburg, Pennsylvania 15217, on behalf of Citizen Power.

Judi L. Sobecki, 1065 Woodman Drive, Dayton, Ohio 45432, on behalf of Dayton Power & Light, Inc.

McNees, Wallace & Nurick, LLC, by Frank P. Darr, Samuel C. Randazzo, and Matthew R. Pritchard, Fifth Third Center, 21 East State Street, Suite 1700, Columbus, Ohio 43215-4228, on behalf of Industrial Energy Users Ohio.

Sherry B. Cunningham, Director of Law, City of Akron, 161 South High Street, Suite 202, Akron, Ohio 44308, and McNees, Wallace & Nurick, LLC, by Joseph E. Oliker, Fifth Third Center, 21 East State Street, Suite 1700, Columbus, Ohio 43215-4228, on behalf of the City of Akron.

Justin M. Vickers, 35 East Wacker Drive, Suite 1600, Chicago, Illinois 60601-2110, on behalf of the Environmental Law & Policy Center.

Bell & Royer Co., LPA, by Barth E. Royer, 33 South Grant Avenue, Columbus, Ohio 43215, on behalf of Cleveland Municipal School District.

Matthew White, 6100 Emerald Parkway, Dublin, Ohio 43016, and Bell & Royer Co., LPA, by Barth E. Royer, 33 South Grant Avenue, Columbus, Ohio 43215, on behalf of Interstate Gas Supply, Inc.

Brickfield, Burchette, Ritts & Stone, P.C., by Michael K. Lavanga, 1025 Thomas Jefferson Street, N.W., 8th Floor, West Tower, Washington, D.C. 20007, on behalf of Nucor Steel Marion, Inc.

Christopher Horn, 3030 Euclid Avenue, Suite 406, Cleveland, Ohio 44118, on behalf of Cleveland Housing Network, the Empowerment Center of Greater Cleveland, and the Consumer Protection Association.

OPINION:

I. HISTORY OF THE PROCEEDINGS

On April 13, 2012, Ohio Edison Company (OE), The Cleveland Electric Illuminating Company (CEI), and The Toledo Edison Company (TE) (collectively, FirstEnergy or the Companies) filed an application pursuant to Section 4928.141, Revised Code, to provide for a standard service offer (SSO), commencing no later than June 20, 2012. The application is for an electric security plan (ESP), in accordance with Section 4928.143, Revised Code, and the application includes a stipulation and recommendation (Stipulation) agreed to by various parties regarding the terms of the proposed ESP (ESP 3). In the Stipulation, FirstEnergy represents that it and numerous other parties engaged in a wide range of discussions over a period of time related to the development of the ESP 3, which extends, with modifications, the stipulation and second supplemental stipulation (Combined Stipulation) modified and approved by the Commission in Case No. 10-388-EL-SSO (*ESP 2 Case*) for an additional two years. By entry issued April 19, 2012, the attorney examiner established a procedural schedule, scheduling a technical conference regarding the application for April 26, 2012, and setting the matter for hearing on May 21, 2012.

Moreover, pursuant to a request contained in FirstEnergy's application, on April 19, 2012, the attorney examiner granted intervention in this proceeding to all parties who participated as intervenors in the *ESP 2 Case*: Ohio Consumers' Counsel (OCC), Ohio Energy Group (OEG), The Kroger Company (Kroger), Industrial Energy Users-Ohio (IEU-Ohio), Ohio Partners for Affordable Energy (OPAE), Nucor Steel Marion, Inc. (Nucor), Constellation New Energy, Inc., and Constellation Energy Commodities Group, Inc., (jointly, Constellation), the city of Cleveland (Cleveland), the Ohio Environmental Council (OEC), the Environmental Law and Policy Center (ELPC), the Ohio Hospital Association (OHA), the Ohio Manufacturers' Association (OMA), The Neighborhood Environmental Coalition, The Empowerment Center of Greater Cleveland, United Clevelanders Against Poverty, Cleveland Housing Network, and The Consumers for Fair Utility Rates (collectively, Citizens' Coalition), Northwest Ohio Aggregation Group (NOAC), Natural Resources Defense Council (NRDC), Direct Energy Services, LLC (Direct Energy), Citizen Power, Inc. (Citizen Power), Material Sciences Corporation (MSC), Ohio Schools Council (OSC), Northeast Ohio Public Energy Council (NOPEC), the Association of Independent Colleges and Universities of Ohio (AICUO), FirstEnergy Solutions Corporation (FES), Morgan Stanley Capital Group, Inc. (Morgan Stanley), Council of Smaller Enterprises (COSE), EnerNOC, Inc. (EnerNOC), the city of Akron (Akron), and CPower, Inc., Viridity

Energy, Inc., Energy Connect, Converge, Inc., Enterprise Technologies, Inc., and Energy Curtailment Specialists, Inc. (collectively, the Demand Response Coalition). Additionally, on May 15, 2012, the attorney examiner granted motions to intervene filed by AEP Retail Energy Partners, LLC (AEP Retail), the Consumer Protection Association (CPA), Dayton Power and Light Company (DP&L), Duke Energy Commercial Asset Management, Inc. and Duke Energy Retail Sales, LLC (jointly, Duke), Exelon Generation Company, LLC (Exelon), Interstate Gas Supply, Inc. (IGS), Ohio Power Company (Ohio Power), Retail Energy Supply Association (RESA), and the Sierra Club (Sierra Club). On that same date, the attorney examiner granted motions for admission *pro hac vice* filed by Michael Lavanga, Justin Vickers, and Theodore Robinson.

On April 24, 2012, ELPC, NRDC, NOPEC, NOAC, OCC, and the Sierra Club (collectively, the Ohio Environmental and Consumer Advocates or OCEA), filed an interlocutory appeal arguing that the procedural schedule set by the attorney examiner does not provide significant time for intervenors to adequately prepare. Thereafter, on April 25, 2012, the Commission granted in part, and denied in part, certain waivers of the standard filing requirements found in Rule 4901:1-35, O.A.C., filed by FirstEnergy. Additionally, on April 26, 2012, OCEA filed a joint motion to extend the procedural schedule and continue the evidentiary hearing. Shortly thereafter, on April 27, 2012, AEP Retail filed a motion to modify the procedural schedule to afford the parties more time to conduct discovery. By entry issued May 2, 2012, the attorney examiner denied OCEA's interlocutory appeal, but granted the motions of OCEA and AEP Retail, with modifications, to extend the procedural schedule. Specifically, the attorney examiner rescheduled the evidentiary hearing for June 4, 2012.

Thereafter, on May 9, 2012, Direct Energy filed a motion to compel FirstEnergy to respond to discovery. By entry issued on May 17, 2012, the attorney examiner granted in part, and denied in part, Direct Energy's motion to compel. Additionally, on May 29, 2012, AEP Retail filed a motion to continue the hearing date. On June 1, 2012, NOPEC, NOAC, and OCC joined AEP Retail's motion to continue the hearing. On that same day, the attorney examiner denied the motion to continue the hearing date.

The hearing commenced, as rescheduled, on June 4, 2012, and continued through June 7, 2012. At the hearing, the attorney examiners granted the motion for admission *pro hac vice* filed by Robb Kapla. Additionally, the attorney examiners orally granted motions for protective order filed by NOPEC and NOAC, as well as FirstEnergy, on the basis that the information sought to be protected constituted trade secrets.

Twelve witnesses testified at the hearing. Three witnesses testified in favor of the Stipulation and the remaining witnesses testified in opposition to the Stipulation in general or to certain provisions of the Stipulation. One witness testified on rebuttal. The attorney examiners established a briefing schedule requiring initial briefs by June 22, 2012, and reply briefs by June 29, 2012. Initial briefs were timely submitted by FirstEnergy, OCC and Citizen Power (jointly, OCC/CP), MSC, ELPC, Nucor, RESA and Direct Energy, AEP Retail, Sierra Club, OSC, OEG, EnerNOC, NOPEC and NOAC (jointly, NOPEC/NOAC), Ohio Power, Exelon and Constellation, IEU-Ohio, IGS, and Staff. Reply briefs were timely submitted by FirstEnergy, OCC/CP, MSC, city of Akron, ELPC, Nucor, RESA and Direct Energy, AEP Retail, Sierra Club, OEG, EnerNOC, NOPEC/NOAC, IEU-Ohio, IGS, and Staff.

Pursuant to published notice, public hearings were held in Akron on June 4, 2012; in Toledo on June 7, 2012; and in Cleveland on June 12, 2012.

## II. DISCUSSION

### A. Applicable Law

Chapter 4928 of the Revised Code provides an integrated system of regulation in which specific provisions were designed to advance state policies of ensuring access to adequate, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges. In considering these cases, the Commission is cognizant of the challenges facing Ohioans and the electric power industry and is guided by the policies of the state as established by the General Assembly in Section 4928.02, Revised Code, as amended by Amended Substitute Senate Bill 221 (S.B. 221).

In addition, S.B. 221 amended Section 4928.14, Revised Code, which provides that, beginning on January 1, 2009, electric utilities must provide customers with an SSO, consisting of either a market rate offer (MRO) or an ESP. The SSO is to serve as the electric utility's default SSO. Section 4928.143, Revised Code, sets out the requirements for an ESP. Section 4928.143(C)(1), Revised Code, provides that the Commission is required to determine whether the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

### B. Summary of the Stipulation

In this proceeding, certain parties submitted a Stipulation. According to the Stipulation, the signatory parties agree to and recommend that the Commission approve and adopt all terms and conditions contained within the Stipulation. The signatory parties assert that the Stipulation essentially extends the combined stipulation as partially modified and approved by the Commission in the *ESP 2 Case* for two additional years. The Stipulation includes, *inter alia*, the following provisions:

(1) For the period between June 1, 2013, and May 31, 2016, retail generation rates for SSO will be determined by a descending-clock format competitive bid process (CBP). In the CBP, the Companies will seek to procure, on a slice of system basis, 100 percent of the aggregate wholesale full requirements SSO supply. The CBP will be conducted by an independent bid manager. The bidding will occur using three products of varying lengths and multiple bid processes over the term of the ESP 3. The bidding schedule has been modified from the ESP 2 so that the bids to occur in October 2012 and January 2013 will be for a three-year period rather than a one-year period. All bidders, including FES, may participate subject to the limitations contained in the Stipulation. The independent auction manager will select the winning bidder(s), but the Commission may reject the results within 48 hours of the auction conclusion. (Co. Ex. 1, Stip. at 7-8.)

(2) The Companies will provide their Percentage of Income Payment Plan (PIPP) customers with a six percent discount off the otherwise applicable price to compare during the period of the ESP 3 (*Id.* at 9).

(3) There will be no minimum stay for residential and small commercial non-aggregation customers (*Id.* at 10).

(4) There will be no minimum default service rider, standby charges, or rate stabilization charges. Unless otherwise noted in the Stipulation, all generation rates for the ESP 3 period are avoidable, and there are no shopping credit caps. (*Id.* at 10.)

(5) Renewable energy resource requirements for the period of June 1, 2014, through May 31, 2016, will be met by using a separate request for proposal (RFP) process to obtain renewable energy credits (RECs). If the Companies are unable to acquire the required number of RECs through the RFP process, then the Companies may seek the remaining needed RECs through bilateral contracts. The costs related to the procurement of all RECs, including costs associated with administering the RFP, will be included in Rider AER for recovery in the year in which the RECs are utilized to meet the Companies' renewable energy requirements, with any reconciliation between actual and forecasted information being

recognized through Rider AER in the subsequent quarter. (*Id.* at 10-11.)

(6) The rate design currently in effect will remain in place, except as modified below. However, the Commission may, with the Companies' concurrence, institute a changed revenue neutral distribution rate design. (*Id.* at 12.)

(a) The average total rate overall percentage increase for the 12-month period ending May 2015, resulting from the CBP for customers on Rate GT, Private Outdoor Lighting, Traffic Lighting, and Street Lighting rates shall not exceed a percentage in excess of one and one-half times the system average overall percentage rate increase by the Companies. If the average percent change by the Companies is negative, then all lighting schedules shall be limited to a maximum increase of zero percent and no cap shall be applied to Rate GT customers.

(b) Any revenue shortfall resulting from the application of the interruptible credits in Rider OLR and Rider ELR will be recovered from all non-interruptible customers as part of the non-bypassable demand side management and energy efficiency rider (Rider DSE).

(c) The seasonality factors adopted in the *ESP 2 Case* shall be adopted in this proceeding.

(d) Capacity costs that result from the PJM Interconnection, LLC (PJM), capacity auctions will be used to develop capacity costs for Rider GEN.

(e) Rate schedule RS will have a flat rate structure.

(*Id.* at 12-13.)

(7) The Generation Service Uncollectible Rider (Rider NDU) shall be continued to recover non-distribution related uncollectible costs associated with supply cost from the CBP arising from SSO customers and will be avoidable (*Id.* at 13-14).

(8) The Generation Cost Reconciliation Rider (Rider GCR) will be avoidable by customers during the period that the customer purchases retail electric generation service from a CRES provider unless the allowed balance of Rider GCR reaches five percent of the generation expense in two consecutive quarters (*Id.* at 14).

(9) Recovery of costs through Rider DFC and Rider DGC may be accelerated if such acceleration would be beneficial to customers and other signatory parties (*Id.*).

(10) The Commission may order a load cap of no less than 80 percent on an aggregated load basis across all auction products for each auction date such that any given bidder may not win more than 80 percent of the tranches in any auction (*Id.* at 15).

(11) The Companies will honor the commitments they made in the Combined Stipulation related to conducting a maximum of four RFPs through which the Companies will seek competitive bids to purchase RECs, including solar RECs, through ten-year contracts. The Companies will file with the Commission a separate application for approval of an RFP the Companies deem most appropriate. The filing of the application shall be within 90 days after the Commission's Opinion and Order or final Entry on Rehearing in this proceeding. The number of solar RECs will continue to be conditioned upon the SSO load of the Companies. The applications to the Commission will seek approval of recovery of all costs associated with acquiring RECs through the ten-year contracts through Rider AER or such other rider established to recover such costs. Additionally, such costs shall be recovered over the contract period (including any period for reconciliation) and shall be recovered irrespective of the Companies' need for RECs to meet their statutory requirement. (*Id.* at 15-18.)

(12) During the ESP 3 period, no proceeding will be commenced whereby an adjustment to the base distribution rates of the Companies would go into effect prior to June 1, 2016, subject to riders and other charges provided in the tariffs and subject to the significantly excessive earnings test (SEET), except in the case of an emergency pursuant to the provisions of Section 4909.16, Revised Code. The Companies are not precluded during this period from implementing changes in rate design

that are designed to be revenue-neutral or any new service offering, subject to Commission approval. (*Id.* at 18-19.)

(13) The Delivery Capital Recovery Rider (Rider DCR) will continue to be in effect to provide the Companies with the opportunity to recover property taxes, commercial activity tax, and associated income taxes, and earn a return on and of plant-in-service associated with distribution, subtransmission, and general and intangible plant, including general plant from FirstEnergy Service Company that supports the Companies and was not included in the rate base determined in *In re FirstEnergy*, Case No. 07-551-EL-AIR, et al., Opinion and Order (January 21, 2009). The return earned on such plant will be based on the cost of debt of 6.54 percent and a return on equity of 10.5 percent determined in that proceeding utilizing a 51 percent debt and 49 percent equity capital structure. (*Id.* at 19.)

For the twelve-month period from June 1, 2014, through May 31, 2015, that Rider DCR is in effect, the revenue collected by the Companies shall be capped at $195 million; for the following twelve-month period, the revenue collected under Rider DCR shall be capped at $210 million. Capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be excluded from Rider DCR and the annual cap allowance. Net capital additions for plant-in-service for general plant shall be included in Rider DCR provided that there are no net job losses at the Companies or as a result of involuntary attrition due to the merger between FirstEnergy Corp. and Allegheny Energy, Inc. (*Id.* at 20-21.)

Rider DCR will be updated quarterly, and the quarterly Rider DCR update filing will not be an application to increase rates within the meaning of Section 4909.18, Revised Code. The first quarterly filing will be made on or about April 20, 2014, based upon the actual plant-in-service balance as of May 31, 2014, with rates effective for bills rendered as of June 1, 2014. For any year that the Companies' spending would produce revenue in excess of that period's cap, the overage shall be recovered in the following cap period subject to such period's cap. For any year that the revenue collected under the Companies' Rider DCR is less than the annual cap allowance, the difference between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap. (*Id.* at 21-23.)

(14) Any charges billed through Rider DCR will be included as revenue in the return on equity calculation for purposes of the SEET test and will be considered an adjustment eligible for refund (*Id.* at 23).

Additionally, the Distribution Uncollectible Rider and the PIPP Uncollectible Rider may be audited by an independent consultant or Staff (*Id.* at 24).

(15) Network integration transmission services (NITS) and other non-market-based Federal Energy Regulatory Commission (FERC)/Regional Transmission Organization (RTO) charges will be paid by the Companies for all shopping and non-shopping load, and the amount shall be recovered through the Non-Market-Based Services Rider (Rider NMB). Winning bidders and retail suppliers will remain responsible for all other FERC/RTO imposed or related charges such as congestion and market-based ancillary services and losses, which would be bypassable as part of Rider GEN. (*Id.* at 24.)

(16) All MTEP charges that are charged to the Companies shall be recovered from customers through Rider NMB. The Companies agree not to seek recovery through retail rates for Midwest ISO (MISO) exit fees or PJM integration costs from retail customers of the Companies. The Companies further agree not to seek recovery through retail rates of legacy Regional Transmission Expansion and Planning (RTEP) costs for the longer of: (1) the five-year period between June 1, 2011, through May 31, 2016, or (2) when a total of $360 million of legacy RTEP costs have been paid by the Companies and have not been recovered by the Companies through retail rates from Ohio retail customers. (*Id.* at 25-27.)

(17) The demand response capabilities of customers taking services under Riders ELR and OLR shall count toward the Companies' compliance with peak demand reduction benchmarks as set forth in Section 4928.66, Revised Code, and shall be considered incremental to interruptible load on the Companies' system that existed in 2008 (*Id.* at 28).

(18) The following issues in the Companies' proposal for cost recovery, Case No. 09-1820-EL-ATA, for the Ohio site deployment of the smart grid initiative were approved in the *ESP 2 Case* as set forth below and shall continue under these terms and conditions. All other issues that were pending in that proceeding were decided in that proceeding.

(a) Costs shall be recovered from customers of OE, CEI, and TE, exclusive of rate schedule GT customers.

(b) All costs approved in Case No. 09-1820-EL-ATA associated with the project will be considered incremental for recovery under Rider AMI.

(c) Recovery of the costs approved in Case No. 09-1820-EL-ATA shall be over a ten-year period for recovery under Rider AMI. The recovery of costs over a ten-year period is limited to this ESP and shall not be used as precedent in any subsequent AMI or smart grid proceeding.

(d) Return on the investment shall be at the overall rate of return from the Companies' last distribution case.

(e) Rate base is defined as plant-in-service, depreciation reserve and accumulated deferred income taxes.

(f) All reasonably incurred incremental operating expenses associated with the project will also be recovered.

(g) During the term of the ESP 3, the deployment of the smart grid initiative will not include prepaid smart meters and there will be no remote disconnection for nonpayment absent compliance with the requirements of Rule 4901:1-18-05, O.A.C.

(h) The Companies shall not complete any part of the Ohio site deployment that the United States

> Department of Energy does not match funding in an equal amount.

(*Id.* at 29-30.)

(19) In lieu of the fixed monthly compensation provided pursuant to Case No. 09-553-EL-EEC, the Companies will provide funding to COSE, AICUO, OHA, and OMA for their roles as energy administrators for completed energy efficiency products in the following amounts, with such amounts being recovered through Rider DSE: COSE, $25,000 in 2014, $50,000 in 2015, and $25,000 in 2016; AICUO, $41,333 in 2014, $21,000 in 2015, and $21,000 in 2016; OHA, $25,000 in 2014, $50,000 in 2015, and $25,000 in 2016; and OMA, $100,000 in 2014, $100,000 in 2015, and $50,000 in 2016 (*Id.* at 30-31).

(20) During the term of the ESP 3, the Companies shall be entitled to receive lost distribution revenue for all energy efficiency and peak demand reduction programs approved by the Commission, except for historic mercantile self-directed projects. The collection of such lost distribution revenues by the Companies after May 31, 2016, is neither addressed nor resolved by the terms of the Stipulation. (*Id.* at 31.)

(21) The Companies will continue funding the Community Connections program under the same terms and conditions and amounts set forth in Case Nos. 07-551-EL-AIR, et al., and 08-935-EL-SSO, for the period of the ESP 3; however, provide that the amount may be increased as a result of the energy efficiency collaborative approval of such funding increase, and the Commission approval of the increase and authorization of recovery of the increased funding through Rider DSE or other applicable rider. OPAE shall be paid an administrative fee equal to five percent of the program funding. (*Id.* at 31-32.)

(22) An AICUO college or university member may elect to be treated as a mercantile customer, and the Companies will treat such college or university as a mercantile customer for the limited purposes of Section 4928.66, Revised Code, provided that the aggregate load of facilities situated on a campus and owned or operated by the college or university qualifies such entity as a mercantile customer and makes the college or university eligible for any incentive, program, or other benefit

made available to a mercantile customer pursuant to Section 4928.66, Revised Code (*Id.* at 32).

(23) The Companies will provide energy efficiency funding to the city of Akron to be used for the benefit of OE customers in the city of Akron in the following amounts, with such amounts recovered through Rider DSE: $100,000 in 2014, and $100,000 in 2015. The Companies also will provide energy efficiency funding to Lucas County to be used for the benefit of TE customers in Lucas County in the following amounts, with such amounts recovered through Rider DSE: $100,000 in 2014, and $100,000 in 2015. (*Id.* at 32-33.)

(24) The Companies are test deploying the Volt-Var Control distribution and communication hardware infrastructure and software systems as part of the Ohio smart grid initiative approved in Case No. 09-1820-EL-ATA. The results of the pilot study, including analysis of the associated costs and benefits, will be shared with the Commission and United States Department of Energy as they become available. (*Id.* at 34.)

(25) For the period of June 1, 2014, through May 31, 2016, the Companies will contribute, in the aggregate, $2 million to support economic development and job retention activities within their service areas. The Companies will not seek recovery of such contribution from customers, and such contribution will not be used to fund special contracts and/or reasonable arrangements filed with the Commission. (*Id.*)

(26) The provisions regarding the Cleveland Clinic Foundation agreed to in the Combined Stipulation shall continue under the terms approved in the *ESP 2 Case*, which included that CEI will be responsible for the cost of the electric utility plant, facilities, and equipment to support the Cleveland Clinic's Main Campus expansion plan to the extent that such cost might otherwise be demanded by CEI from the Clinic in the form of a contribution in aid of construction or otherwise. CEI shall be entitled to classify the original cost of investment made in utility plant, facilities, and equipment at or below the subtransmission level as distribution plant-in-service subject to the Commission's jurisdiction for ratemaking purposes at the time of the next base rate case. The first $70 million of the original cost of such plant, facilities, and equipment shall be funded by a non-

bypassable distribution rider that shall apply to retail residential, commercial, and industrial customers (exclusive of customers on rate schedules STL, TRF, and POL). Further, the Cleveland Clinic will be obligated to work in good faith to install cost-effective energy efficiency measures in its facilities, with, where needed, the assistance of an independent energy facility auditor selected by the Clinic with input from the Companies and Staff. The Cleveland Clinic will work with the Companies and Staff for the purpose of committing its new customer-sited capabilities to the Companies for integration into their Section 4928.66, Revised Code, compliance benchmarks, in exchange for the Companies' investment in the distribution utility plant, facilities, and equipment. (*Id.* at 34-37.)

(27) Domestic automaker facilities that used more than 45 million kilowatt-hours at a single site in 2009 will receive a discount on usage which exceeds, by more than ten percent, a baseline energy consumption level based upon their average monthly consumption for the year 2009. Any discount provided will be collected based on a levelized rate for all three Companies under Rider EDR from customers under the RS, GS, GP, and GSU rate schedules. (*Id.* at 37.)

(28) CEI agrees to continue the LED streetlight program approved in the *ESP 2 Case* for the city of Cleveland for the period of the ESP 3 (*Id.* at 38).

(29) The Companies agree to continue providing enhanced customer data and information and web-based access to such information, subject to and consistent with the Commission's rules (*Id.* at 39).

(30) The Companies' corporate separation plan approved in *In re FirstEnergy*, Case No. 09-462-EL-UNC, remains approved and in effect as filed (*Id.*).

(31) The Companies will file a separate application to commence recovery of any new or incremental taxes arising after June 1, 2011, whether paid by or collected by the Companies, and not recovered elsewhere, the recovery of which is contemplated by the Stipulation (*Id.*).

(32) Time-differentiated pricing concepts as proposed by the Companies and approved by the Commission in Case No. 09-541-EL-ATA shall continue in effect through the term of the ESP 3 (*Id.*).

(33) The Signatory Parties agree for themselves, and recommend to the Commission, to withdraw from FERC cases *FirstEnergy Service Co. v. PJM*, Docket No. EL10-6-000, and *American Transmission Systems, Inc.*, Docket No. ER09-1589-000 (*Id.* at 40).

(34) The Companies will make available $1 million dollars to OPAE for its fuel fund program, allocated as $500,000 in 2015, and $500,000 in 2016 (*Id.*).

(35) In order to assist low-income customers in paying their electric bills from the Companies, the fuel fund provided by the Companies shall be continued consisting of $4 million to be spent in each calendar year from 2015 through 2016 (*Id.*).

(36) Nothing in the Companies' proposed ESP 3 is intended to modify the Commission's order in Case No. 10-176-EL-ATA (*Id.* at 42).

(37) MSC agrees to dismiss with prejudice its complaint against TE, filed in Case No. 12-919-EL-CSS, upon Commission approval of the Stipulation, which authorizes TE to bill and collect a charge of $6.00 per kVa of billing demand under Rider EDR (*Id.*).

(38) The ESP 3 is more favorable in the aggregate as compared to the expected results that would otherwise occur under an MRO alternative, represents a serious compromise of complex issues, and involves substantial customer benefits that would not otherwise have been achievable (*Id.* at 40).

C. Procedural Issues

1. Waiver of Filing Requirements

OCC/CP claim that procedural due process has been denied in this proceeding. Specifically, OCC/CP note that the Commission granted, in part, and denied, in part, the Companies' motion for a waiver of certain filing requirements contained in Rule 4901:1-35-03, Ohio Administrative Code (O.A.C.). However, OCC/CP claim that granting the waivers, in part, denied parties' due process rights. OCC/CP acknowledge that, on June 1, 2012, the attorney examiner granted a motion to compel discovery submitted by

AEP Retail and that the Companies subsequently complied with the discovery request, providing additional analysis regarding the impact on customers' bills of the proposed ESP 3.

FirstEnergy responds that the Commission properly granted certain waivers of the filing requirements. FirstEnergy argues that OCC/CP had the opportunity to respond to the motion requesting waivers and that they took advantage of that opportunity by filing a memorandum contra the motion for waivers.

The Commission finds that any claims by OCC/CP regarding the waivers of the filing requirements are not timely. FirstEnergy filed a motion for waivers of the filing requirements on April 13, 2012, contemporaneous with the filing of the application. Several parties timely filed memoranda contra the motion. Subsequently, on April 25, 2012, the Commission granted, in part, and denied, in part, the request for waivers of the filing requirements. Neither OCC nor CP filed an application for rehearing of the April 25, 2012, Entry within 30 days of the issuance of the Entry as required by Section 4903.10, Revised Code. Accordingly, any claims by OCC or CP regarding the waivers are not timely and should be disregarded.

2. Administrative Notice

Moreover, OCC/CP, AEP Retail, ELPC, and NOPEC/NOAC argue that the Commission should reverse the attorney examiners' ruling taking administrative notice of parts of the record from Case No. 09-906-EL-SSO and the *ESP 2 Case*. OCC/CP contend that the attorney examiners' ruling taking administrative notice of the record from the previous cases was unreasonable and unlawful. OCC/CP concede that the Companies requested that administrative notice be taken of the record in the *ESP 2 Case* in the application filed in this proceeding on April 13, 2012, and that, at hearing, the examiners required the Companies to submit a list of specific documents for which administrative notice was requested rather than the entire record of the *ESP 2 Case* (Tr. I at 29).

NOPEC/NOAC contend that, although there is precedent for taking administrative notice in Commission proceedings, such precedent is inapplicable here because the parties did not have prior knowledge of the facts to be administratively noticed and were not provided with the opportunity to rebut such facts. NOPEC/NOAC argue that, although FirstEnergy had requested the Commission to take administrative notice of the record in the *ESP 2 Case* in its application, they did not have knowledge of the specific facts to be administratively noticed until the third day of the hearing when FirstEnergy provided a list of documents at the request of the attorney examiners. AEP Retail and ELPC also claim that parties had no prior notice of the facts administratively noticed, stating that parties had no way of knowing which facts from the *ESP 2 Case* would be administratively noticed. ELPC also claims that parties had no opportunity to explain and rebut the administratively noticed facts because the examiners did not rule on FirstEnergy's request for administrative notice until the third day of the hearing.

OCC/CP argue that the Commission may not take administrative notice of the record in another case if the decision lessens the Companies' burden of proof, noting that administrative notice, even when taken, has no effect other than to relieve one of the parties of the burden of resorting to the usual forms of evidence and that administrative notice does not mean that the opposing parties are prevented from disputing the matter by evidence if the opposing matter believes it is disputable. *Ohio Bell Tel. Co. v. Pub. Util. Comm.*, 301 U.S. 292, 301-302, 57 S.Ct. 724, 81 L.Ed. 1093 (1937). Moreover, OCC/CP claim that the non-signatory parties did not have knowledge of the specific documents which the Companies were requesting to be noticed until June 6, 2012, the third day of the evidentiary hearing. OCC/CP contend that it is unreasonable to expect parties to conduct discovery to determine the specific documents for which FirstEnergy sought administrative notice or to subpoena witnesses who did not file testimony in this case. OCC/CP further claim that the effect of this ruling was to lessen the Companies' burden of proof as prohibited by the Ohio Supreme Court in *Canton Storage and Transfer Co. v. Pub. Util. Comm.*, 72 Ohio St.3d 1, 9, 647 N.E.2d 136 (1995). OCC/CP claim that the reduction in the burden of proof was prejudicial to the non-signatory parties in the proceeding because the Companies bear the burden of proof in this proceeding. Section 4928.143(C), Revised Code.

NOPEC/NOAC and AEP Retail also argue that the attorney examiners erred in taking administrative notice of facts which were not undisputed. NOPEC/NOAC and AEP Retail claim that the Ohio Rules of Evidence limit administrative notice to adjudicative facts not subject to reasonable dispute. Evid.R. 201(B).

FirstEnergy and Nucor respond that the Commission properly took administrative notice of the record in the prior case. FirstEnergy and Nucor note that the arguments raised in opposition to the taking of administrative notice already have been considered and rejected by the Commission. *ESP 2 Case*, Entry on Rehearing (May 13, 2010) at 6. FirstEnergy argues that the Companies provided notice to all parties in the application filed on April 13, 2012, that the Companies sought administrative notice of the record in prior cases and that the parties did not seek any discovery regarding the Companies' request. Nucor also claims that the parties had every opportunity to contest or rebut Nucor's evidence. The Companies also reject OCC/CP's and NOPEC/NOAC's claims that the taking of administrative notice has reduced the Companies' burden of proof. The Companies claim that the Commission also rejected this argument in the *ESP 2 Case*. *ESP 2 Case*, Entry on Rehearing (May 13, 2010) at 7.

The Companies further argue that the attorney examiners did not err by taking administrative notice of opinions, as alleged by OCC/CP and NOPEC/NOAC.

FirstEnergy notes that OCC/CP and NOPEC/NOAC cite to no case that holds that administrative notice is inappropriate. Moreover, the Companies posit that administrative notice is a means of putting evidence in the record rather than a finding that the evidence is undisputed. The Companies argue that OCC/CP misinterpret *Ohio Bell*, failing to appreciate that the United States Supreme Court held in that case that "[Administrative notice] does not mean that the opponent is prevented from disputing the matter by evidence if he believes it disputable." *Ohio Bell*, 301 U.S. at 301-302, 57 S.Ct. 724.

The Commission notes that, with respect to the arguments raised by parties regarding the taking of administrative notice of certain documents, the Supreme Court has held that there is neither an absolute right for nor a prohibition against the Commission's taking administrative notice of facts outside the record in a case. Instead, each case should be resolved on its facts. The Court further held that the Commission may take administrative notice of facts if the complaining parties have had an opportunity to prepare and respond to the evidence and they are not prejudiced by its introduction. *Canton Storage* at 8. In addition, the Court has held that the Commission may take administrative notice of the record in an earlier proceeding, subject to review on a case by case basis. Further, parties to the prior proceeding presumably have knowledge of, and an adequate opportunity to explain and rebut, the evidence, and prejudice must be shown before an order of the Commission will be reversed. *Allen v. Pub. Util. Comm.*, 40 Ohio St.3d 184, 185-186, 532 N.E.2d 1307 (1988).

With respect to the claims that the Commission may not take administrative notice of opinions or that the Commission is bound by Evid.R. 201, the Commission notes that the Court has placed no restrictions on taking administrative notice of expert opinion testimony, and we decline to impose such restrictions in this case. Thus, expert opinion testimony may be administratively noticed if it otherwise meets the standards set forth in *Allen*. Likewise, the narrow provisions for judicial notice the parties claim are set forth in Evid.R. 201 are not consistent with the standards for Commission proceedings set forth in *Allen*; and, in any event, no party has cited any case demonstrating that administrative proceedings before the Commission are strictly bound by the Ohio Rules of Evidence.

In this proceeding, the Companies requested in the application filed on April 13, 2012, that administrative notice be taken of the full record of FirstEnergy's last SSO proceeding, the *ESP 2 Case*. In the *ESP 2 Case*, the Commission had taken administrative notice of an earlier proceeding, *In re FirstEnergy*, Case No. 09-906-EL-SSO (*MRO Case*); thus, the record of the *ESP 2 Case* includes the full record of the *MRO Case*. No party filed a memorandum contra or any other pleading in opposition to the request in the application in this case. At the hearing, the attorney examiners requested that the Companies provide a list of the specific documents for which administrative notice was sought (Tr. I at 29). The Companies complied with the attorney examiners' request (Tr. III at 11-12), and Nucor moved for administrative notice to be taken of one document (Tr. III at 19). Subsequently, the examiners took administrative notice of the enumerated documents (Tr. III at 171).

The Commission affirms the ruling of the attorney examiners that the parties had ample opportunity to prepare for and respond to the evidence administratively noticed in the *ESP 2 Case* and the *MRO Case*. The Commission notes that, at the request of the attorney examiners, FirstEnergy specified a relatively small number of documents for which it sought administrative notice (Tr. III at 11-12). Nucor supplemented this request with the inclusion of a single document (Tr. III at 19). Nothing prevented any party to this proceeding from making a similar discovery request of FirstEnergy, Nucor, or any other party. However, despite that fact that the parties were on notice that FirstEnergy was seeking administrative notice of documents in the record of the *ESP 2 Case* and the *MRO Case*, there is no record that any party requested in discovery that FirstEnergy specifically identity the evidence in the record of the *ESP 2 Case* and the *MRO Case* that the Companies intended to rely upon in this proceeding or that FirstEnergy refused such a request. Further, although motions to compel discovery were filed by parties in this proceeding and were promptly granted by the attorney examiners, no motions to compel discovery on this issue were filed by any party.

Further, the Commission notes that the parties had ample opportunity to explain or rebut the evidence for which FirstEnergy sought administrative notice, as the Commission described in our ruling on this same issue in the *ESP 2 Case*. *ESP 2 Case*, Entry on Rehearing (May 13, 2010) at 6-7. The parties had the opportunity to conduct further discovery on FirstEnergy and any other party regarding any evidence presented in the *ESP 2 Case* or the *MRO Case*. The record indicates that the parties had the opportunity to serve multiple sets of discovery upon the Companies in this proceeding; for example, OCC alone served six sets of discovery upon FirstEnergy (Tr. I at 18). Further, the parties had the opportunity to request a subpoena to compel witnesses from the *ESP 2 Case* or the *MRO Case* to appear for further cross-examination at hearing in this proceeding. The parties had the opportunity to cross-examine the witnesses at this hearing regarding any testimony presented in the *ESP 2 Case* or the *MRO Case* which was administratively noticed in this proceeding; in fact, OCC did cross-examine Staff witness Fortney regarding his testimony in the *ESP 2 Case* (Tr. II at 245-246, 250-251). Moreover, the parties had the opportunity to present testimony at hearing in this proceeding to explain or rebut any evidence in the record of the *ESP 2 Case* or the *MRO Case* which was administratively noticed in this proceeding.

Further, the Commission finds that the parties have not demonstrated that they were prejudiced by the taking of administrative notice of evidence in the record of the *ESP 2 Case* or the *MRO Case*. OCC/CP broadly claim that the taking of administrative notice lessened the burden of proof on FirstEnergy. This claim has been rejected by the Commission in identical circumstances. As we noted in the *ESP 2 Case*, the circumstances in an SSO proceeding are not remotely analogous to those in *Canton Storage*. In *Canton Storage*, the Court determined that the Commission "never expressly took administrative notice of any testimony below." *Canton Storage*, 72 Ohio St.3d at 8, 647 N.E.2d 136. Further, *Canton Storage* involved separate applications by 22 motor carriers seeking statewide operating authority rather than three affiliated utilities filing a single application for an electric security plan. In *Canton Storage*, the Commission relied upon shipper testimony as a whole to support the applications rather than on testimony related to the individual applicants, which the Court rejected as an elimination of a portion of the applicant's burden of proof. *ESP 2 Case*, Entry on Rehearing (May 13, 2010) at 7, citing *Canton Storage* at 8-10. In this case, there is no claim that FirstEnergy used evidence from one of the three affiliated electric utilities or from any other Ohio utility to bolster the case of any of the companies.

In addition, in our ruling in the *ESP 2 Case*, the Commission specifically noted that, pursuant to Section 4928.143(C)(1), Revised Code, the burden of proof was on FirstEnergy, and the Commission neither intended to nor eliminated any portion of that burden of proof on FirstEnergy by taking administrative notice of evidence in the prior proceeding. *ESP 2 Case*, Entry on Rehearing (May 13, 2010) at 7-8. However, consistent with our ruling in the *ESP 2 Case*, FirstEnergy, as well as every other party in this proceeding, is entitled to rely upon the evidence administratively noticed in the record of the prior proceeding to meet its burden of proof, and the Commission may rely upon evidence administratively noticed in reaching our decision in the instant proceeding.

Finally, the Commission notes that all claims of prejudice have been vague and overly broad. No party has identified a single specific document for which administrative notice was taken that in any way prejudices such party. No party has presented any arguments detailing how that party was prejudiced by the single document for which Nucor sought administrative notice. Therefore, consistent with our holding in the *ESP 2 Case*, we find that the taking of administrative notice of evidence in the prior proceeding has not lessened or reduced FirstEnergy's burden of proof in any way, and we find that no party has demonstrated that it has been prejudiced in any way in this proceeding.

3. Procedural Schedule

In addition, OCC/CP argue that the parties were denied thorough and adequate preparation for participation in this proceeding, in contravention of Rule 4901-1-16(A), O.A.C. OCC/CP claim that the parties had only 52 days to prepare for the hearing in this proceeding and that the consequence of the procedural schedule was that parties were limited in their ability to conduct follow-up discovery on initial and later responses. OCC/CP further note that the Companies filed a voluminous amount of material in the docket on May 2, 2012, in response to the Commission's denial of certain waivers sought by the Companies, which OCC/CP claim severely limited the parties' ability to conduct discovery on the material.

FirstEnergy claims that the procedural schedule in this proceeding was appropriate to consider the issues in dispute. The Companies note that Section 4928.143(C)(1), Revised Code, sets a maximum period in which the Commission should act upon an application for an ESP. It does not set a minimum period and the Commission has previously rejected claims that parties are entitled to the full 275-day period. *ESP 2 Case*, Entry on Rehearing (May 13, 2010) at 8. The Companies also argue that an expedited schedule was necessary because the Companies seek to modify the auction currently scheduled for October 2012 and that any Commission order modifying the auction must provide time for the Companies to implement the changes as well as allow for consideration of applications for rehearing (Co. Ex. 3 at 19; OCC Ex. 1).

The Companies also claim that the parties had adequate opportunities for discovery. The Companies claim that the parties fail to identify how they were prejudiced by the discovery schedule and that the Companies timely responded to numerous discovery requests served by intervenors (Tr. I, 18-19, 236).

The Commission notes that, by entry dated April 19, 2012, the attorney examiner shortened the discovery response time in this proceeding to ten days. With the shortened discovery response time, OCC was able to serve, and receive responses for, no less than six sets of discovery prior to the hearing in this proceeding (Tr. I at 18; Tr. III at 146-147). Further, the Commission notes that motions to compel discovery were filed by both Direct Energy and AEP Retail; these motions were granted, at least in part, and there is no indication in the record that the Companies failed to timely comply with the discovery orders. In addition, according to OCC/CP, the Companies filed a "voluminous" amount of material in the docket on May 2, 2012, in response to the denial of certain waiver requests by the Commission. Thus, the Commission cannot find that OCC/CP were denied the opportunity for through and adequate participation in this proceeding.

The Commission also notes that, on the last business day prior to the hearing, OCC/CP and other parties filed a motion for a continuance of the hearing. We note that objective facts which may be considered in determining whether to grant a continuance include the length of delay requested; whether other continuances have been granted; the inconvenience to parties' witnesses and opposing counsel; whether the delay is for legitimate reasons; whether the movant contributed to the necessity of the continuance; and any other facts unique to the case. *Niam Investigations, Inc. v. Gilbert*, 64 Ohio App.3d 125, 128, 580 N.E.2d 840 (1989). In this case, the attorney examiner denied the motion for a continuance based upon the following facts: the motion was filed on the eve of the hearing; the Commission had previously granted an extension of the hearing date; inconvenience to the parties' witnesses and counsel, many of whom had made travel arrangements to attend the hearing; and the discovery which gave rise to the motion could have been timely served and responded to, with minimal diligence by the moving parties (Tr. I at 25-26). *The Commission affirms the ruling of the examiner denying the continuance.*

4. Admission of AEPR Exhibit 6

AEP Retail argues that the attorney examiners erred when they did not admit AEPR Ex. 6 into evidence. AEP Retail submits that it offered AEPR Ex. 6 solely to illustrate how the proposed three-year blended auction rates necessarily increase migration risks and how a migration risk necessarily induces a CBP bidder to raise the price of its bid. AEP Retail represents that AEPR Ex. 6 adopted the Companies' own projections of wholesale rates under the current ESP 2 and the proposed ESP 3 blend; further, AEP Retail claims that, to illustrate how the proposed blend must increase costs, AEP Retail assumed a hypothetical migration rate in response to the price changes. AEP Retail claims that AEPR Ex. 6 is probative of the manner in which risk migration can be quantified and how that quantification results in a higher price as a result of the blending.

FirstEnergy responds that AEPR Ex. 6 was properly excluded because it lacked a foundation and because AEPR Ex. 6 is based on assumptions that are not in the record in this proceeding. FirstEnergy claims that AEP Retail is seeking the introduction of AEPR Ex. 6 for the sole purpose of showing that the longer a particular product is, the more potential there is for migration risk. FirstEnergy argues that AEP Retail is free to argue this point, notwithstanding whether AEPR Ex. 6 is admitted.

The Commission affirms the ruling of the attorney examiners not to admit AEPR Ex. 6 (Tr. IV at 153-154). The Commission notes that AEP Retail was free to provide a witness to sponsor AEPR Ex. 6 in order to lay a proper foundation for the exhibit, including the assumptions underlying the exhibit, subject to cross examination. AEP Retail chose not to provide a witness to sponsor AEPR Ex. 6, attempting instead to seek the admission of the exhibit through FirstEnergy rebuttal witness Stoddard. However, AEP Retail has provided no basis in the record for the assumptions contained in AEPR Ex. 6, and FirstEnergy witness Stoddard declined to agree with the assumptions (Tr. IV at 77-89). Accordingly, the Commission finds that AEP Retail failed to establish a proper foundation for AEPR Ex. 6, that the exhibit lacks any probative value in this proceeding, and that the attorney examiners properly denied admission of the exhibit. In any event, the Commission has thoroughly reviewed AEPR Ex. 6, and we find that its admission would not alter in any way the Commission determinations below.

D. Consideration of the Combined Stipulation

Rule 4901-1-30, O.A.C., authorizes parties to Commission proceedings to enter into a stipulation. Although not binding on the Commission, the terms of such an agreement are accorded substantial weight. *Consumers' Counsel v. Pub. Util. Comm.*, 64 Ohio St.3d 123, 125, 592 N.E.2d 1370 (1992), citing *Akron v. Pub. Util. Comm.*, 55 Ohio St.2d 155, 157, 378 N.E.2d 480 (1978). The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR (April 14, 1994); *Western Reserve Telephone Co.*, Case No. 93-230-TP-ALT (March 30, 1994); *Ohio Edison Co.*, Case No. 91-698-EL-FOR, et al. (December 30, 1993). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.*, 68 Ohio St.3d 559, 629 N.E.2d 423 (1994), citing *Consumers' Counsel* at 126. The Court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission.

1. Is the settlement a product of serious bargaining among capable, knowledgeable parties?

FirstEnergy, OEG, Nucor, MSC, and Staff argue that the Stipulation is the product of serious bargaining among capable, knowledgeable parties, in conformance with the first prong of the Commission's test for the evaluation of stipulations. OEG, Nucor, MSC, and the Companies note that each of the signatory parties has a history of participation and experience in Commission proceedings and is represented by experienced and competent counsel (Co. Ex. 3 at 10-11). Staff claims that support for the Stipulation is broad and varied with support from industrial customers, commercial customers, and the public; FirstEnergy also claims that the signatory parties are numerous and diverse (Co. Ex. 3 at 10). The Companies note that the signatory parties include many of the same capable and knowledgeable parties that the Commission recognized in approving the current ESP 2. *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 24. FirstEnergy claims that the absence of OCC, NOPEC, and NOAC does not diminish the diversity of the signatory parties, noting that, in past cases, OCC has considered OPAE and the Citizens' Coalition as representatives of the interests of "consumers" (Tr. III at 109-113; Co. Ex. 10, 11).

OCC/CP claim that the settlement is not a product of serious bargaining among capable, knowledgeable parties because the settlement lacked serious negotiations among all interested parties. OCC/CP and NOPEC/NOAC claim that, unlike negotiations in other proceedings, the parties to this case did not meet as a group even once before the filing of the Stipulation (OCC Ex. 11 at 7). OCC/CP contend that this violates the spirit of the Supreme Court's admonition regarding exclusionary settlement processes. *Time Warner AxS v. Pub. Util. Comm.*, 75 Ohio St.3d 229, 661 N.E.2d 1097 (1996). OCC/CP also note that intervenors who were not parties to the *ESP 2 Case*, such as AEP Retail and Sierra Club, were not included in the settlement discussions. Thus, OCC/CP posit that, because of the exclusionary nature of the settlement discussions, the Stipulation fails the first prong.

OCC/CP and NOPEC/NOAC contend that, although the Companies claim that a broad range of interests support the Stipulation, there is not a broad residential interest represented in the Stipulation. NOPEC/NOAC claim that the City of Akron is not a genuine representative of residential customers in the city. Likewise, AEP Retail claims that no customer receiving service through residential or commercial rates and no entity that represents residential or commercial customers in their capacity as ratepayers is a signatory party to the Stipulation. OCC/CP claim that, without a party that represents all residential customers, the Stipulation fails to represent the interests of most of FirstEnergy's customers and thus fails the first prong. OCC/CP acknowledge that OPAE and the Citizens' Coalition represent residential customers; however, OCC/CP claim that their interests are limited to low-income and moderate-income residential customers in the case of OPAE and low-income residential customers in the case of the Citizens' Coalition. OCC/CP further note that FirstEnergy will provide a $1.4 million fuel fund contribution to OPAE and the Citizens' Coalition to assist low-income customers in the years 2012 through 2016 (OCC Ex. 11, Att. 1).

AEP Retail argues that any appearance of broad support for the Stipulation exists solely because the Companies have agreed to subsidize the activities of certain parties at the expense of FirstEnergy's ratepayers. AEP Retail claims that large industrial customers support the proposed ESP 3 because benefits secured in the *ESP 2 Case* continue to flow to them. AEP Retail claims that all other signatory parties, except Staff, signed in support of the Stipulation in order to obtain a specific benefit in return for their support.

Akron responds that, in *Time Warner*, the Supreme Court held that a settlement is not a product of serious bargaining if an entire customer class is excluded from settlement negotiations. *Time Warner*, 75 Ohio St.3d at 241, 661 N.E.2d 1097. Akron claims that OCC/CP and NOPEC/NOAC are unable to claim that the entire residential class was excluded from negotiations because each of these parties was contacted prior to the execution of the settlement and given the opportunity to review and comment upon the draft stipulation prior to its filing (Tr. III at 25, 26, 101). Moreover, in response to NOPEC/NOAC's claim that Akron does not represent residential customers, Akron claims that NOPEC/NOAC witness Frye admitted that municipalities may represent residential customers and that neither NOAC nor NOPEC would have any connection to residential customers but for their agency relationship to local governments (Tr. III at 27-29).

The Commission finds that the Stipulation, as supplemented, appears to be the product of serious bargaining among capable, knowledgeable parties. We note that the signatory parties routinely participate in complex Commission proceedings and that counsel for the signatory parties have extensive experience practicing before the Commission in utility matters (Co. Ex. 3 at 10-11). The signatory parties represent diverse interests including the Companies, a municipality, competitive suppliers, commercial customers, industrial consumers, advocates for low and moderate-income customers, and Staff (*Id.* at 10). AEP Retail is simply wrong in its claim that there is no representation of residential or commercial customers in support of the Stipulation. OPAE advocates on behalf of low and moderate-income customers, and the Citizens' Coalition advocates on behalf of low-income customers. COSE and AICUO represent customers in the commercial rate classes.

Further, OCC/CP have specified a test under which a stipulation may be approved by the Commission only if the stipulation is agreed to by a representative of all residential customers in the Companies' service territory, and the only party which represents all residential customers is OCC. However, the Commission has already rejected this test, holding that we will not require any single party, including OCC, to agree to a stipulation in order to meet the first prong of the three-prong test. *Dominion Retail v. Dayton Power & Light Co.*, Case No. 03-2405-EL-CSS, Opinion and Order (February 2, 2005) at 18; Entry on Rehearing (March 23, 2005) at 7.

With respect to the form and manner of the negotiations, the Commission declines to impose a requirement that all interested parties meet as a group prior to the filing of a stipulation. Many parties or their counsel are not located in this state. There is no reason to impose a requirement that they be physically present in this state at least one time prior to the execution of a stipulation. On the other hand, with advances in technology, information and settlement proposals can be easily and quickly shared among parties located in or out of this state. Moreover, in order to promote confidentiality in settlement negotiations, the Commission has available to it a very limited record with respect to the settlement process in any given proceeding; in this case, however, it appears that every party to the *ESP 2 Case* was contacted by FirstEnergy during the negotiations and that each party was given an opportunity to review and comment upon the draft stipulation before it was filed with the application in this proceeding (Tr. III at 101). In addition, there is no evidence in the record that an entire customer class was excluded from the settlement negotiations, which was the factual predicate of *Time Warner*. *Constellation NewEnergy, Inc. v. Pub. Util. Comm.*, 104 Ohio St.3d 530, 2004-Ohio-6767, 820 N.E.2d 885, at ¶ 8-9. Accordingly, we do not find that the settlement negotiations were exclusionary or that the negotiations violated the admonition in *Time Warner*.

Further, the Commission notes that many signatory parties receive benefits under the Stipulation, but the Commission will not conclude that these benefits are the sole motivation of any party in supporting the Stipulation, as AEP Retail alleges without any evidentiary support. The Commission expects that parties to a stipulation will bargain in support of their own interests in deciding whether to support that stipulation. The question for the Commission under the first prong of our test for the consideration of stipulations is whether the benefits to parties are fully disclosed as required by Section 4928.145, Revised Code.

The Commission also finds that OCC/CP misrepresent the fuel fund contribution to assist low-income customers as a "side-deal." The fuel fund contribution is fully disclosed in the Stipulation (Co. Ex. 1, Stip. at 40-42). OCC's witness Gonzalez admitted that there is no agreement that provides for some additional payment above and beyond the payment provided for by the Stipulation (Tr. III at 114-115).

Accordingly, we find that, based upon the record before the Commission, all benefits to signatory parties are fully and adequately disclosed pursuant to Section 4928.145, Revised Code. The Commission will determine whether the cumulative benefits parties receive under the Stipulation, as a package, benefit ratepayers and the public interest in our consideration of the second prong of our test for the consideration of stipulations below.

2. Does the settlement, as a package, benefit ratepayers and the public interest?

a. General Arguments

The Companies contend that the Stipulation will benefit ratepayers and the public interest because the Stipulation proposes to adopt an ESP that contains essentially the same terms as the ESP 2, which has produced several successful auctions that have benefited customers with reasonably priced generation service. Further, the Companies argue that the ESP 3 will provide greater price certainty during its term.

The Companies argue that the CBP proposed in the Stipulation mirrors the process the Commission accepted in its approval of the ESP 2. The Companies further point out that OCC witnesses Gonzalez and Wilson and NOPEC/NOAC witness Frye admitted in their testimony that the Companies' SSO auctions have been successful (Tr. II at 112; Tr. III at 49-50, 143). Additionally, the Companies contend that the proposed ESP 3 will allow the Companies to blend the results from the October 2012 and January 2013 auctions with results from prior auctions to set the price for the June 1, 2013, through May 31, 2014, period in the ESP 2 (Co. Ex. 1, Stip.; Co. Ex. 3 at 3-4). The Companies also argue that, like the prior CBPs, the proposed CBPs in the ESP 3 are open, fair, transparent, competitive, standardized, clearly defined, and independently administered processes (Co. Ex. 3 at 11-12). The Companies note that the proposed CBPs continue to allow for significant Commission oversight and benefit ratepayers and the public interest by continuing to provide an open and competitive process that promotes lower and more stable generation prices during the two-year term of the proposed ESP 3 (Co. Ex. 1, Stip.). As to competition, the Companies note that, under the ESP 2, governmental aggregation and customer shopping have been very active, leading to savings for customers, and that the ESP 3 will also contain no minimum default service charges, standby charges, or shopping caps, which will continue to support governmental aggregation and customer shopping (Co. Ex. 3 at 12). Further, the Companies note that, in an agreement with Constellation and Exelon, the Companies have agreed to make a number of changes to the electronic data interchange protocol to further support customer shopping (Tr. II at 73-76; Co. Ex. 7).

The Companies claim that the ESP 3 incorporates an improvement over the ESP 2 because the ESP 3 extends the products in the currently scheduled October 2012 and January 2013 auctions from 12 months to 36 months, for a portion of the Companies' SSO load, in order to capture the value of current low energy and capacity prices for the term of the ESP 3 (Co. Ex. 3 at 8). The Companies state that this use of varied lengths of SSO load over multiple auctions, or "laddering," will smooth out generation prices, and that laddering is a mitigation strategy for risk and price volatility that has been accepted by the Commission for use to procure loads under the ESP 2 (Co. Ex. 3 at 8). *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 8, 36. The Companies state that, if laddering is not used, customers could experience substantial year-to-year increases (Tr. I at 155).

Regarding distribution, FirstEnergy contends that the distribution provisions of the ESP 3 will provide additional certainty and stability to customer rates because the ESP 3 continues the distribution rate freeze instituted by the *ESP 2 Case* through May 31, 2016, except for certain emergency conditions provided for by Section 4909.16, Revised Code (Co. Ex. 3 at 12-13). FirstEnergy further notes that the ESP 3 would continue to provide for investments in the Companies' distribution infrastructure by continuing Rider DCR through the ESP 3 period, which would also be capped (Co. Ex. 1, Stip. at 18-20; Co. Ex. 3 at 14). Additionally, the Companies point out that Staff and other signatory parties would have the opportunity to review quarterly updates and participate in an annual audit process (Co. Ex. 1, Stip. at 21-23).

Another improvement in the proposed ESP 3, according to the Companies, is the extension of the recovery period for renewable energy credit costs over the life of the proposed ESP 3 (Co. Ex. 1, Stip. at 10-11). FirstEnergy argues that this extension will mitigate the near-term rate impact on customers related to the costs for the Companies' compliance with the statutory benchmarks for renewable energy resources (Co. Ex. 3 at 8).

Next, FirstEnergy asserts that the ESP 3 continues to provide substantial support for energy efficiency and peak demand reduction requirements. Specifically, the proposed ESP 3 will continue Riders ELR and OLR as a demand response program under Section 4928.66, Revised Code (Co. Ex. 1, Stip. at 28-29). The Companies contend that this provision may benefit all customers because suppliers will take into account the ability to reduce load at peak pricing in their CBP bids, which may promote lower prices resulting from the CBP (Co. Ex. 1, Stip. at 28). OEG similarly contends that continuation of the Companies' interruptible credit under Riders ELR and OLR may reduce capacity costs for customers and will facilitate economic development (Co. Ex. 1, Stip. at 28-29).

FirstEnergy next argues that recovery of lost distribution revenue is both permissible and proper under the proposed ESP 3. FirstEnergy points to Section 4928.143, Revised Code, as allowing the collection of lost distribution revenue. Additionally, the Companies note that the lost distribution recovery collection period proposed in the ESP 3 seeks authority to recover during the period of June 1, 2014, through May 31, 2016 (Co. Ex. 1, Stip. at 31). Finally, the Companies note that the Commission has previously found that any recovery of lost distribution revenue beyond the time period covered by the stipulation at issue is not relevant. *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 44-45.

With regard to transmission, the Companies state that the Stipulation will continue their commitment not to seek recovery from customers for Midwest ISO (MISO) exit fees and PJM integration costs. Further, the Companies contend that they will continue to not seek recovery of RTEP legacy charges, for the longer of the five year period of June 1, 2011, through May 31, 2015, or when a total of $360 million of legacy RTEP charges have been paid by the Companies, but not recovered through retail rates.

The Companies further assert that, under the ESP 3, AICUO member schools will continue to be eligible to institute mercantile customer-sited energy efficiency projects if their aggregate load qualifies as a mercantile customer (Co. Ex. 1, Stip. at 32). Moreover, the Companies note that the ESP 3 will continue to provide for an LED streetlight pilot program for Cleveland, energy efficiency funding for Akron and Lucas County; and continued funding for energy efficiency administrators, as approved in the *ESP 2 Case*.

The Companies further emphasize that the ESP 3 will continue to provide economic development funding to help stimulate the economy of the Companies' territories and job development and retention in those regions. The ESP 3 will continue to support the expansion of the Cleveland Clinic, one of the largest private employers in northern Ohio. Additionally, the ESP 3 will continue to provide incentives for domestic automakers that increase production. Further, the ESP 3 continues to provide rate mitigation for certain rate schedules and shareholder funding for economic development and job retention programs. (Co. Ex. 1, Stip. at 34-38.)

The Companies also claim that the ESP 3 will continue to provide support for low-income residential customers. This includes continuation of a six percent discount for PIPP customers off the price-to-compare. This discount will continue to be provided through a bilateral contract with FES. (Co. Ex. 1, Stip. at 9.) However, the Stipulation recognizes that the Ohio Department of Development (ODOD) may secure a better price with another supplier pursuant to Section 4928.66, Revised Code (Tr. I at 113-114, 123-124). The ESP 3 also continues to provide funding for the Community Connections program and for low-income customer assistance through the fuel fund program (Co. Ex. 3 at 7; Co. Ex. 1, Stip. at 31-32, 40-41).

Finally, FirstEnergy notes that the Stipulation will resolve several other matters that would otherwise be the subject of litigation. This includes *Material Sciences Corporation v. The Toledo Edison Company*, Case No. 12-919-EL-CSS, as well as the possibility of a distribution base rate increase during the term of the ESP 3 (Co. Ex. 1, Stip. at 18-19). Further, the Stipulation resolves disputes related to the Companies' recovery of lost distribution revenue associated with energy efficiency and peak demand reduction programs through May 31, 2016 (Co. Ex. 1, Stip. at 31).

OEG, IEU-Ohio, Nucor, and MSC all concur that the Stipulation benefits ratepayers and the public interest.

Staff contends that the Stipulation is beneficial to the public and the ratepayers for many of the reasons that the ESP 2 is beneficial but that, particularly, the primary benefit of the Stipulation is the blending effect of prices that will be achieved through the use of laddered auction products in order to lower volatility (Tr. II at 154). Staff contends that the Stipulation is also beneficial because it provides for a discount from the auction price for PIPP customers, supports shopping by the absence of shopping caps and standby charges, retains a variety of bill credits, and continues support for economic development and low-income customers (Co. Ex. 3 at 3-8).

OEG argues that the Stipulation supports competition, both at the wholesale and retail level, which can result in savings benefits for customers (Co. Ex. 3 at 12). OEG also points out that the Stipulation provides benefits to multiple customer groups, including low-income customers, non-standard residential customers, schools, local governments, and large industrial customers (Co. Ex. 3 at 13). Nucor contends that the Stipulation continues the existing cost allocation and rate design, which the Commission has previously found to be just and reasonable (Co. Ex. 3 at 8; Tr. II at 114-115). MSC states that the Stipulation benefits ratepayers and the public interest by providing MSC with a load factor adjustment, which will promote economic development in the Toledo, Ohio, region, and supports MSC retention of existing manufacturing (Co. Ex. 1, Stip. at 42-43).

b. Competitive Bid Process

OCC/CP argue that the Stipulation, as a package, does not benefit ratepayers and is not in the public interest because it subjects FirstEnergy's customers to higher rates so that price stability may be accomplished. OCC/CP specify that impending plant retirements, planned transmission upgrades, and uncertain market reaction to provide new generation, demand response, and energy efficiency capacity, have rendered future generation supply and prices in the American Transmission System Incorporated (ATSI) zone highly uncertain (OCC Ex. 9 at 3-4). Due to that high uncertainty, OCC/CP contend that the proposed three-year auction product creates risks that will raise costs for the Companies' customers. Further, OCC/CP argue that customers do not need the Stipulation to achieve stability but can obtain price stability in the market through use of a CRES provider. OCC/CP continue that the generation prices resulting from the proposed three-year product do not serve the public interest, but serve to benefit FES, FirstEnergy's affiliate, because FES will receive higher auction clearing prices that will result from the uncertainties that cause other bidders to raise their offer prices (OCC Ex. 9 at 7-8).

Similarly, NOPEC/NOAC argue that the ESP 3 proposal does not benefit ratepayers and the public interest because residential and small commercial customers will be negatively affected by the proposed alterations to the CBP schedule. AEP Retail also argues that the Stipulation will result in higher rates because of the proposed auction structure and claims that record evidence necessary to quantify the magnitude of that increase is lacking.

The Companies respond to other parties' concerns about high risk premiums caused by uncertainty by arguing that this result is unlikely based on past experience. In support of this assertion, the Companies point out that OCC witness Wilson predicted similar calamities in 2009 during the *ESP 2 Case* proceedings (Co. Ex. 14 at 4, 14) but that the CBPs during the ESP 2 period were characterized by numerous bidders and the procurement of reasonably priced reliable power. Further, the Companies point to FirstEnergy witness Stoddard's testimony that a three-year product has been widely used in similar auctions and note that OCC witness Wilson presented no evidence that a three-year period was difficult to hedge or carried a significant premium (Co. Ex. 14 at 5, 16-17). Further, the Companies respond to OCC/CP's argument that customers can obtain price stability by purchasing power in the market from a CRES provider by pointing out that nonshopping customers should also be able to receive this benefit, particularly during a time OCC/CP claim is characterized by high uncertainty.

In their reply brief, OCC/CP argue that FirstEnergy has not offered any evidence to dispute the fact that FES does not face the same degree of uncertainty and risk as its competitors and, thus, that FES will benefit from the higher auction clearing prices. Further, OCC/CP contend that the Commission should not over-rely upon the historical success of the FirstEnergy auctions under the ESP 2 because unprecedented unknowns in the future will impact the generation portion of a customer's bill. OCC/CP also state that the significant increase in capacity prices obtained in the recent base residual auction may be an indication that increased energy prices will result from future auctions.

In its reply brief, AEP Retail contends that, although the Companies have claimed that approval will permit them to "lock in" low prices, they have introduced no evidence concerning what energy prices within the ATSI zone might be at the time of their proposed auctions, and no information suggesting what the price of energy might be at any later point. Further, AEP Retail argues that the Companies have ignored information currently available regarding future energy prices and contends that the recent base residual auction results strongly suggest that prices will increase dramatically if the 2015/2016 year is included in the October 2012 CBP auction. AEP Retail also argues that, during the ESP 2, customers paid the costs associated with the benefits of laddering in advance and were to receive the benefits of that payment in the third year of the ESP 2. If the ESP 3 is approved, however, AEP Retail argues that these planned nominally lower rates will be replaced by nominally higher rates that reflect the new costs that must be paid up front in return for nominally lower rates to be expected in the 2015/2016 year.

The Commission agrees with the Companies and Staff that the laddering of products in order to smooth out generation prices, mitigating the risk of price volatility, will benefit ratepayers and the public interest. The Commission finds that OCC/CP and AEP Retail's arguments have merely established that future prices are uncertain; however, unlike OCC/CP and AEP Retail, the Commission believes that future price uncertainty makes laddering of products in order to mitigate volatility an even greater benefit for ratepayers (Co. Ex. 3 at 8; Tr. I at 155; Tr. II at 154). *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 8, 36. Further, although OCC/CP contend that customers could achieve price stability by purchasing power in the market from a CRES provider, the Commission believes that non-shopping customers are also entitled to receive the benefit of price stability.

c. Distribution Rate Freeze and Rider DCR

OCC/CP argue that the continued use of Rider DCR is not in the public interest. Initially, OCC/CP admit that Ohio law provides an opportunity for an electric distribution utility (EDU) to request recovery for distribution expenditures as part of an ESP proposal under Section 4928.143(B)(2)(h), Revised Code. However, OCC/CP note that the statute also requires the Commission to review the reliability of the EDU's distribution system to ensure that customers' and the EDU's expectations are aligned and that the EDU is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system. Here, OCC/CP argue that the Companies have failed to provide the information necessary for the Commission to complete this review. OCC/CP contend that testimony presented by Staff witness Baker demonstrated that the reliability standards were achieved in 2011 but did not correlate the Companies' reliability performance in 2011 to the Rider DCR recovery sought in the proposed ESP 3. Further, OCC/CP argue that the evidence submitted on customer expectations utilized reliability standards established in 2009 or 2010 compared to the Companies' actual performance in 2011 (Staff Ex. 2 at 5; Tr. II at 221-222). OCC/CP state that this information will be "stale" at the beginning of the term of the proposed ESP 3. Further, OCC/CP argue that the Companies' and customers' expectations are not aligned, that the resources the Companies have dedicated to enhance distribution service are excessive, and that there is no remedy to address excessive distribution-related spending in the annual Rider DCR audit cases.

Similarly, NOPEC/NOAC argue that the ESP 3 proposal does not benefit ratepayers and the public interest because residential and small commercial customers will be negatively affected by increases of approximately $405 million in the amount of distribution improvement costs proposed to be recovered through Rider DCR.

AEP Retail also argues that the "cap" on recovery under Rider DCR under the Stipulation may provide a benefit, or may not, depending on the amounts FirstEnergy invests in distribution over the ESP 3 period. However, AEP Retail claims that the Companies have failed to introduce evidence concerning their anticipated distribution investments or accumulated depreciation, making it impossible for the Commission to evaluate this claimed benefit.

OSC contends that Rider DCR recovery is only limited by certain revenue caps and could total $405 million during the period of the proposed ESP 3. OSC argues that, instead of Rider DCR, the Companies should be required to file a formal distribution rate increase case, as, in the past, the Commission has not awarded the Companies the full amount of the requested increase for distribution-related investments. *Distribution Rate Case*, Case No. 07-551-EL-AIR, Opinion and Order (January 21, 2009) at 48.

The Companies respond that the reliability information utilized in this proceeding was not "stale," citing the fact that OCC witness Gonzales admitted that the Companies' reliability performance standards are not required to be updated (Tr. III at 117-118). Further, the Companies point out that they are also not required by statute to prove that additional investments in the system will impact reliability performance or demonstrate that the Companies' reliability performance and customers' expectations for a proposed ESP are aligned. The Companies also argue that OCC/CP and OSC's claims that the Companies have proposed to recover $405 million as increased distribution revenue recovery is wrong. The Companies proffer that the ESP 3 proposes that recoveries under Rider DCR be capped, and that the caps are proposed to increase by $15 million on an annual basis, identical to the annual increases in the *ESP 2 Case* (Co. Ex. 3 at 14). The Companies state that this increase in the amount of the caps represents a cumulative $45 million increase over the caps allowed in the *ESP 2 Case*. Further, the Companies note that, as stated in the Stipulation, they will be required to show what they spent and why it is appropriate to recover these investments through Rider DCR and that the recovery will also be subject to an annual audit.

The Commission finds that the Companies have demonstrated the appropriate statutory criteria to allow continuation of Rider DCR as proposed in the Stipulation. As discussed in Staff's testimony, Staff examined the reliability of the Companies' system and found that the Companies complied with the applicable standards (Staff Ex. 2 at 5-6). Further, the Stipulation provides for an annual audit of recovery under Rider DCR and requires the Companies to demonstrate what they spent and why the recovery sought is not unreasonable. Additionally, the Commission notes that the caps on Rider DCR do not establish certain amounts that the Companies will necessarily recover – thus, the Commission emphasizes that the $405 million figure discussed by NOPEC/NOAC and OSC is the maximum that could be collected under Rider DCR and is not a guaranteed amount. (Co. Ex. 1, Stip. at 20-23; Co. Ex. 3 at 14.)

d. Renewable Energy Credit Recovery Period

NOPEC/NOAC argue that the ESP 3 proposal does not benefit ratepayers and the public interest because residential and small commercial customers will be negatively affected by the proposed modifications to the recovery period of renewable energy credit costs. Similarly, RESA/Direct Energy contend that the Companies' proposal to extend the recovery period for renewable energy credit costs over the life of the ESP 3 is not in the ratepayers' best interest. Specifically, RESA/Direct Energy argue that the proposed extension would cause the Companies' price-to-compare to be artificially low when comparing it to offers from CRES providers, which would dampen shopping (RESA Ex. 1; Tr. I at 255). Further, RESA/Direct Energy contend that, in the long-term, customers will still be charged for the renewable energy credit costs in addition to seven percent carrying costs.

In their reply brief, OCC/CP echo RESA/Direct Energy's concerns about carrying costs. By way of example, OCC/CP point out that, from 2011, the Companies accrued nearly $680,000 in carrying charges associated with Rider AER deferrals (OCC Ex. 5).

In their reply brief, the Companies respond to these arguments regarding the recovery period for renewable energy credit costs by noting that CRES providers are free to take advantage of the same opportunity to extend the period for recovery of alternative energy costs. Further, the Companies counter RESA/Direct Energy's argument regarding artificially low prices by arguing that the current situation actually reflects an artificially high Rider AER. The Companies explain that, because the statutory alternative energy requirements are based on a historical baseline, if the Companies' customers shop, there is less SSO load over which to spread the recovery of a larger potential cost, which inflates Rider AER (Tr. I at 257-258). This sentiment is echoed in Nucor and OEG's reply briefs.

The Commission finds that the extension of the recovery period for renewable energy credit costs over the life of the proposed ESP 3 is an appropriate method to mitigate rate impacts on customers related to the costs for the Companies' compliance with statutory renewable energy requirements (Co. Ex. 3 at 8). As stated in our discussion of the proposed changes to the competitive bid process, the Commission believes that mitigating the risks of price volatility and smoothing of prices is a benefit for ratepayers and is in the public interest. Further, the Commission finds that the mitigating effects of this benefit outweigh the potential carrying costs (*Id.*). Further, as to RESA/Direct Energy's argument that extension of the recovery period will artificially lower the Companies' price-to-compare and inhibit shopping, the Commission finds that, as argued by FirstEnergy, CRES providers are not prohibited from seeking to extend the period for recovery of alternative energy compliance costs to lower their own prices. Consequently, the Commission finds that the extension of the recovery period for renewable energy credits is competitively neutral.

e. Energy Efficiency/Peak Demand Reduction

OCC/CP first contend that the resolution of issues related to Riders ELR and OLR would be more appropriately determined in the Companies' energy efficiency/peak demand reduction portfolio filing. Additionally, OCC/CP argue that it is unreasonable for the Companies to seek collection of the costs associated with Riders ELR and OLR from all customers, including residential customers (Co. Ex. 1, Stip. at 12-13). In support of their argument, OCC/CP note that large customers are not required to pay for residential energy efficiency and peak demand reduction programs. Consequently, OCC/CP argue that this provision in the Stipulation should be eliminated in favor of full cost collection from non-residential customers.

EnerNOC states that, although it does not oppose the Stipulation and agrees that the Stipulation is a fair compromise, it did not sign the Stipulation as a supporting party because it cannot support the proposed ESP 3 provision that extends the ELR program from June 1, 2014, through May 31, 2016. EnerNOC argues that the Commission should enforce language in the Stipulation limiting participation in the Companies' ELR program to those customers who signed up prior to May 3, 2012. EnerNOC contends that failure to enforce this deadline could reduce the amount of available customers with interruptible load capacity that might participate in the PJM base residual auctions going forward.

Sierra Club notes that Section 4928.143, Revised Code, permits electric utilities to include in an ESP provisions for energy efficiency programs. Sierra Club argues that, despite ample notice of the 2015/2016 base residual auction and the likely consequences for the Companies' customers, the Companies failed to take any steps to prepare for the base residual auction. Instead, Sierra Club argues that FirstEnergy made only a token bid of energy efficiency obtained through lighting programs, which cleared a mere 36 megawatts (MW) of energy efficiency (Tr. I at 301). Sierra Club claims that FirstEnergy's viable energy efficiency resources amount to 339 MW.

Sierra Club rejects the explanations offered by FirstEnergy witness Ridmann as *post hoc* excuses (Tr. I at 288). Sierra Club argues that the Companies planned compliance with future benchmarks mitigates any risks to the Companies and that the Companies could have made up any shortfall by purchasing needed resources in future incremental auctions. Sierra Club observes that, although questions of ownership of the energy efficiency resources are legitimate, this question could have been addressed by making it a condition of future participation in energy efficiency programs. Accordingly, Sierra Club argues that FirstEnergy should be held accountable for financial harm caused to its customers. Sierra Club recommends that financial harm to ratepayers be quantified and that FirstEnergy be required to compensate its customers by investing in energy efficiency programs above the statutory minimums without compensation to the Companies through shared savings.

In its reply brief, OEG contends, in response to EnerNOC's argument, that FirstEnergy witness Ridmann testified that, given the procedural schedule set by the Commission in this case, the May 3, 2012, deadline was no longer necessary (Co. Ex. 4 at 6). Similarly, IEU-Ohio contends in its reply brief that FirstEnergy intends to rely upon customers electing service under Rider ELR as an option to meet its statutorily required peak demand reduction, and that FirstEnergy witness Ridmann testified that the Companies would inform relevant customers of the new required date to elect to continue service pursuant to Rider ELR following the issuance of a Commission order in this proceeding in light of the fact that the Stipulation was not approved prior to the May 7, 2012, base residual auction (Tr. I at 311; Co. Ex. 4 at 6).

In its reply, Nucor argues that EnerNOC's recommendation that only customers who renewed their commitment by May 3, 2012, be permitted to stay on Rider ELR should be rejected because it would punish other ELR customers. Further, Nucor argues that EnerNOC's claim that a Rider ELR extension will result in less interruptible load to be bid into the 2016/2017 and 2017/2018 base residual auctions is nonsensical, and that EnerNOC has failed to demonstrate any harm from the elimination of the May 3 deadline. Nucor recommends that the Commission clarify in its order that current ELR customers do not need to have signed a contract addendum by May 3, 2012, in order to qualify for the ELR extension. Finally, Nucor opposes OCC/CP's recommendations and contends that Riders ELR and OLR should be addressed in this proceeding and that allocation and recovery of ELR and OLR costs under Rider DSE is appropriate because the rates provide benefits spanning all customer classes.

In its reply brief, FirstEnergy urges the Commission to reject OCC/CP's recommendation that the Commission reject continuation of the provisions in the ESP 2 that allow for the costs arising from Riders ELR and OLR to be recovered from all customers. FirstEnergy argues that OCC/CP's complaint that these costs should not be recovered from residential consumers lacks rationality because OCC witness Gonzalez admitted that these riders benefit residential customers (Tr. III at 99). Further, FirstEnergy responds that EnerNOC's argument regarding the May 3, 2012, deadline ignores the condition precedent in the Stipulation requiring Commission approval of the ESP 3 by May 2, 2012, in order to trigger the requirement that customers sign up for the approved tariff by May 3, 2012 (Co. Ex. 1, Stip. at 28-29).

The Commission agrees with FirstEnergy and Nucor that OCC/CP have failed to support their recommendations that the costs related to Riders ELR and OLR should not be collected from all customers, and no reason is apparent in light of the fact that all customer classes benefit from the rates related to ELR and OLR (Tr. III at 99). Additionally, the Commission finds that OCC/CP have set forth no persuasive reason why Riders ELR and OLR would be more appropriately addressed in another proceeding.

Additionally, as to EnerNOC's arguments, the Commission notes that the Stipulation provides for extension of the ELR and OLR programs and states that Commission approval of the continuation of Riders ELR and OLR will potentially enable the Companies to bid the demand response resources arising from these tariffs into the PJM base residual auction scheduled for May 7, 2012 (Co. Ex. 1, Stip. at 28). Further, this provision states that customers wishing to continue to remain on Rider ELR must sign an addendum to their contract for electric service by May 3, 2012, signaling their commitment of their demand response capabilities to the Companies (*Id.* at 28-29). In light of the fact that the Stipulation specified this deadline would be triggered by Commission approval of the ESP 3, which had not yet occurred by May 3, 2012, the Commission finds that EnerNOC's argument regarding the May 3, 2012, deadline is unreasonable. Consequently, the Commission clarifies that current ELR customers do not need to have signed a contract addendum by May 3, 2012, in order to qualify for the ELR extension.

With respect to energy efficiency and participation in base residual auctions, the Commission finds that this proceeding was not opened to investigate the Companies' actions in the 2015/2016 base residual auction and that the record does not support a finding that the Companies' actions in preparation for bidding into the 2015/2016 base residual auction were unreasonable. Sierra Club witness Neme acknowledged that the ownership concerns are legitimate, and no party has claimed that it brought these concerns to FirstEnergy's attention in its energy efficiency collaborative or raised this issue before the Commission in the Companies' most recent program portfolio proceeding, *In re FirstEnergy*, Case Nos. 09-1947-EL-POR, et al. (Tr. I at 352-353, 363-365). The Commission did open a proceeding to review FirstEnergy's preparations for the 2015/2016 base residual auction, and, in response, the Companies did bid energy efficiency resources into the auction.

However, the Commission notes that additional steps may be taken to mitigate the impact of the transmission constraint in the ATSI zone for future base residual auctions. Specifically, the Companies should take steps to amend their energy efficiency programs to ensure that customers, knowingly and as a condition of participation in the programs, tender ownership of the energy efficiency resources to the Companies. Further, the Companies should continue to take the necessary steps to verify the energy savings to qualify for participation in the base residual auctions, and the Companies should bid qualifying energy resources into the auction. The record demonstrates that there has been tremendous growth in the use of energy efficiency resources in the capacity auctions, and the Companies are well positioned to substantially increase the amount of energy efficiency resources they can bid into the auction, which will assist in mitigating the impact of the transmission constraint in the ATSI zone. Further, the Commission will continue to review the Companies' participation in future base residual auctions until such time as the transmission constraint in the ATSI zone is resolved.

f. Lost Distribution Revenue

OCC/CP contend that the lost distribution revenue provision in the Stipulation does not benefit residential consumers. Specifically, OCC/CP argue that the Stipulation allows for an open-ended lost distribution revenue collection period that is excessive and unprecedented because it is not capped by either a dollar amount or a time period. Further, OCC/CP argue that this provision in the Stipulation could allow collection of lost distribution revenues of $50 million if the Companies ceased their energy efficiency programs on December 31, 2012, or hundreds of millions if the Companies continued their programs past that point (OCC Ex. 11 at 39; Tr. III at 150-151). Finally, OCC/CP contend that members of the Commission have previously raised concerns with the recovery of lost distribution revenues. *In re FirstEnergy*, Case Nos. 09-1947-EL-POR, et al., Opinion and Order (*March 23, 2011*) (*Snitchler, concurring*) (*Roberto, concurring*). Similarly, NOPEC/NOAC argue that residential and small commercial customers will be negatively affected by the continuation of full recovery for lost distribution revenue from energy efficiency efforts, which NOPEC/NOAC contend that no other EDU in Ohio enjoys.

FirstEnergy responds to these arguments concerning lost distribution revenue by pointing out that OCC witness Gonzalez admitted in his testimony that he had testified in other past proceedings in favor of lost distribution revenue recovery because such recovery provided an incentive for utilities to participate in energy efficiency efforts (Tr. III at 121). Further, FirstEnergy points out that OCC/CP's arguments are a repeat of the opposition to the same provisions in the ESP 2, which the Commission rejected in the *ESP 2 Case* (Tr. III at 103). *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 45. The Companies additionally argue that OCC/CP's estimate that the lost distribution revenue recovery under the ESP 3 will be $50 million, or perhaps hundreds of millions, is a gross exaggeration and point out that OCC witness Gonzalez admitted that, using the Companies' currently available information, the amount of lost distribution recovery that would be added as a result of the ESP 3 would be $22.2 million (Tr. III at 124). Finally, the Companies note that the collection period is not open-ended as argued by OCC/CP, but is limited by the Stipulation to the period of the ESP 3, which is set to end on May 31, 2016.

In their reply brief, OCC/CP argue that the Companies ignored OCC witness Gonzalez's testimony that he had testified in previous cases involving lost distribution revenue and had, in fact, expressed concern about growing levels of cumulative lost distribution revenues in Case No. 11-351-EL-AIR. Further, OCC/CP criticize the Companies for admitting they did not consider another mechanism even after members of the Commission had raised concerns over lost distribution revenue recovery mechanisms (Tr. I at 180).

The Commission finds that the lost distribution revenue collection provision in the Stipulation is the result of a reasonable compromise and should be adopted. In so finding, the Commission emphasizes that, although the Commission has previously approved the collection of lost distribution revenues through its adoption of the Combined Stipulation in the *ESP 2 Case*, we are currently examining methods of innovative rate design to promote energy efficiency as well as the policies set forth in Section 4928.02, Revised Code, and that a docket has been initiated in order to examine issues related to lost distribution revenue. *See In the Matter of Aligning Electric Distribution Utility Rate Structure with Ohio's Public Policies to Promote Competition, Energy Efficiency, and Distributed Generation*, Case No. 10-3126-EL-UNC, Entry (December 29, 2010). Further, in contrast to OCC/CP's assertion, the provision in the Stipulation is not open-ended but clearly states that the collection of lost distribution revenues by the Companies after May 31, 2016, is not addressed or resolved by the Stipulation. Thus, as of June 1, 2016, the Commission will have the opportunity to revisit the lost distribution revenue collection mechanism. The Commission also emphasizes that the Stipulation provides that the Commission may, with the Companies' concurrence, institute a changed revenue-neutral rate design, which would also permit the Commission to revisit the lost distribution revenue collection mechanism (Co. Ex. 1, Stip. at 12). Finally, the Commission notes that, despite NOPEC/NOAC's argument that no other utility in Ohio enjoys full recovery for lost distribution revenue from energy efficiency efforts, other utilities in Ohio are made whole for such losses through other recovery mechanisms, such as balancing adjustment riders.

g. Purchase of Receivables Program

IGS argues that the Commission should modify the ESP 3 as proposed to require FirstEnergy to offer a purchase of receivables (POR) program to those CRES providers to which it provides consolidated billing service. IGS contends that such a POR program would provide benefits to consumers because it would enhance competition and provide other benefits to customers, such as lower prices. Further, IGS contends that a POR program would provide benefits to the host distribution utility. IGS also refutes the reasons set forth by FirstEnergy in opposition to adoption of a POR program. Specifically, IGS argues that the factors cited by FirstEnergy in support of its claim that there is no correlation between the availability of a POR program and the state of competition do not represent relevant measures for determining the state of competition. Additionally, IGS argues that FirstEnergy's concern that expanding its generation-related uncollectible expense rider to provide for the recovery of shopping customer bad debt will require SSO customers to subsidize CRES providers is unfounded. Next, IGS argues that, although POR programs that utilize non-bypassable uncollectible expense riders to make the utility whole assure that CRES providers are paid in full, customers are the primary beneficiaries of POR programs. Further, IGS states that, contrary to FirstEnergy's claim, POR programs that utilize non-bypassable uncollectible expense riders to make the utility whole will serve the interests of low-income customers. Finally, IGS argues that FirstEnergy operating subsidiaries offer POR programs in other states and that FirstEnergy has agreed to a form of a POR arrangement in connection with governmental aggregation service as part of the Stipulation. IGS concludes by proposing that the Commission modify the Stipulation to include a term requiring FirstEnergy to offer to purchase the receivables of CRES providers and to expand the generation-related uncollectible expense rider to permit purchase of such receivables at no discount.

RESA/Direct Energy argue that the Stipulation, as a package and as proposed, does not benefit ratepayers and public interest and violates important regulatory principles and practices. RESA/Direct Energy argue that the Stipulation could be modified, however, in order to bring it into compliance with the Commission's standards. RESA/Direct Energy propose that the Stipulation be modified to include a POR program, as suggested by IGS. RESA/Direct Energy contend that the Commission could remove a large barrier to competition by directing the Companies to implement a POR program, which they contend would place CRES providers on par with the utilities for amounts that must be paid for a customer to avoid disconnection. Further, RESA/Direct Energy argue that implementation of a POR program would encourage more CRES providers to make offers in the Companies' service territories.

In its reply brief, FirstEnergy argues that the absence of a POR program is appropriate because a POR program is unnecessary. Initially, the Companies contend that requiring nonshopping customers to pay the cost of a CRES provider's uncollectible expenses is a subsidy that is contrary to the policy of the state of Ohio. Additionally, the Companies argue that IGS, RESA, and Direct Energy provided no concrete proposal of a POR program or any quantitative analysis of the costs and benefits of such a program. More specifically, the Companies suggest that a POR program is unnecessary to jumpstart shopping because the Companies already have shopping levels that are the highest in the state. Next, the Companies contend that the lack of a POR program is not a barrier to competition because the Companies have high levels of shopping, numerous registered CRES providers, and several CRES providers actively making offers. The Companies also argue that a POR program would create unnecessary costs for customers due to the burden of administering and collecting CRES providers' uncollectible expenses. Further, the Companies contend that they also will not benefit from a POR program, as they would be required to design and implement a new system to track arrearages, implement processes to seek collections, retrain employees on the new systems, and handle customer confusion and complaints due to the program. Finally, FirstEnergy argues that IGS, RESA, and Direct Energy are asking the Commission to ignore its own order in Case No. 02-1944-EL-CSS, in abrogating a settlement that remains in full force and effect today.

The Commission notes that we have previously addressed the question of the purchase of receivables in the FirstEnergy service territories. *WPS Energy Services, Inc., and Green Mountain Energy Company v. FirstEnergy Corp., et al.*, Case No. 02-1944-EL-CSS (*WPS Energy*). In *WPS Energy*, two marketers filed a complaint against the Companies for failing to offer a purchase of receivables program. On August 6, 2003, the Commission adopted a stipulation resolving the case (IGS Ex. 1a at 13). In the stipulation, the Commission approved the modification of the partial payment posting priority set forth in Commission rules, the marketers agreed to dismiss their complaints, and the Commission approved a waiver of any obligation of the Companies to purchase accounts receivable. *WPS Energy*, Case No. 02-1944-EL-CSS, Opinion and Order (August 6, 2003) at 3, 5, 8. Although the marketers have demonstrated that the purchase of receivables by the utility is their preferred business model, there is no record in this proceeding demonstrating that the absence of the purchase of receivables has inhibited competition. There is no record in this proceeding that the Companies are under any legal obligation to purchase receivables. There is no record that circumstances have changed since the adoption of the stipulation to justify abrogating the stipulation. In fact, at the hearing, IGS witness Parisi was unable to specify any changes in the competitive market since the adoption of the stipulation (Tr. II at 213-214). Accordingly, although the Commission retains the authority to modify a prior order adopting a stipulation, the Commission finds that RESA, IGS, and Direct Energy have not demonstrated sufficient grounds to disturb the stipulation adopted in *WPS Energy*.

However, the Commission notes that the record includes uncontroverted testimony indicating issues regarding the implementation of the stipulation in *WPS Energy* with respect to customers on deferred payment plans (RESA Ex. 3 at 8-12). Although the Commission does not believe, at this time, that this testimony justifies the abrogation of the stipulation adopted in *WPS Energy*, the Commission believes that the issues raised merit further review. Accordingly, the Commission directs Staff to hold a workshop in the newly-opened five-year rule review for Chapter 4901:1-10, O.A.C., specifically for the purpose of reviewing FirstEnergy's implementation of the partial payment priority, including, but not limited to, the implementation of the stipulation with respect to customers on deferred payment plans. At the conclusion of the workshop, Staff shall identify whether, in order to protect consumers, protect the financial integrity of the Companies, and promote competition in the Companies' service territories, amendments to Chapter 4901:1-10, O.A.C., are necessary, additional waivers of Chapter 4901:1-10, O.A.C., are necessary, modifications to FirstEnergy's tariffs or practices are necessary, or additional measures should be undertaken as recommended by Staff.

h. Commission Decision.

In light of the reasons set forth above, the Commission finds that the evidence in the record indicates that, as a package, the Stipulation benefits the public interest by resolving all of the issues raised in these matters without resulting in expensive litigation and by providing for stable and predictable rates, established by a competitive procurement process and use of laddered auction products to lower the volatility of prices for customers during both the last year of ESP 2 and the period of the ESP 3 (Tr. II at 154). The Stipulation further serves the public interest by resolving potential subjects of litigation, including a complaint case between TE and MSC, the possibility of a distribution base rate increase during the term of the ESP 3, as well as disputes related to the Companies' recovery of lost distribution revenue associated with energy efficiency and peak demand reduction programs through May 31, 2016 (Co. Ex. 1, Stip. at 18-19, 31, 42-43). Additionally, the proposed ESP 3 supports shopping because there are no shopping caps or standby charges (Co. Ex. 3 at 3-8).

Moreover, the record indicates that there are significant additional benefits for customers in the Stipulation. In the Stipulation, the Companies have provided for a discount from the auction price for PIPP customers, have retained a variety of bill credits, have committed shareholder funding for economic development and assistance for low-income customers, have provided funding for energy efficiency coordinators, have continued significant support for the distribution system, and have spread renewable energy cost recovery over a longer period in order to reduce customer prices. (Co. Ex. 3 at 3-8.)

Nonetheless, before the Commission can find that the Stipulation is in the public interest, the Commission believes a number of modifications and clarifications are necessary where the Stipulation differs from the Combined Stipulation in the *ESP 2 Case*.

The Stipulation provides that the CBP process will be conducted by an independent auction manager but does not specify who selects the auction manager (Tr. II at 40). The Commission will clarify that the Companies shall select the independent auction manager, subject to the approval of the Commission. However, this clarification should not be interpreted to require the Companies to seek a new independent auction manager, or to seek the approval of the Commission to retain its current auction manager, for the auctions currently scheduled for October 2012 and January 2013.

Further, with respect to Rider DCR, the Commission encourages the Companies to consult with Staff to select projects, among others, which will mitigate effects of the transmission constraint in the ATSI zone of PJM (Co. Ex. 1, Stip. at 19-20). There is an ample record in this proceeding that the transmission constraint has resulted in a higher charge for capacity in the ATSI zone than PJM as a whole. Moreover, the record demonstrates that there are projects which can be undertaken by the Companies to mitigate, at the distribution level, the transmission constraint, in order to reduce capacity charges resulting from future base residual auctions (Tr. I at 335-336; Staff Ex. 1; Tr. II at 240-242). The Stipulation also adopts the terms and conditions of the Combined Stipulation regarding distribution rate design, as clarified by the Commission in the *ESP 2 Case*.

The Stipulation provides that, if the Commission rejects the results of the long term RFPs described in the Stipulation, the event shall be deemed a force majeure and the Companies shall incur no penalty. The Stipulation does not specify whether it is intended for the force majeure to apply for the entire ten-year term of the RFP or just the first year; the Commission clarifies that the force majeure determination will only apply to the first year covered by the rejected RFP.

The Commission also notes that the auditor for Rider DCR is to be selected by the Staff with the consent of the Companies (Co. Ex. 1, Stip. at 22). Although the Commission is confident that the Companies would not unreasonably withhold consent, the Commission uses independent, outside auditors for a number of functions, and the Commission generally does not obtain the consent of the utility. Although this case does include unique circumstances, the Commission does not find that such circumstances justify this departure from general Commission practice. Accordingly, we will eliminate the provisions of the Stipulation requiring the consent of the Companies in the selection of the auditor for Rider DCR.

The Commission notes that the Stipulation provides that the riders listed on Attachment B of the Stipulation shall be subject to ongoing Staff review and audit. According to the terms of the Combined Stipulation and past practice, separate dockets have been opened for the review of Riders DCR, AMI, and AER. The Commission clarifies that the Companies annually should file applications in separate dockets for the review and audit of Riders DCR, AMI, AER, NMB, and DSE. In addition, the Companies annually should file an application for the combined review of Riders PUR, DUN, NDU, EDR, GCR, and GEN. The Commission directs the Companies and Staff to develop a schedule for the filing of the annual reviews and audits. For all other riders on Attachment B, the Companies should continue to docket the adjusted tariff sheets; however, these tariff sheets should be filed in a separate docket rather than this proceeding, as has been the practice in the *ESP 2 Case*. Further, all filings adjusting riders listed on Attachment B should include the appropriate work papers.

With this clarification, the Commission finds that the Stipulation as modified benefits ratepayers and the public interest, in accordance with the second prong of our test for the consideration of stipulations.

3. <u>Does the settlement package violate any important regulatory principle or practice?</u>

FirstEnergy, Nucor, OEG, MSC, and Staff all represent that the Stipulation violates no important regulatory principle or practice. The parties note that most of the provisions of the proposed ESP 3 are similar or identical in all material respects to the provisions of the Combined Stipulation approved by the Commission in the *ESP 2 Case* and that the Commission determined that such provisions did not violate important regulatory principles or practices. *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 39-42.

Staff further claims that the Stipulation affirmatively supports the state policies enumerated in Section 4928.02, Revised Code. Staff contends that the Stipulation supports competition by avoiding standby charges and other limitations consistent with Ohio policy. Section 4928.02(B), (C), Revised Code. It supports reliability though the continuation of the DCR mechanism consistent with Ohio policy. Section 4928.02(A), Revised Code. Staff claims that the Stipulation supports energy efficiency efforts through the support of energy coordinators, Section 4928.02(M), Revised Code, and supports at-risk populations, Section 4928.02(L), Revised Code. Finally, Staff contends that economic development measures support Ohio's effectiveness in the global economy consistent with state policy. Section 4928.02(N), Revised Code.

a. Proposed Modification of ESP 2 Auction Product

NOPEC/NOAC claim that the provision in the proposed ESP 3 to alter the previously approved one-year auction product in the Combined Stipulation to a three-year product allows FirstEnergy to unilaterally change the terms of the Commission-approved stipulation. NOPEC/NOAC claim that it is inappropriate for FirstEnergy to seek to unilaterally modify an existing Commission-approved stipulation without the written approval of all of the signatory parties of the stipulation.

The Commission notes that, while the proposed ESP 3 does materially change the bidding product for the last year of the ESP 2, it is inaccurate to characterize this as a "unilateral" action by FirstEnergy. The Stipulation in this proceeding was agreed to by 19 parties including the three FirstEnergy electric utilities, and five additional parties formally agreed not to oppose the Stipulation. More importantly, no modifications to the bidding product for the last year of the ESP 2 will take effect without the approval of the Commission, and all parties, including NOPEC/NOAC, have been given a full and fair opportunity to oppose any modifications through the hearing process.

It is well-established that the Commission may change or modify previous orders as long as it justifies any changes. *Consumers' Counsel v. Pub. Util. Comm.*, 114 Ohio St.3d 340, 2007-Ohio 4276, 872 N.E.2d 269, at ¶ 5-6, citing *Consumers' Counsel v. Pub. Util. Comm.*, 10 Ohio St.3d 49, 50-51, 561 N.E.2d 303 (1984). In fact, the Supreme Court has expressly rejected the argument that the agreement of all signatories to a stipulation was required before the Commission could approve a modification to the stipulation. *Consumers' Counsel* at ¶ 6. Accordingly, we find that the proposed modification of the auction product for the final year of the ESP 2 does not violate an important regulatory principle or practice.

b. Transparency and Public Participation

AEP Retail claims that the Stipulation violates the regulatory principles of transparency and public participation. AEP Retail contends that the Commission's rules facilitate public participation in proceedings before the Commission and that those rules contemplate the filing of a proposal, public notice of the proposal, an opportunity for interested parties to review the proposal, to seek intervention, and to meaningfully participate in the proceedings through discovery, settlement negotiations, and evidentiary hearings.

ELPC claims that the Companies did not file a proper ESP application, comparing the length of the application in this case with applications filed by FirstEnergy and other electric utilities in previous SSO proceedings. ELPC claims that the taking of administrative notice of the *MRO Case* and the *ESP 2 Case* does not cure the deficiencies in the Companies' application. ELPC further argues that FirstEnergy and ratepayers will not be harmed if the Commission rejects the expedited application and requires the Companies to file a complete application. ELPC notes that the first part of the bid application for the October 2012 auction is not due until September 5, 2012 (OCC Ex. 1 at 3) and that FirstEnergy witness Ridmann could not confirm whether the duration of the auction product would have any bearing on the first part of the bidders' applications (Tr. I at 196-197).

OCC/CP allege that procedural due process has been denied in this proceeding. OCC/CP contend that Ohio law establishes 275 days as the period of time for the review of an ESP application although OCC/CP acknowledge that the Commission is not required to use the entire 275 day period allotted under the statute. Section 4928.143(C)(1), Revised Code.

AEP Retail also claims that the Companies failed to provide meaningful projections of bill impacts, avoiding the intent of the Commission's rules. Likewise, OCC/CP note that the Companies provided typical bill impacts which did not include projections of generation costs under the proposed ESP 3 and that the attorney examiners granted AEP Retail's motion to compel discovery regarding the impact on customer bills of such costs. OCC/CP acknowledge that the Companies complied with the examiners' ruling on June 4, 2012, the first day of the hearing.

FirstEnergy contends that the parties all had ample opportunity to conduct discovery and that most of the provisions of the proposed ESP 3 are similar to provisions in the current ESP 2 and, thus, are known to the parties in this proceeding.

Although the Commission has addressed above the specific challenges raised by parties to the attorney examiners' rulings regarding procedural issues, the Commission further finds that the issues regarding transparency and public participation raised by AEP Retail, OCC/CP, and ELPC do not constitute a violation of important regulatory principles and practices. With respect to ELPC's concerns regarding the length of the application, the Commission finds that there is no minimum length requirement for an application; the question is whether the Companies' application complies with the filing requirements set forth in Chapter 4901:1-35, O.A.C. The Commission notes that, on May 2, 2012, in response to the denial of certain waiver requests, the Companies filed supplemental information regarding the application on May 2, 2012, which OCC/CP acknowledge contained a "voluminous" amount of material regarding the application. We further note that neither ELPC nor any other party has identified any specific provision of Chapter 4901:1-1-35, O.A.C., that the application fails to meet where such provision has not been waived by the Commission.

With respect to bill impacts, the Commission notes that, in prior cases, we have not required electric utilities to provide projections of generation costs in bill impacts because the results of future CBPs are inherently unknowable. In this case, FirstEnergy was required by the attorney examiners to include the known impacts from PJM's most recent base residual auction. Entry (June 1, 2012) at 4-5.

Accordingly, we find that the record includes all information regarding bill impacts which is currently knowable. Moreover, with respect to the capacity costs stemming from the base residual auction, the Commission notes that these capacity charges are the result of a FERC regulated, PJM auction and that such charges will be in place irrespective of whether the proposed ESP is adopted or a market rate offer is adopted.

Moreover, in this proceeding, the parties had 52 days to prepare for the hearing after the filing of the Stipulation in this case. The time period is not an unusually brief length of time between the filing of a stipulation and the hearing in an SSO proceeding. Many of the parties had been previously contacted and were aware that the Companies were preparing the Stipulation to be filed in conjunction with the application (Tr. III at 101). As noted earlier, discovery response times were shortened to ten days in order to allow ample opportunity for multiple sets of written discovery; for example, OCC served and received responses to six sets of discovery (Tr. I. at 18). Where discovery disputes arose, the attorney examiners promptly ruled on motions to compel discovery. Entry (May 17, 2012) at 4-5; Entry (June 1, 2012) at 4-5. No party was denied intervention, and intervention out of time was granted to a party that missed the deadline to intervene. Entry (May 15, 2012) at 2. Moreover, the Commission notes that, prior to the evidentiary hearing, three public hearings were held in which 48 public witnesses testified regarding the Stipulation. At the evidentiary hearing, the parties presented testimony by a total of 13 witnesses.

c. *Deferred Carrying Charges*

OCC/CP and NOPEC/NOAC claim that the provision of the Stipulation that provides for the exclusion of deferred interest income from the SEET test required by Section 4928.143(F), Revised Code, is inconsistent with Commission precedent. OCC/CP and NOPEC/NOAC cite to the Commission's decision in the AEP-Ohio SEET proceeding, in which the Commission determined that deferrals, including deferred interest income, should not be excluded from the electric utility's return on equity calculation for purposes of SEET. *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 10-1261-EL-UNC, Opinion and Order (July 2, 2012) (*AEP-Ohio SEET Case*) at 31.

FirstEnergy replies that the Commission has determined that it will address the question of deferrals in SEET reviews on as case-by-case basis. *In the Matter of the Investigation into the Development of the Significantly Excessive Earnings Test*, Case No. 09-786-

EL-UNC, Finding and Order (June 30, 2010) at 16. FirstEnergy notes that the AEP-Ohio ESP which gave rise to the SEET proceeding was silent on the treatment of deferred interest income while the Commission has previously approved stipulations which expressly provided that deferred interest income should be excluded from the SEET. *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 12. Further, FirstEnergy claims that the impact of including the deferred carrying charges would be minimal; for example, for CEI, the maximum impact would be only 100 basis points in the return on equity calculation (Tr. I at 220).

The Commission notes that, under the terms of the proposed Stipulation, charges billed though Rider DCR will be included as revenue in the return on equity calculation for purposes of SEET and will be considered an adjustment eligible for refund. However, the Stipulation specifically excludes deferred carrying charges from the SEET calculation (Co. Ex. 1, Stip. at 23). We find that the provision of the Stipulation that provides for the exclusion of deferred carrying charges from the SEET does not violate an important regulatory principle or practice. Although the *AEP-Ohio SEET Case* stands for the principle that deferrals, including deferred carrying charges, generally should not be excluded from the SEET, Section 4928.143(F), Revised Code, specifically requires that consideration "be given to the capital requirements of future committed investments in this state." Rider DCR will recover investments in distribution, subtransmission, and general and intangible plant. Therefore, the Commission finds that, in order to give full effect to this statutory requirement, we may exclude deferred carrying charges from the SEET where, as in the instant proceeding, such deferred carrying charges are related to capital investments in this state and where the Commission has determined that such deferrals benefit ratepayers and the public interest. Accordingly, we find that the Stipulation provision excluding deferred carrying charges from the SEET does not violate an important regulatory principle or practice.

OCC/CP, AEP Retail, and other parties also contend that the Stipulation violates important regulatory principles or practices because the ESP proposed in the Stipulation is not more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. The Commission will address all arguments related to this issue below.

4. Is the proposed ESP more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

The Commission must also consider the applicable statutory test for approval of an ESP. Section 4928.143(C)(1), Revised Code, provides that the Commission should approve, or modify and approve, an application for an ESP if it finds that the ESP, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

a. Summary of the Parties' Arguments

FirstEnergy argues that the provisions of the ESP 3 are more favorable than an MRO from both a quantitative and qualitative perspective. In so arguing, FirstEnergy initially points out that the ESP 3 is a continuation of many provisions in the ESP 2, which the Commission previously found to be more favorable than an MRO. *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 42-45.

FirstEnergy first contends that the quantitative benefits of the ESP 3 are more favorable than an MRO. FirstEnergy specifies that, in its ESP v. MRO analysis, it considered the following quantitative provisions of the ESP: (1) estimated Rider DCR revenues from June 1, 2014, through May 31, 2016; (2) estimated PIPP generation revenues for the period of the ESP 3, reflecting the six percent discount provided by the Companies; (3) economic development funds and fuel fund commitments that the Companies' shareholders will contribute; and (4) estimated RTEP costs that will not be recovered from customers (Co. Ex. 3 at 17-19). Further, FirstEnergy states that it considered the following quantitative provisions of the MRO: (1) estimated revenue from base distribution rate increases based on the proposed Rider DCR revenue caps; and (2) generation revenue from PIPP customers excluding the six percent discount provided by the Companies. After comparing these quantitative factors, the Companies calculate that the quantitative benefits of the ESP 3 exceed the quantitative benefits of an MRO by $200 million. (Co. Ex. 3 at 17-19.)

In its discussion of the quantitative benefits of the ESP 3, FirstEnergy acknowledges that Staff witness Fortney provided a different perspective of the ESP v. MRO analysis. In particular, the Companies note that Staff witness Fortney testified that the costs to customers of Rider DCR, which are included in FirstEnergy witness Ridmann's ESP analysis, and the costs of a distribution case, which are included in FirstEnergy witness Ridmann's MRO analysis, could be considered as a "wash" (Staff Ex. 3 at 4-5). Consequently, the Companies point out that Staff witness Fortney concluded that, even if foregoing RTEP cost recovery was eliminated as a benefit of the ESP 3, he would nevertheless consider the ESP 3 as benefiting customers relative to an MRO by over $21 million (Staff Ex. 3 at 5).

Next, FirstEnergy argues that the qualitative benefits of the ESP 3 are more favorable than an MRO. Specifically, FirstEnergy contends that the qualitative benefits of the ESP 3 that are not present in an MRO include economic development, rate design provisions, energy efficiency funding, support for customer shopping, and price certainty and stability for customers (Co. Ex. 1, Stip.). Further, FirstEnergy emphasizes that Staff has recommended approval of the ESP 3 based, in large part, on its qualitative benefits (Staff Ex. 3 at 4).

As noted by the Companies, Staff also takes the position that an MRO is not preferable to the ESP 3 in this proceeding. In its ESP v. MRO analysis, Staff states that there are two ways to view the situation. Under the first view, Staff argues that one should remove the effect of the agreement to forego collection of RTEP costs from the analysis because this benefit was agreed to and provided in the ESP 2 and brings no new value to the ESP 3. Under this interpretation, Staff finds that the difference in cost between the ESP and MRO is less than $8 million. Staff contends that this is a sufficiently small difference in costs that the flexibility provided by the proposed ESP 3 makes it superior to an MRO. Further, Staff notes that the qualitative benefits of the ESP 3 further counterbalance the nominal difference in cost. Under the second view, Staff argues that the costs of Rider DCR under the ESP 3 and the effects of a rate case under an MRO are essentially a "wash," and that FirstEnergy witness Ridmann's analysis should be adjusted to remove the Rider DCR costs from the ESP 3 and the rate case expense from the MRO, respectively. Under this view, Staff argues that the ESP 3 is the more advantageous option by $21 million, even disregarding qualitative factors. (Staff Ex. 3 at 2-5.)

MSC also asserts that the ESP 3 is more favorable in the aggregate than the expected results of an MRO from both a qualitative and quantitative perspective. MSC contends that the evidence in the record demonstrates that the ESP 3 provides over its duration, at a minimum, benefits to customers of $200.6 million based on compared differences between the present value amounts calculated on a year-to-year basis for the ESP 3 and MRO (Co. Ex. 4 at 7, 8). Further, MSC contends that there are substantial qualitative benefits of the ESP 3 that are not even reflected in the $200.6 million figure (Co. Ex. 3 at 15-16).

In contrast, OCC/CP contend that the ESP 3 is not more favorable in the aggregate than an MRO under a quantitative or qualitative analysis. Regarding the Companies' quantitative analysis, OCC/CP contend that the alleged RTEP benefit was improperly double-counted by the Companies and should be excluded from the analysis. Specifically, OCC/CP argue that the RTEP cost recovery forgiveness amount would remain the Companies' obligation under the ESP 2 and is not contingent upon the Commission's approval of the ESP 3 (Joint NOPEC/NOAC Ex. 1 at 5). Next, OCC/CP argue that Rider DCR cannot be considered a "wash" with a distribution rate case outcome. More specifically, OCC/CP contend that Rider DCR is more costly to customers because, according to FirstEnergy witness Ridmann, $29 million net cost is attributed to Rider DCR due to lag in distribution cost recovery (Co. Ex. 3 at 18). OCC/CP next argue that the FES offer of a six percent discount to PIPP customers should not be considered a benefit of the ESP 3, because it would not be a prohibited arrangement in an MRO (OCC Ex. 11 at 30-31). Further, OCC/CP point out that the Companies did not solicit bids from other suppliers besides FES to determine if there was interest in serving the PIPP load at an even greater discount. Next, OCC/CP contend that the alleged public benefits of the fuel funds ignore the benefit derived by FirstEnergy. OCC/CP explain that the $9 million in fuel fund monies is used for the payment of electric bills and, consequently, argue that this represents a benefit to the Companies because it ensures revenues. Finally, OCC/CP argue that the costs associated with the economic development provisions of the Stipulation are merely "transfers" of payments and should not be considered a benefit of the ESP 3. OCC/CP specify that the economic development provisions contain dollar amounts and non-bypassable discounts given to certain entities, which are ultimately recovered from other customers (OCC Ex. 11 at 33).

Next, OCC/CP argue that the ESP 3 is not more favorable in the aggregate than an MRO under a qualitative analysis. First, OCC/CP claim that the benefits of the Companies' bid of demand response and energy efficiency resources into the base residual auction were underwhelming. OCC/CP specify that the Companies bid 36 MW of energy efficiency into the PJM base residual auction on May 7, 2012, which was well below the 65 MW that the Companies could have bid. OCC/CP note that Sierra Club witness Neme estimated that this missed opportunity created a loss ranging from $22 to $39 million to FirstEnergy's customers (Sierra Club Ex. 5 at 13). Next, OCC/CP contend that modification of the bid schedule to accommodate a three-year auction product does not constitute a qualitative benefit. More specifically, OCC/CP state that uncertainties resulting from upcoming plant retirements and transmission restraints in the ATSI zone cast doubt that a three-year product is appropriate (Tr. II at 263-264). OCC/CP propose that a one or two-year generation product as recommended by OCC witness Wilson will mitigate the impact of generation costs on customer bills and eliminate the need for alternative energy resource rider deferrals, which would incur carrying costs. Next, OCC/CP argue that the distribution rate freeze cannot be considered a benefit of the ESP 3 because, under the Stipulation, FirstEnergy would be allowed to receive costs associated with investments in enhanced distribution service through Rider DCR up to $405 million through the term of the ESP 3. OCC/CP argue that it is disingenuous for the Companies to argue that this is a benefit when that Stipulation provides for such a significant collection for distribution-related investment. Finally, OCC/CP repeat their arguments from their quantitative analysis that the RTEP cost recovery forgiveness was a benefit of the ESP 2 and should not be counted as a benefit of the ESP 3.

Similar to OCC/CP's arguments, NOPEC/NOAC contend that FirstEnergy has failed to demonstrate that the ESP 3 is more favorable in the aggregate than the expected results of an MRO. Specifically, NOPEC/NOAC argue that FirstEnergy's analysis wrongly seeks to double-count the RTEP cost recovery forgiveness benefits for purposes of the ESP v. MRO test, although that obligation was incurred as part of the ESP 2 (NOPEC/NOAC Joint Ex. 1 at 5). NOPEC/NOAC argue that, when this quantitative benefit is removed, the ESP 3 value becomes $7 million less favorable than an MRO (*Id.* at 6). Additionally, NOPEC/NOAC argue that FirstEnergy improperly included in its analysis an assumed Commission-approved distribution rate increase of $376 million under an MRO in order to offset the $405 million to be collected from Rider DCR under the ESP 3 (Co. Ex. 3, Att. WRR-1). NOPEC/NOAC contend that the $376 million assumption is unrealistic and speculative, given that FirstEnergy was only awarded a distribution rate increase of $137.6 million in 2007. NOPEC/NOAC argue that a more accurate estimate of a distribution rate increase would make the proposed ESP 3 less favorable than the MRO by several hundred million dollars.

NOPEC/NOAC next contend that, if the Commission desires to adopt an ESP over an MRO, the Commission should also adopt NOPEC/NOAC's recommendations so that the ESP 3 proposal can satisfy the ESP v. MRO test. NOPEC/NOAC recommend that the Commission include the following modifications to the proposed ESP 3 (1) elimination of the continuation of Rider DCR after May 31, 2014, and replacement with a separately filed distribution rate case; (2) elimination of FirstEnergy's proposal to exclude income it receives from deferred charges from the SEET calculation; (3) requirement that the Companies bid all of their eligible demand response and energy efficiency resources into all future PJM capacity auctions; and (4) holding of the proposed energy auctions in October 2012 and January 2013 in accordance with the terms of the Combined Stipulation.

OSC similarly contends that, when the Companies' proposal is viewed in light of the evidence presented in this case, the Companies have failed to demonstrate that the ESP 3 is more favorable in the aggregate than the expected results of an MRO. Specifically, OSC claims that the evidence presented at hearing shows that, quantitatively, the ESP 3 proposal will cost consumers more than the expected results of an MRO because the ESP 3 proposal will allow FirstEnergy to continue Rider DCR after May 31, 2014, to recover up to $405 million in distribution improvement expenditures. (Tr. I at 129.)

AEP Retail also contends that the Companies' proposed ESP 3 fails the ESP v. MRO test quantitatively. Specifically, AEP Retail contends that the $293.7 million in RTEP costs should not be included in the analysis because this benefit was a result of the Commission's decision in the *ESP 2 Case* and would not be a benefit of the ESP 3 (Staff Ex. 3 at 2). AEP Retail also argues that the claimed qualitative benefits are suspect because the Companies were unable to secure any benefit by bidding demand response resources into the 2015-2016 base residual auction, because the benefits of a six percent PIPP discount are unknown and violate Section 4928.02, Revised Code, because the extension of the recovery period for REC costs is not a benefit, because the distribution "stay out" period and Rider DCR are an illusory benefit, and because any benefit of the three-year blending proposal is impossible to assess. (Tr. IV at 23; OCC Ex. 9 at 8-9; OCC Ex. 11 at 32; Tr. I at 250-257.)

In its reply, FirstEnergy first addresses the other parties' arguments that the foregoing of legacy RTEP cost recovery should not be considered as a quantitative benefit of the ESP 3. FirstEnergy argues that, as part of the ESP 3, the parties were free to negotiate a completely new framework, which could have included modifying the ESP 2 agreement provision regarding legacy RTEP cost recovery. Consequently, FirstEnergy maintains that the foregoing of legacy RTEP cost recovery is a benefit of the ESP 3.

Regarding Rider DCR, the Companies reply to other parties' arguments that the recovery of any dollars in a rate case is speculative, especially when compared to the amounts that the Companies recovered in their last distribution rate case. The Companies contend that, if they are able to make a proper showing to obtain recovery of distribution infrastructure costs under Rider DCR, there is no reason to believe that they would be unable to make a similar showing to obtain recovery in a rate case. Further, the Companies argue, in response to OCC/CP, NOPEC/NOAC, and OSC's arguments that recovery could be up to $405 million, that the caps established in Rider DCR are just caps—and that there is no guarantee to what the Companies may recover under Rider DCR.

As to other parties' arguments regarding the six percent discount for PIPP customers, the Companies reply that this is a benefit of the ESP 3 because the potential burden to pay is lessened for PIPP customers who may become PIPP-ineligible and responsible for arrearages, and for other customers who might be required to pay arrearages accrued in PIPP accounts.

Next, the Companies reply to OCC/CP's contention that the Companies' contributions to fuel funds should not be considered a benefit. The Companies argue that OCC/CP are wrong to argue that the Companies benefit from having low-income customers pay their bills, because other customers, not the Companies, would bear the burden of unpaid bills through the uncollectible expense riders and the Universal Service Fund riders. Similarly, the Companies challenge OCC/CP's argument that the economic development provisions of ESP 3 should not be considered a benefit on the basis that the Commission rejected the same argument regarding economic development in the *ESP 2 Case*. *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 39.

Additionally, in its reply brief, the Companies respond to other parties' arguments that the qualitative benefits of the ESP 3 are not more favorable than an MRO. First, the Companies contend that use of a three-year product is an appropriate risk mitigation strategy that benefits customers, stating that the "undue uncertainty" expressed by OCC/CP just enforces FirstEnergy's plan to hedge the uncertainty with a multi-year, multi-event, multi-product CBP.

Next, the Companies rebut OCC/CP and AEP Retail's arguments that the Companies' agreement not to seek a base distribution rate increase is not a benefit. The Companies point out that a rate case would involve the recovery of costs beyond those permitted to be recovered under Rider DCR. Further, the Companies point out that the

Commission has already held that a base distribution rate freeze provides a benefit that makes an ESP more favorable in the aggregate than an MRO in the *ESP 2 Case*. Finally, the Companies note that they cannot recover any monies unless they can show that the plant is in service, and that Rider DCR is subject to quarterly reconciliations and an annual audit. *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 44.

The Companies also argue in response to OCC/CP, AEP Retail, and RESA's contentions that the ESP 3's proposed extension of the time to recover alternative energy costs under Rider AER is not a benefit. The Companies argue that they have included the estimated impact of the lower Rider AER charge in their supplemental filing, that OCC/CP have offered no analysis to support their conclusion that the extension of the recovery of Rider AER would be counterbalanced by the effect of increased costs from the CBPs, that CRES providers are free to seek extended recovery periods for alternative energy costs, and that the current Rider AER is artificially high, as more customers are shopping, resulting in less SSO load over which to spread the recovery.

The Companies also reemphasize that the ESP 3 promotes shopping in response to RESA's argument that a large percentage of the residential customers shopping do so through governmental aggregation. The Companies respond that, although these customers may shop through governmental aggregation, they are nevertheless shopping.

In its reply, Staff reiterates that the Companies have met their criteria regarding Rider DCR. Staff contends that it examined the reliability of the Companies' system and found that the Companies were in compliance with the applicable standards (Staff Ex. 2 at 5-6). Staff states that compliance with the standards means that customers are getting the level of reliability that they want.

In their reply brief, OCC/CP respond that the Companies are unrealistic in assuming that, if they collected $405 million through Rider DCR, they would likely recover that same amount of costs through a distribution rate case. OCC/CP point out that, in the last distribution rate case, the Companies requested $340 million, but that the Commission reduced the amount to $137 million in annual rate increases. *Distribution Rate Case*, Case No. 07-551-EL-AIR, Opinion and Order (January 21, 2009) at 48. Further, OCC/CP contend that they are not advocating for a decrease in service quality, but do not want the Companies to "gold plate" their distribution systems.

OCC/CP also contend that FirstEnergy's and other parties' arguments that no other suppliers have committed to serve the PIPP load at a below-market price are unfair because no supplier—other than FES—has been given the opportunity through an open bid, request for proposal, or auction arrangement to demonstrate a willingness to serve that load. OCC/CP contend that, even if the Commission does not reject the Stipulation, the Commission should provide for the PIPP load to be auctioned separately with a six percent discount as a floor.

OCC/CP also reply to FirstEnergy's arguments regarding qualitative benefits, contending that the qualitative benefits identified by the Companies will not elevate the ESP proposal to be more favorable in the aggregate than an MRO for customers. Specifically, OCC/CP argue that the credits for large customers, credits for large automaker facilities, and financial support for the Cleveland Clinic are ultimately collected from other customers, which should not be considered a benefit of the ESP 3.

NOPEC/NOAC contend that the Companies' arguments have placed virtually sole reliance on the Commission's approval of the ESP 2 in order to support its claims. Additionally, NOPEC/NOAC contend that Staff witness Fortney is incorrect that Rider DCR and a distribution rate case would be a wash in the ESP v. MRO analysis. NOPEC/NOAC emphasize that Staff witness Fortney testified that Rider DCR and a distribution rate case would be a wash *over time*, which NOPEC/NOAC argues does not comport with the ESP v. MRO test. Further, NOPEC/NOAC contend that FirstEnergy has ignored other parties' contentions that a distribution rate increase would afford all parties and the Commission an extensive period to review any rate increase request.

b. Commission Decision

The Commission finds that the record in these proceedings demonstrates that the proposed ESP 3 is, in fact, more favorable in the aggregate than the expected results under Section 4928.142, Revised Code. Under the proposed ESP 3, the rates to be charged customers will be established through a competitive bid process; therefore, the rates in the ESP 3 should be equivalent to the results which would be obtained under Section 4928.142, Revised Code. However, the evidence in the record demonstrates that there are additional benefits contained in the Stipulation that make the proposed ESP 3 more favorable in the aggregate than the expected results under Section 4928.142, Revised Code.

Initially, the Commission finds that the proposed ESP 3 is more favorable quantitatively than an MRO. Although the Companies' witness Ridmann testified that a credit reflecting the estimated RTEP costs that will not be recovered from customers should be reflected as a quantitative benefit of the ESP 3, the Commission agrees with Staff witness Fortney, OCC/CP, NOPEC/NOAC, and AEP Retail that the benefit of this credit was a result of the Commission's decision in the *ESP 2 Case* and cannot be considered a benefit of the ESP 3 to be reflected in the ESP v. MRO analysis (Staff Ex. 3 at 2). Nevertheless, the Commission also notes that Staff witness Fortney testified that costs to consumers of Rider DCR, which are included in FirstEnergy witness Ridmann's ESP analysis, and the costs of a distribution rate case, which are included in FirstEnergy witness Ridmann's MRO analysis, would simply be a wash (Staff Ex. 3 at 4-5). The

Commission agrees with Staff witness Fortney that these costs should be considered substantially equal and removed from the ESP v. MRO analysis. Upon the removal of these costs, as well as the RTEP credit, the Commission finds that, quantitatively, the ESP 3 is better in the aggregate than an MRO by $21.4 million (Staff Ex. 3 at 5).

Further, the Commission finds that the proposed ESP 3 is more favorable qualitatively than an MRO. The Commission finds that the additional qualitative benefits of an ESP, which would not be provided for in an MRO, include (1) modification of the bid schedule to provide for a three-year product in order to capture current lower market-based generation prices and blend them with potentially higher prices in order to provide rate stability; (2) continuation of the distribution rate increase "stay-out" for an additional two years to provide rate certainty, predictability, and stability for customers; (3) continuation of multiple rate options and programs to preserve and enhance rate options for various customers provided in the ESP 2; and (4) flexibility that offers significant advantages for the Companies, ratepayers, and the public. (Staff Ex. 3 at 3-4.) More specifically, the Commission emphasizes its opinion in its discussion of the three-part test that laddering of products and continuation of the distribution rate increase freeze will smooth generation prices and mitigate the risk of volatility, which is a benefit to customers. Further, the Commission finds that the additional benefits provided via the Stipulation to interruptible industrial customers, schools, and municipalities, as well as shareholder funding for assistance to low-income customers, also make the proposed ESP 3 more favorable qualitatively than an MRO (Co. Ex. 3 at 12-13). Additionally, the Commission notes in response to OCC/CP's arguments that the six percent discount for PIPP customers is not a benefit and that FES should not have been given the sole opportunity to bid on this load, that the Commission previously rejected these arguments in the *ESP 2 Case*. *ESP 2 Case*, Opinion and Order (Aug. 25, 2010) at 33. Further, as in the *ESP 2 Case*, the Commission notes that ODOD continues to retain its authority to competitively shop the aggregated PIPP load if a better price can be obtained. Section 4928.54, Revised Code. Thus, as in the ESP 2, the six percent discount to be provided to PIPP customers represents the minimum discount during the proposed ESP 3, and a better price may be obtained by ODOD through a competitive bid.

The Commission also notes that the proposed ESP 3 is consistent with policy guidelines in Ohio. Specifically, the proposed ESP 3 supports competition and aggregation by avoiding standby charges, supports reliable service through the continuation of the DCR mechanism, supports business owners' energy efficiency efforts, protects at-risk populations, and supports industry in order to support Ohio's effectiveness in the global economy (Co. Ex. 3 at 11-12).

Therefore, based upon the evidence in the record in this proceeding, the Commission finds that the ESP 3, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. Accordingly, we find that the Stipulation, as modified, should be adopted. The Commission also notes that our finding in this section that the ESP 3 is more favorable in the aggregate than the expected results that would otherwise apply under an MRO also resolves the arguments by several parties that the settlement package violates important regulatory principles by failing the ESP v. MRO test.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) The Companies are public utilities as defined in Section 4905.02, Revised Code, and, as such, as subject to the jurisdiction of this Commission.

(2) On April 13, 2012, FirstEnergy filed an application for an SSO in accordance with Section 4928.141, Revised Code. A stipulation was included with the application.

(3) The signatory parties to the Stipulation are FirstEnergy, Staff, OEG, OMA, IEU-Ohio, OPAE, AICUO, OHA, Nucor, COSE, MSC, Citizens' Coalition, FES, Akron, and Morgan Stanley. Additionally, Kroger, GEXA, EnerNoc, Duke Retail, and Duke Commercial signed the Stipulation as non-opposing parties.

(4) The evidentiary hearing in this proceeding was held on June 4, 2012, through June 8, 2012.

(5) Pursuant to published notice, public hearings were held in Akron on June 4, 2012; in Toledo on June 7, 2012; and in Cleveland on June 12, 2012.

(6) The Companies' application was filed pursuant to Section 4928.143, Revised Code, which authorizes the electric utilities to file an ESP as their SSO.

(7) The Commission finds that the Stipulation, as modified, meets the three criteria for adoption of stipulations, is reasonable, and should be adopted.

(8) The proposed ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

ORDER:

It is, therefore,

ORDERED, That the Stipulation, as modified by the Commission, be adopted and approved. It is, further,

ORDERED, That the Companies file proposed tariffs consistent with the Stipulation as modified. It is, further,

ORDERED, That the Companies take all steps necessary to implement the Stipulation. It is, further,

ORDERED, That a copy of this Opinion and Order be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

Lynn Slaby

MLW/GAP/sc

Entered in the Journal
JUL 18 2012

Barcy F. McNeal

Barcy F. McNeal
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

| | | |
|---|---|---|
| In the Matter of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan. | )<br>)<br>)<br>)<br>)<br>)<br>) | Case No. 12-1230-EL-SSO |

DISSENTING OPINION OF COMMISSIONER CHERYL L. ROBERTO

Because I find the proposed ESP 3 is not superior to an MRO and it does not benefit ratepayers and/or violates important regulatory principles or practices, in at least the various ways detailed below, I reject the proposed ESP 3 and thereby dissent from the majority opinion.

I. The ESP 3 is not superior to an MRO

The burden of proof in this proceeding is on the Companies to establish that the ESP 3, including its pricing and all other terms and conditions is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. Section 4928.143(C)(1), Revised Code. The Companies have not met this burden.

A. RTEP Value Absent

The Companies represent that the ESP 3 is largely a continuation of the ESP 2 that the Commission adopted less than two years ago on August 25, 2010, and which remains under its current terms and conditions in effect until May 31, 2014. The ESP 2 provided for a standard service offer based upon competitive bidding that would yield pricing results similar to an MRO. Thus, a principle reason identified by this Commission for adopting the ESP 2 was the additional term or condition that resolved questions of charges and fees related to the Companies' decision to transfer from MISO to PJM including RTEP and MTEP charges, MISO exit fees, and PJM integration charges. That reason is absent here. I agree with the majority that the ESP 3 provides no benefit relating to MISO/PJM transition charges and fees.

B. Benefits of 'Laddering' Too Ambiguous To Value

The Companies propose to amend the procurement schedule in the ESP 2 to shift bids that are to occur in October 2012 and January 2013 from one-year products to three-year products. The Companies propose that this is a benefit because it may provide an opportunity to capture historically lower generation prices for a longer period of time that would then be blended with potentially higher prices occurring over the life of the ESP 3 thereby smoothing out generation prices and mitigating volatility for customers. As I have in the past, I agree that staggered procurement is a valuable technique to mitigate the risks of market volatility. In this instance, however, customers will enjoy whatever the prices are during the period prior to May 31, 2014, under the current terms of the ESP 2. Any benefit proposed by the ESP 3 requires the assumption that as opposed to customers enjoying those lower prices initially - as they are now entitled to do - we should ask them to relinquish them. To achieve any benefit, we must assume that a bidder for a three-year product will capture all of the benefit of the prices provided by the one-year product and offer them back to the customers and, in addition, offer a lower price than they would otherwise for the product covering years two and three. There is nothing in the record to suggest that this will be true. In fact, the only suggested benefit is averaging the lower prices (which customers would already receive) with the anticipated higher prices - in essence simply paying ahead for the ability to experience less of a price change on June 1, 2014. This proposal would then merely re-create the same phenomenon on June 1, 2016, at which time customers will again face a period in time when the products procured do not overlap. I find that this proposal provides too ambiguous of a benefit, if any benefit exists at all, to value. Additionally, to the extent that this Commission is concerned that prices after May 31, 2014, will increase such as to provide a rate shock to customers (something for which there is no evidence in this record), it always has the authority granted in Section 4928.143(B)(2)(f)(i), Revised Code, to phase in and securitize a utility's standard service offer price.

II. <u>The ESP 3 does not benefit ratepayers or the public interest and violates important regulatory principles or practices</u>

A. <u>Contracting with an affiliated company for an un-bid contract to serve PIPP customers provides ambiguous benefits to ratepayers, is not in the public interest, and undermines market development.</u>

The ESP 3 provides that PIPP customers will be served by the Companies' sister company, FES, through a bi-lateral contract at a rate 6 percent below the auction rate. There is no record that FES is the only or best means of providing PIPP customers with discounted service. Such a provision removes the PIPP load from the market competition. While the potential size of the PIPP load was not explored in the record, customers are eligible when total household income is at or below 150 percent of the federal poverty level. *Rule 122:5-3-02, O.A.C.* "The State of Poverty in Ohio: Building a Foundation for Prosperity" prepared by Community Research Partners for the Ohio Association of Community Action Agencies and issued in January 2010 reports that 30.5 percent of residents of Cleveland are living at or below the poverty rate (100 percent of poverty - not the 150 percent level for PIPP eligibility), 24.7 percent of Toledo residents are living in poverty, and 22.5 percent of Akron residents are living in poverty. Thus, this potential load is not insignificant. There is no reason that the PIPP load could not be part of the auction so that all suppliers have an opportunity to compete for this load. The majority notes that the Ohio Department of Development is authorized to bid out this load - as it has been for more than a decade but has not exercised this authority. Relying on the Department of Development to inject competition when the remainder of the load is going to auction is nonsensical. This solution adds a layer of complexity on an agency which has no reason to have expertise in running electricity auctions. Contracting with an affiliated company for an un-bid contract to serve PIPP customers provides ambiguous benefits to ratepayers, is not in the public interest, and undermines market development.

B. Paying above-market rates for demand response doesn't benefit customers or the public interest and undermines market development

The ESP 3 provides for continued above-market payments to a limited body of customers though Riders OLR and ELR for demand response. The revenue shortfall resulting from these above-market payments would be recovered from all non-interruptible customers as part of the non-bypassable demand side management and energy efficiency rider (Rider DSE). The Companies contend that this provision benefits all customers because suppliers will take into account the ability to reduce load at peak pricing in their CBP bids, which may promote lower prices resulting from the CBP. Other parties contend that it may reduce capacity costs for customers.

While I agree that demand response is valuable, may promote lower CBP pricing, and could reduce capacity costs for customers, this mechanism provides less benefit at a higher cost than simply permitting the PJM demand response market to operate --- and customers must a pay a premium for this less beneficial, higher-cost demand response program. The time has come to allow this above-market program to expire. To be clear, there is no evidence that it is necessary to pay above-market rates to find participants for demand response programs. Thus, the same demand response could be available at the market price—without the need for customer subsidy. Additionally, demand response through the PJM market is visible to PJM such that it will be used to plan for reliability and as a result will *directly* reduce capacity costs for customers. Under the proposed mechanism we can only hope that demand response paid for at the above-market rates will find its way into the RPM market. Finally, providing an above-market payment for demand response can only suppress the development of a true demand response market. As is evidenced by the recent RPM auction results, demand response plays an important and valuable role in reducing capacity costs—but only when it is bid into the RPM market. An ESP provision requiring customers to pay above-market rates for demand response that may or may not actually find its way into the RPM process doesn't benefit customers or the public interest and undermines market development.

C. Gifting stipulation signatories with obligation-free energy efficiency dollars does not benefit customers or the public interest and violates cost-effective rule requirements

The Companies are required to develop a portfolio of energy efficiency programs that is cost-effective. Rule 4901:1-39-04(B) O.A.C. In general, each program proposed within a portfolio must also be cost-effective. *Id.* However, an electric utility may include a program within its portfolio that is not cost-effective when that program provides substantial nonenergy benefits. *Id.* The Companies submit a request for recovery of the costs of these programs within the portfolio proposal. Rule 4901:1-39-07, O.A.C. The Companies' current cost recovery mechanism for these programs is Rider DSE.

The ESP 3 provides the following stipulation signatories with obligation-free payments from Rider DSE:

- COSE: $25,000 in 2014, $50,000 in 2015, and $25,000 in 2016;
- AICUO: $41,333 in 2014, $21,000 in 2015, and $21,000 in 2016;
- OHA: $25,000 in 2014, $50,000 in 2015, and $25,000 in 2016;
- OMA: $100,000 in 2014, $100,000 in 2015, and $50,000 in 2016;
- City of Akron: $100,000 in 2014, and $100,000 in 2015;
- Lucas County: $100,000 in 2014, and $100,000 in 2015; and

None of these recipients is under any obligation to demonstrate that these funds will be used to deploy cost-effective energy efficiency. The funds from Rider DSE are paid by all customers in order to obtain cost-effective energy efficiency. These payments do not provide this benefit and are not consistent with the requirements of Chapter 4901:1-39, O.A.C.

D. Continuation of Rider DCR: utility and customer expectations are not aligned; without alignment utility gains additional revenues without produces additional customer value

Rider DCR is proposed pursuant to Section 4928.143(B)(2)(h), Revised Code, which authorizes an ESP to include:

> 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 ... provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include ... any plan providing for the utility's recovery of costs ... 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.

In order for Rider DCR to be included appropriately within the ESP 3, the Companies have the burden to demonstrate that the Companies' and customers' expectations are aligned and the Companies are dedicating sufficient resources to reliability. Additionally, this provision must be judged as part of the aggregate terms and conditions of an ESP; *e.g.* if a similar or better result is achievable through an MRO, then it calls into question whether the ESP is beneficial.

The Sierra Club notes that despite ample notice of the 2015/2016 RPM auction and the likely consequences for the Companies' customers, the Companies failed to take any steps to prepare for the RPM auction. These actions could have included bidding in energy efficiency and demand response. Accordingly, the Sierra Club argues that the Companies should be held accountable for the financial harm caused to its customers. I agree with the majority that this proceeding was not opened to investigate the Companies' bidding behavior. It is not a complaint case. The majority notes that "the record does not support a finding that the Companies' actions in preparation for bidding into the 2015/2016 base residual auction were unreasonable." If this were a complaint case, a standard of reasonableness would be appropriate. See Section 4905.26, Revised Code. In this instance, however, the burden is upon the Companies to demonstrate that its actions are aligned with both its own interests and those of its customers and that it is dedicating sufficient resources to reliability. The Companies may only avail themselves of the benefits of single-issue rate-making pursuant to Section 4928.143, Revised Code, after they have successfully made this demonstration. The information in our record is insufficient to find that the Companies dedicated sufficient resources to reliability, particularly in the form of participation in the base residual auctions whose very purpose is reliability. For this reason, I find that continuation of Rider DCR is not supported by this record.

Finally, the Companies have a remedy for cost recovery for prudent distribution system investments in the form of a distribution rate case. If the Companies require additional resources, they may file requests under traditional rate-making processes.

E. Lost Revenue Recovery mechanism has out-lived its value to customers and should be permitted to expire

The ESP 3 provides that during its term, the Companies shall be entitled to receive lost distribution revenue for all energy efficiency and peak demand reduction programs approved by the Commission, except for historic mercantile self-directed projects. In adopting the Companies' energy efficiency portfolio on March 23, 2011, Chairman Snitchler penned a concurring opinion that I joined then and find worth repeating a portion of that now:

> I strongly encourage the Companies, the other electric utilities in this state, and all other stakeholders to provide the Commission, in both that docket and in future rate proceedings, with proposals for innovative rate designs that promote both energy efficiency as well as the state policies enumerated in Section 4928.02, Revised Code.

The lost revenue mechanism should be permitted to expire under the terms of the ESP 2. It has out-lived its value to customers.

F. Adequacy of the Companies' current corporate separation is a legitimate question worthy of Commission consideration

The ESP 3 proposes that the Companies' corporate separation plan approved in *In re FirstEnergy*, Case No. 09-462-EL-UNC, would remain approved and in effect as filed.

The combination of recent discretionary utility decisions by separate generation, transmission, and distribution affiliates within the Companies' corporate family have seemingly produced enhanced investor value without an increase in consumer value but added consumer costs in the nature of significantly higher capacity charges. The specific discretionary decisions I reference include the FES decision to close two generation plants two years earlier than any environmental new requirement was to be imposed resulting in a capacity constraint; FES' continuance nonetheless operating these plants at above-market rates under must-run contracts; ATSI's advocacy of its solution to the constraint of approximately $900 million dollars in additional infrastructure to be built at cost plus; the apparent absence of effort by the Companies to use cost-effective means to control the shape and size of its native load; and the proposal in the ESP 3 for un-bid purchase by the Companies from its sister affiliate FES of the PIPP customer load. By itemizing these observations, I am not suggesting that the Companies or any other member of the Companies' family has taken an action that is unauthorized or outside of any existing authority in any manner. By highlighting them, however, I am suggesting that the Commission should not be eager to re-approve and extend the Companies' current corporate separation plan without a more deliberative review.

G. The timing of this matter and bundling of disparate issues does not benefit customers or the public interest

While I agree with the majority that the Commission cannot find that parties were denied the opportunity for thorough and adequate participation in this proceeding, the urgency that seemed to accompany this matter seems out of proportion to any real need to act. The ESP 2 is in effect until May 31, 2014. The Commission has up to 275 days after an application is filed to act. Section 4928.143(C)(1), Revised Code. This timing leaves a significant window for a deliberative review of any proposal for the Companies next timely ESP. Yet this case was filed on April 13th – just three months ago – and is now before us for final resolution. Customers and the public interest would benefit from the matters included within the ESP 3 relating to distribution improvements and energy efficiency programs to be considered within appropriate separate dockets. This is particularly true in light of the strain on available resources, including those within the significantly down-sized Office of Consumers' Counsel, resulting from the pendency of AEP SSO and Capacity cases during the past three months as well. While the alacrity of this case does not mean that parties did not have an adequate opportunity to participate, I believe that a superior public interest result would be attained by using the time and regulatory frameworks available to us for a disciplined review of the distribution and energy efficiency/demand response portions of this matter in separate dockets.

For the above reasons, which do not represent an exhaustive list, I find that the Companies have not met their burden and, therefore, I would reject the ESP.

Cheryl L. Roberto

Cheryl L. Roberto

CLR\sc

Entered in the Journal
JUL 18 2012

Barcy F. McNeal

Barcy F. McNeal
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

| | | |
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| In the Matter of the Application of Ohio Power Company for Approval of an Amendment to its Corporate Separation Plan. | ) ) ) ) | Case No. 12-1126-EL-UNC |

FINDING AND ORDER

The Commission finds:

(1) Ohio Power Company (OP, Company) is a public utility as defined in Section 4905.02, Revised Code, and, as such, is subject to the jurisdiction of this Commission.

(2) On January 27, 2011, in Case No. 11-346-EL-SSO, *et al.* (ESP 2), OP and Columbus Southern Power Company (CSP) filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code.[1] The application was for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code.

(3) On September 7, 2011, a stipulation and recommendation (ESP 2 stipulation) was filed by OP, Staff, and other parties to resolve the issues raised in 11-346 and several other cases pending before the Commission.[2]

(4) On December 14, 2011, the Commission issued an opinion and order in the ESP 2 and other pending cases, modifying

[1] *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 Section 4928.143, Revised Code, in the Form of an Electric Security Plan,* Case Nos. 11-346-EL-SSO and 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 Nos. 11-349-EL-AAM and 11-350-EL-AAM.

[2] *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals,* Case No. 10-2376-EL-UNC; *In the Matter of the Application of Columbus Southern Power Company to Amend its Emergency Curtailment Service Riders,* Case No. 10-343-EL-ATA; *In the Matter of the Application of Ohio Power Company to Amend its Emergency Curtailment Service Riders,* Case No. 10-344-EL-ATA; *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company,* Case No. 10-2929-EL-UNC; *In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144, Revised Code,* Case No. 11-4920-EL-RDR; *In the Matter of the Application of Ohio Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144, Revised Code,* Case No. 11-4921-EL-RDR.

(30) IEU proposes more specific conditions be imposed on AEP-Ohio's request for full corporate separation:

(a) OP and its affiliates irrevocably consent to the Commission's exercise of its full authority as delegated by Section 4928.18, Revised Code.

(b) OP retain an independent auditor, at the expense of OP shareholders, to evaluate the corporate separation from the perspective of the public interest and make recommendations to the Commission.

(31) In its application, OP agreed to abide by conditions substantially similar to the conditions offered in the Duke Energy Ohio Inc., in Case No. 11-3549-EL-SSO, et al., (See Duke Stipulation at 25-27 filed October 24, 2011).

(32) Upon review of the application, the Company's supplemental statement, comments and reply comments, and taking into account the Commission decision in the Company's modified ESP 2 Order, the Commission concludes that OP's corporate separation application should be subject to the following conditions:[10]

(a) Staff, or an independent auditor at the Commission's discretion, shall audit the terms and conditions of the transfer of the generating assets to ensure compliance with Section 4928.17, Revised Code, and Chapter 4901:1-37, O.A.C., and any successors to the rules in that chapter, to ensure that no subsidiary or affiliate of OP that owns competitive generating assets has any competitive advantage due to its affiliation with OP. OP may file an application with the Commission to seek approval of the recovery of the costs associated with an independent audit.

[10] The Commission notes that these conditions are comparable to the conditions that we recently approved for Duke. *In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications, and Tariffs for Generation Service,* Case No. 11-3549-EL-SSO, *et al.*, Opinion and Order (November 22, 2011) and OP's prior corporate separation proceeding.

(b) Staff shall be provided with access to all books, accounts, and records in compliance with Rule 4901:1-37-09(F), O.A.C.

(c) Following the transfer of the generating assets, OP shall not, without prior Commission approval, provide or loan funds to, provide any parental guarantee or other security for any financing for, and/or assume any liability or responsibility for any obligation of subsidiaries or affiliates that own generating assets; provided, however, that contractual obligations arising before the date of this finding and order shall be permitted to remain with OP, without prior Commission approval, for the remaining period of the contract, but only to the extent that assuming or transferring such obligations is prohibited, and can not be effectively negotiated by the terms of the contract or would result in substantially increased liabilities for OP if OP were to transfer such obligations to its subsidiary or affiliate and to the extent that AEPGenCo be made contractually responsible to OP for all costs resulting from such generation related liabilities. In order to facilitate verification of these obligations, OP shall identify such by October 31, 2013.

(d) OP shall ensure that all new contractual obligations have a successor-in-interest clause that transfers all of OP's responsibilities and obligations under such contracts and relieves OP from any performance or liability under the contracts upon the transfer of the generating assets to its subsidiary or affiliate.

(e) The above provisions do not restrict OP's ability to receive and pass through to the subsidiary or affiliate that owns the generating assets equity contributions from its parent that are in support of the generating assets, nor do they restrict OP's ability to receive dividends from the subsidiary or affiliate that owns the generating assets and pass through such dividends to its parent.

(f) Generation-related costs associated with implementing corporate separation shall not be recoverable from OP customers.

(g) Any subsidiary or affiliate of OP to which generating assets are transferred shall not use or rely upon the ratings from credit rating agencies for OP. If such subsidiary or affiliate currently does not maintain separate ratings from the credit rating agencies, then upon transfer of any of the generating assets, it shall either seek to establish such ratings or shall tie its credit ratings to AEP as soon as practicable but no later than six months following such transfer.

(h) Further, in the modified ESP 2 Opinion and Order the Commission found:

> Despite the Staff's recommendation, the Commission approves AEP-Ohio's requests to retain the pollution control bonds contingent upon a filing with the Commission demonstrating that AEP-Ohio ratepayers have not and will not incur any costs associated with the cost of servicing the associated debt. More specifically, AEP-Ohio ratepayers shall be held harmless for the cost of the pollution control bonds, as well as any other generation or generation related debt or inter-company notes retained by AEP-Ohio.

Consistent with the Commission directives in the modified ESP 2 Order, and as OP recognizes in its application for rehearing of the modified ESP 2 Order, the Commission believes the Company could achieve the Commission's directive by utilizing an intercompany note between OP and AEPGenCo wherein OP could retain the PCRB as OP requests and yet require AEPGenCo to provide to OP amounts sufficient to pay principal and interest on the PCRB.

The Commission is also aware that in the pending securitization application filed in Case No. 12-1969-EL-ATS, OP has reiterated its original request to either permanently retain the PCRB maturing after corporate separation or to transfer those bonds only when there is no defeasance costs.[11] The Commission reiterates its directive in the modified ESP 2 Order that PCRB maturing post corporate separation shall not be a cost recoverable, directly or indirectly, from OP distribution ratepayers. Therefore, the Commission will not permit OP to fund the defeasance costs of the PCRB with proceeds from the securitized bonds that are the subject of its application in Case No. 12-1969-EL-ATS. The Commission believes the Company could achieve the Commission's directive by utilizing an intercompany note between OP and AEPGenCo wherein OP could retain the PCRB as OP requests and yet require AEPGenCo to provide to OP amounts sufficient to pay principal and interest on the PCRB.

REPAs

(33) FES asks the Commission to treat the REPAs similarly such that either all the REPAs stay with OP or they should be transferred with the generation assets.

(34) OP responds, as the Company explained in its application, that transfer of the REPAs does not require Commission approval or need to be part of a corporate separation plan or amendment. Further, the Company emphasizes that it is not "cherry picking" the REPAs to be retained or transferred but would retain all of the existing REPAs.

(35) The Commission recognizes and approves, to the extent that it is necessary, OP's request to retain the existing REPAs

[11] Ohio Power Reply Comments at 5-6.

ORDERED, That a copy of this finding and order be served upon all parties and other interested persons of record in this case.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

Lynn Slaby

GNS/dah

Entered in the Journal

OCT 17 2012

Barcy F. McNeal

Secretary