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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company to Update its gridSMART Rider.	)))	Case No. 10-164-EL-RDR

FINDING AND ORDER

The Commission finds:

On March 18, 2009, the Commission issued its opinion and order in Columbus Southern Power Company's (CSP) and Ohio Power Company's (OP) (jointly, AEP-Ohio or the Companies) electric security plan (ESP) cases (ESP Order).[1] By entries on rehearing issued July 23, 2009 (First ESP EOR) and November 4, 2009 (Second ESP EOR), the Commission affirmed and clarified certain issues raised in AEP-Ohio's ESP Order. As ultimately modified and adopted by the Commission, CSP's ESP directed that CSP create the gridSMART rider.[2]

On February 11, 2010, CSP filed, in Case No. 10-164-EL-RDR (gridSMART case), its application to update its gridSMART rider. CSP explains that, as directed by the Commission in the ESP cases, it pursued, and has been awarded, funding through the American Reinvestment Recovery Act (ARRA) from the United States Department of Energy (USDOE). As presented in the ESP cases, gridSMART consist of advanced meter infrastructure (AMI), home area network (HAN) and distribution automation (DA).[3] CSP claims that ARRA funding further required enhancement of the gridSMART plan presented to the Commission in the ESP cases to include real-time pricing, community energy storage, smart appliances, cyber security operation center, and plug-in electric vehicle components at an additional cost of approximately $41 million. CSP states that it secured in-kind contributions from non-affiliated corporate partners to enhance its gridSMART plan, and the cost of the additional work and components will not be collected through the gridSMART rider. CSP states that it expects to avoid increasing the 2009-2011 revenue requirement for gridSMART Phase I. In other words, CSP expects to maintain approximately the same level of ratepayer funding during this ESP period. CSP states that in the ESP case, the Commission approved CSP's initial gridSMART rider at $32 million, subject to annual reconciliation, based on the Companies' prudently incurred costs and receipt of ARRA grant funding. CSP acknowledges that it suspended its gridSMART spending in 2009 because, under the

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1 In re AEP-Ohio ESP cases, Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, Opinion and Order (March 18, 2009).

2 In re AEP-Ohio ESP Order at 34-38; First ESP EOR at 18-24.

3 In re ESP cases, Order at 34 (March 18, 2009).

ARRA process, expenditures incurred more than 90 days prior to USDOE award notification are not eligible for matching funds. Based in part on the company's suspension of gridSMART expenditures, CSP over-recovered its gridSMART costs via the gridSMART rider for 2009. CSP states that it has resumed its gridSMART expenditures and expects to incorporate the "delayed" investments in 2010. CSP requests that the company's gridSMART rider be updated to 2.30342 percent for actual gridSMART Phase I investments, a decrease from the current rate of 2.55030 percent. CSP requests that the gridSMART rider rates commence with the first billing cycle in July 2010, to coincide with the effective date of the fuel adjustment clause (FAC) adjustment, as any increase associated with the gridSMART rider and FAC rates are limited by the rate caps established in the ESP cases.[4]

By entry issued April 8, 2010, a procedural schedule in this matter and two other AEP-Ohio rider proceedings was established. In the April 8, 2010 entry, interested persons were directed to file comments to this or two other rider applications by April 30, 2010. Reply comments were due by May 10, 2010. The Office of the Ohio Consumers' Counsel (OCC), the Industrial Energy Users-Ohio (IEU-Ohio), and Ohio Partners for Affordable Energy (OPAE) filed motions to intervene in the gridSMART case. The April 8, 2010 entry also granted OCC's, IEU-Ohio's and OPAE's motions to intervene in the gridSMART case. Further, the entry admitted David C. Rinebolt to practice *pro hac vice* before the Commission in the gridSMART case.

On July 21, 2010, CSP filed a letter and updated exhibits to the gridSMART application. In the letter, CSP agrees to certain Staff recommendations, as noted below, and requests that the updated gridSMART rider be adopted (CSP letter).

On August 9, 2010, OCC filed reply comments to CSP's July 21, 2010 letter (Second OCC Reply Comments), to which CSP filed reply comments on August 10, 2010 (Second CSP Response). In these comments, OCC makes some arguments regarding time of use rates. The Commission finds that OCC's comments regarding time of use rates, and CSP replies thereto are more appropriately addressed in other Commission proceedings for gridSMART service offerings and will not be further discussed in this case.

[4] On a total bill basis, rate increases are capped at 7 percent for CSP and 8 percent for OP in 2009, 6 percent for CSP and 7 percent for OP in 2010, and 6 percent for CSP and 8 percent for OP in 2011. ESP Order at 22; First ESP EOR at 8-9.

A. IEU-Ohio's General Comments to AEP-Ohio Rider Cases[5]

In its comments to the gridSMART case, IEU-Ohio argues that the Commission lacks subject matter jurisdiction. IEU-Ohio asserts that the Commission lost jurisdiction over AEP-Ohio's ESP, and all proceedings stemming from the ESP, including these rider proceedings, when the Commission failed to issue an order within 150 days of AEP-Ohio filing its ESP application. (IEU-Ohio Comments at 7-9; IEU-Ohio Reply at 2-3.) IEU-Ohio also argues that AEP-Ohio must accept the modified ESP and withdraw its appeal of the modified ESP (IEU-Ohio Comments at 9-12).

IEU-Ohio has raised these issues in other Commission proceedings and in each case the Commission has rejected both arguments.[6] IEU-Ohio has raised no new arguments in this proceeding that the Commission has not previously considered in other cases and rejected. Accordingly, for the same reasons as stated in previous cases where the issues have been raised, the Commission again rejects IEU-Ohio's arguments. However, the Commission will provide further explanation as to why IEU-Ohio's jurisdictional argument is without merit.

The Commission did not lose jurisdiction over the ESP application after 150 days. The 150-day period specified in Section 4928.143(C)(1), Revised Code, does not limit the Commission's jurisdiction. The general rule is that "a statute providing a time for the performance of an official duty will be construed as directory so far as time for performance is concerned, especially where the statute fixes the time simply for convenience or orderly procedure." *Hardy v. Delaware Cty. Bd. Of Revision*, 106 Ohio St. 3d 359, 363, 835 N.E.2d 348, 353 (2005), quoting *State ex rel. Jones v. Farrar*, 146 Ohio St. 467, 66 N.E.2d 531, ¶ 3 of the syllabus (1946). As the Court has explained:

> Statutes which relate to the manner or time in which power or jurisdiction vested in a public officer is to be exercised, and not to the limits of the power or jurisdiction itself, may be construed to be directory, unless accompanied by negative words importing that the act required shall not

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[5] IEU-Ohio filed the same comments to AEP-Ohio's rider applications in *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Establish Environmental Investment Carrying Cost Rider*, Case No. 10-155-EL-RDR and *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Update Each Company's Enhanced Service Reliability Rider*, Case No. 10-163-EL-RDR.

[6] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Adjust Their Economic Development Cost Recovery Rider Pursuant to Rule 4901:1-38-08(A)(5), Ohio Administrative Code*, Case No. 10-154-EL-RDR, Entry on Rehearing at 3-4 (May 19, 2010); *In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company*, Case No. 09-872-EL-FAC, et al., Entry on Rehearing (March 24, 2010).

be done in any other manner or time than that designated. *Schick v. Cincinnati*, 116 Ohio St. 16, 155 N.E. 555, ¶ 1 of the syllabus (1927).

The Court has repeatedly held that a tribunal does not lose jurisdiction for failing to act within a prescribed time absent an express intent to restrict jurisdiction for untimeliness. *See, e.g. In re Davis*, 84 Ohio St. 3d 520, 705 N.E.2d 1219 (1999); *State v. Bellman*, 86 Ohio St. 3d 208, 714 N.E.2d 381 (1999). There is no such expression of intent in Section 4928.143(C)(1), Revised Code, or elsewhere in Amended Substitute Senate Bill 221 (SB 221). The statute expresses no purpose for the requirement that an application be approved within 150 days. Absent a discernable purpose in the text of the statute, the time for performance is viewed as directory, not mandatory, *State ex rel. Smith v. Barnell*, 109 Ohio St. 246, 142 N.E.2d 611 (1924). The Commission, thus, retained jurisdiction to act on the ESP application.

IEU-Ohio also urges the Commission to reconsider the modified ESP to evaluate whether the ESP meets the goals set forth in Section 4928.02, Revised Code (IEU-Ohio Comments at 5-6).

We reject IEU-Ohio's request to re-evaluate CSP's Commission-modified and approved ESP in light of the company's earnings. Pursuant to SB 221 the Commission will evaluate CSP's ESP, as well as that of other electric utilities, to determine whether the plan produces significantly excessive earnings for the electric utility determined in *In the Matter of the Investigation into the Development of the Significantly Excessive Earnings Test Pursuant to Amended Substitute Senate Bill 221 for Electric Utilities*, Case No. 09-786-EL-UNC, and, for this reason, we find it unnecessary to explore the issue in this case. We also find IEU-Ohio's request to reconsider whether CSP's ESP meets the goals of Section 4928.02, Revised Code, to be an untimely attempt to relitigate the Commission's decision in the ESP case.

B. <u>Staff Audit Process</u>

As a part of its investigation, Staff reviewed CSP's operations and maintenance (O&M) expenses and equipment purchase costs as well as the carrying charge rate. Staff requested detailed lists of capital and O&M costs, supporting documentation of a selected sample of such cost and reviewed the documentation until Staff was satisfied or determined an adjustment was warranted. Staff also determined the major equipment purchased in 2009 for the DA Integrated Volt Var Control (IVVC) program and physically verified that such equipment had been located at substations and installed on the associated circuits. Staff did not note any discrepancies with regard to its physical audit. (Staff Comments at 12.)

C. Staff Recommendations and Intervenor Comments

(1) Advanced Metering Infrastructure (AMI)

Staff determined that CSP counted certain meter purchase invoices and accounts payable accrual entries twice which CSP subsequently corrected beyond the audit review period. Staff recommends an adjustment of $10,747,780 to 2009 capital expenditures for AMI. (Staff Comments at 11.)

CSP answers that the company accrued $8,789,680 as an estimate of invoices not yet processed at the end of 2009 to assure that services rendered through December 31, 2009 were booked during the proper period. CSP contends this is a routine practice and the entry is corrected and reversed when the invoices are received and entered. For this reason, CSP agrees that it is appropriate to omit $8,789,680 from the company's December capital balance for property with a seven-year depreciable life but notes that this amount will need to be reflected in January 2010 capital expenditures. (CSP Reply 1-2.) Further, CSP argues that the remaining $1,958,100 was supported by documentation provided to Staff in response to data requests. CSP explains that $979,050 was presented on two invoices, and, therefore, $1,958,100 was not actually counted twice and should not be excluded from the gridSMART filing. (CSP Reply at 2-3.) By letter dated July 21, 2010, CSP agrees that, due to the timing of unvouchered liabilities from December 2009, the company will exclude $8,789,680 from the 2009 recovery request (AEP-Ohio Letter at 1).

By letter dated July 30, 2010, Staff states that it agreed with the resolution proposed by CSP in its letter for purposes of reaching a reasonable outcome in this matter. Staff further states it has no remaining issues that require an adjudicatory hearing. (Staff Letter at 1-2.) In its comments of August 9, 2010, OCC states that it does not object to the exclusion of the unvouchered liabilities from the gridSMART rider (Second OCC Reply Comments at 3).

The Commission finds this to be a reasonable resolution of the issue.

(2) Labor Expense

Staff contends that any allowable O&M labor expense allocated to gridSMART should be incremental and specifically related to gridSMART. Based on its review, Staff asserts that there is no evidence that labor expenses are incremental. For this reason, Staff recommends that O&M labor/overheads of $120,895, labor fringe benefits of $47,375, and stock-based compensation of $3,486, for a total of $171,756, be excluded from CSP's expenses. (Staff Comment at 11.)

CSP states that on June 1, 2009, the company created three new positions to support the gridSMART project, incurring $166,728 in O&M labor expenses. Existing employees also specially allocated time to the gridSMART project, resulting in $5,028 in labor expenses. CSP argues that, while only incremental labor costs directly attributable to the gridSMART project should be included in the gridSMART rider, it will not always be the case that new employees are dedicated exclusively to gridSMART. In support of it position, CSP notes that the ESP cases included O&M expenses for internal labor as part of the proposal which the Commission approved. CSP contends that only permitting internal labor costs to be recoverable for new full-time positions through the rider may not utilize the lowest reasonable costs to be passed on to ratepayers or permit CSP management to utilize the most experienced employees on gridSMART. CSP is willing to conditionally accept Staff's proposed adjustment of $5,028, contingent upon the Commission's willingness to accept the $5,028 adjustment in this case without prejudice to resolution of incremental internal labor costs in future gridSMART rider reconciliation proceedings. (CSP Reply at 3-4.)

Nonetheless, based on discussions with the Staff and other interested parties, CSP agrees to exclude from the $602,605 of O&M internal labor expenses included in the application $435,877. Thus, only $166,728 of incremental labor costs for gridSMART will be recovered for 2009 (AEP-Ohio Letter at 1). Staff agrees with CSP's proposed resolution of this issue (Staff Letter at 1-2). OCC states that it does not object to the exclusion of the unvouchered liabilities from the gridSMART rider (Second OCC Reply Comments at 3).

The Commission finds CSP's agreement, and the Staff's and OCC's acquiescence, to include only $166,728 of incremental labor in the O&M internal labor expense for the gridSMART rider to be a reasonable resolution of the issue.

(3) <u>Other Expense</u>

(a) <u>Mobile Interest Center</u>

Staff opposes CSP's inclusion of costs related to its Mobile Interest Center through the gridSMART rider asserting that it is not part of the deployment. Further, Staff reasons that this position is consistent with the position the Commission took in Duke Energy of Ohio's SmartGrid Deployment Case.[7] Accordingly, Staff recommends a reduction in the rider of $152,096. (Staff Comment at 11-12.)

In response, CSP states that the mobile interest center, unlike Duke's Envision Center, is a key component to customer education and understanding the gridSMART initiative. Through the mobile interest unit, CSP asserts that it will be able to expose customers to the benefits of the gridSMART project. Customers will be able to touch

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[7] *In the Matter of the Application of Duke Energy Ohio Inc. to Adjust and Set its Gas and Electric Recovery Rate for SmartGrid Deployment under Rider AU and Rider DR-IM*, Case No. 09-543-GE-UNC, (Duke SmartGrid Deployment), Opinion and Order at 6, 10 (May 13, 2010).

and see, as well as have an opportunity to discuss the various components of the gridSMART project and enroll in various consumer programs at community events, city council meetings and other special activities. The mobile interest unit also provides the customer with information on energy efficiency. (CSP Reply at 4-6.)

The Commission believes that customer education is vital to the success of the gridSMART Phase I project. Through the Mobile Interest Center, CSP can make contact with the customer and demonstrate the technology available to monitor energy usage and permit the customer the option to better control energy usage and electric bills. In addition to sending customers within the project area information about gridSMART by the usual means (mail, bill messages and making it available on the company's website), the Mobile Interest Center is a proactive means of demonstrating aspects of Phase I gridSMART to project customers, as well as other CSP customers, in preparation for gridSMART deployment throughout its service territory. Further, the Mobile Interest Center is an interactive means of getting the information to customers, with the opportunity for customers to ask questions and enroll in the service options available. For these reasons, the Commission finds that the cost of the Mobile Interest Center is a key component of gridSMART and the costs are appropriately included in the gridSMART rider.

(b) Carrying Charge

In its comments, Staff explains that the carrying charge to be applied to the gridSMART investment made in 2009 and projected for 2010 consists of four components. The revenue requirement rate consists of: (1) a rate of return factor; (2) a depreciation expense factor; (3) a federal income tax (FIT) factor; and (4) a combined property taxes and administrative and general (A&G) factor. (Staff Comments at 12.)

(1) Rate of Return Factor

Staff notes the rate of return factor used in the 2009 actual cost calculations is not the same as that reflected in the projected period. The factor in the 2009 actual calculation was based on actual interest rates updated monthly, and the debt portion was adjusted. According to Staff, the rate of return factor CSP used for the projected calculation is based on the weighted average cost of capital (WACC), 8.11 percent. Staff says that the actual interest cost used by the CSP, however, includes the effect of short-term interest costs which causes the rate to vary monthly. Therefore, Staff recommends that the CSP use the same WACC approved by the Commission in the Companies' ESP cases, subject to update should the Commission approve another debt/equity structure. (Staff Comments at 12-13.)

Subsequently, based on discussions with the Staff and other interested parties, CSP agrees to revise the carrying cost calculations to use the same WACC and debt/equity ratio approved in its ESP case (AEP-Ohio Letter at 1).

(2) Depreciation Expense Factor

Staff notes that in the gridSMART filing, CSP used a different depreciation factor for the actual revenue requirement and the projected revenue requirement. Staff recognizes that CSP updated the 2009 depreciation factor to reflect current depreciation rates and that the projected revenue requirement is based on the depreciation factor approved in the ESP cases. Staff recommends that the latest approved depreciation factor be used to calculate the revenue requirement for the actual and projected periods 2009 – 2010. (Staff Comments at 13.)

CSP has agreed to revise the carrying cost calculation to use the depreciation factor approved in its ESP case as Staff recommends (AEP-Ohio Letter at 1).

(3) FIT Factor

The FIT factor normalizes the effect of accelerated depreciation to straight line depreciation. Staff determined that the FIT factor in the gridSMART application is the same as the factor approved in the Companies' ESP order and has been consistently applied; therefore Staff recommends no changes unless there is an approved change in the depreciation factor. (Staff Comments at 13.)

(4) Property Taxes and A&G factor

According to Staff, the gridSMART application incorporates the same CSP property taxes and A&G factor as that approved in the ESP case, for both the actual and projected revenue requirements. Staff notes that the revenue recovery rate of 13.52 percent for the property taxes is based on a ratio of the booked property tax as of December 31, 2007, to the total plant, as used in CSP's ESP case for environmental plant investments. Staff notes that Ohio law exempts certified pollution control facilities from personal property taxes pursuant to Sections 5709.20 to 5709.27, Revised Code. Staff further contends that certified pollution control facilities are generation-related property and that the noncertified plant is assessed property taxes on 24 percent of the true value pursuant to Section 5727.111, Revised Code.[8] In this case, Staff argues that CSP's gridSMART investment is part of the distribution function and, property tax for distribution-related property is assessed on 85 percent of the true value. For this

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[8] Section 5727.111(E), Revised Code, states:

(1) For tax year 2005, eighty-eight per cent in the case of the taxable transmission and distribution property of an electric company, and twenty-five per cent for all its other taxable property;

(2) For tax year 2006 and each tax year thereafter, eighty-five per cent in the case of the taxable transmission and distribution property of an electric company, and twenty-four per cent for all its other taxable property.

reason, Staff believes that the property tax component of the carrying cost developed in the ESP case should be corrected to 15.14 percent. (Staff Comments at 13-14.)

The total effect of Staff's recommended adjustments to the carrying charge would result in an increase of $560,378 (Staff Comments at 14).

OCC opposes Staff's recommendation to increase the carrying charge rate to 15.14 percent and ultimately increase carrying charges by $560,378. OCC reasons that the Staff did not present its calculation in its comments and that the increase will further burden AEP-Ohio customers during difficult economic times. (OCC Reply at 3.)

By letter dated July 21, 2010, CSP agrees to revise the carrying cost calculation to use the same FIT factor, property taxes and A&G factor approved by the Commission in the company's ESP case, except with a correction to the property tax component to reflect that the gridSMART facilitates are not exempt from personal property taxes, as the Staff recommends (AEP-Ohio Letter at 1). Staff agrees with CSP's proposed resolution of the issues raised with regard to the calculation of carrying costs (Staff Letter at 1-2).

OCC continues to object to the method for calculating the annual carrying cost as presented by CSP in its July 21, 2010 letter. OCC argues that although the revised method for calculating carrying charges reflects the elimination of most of the personal property taxes and the change in the valuation of the enhanced vegetation investment for property tax purposes, as the Commission did not specify the carry charge for gridSMART in the ESP case. OCC further argues that CSP has not demonstrated that the proposed annual carrying charge rates are just and reasonable or demonstrated that the financial data and operating information used in 2006-2007 is just and reasonable in calculating the 2009 carrying charge for gridSMART investments. If the Commission accepts CSP's and Staff's carrying charge proposal, OCC states that CSP should be directed to record all depreciation expenses it collects through the annual carrying charges in the gridSMART rider as accumulated depreciation and that the accumulated depreciation should be deducted from the rate base of distribution-related assets in the company's next distribution or ESP case. (Second OCC Reply Comments at 4-5.)

In response, CSP argues that OCC ignores that the Commission specifically provided for the "recovery of half of the gridSMART Phase I incremental revenue requirement, $32 million, in the First ESP EOR. CSP contends that the $32 million was based on one-half of the 2009-2011 gridSMART costs over the ESP period including $9.8 million of O&M and carrying costs exceeding $20 million on gridSMART expenditures as set forth in CSP's exhibits to the ESP cases.[9] CSP notes that Staff agreed with its updated position on the carrying charge. Finally, as to the carrying charge, CSP states

[9] Cos Ex. 1, DMR-4 (Roush) and Cos. Ex. 7, PJN-10 (Nelson).

that it is recording depreciation of the gridSMART equipment on its books with a contra credit entry to accumulated depreciation which would be deducted from rate base in any future distribution or ESP case. (Second CSP Response at 3-4.)

As part of AEP-Ohio's ESP cases, the Commission evaluated and approved the carrying cost rate for the Companies' gridSMART and environmental investments.[10] The carrying cost in the ESP case is the most recent approved for AEP-Ohio. While we are mindful that using the most recent approved carrying cost rate increases the carrying charges, as OCC notes, it is the Commission's practice in subsequent proceedings to use the most recently approved carrying cost rate. Accordingly, we find it reasonable and appropriate to use the carrying cost rate approved in CSP's ESP case in the gridSMART rider calculation, except as to the amendments recommend by Staff and agreed to by CSP to correct the property tax component. Further, to the extent that CSP is recording depreciation on gridSMART equipment with an entry to accumulated depreciation to be deducted from rate base in any future distribution or ESP proceeding. We find that such transactions avoid double recovery of capital investments in gridSMART. For these reasons, the Commission finds that the issues raised regarding the carrying cost calculation for CSP's gridSMART rider have been adequately and reasonably addressed.

(c) Other Staff Adjustment

Staff notes that it identified a $9,554 Allowance for Funds Used During Construction (AFUDC). Staff reasons that such charges are inappropriate since CSP has been recovering gridSMART costs through the gridSMART rider as established in the ESP cases. The Commission agrees with the Staff that since CSP was collecting under the gridSMART rider, it is inappropriate for the company to include AFUDC in the rider. CSP should exclude $9,554 from the gridSMART rider calculation.

D. Intervenor Comments

In its comments and reply comments on the gridSMART application, IEU-Ohio notes that CSP did not provide an itemization of the individual enhancements to the gridSMART plan. IEU-Ohio reasons that a more detailed examination of the gridSMART enhancements is necessary and requests that the Commission not approve recovery of the enhancements as a part of this case. (IEU-Ohio Comments at 6-7; IEU-Ohio Reply at 4-5.)

Similarly, OPAE notes that CSP's proposed gridSMART project, as set forth in the ESP case, has been significantly enhanced by CSP. OPAE offers that it is not unlikely that the implementation of CSP's gridSMART Phase I would be delayed given

[10] In re AEP-Ohio ESP Order at 24-28; First ESP-EOR at 11-13.

the demand throughout the country. OPAE, therefore, encourages the Commission to true-up the gridSMART rider for prudently incurred cost pursuant to the gridSMART project approved by the Commission in the ESP case and the overrecovery for 2009. (OPAE Comments at 2-3.)

CSP responds that OPAE's presumption of further delay is without merit. CSP explained the unique circumstances of the temporary deployment delay. CSP requests that the Commission deny OPAE's request to modify the gridSMART application. (CSP Reply at 8-9.)

Further, IEU-Ohio and OPAE implore the Commission to include, as a part of any order issued, that the Commission will investigate and determine whether CSP may collect on the increased gridSMART plan costs in a future CSP case. OPAE reasons that if the enhancements/equipment is included in rate base, even if donated, the Commission should determine if the expanded gridSMART project is beneficial to customers. (IEU-Ohio Comments at 6-7; IEU-Ohio Reply at 4-5; OPAE Comments at 3-4.) OPAE argues that CSP mistakenly believes that the Commission approved $109 million for gridSMART but the First ESP EOR only approved recovery of half the cost of $64 million. OPAE contends that recovery of any additional funds must be separately authorized by the Commission after a prudency review in a separate proceeding or as a component of the next SSO proceeding (OPAE Comments at 4.)

Similarly, OCC expresses some reservation that CSP may attempt to collect the additional gridSMART enhancement costs from Ohio's ratepayers via another rider proceeding or as part of a general distribution rate case. Thus, OCC requests assurance that neither CSP nor its affiliates will seek recovery of the $41.3 million in a future distribution rate case or new rider and further requests that the Commission prohibit recovery of gridSMART-related costs by any other means than the gridSMART rider. (OCC Comments at 4-5).

In response to OCC's arguments, CSP explains that a review of the company's ESP application and this reconciliation application clearly indicate that CSP did not intend and never would recover the entire cost of the gridSMART Phase I investment during the 2009 – 2011 ESP period and that additional investment would need to be recovered from ratepayers during CSP's next standard service offer or through a general distribution rate proceeding. CSP interprets the ESP Order and EORs to confirm the Commission understanding that such was to be the case. Thus, CSP requests that the Commission affirm that the company's prudently incurred costs relating to the enhanced gridSMART Phase I initiative, minus federal funding and vendor in-kind contributions, will be recoverable from ratepayers. (CSP Reply at 6-8.)

In its letter dated July 21, 2010, CSP requests that, based on the ARRA stimulus funding of $75 million and the additional nonaffiliated in-kind contribution of $10.85

million, the Commission approve CSP's continued implementation of the enhanced gridSMART *initiative as described in this* application. CSP recognizes that recovery of CSP's enhanced gridSMART implementation costs will continue to be subject to review in future rider proceedings. CSP argues that the 2009 costs reviewed in this proceeding were prudently incurred and appropriate for recovery. (AEP-Ohio Letter at 2.)

The Commission recognizes that it directed CSP to apply for ARRA matching funds and that CSP, as a requirement for securing ARRA funding, was required to expand its smart grid project. Such costs, if found to be just and reasonable, will be recoverable in a future proceeding. However, the Commission clarifies that we are not approving recovery of specific expenditures at this time.

Further, based on discussions with the Staff, CSP agrees to establish a gridSMART working group. Participation in the gridSMART working group will be open to interested stakeholders, including Staff and OCC. The gridSMART working group will meet quarterly to discuss ongoing matters involving customer education programs, implementation milestones, metrics for evaluation of various aspects of the initiative, updated projections of operational cost savings, cost recovery issues and other matters of interest to the group. CSP proposes that the primary goal of the working group be to allow for input by stakeholders and provide updates on CSP's implementation progress and plans. Further, according to CSP, the focus of the gridSMART working group's efforts would be on post-2012 plans for expanding beyond Phase 1 gridSMART for both CSP and OP. (AEP-Ohio Letter at 2.)

Although, OCC supports the establishment of a gridSMART working group, OCC would like the Commission to go further to mandate the timing and substance of the working group. (Second OCC Reply Comments at 3-4.)

The Commission supports CSP's proposal and encourages the timely establishment of a gridSMART working group for CSP and interested stakeholders which should emphasize the development of a coordinated consumer education program. Working groups can provide an efficient and effective means to implement various programs and address a wide-range of issues. It is critical that working groups have sufficient flexibility to raise and address the concerns presented.

In regard to the customer-interface capabilities of gridSMART, CSP agrees that through the end of 2011:

(1) CSP will not utilize prepaid metering;

(2) CSP will not require mandatory time-of-use rates although an opt-out program would be permissible; and

(3) CSP will not seek a waiver of Rule 4901:1-18-05(A), Ohio Administrative Code (O.A.C.), regarding personal or written notice, prior to utilizing any remote disconnection capabilities for nonpayment with the understanding that, once properly noticed, the Companies may utilize the remote disconnect functionality. CSP requests that, in this context, the Commission confirm that no rule waiver is required to utilize the remote disconnect capabilities when disconnecting services at a customer's request.

(AEP-Ohio Letter at 2.)

Although, CSP agrees not to seek a waiver of Rule 4901:1-18-05(A), O.A.C., OCC expresses some concern about CSP's capability to utilize remote disconnection capabilities and the consumer protection provisions in the rule. OCC notes that the Commission recently denied Duke Energy Ohio's request to waive personal notice provisions of Rule 4901:1-18-05(A), O.A.C., and the Commission's decision not to adopt prepaid metering provisions in its rule review proceedings.[11] Further, OCC argues that CSP did not address any reduction in the distribution charges that would result from remote disconnections and notes that the Commission has not determined the reasonableness of imposing disconnection/reconnection charges where such actions are performed remotely. OCC advocates that gridSMART customers be provided special notices several business days prior to disconnection informing the customer that the disconnection will occur remotely and, therefore, a company employee will not be out to perform the task and the specific date of disconnection. (Second OCC Reply Comments at 5-8.)

CSP states that the July 21, 2010 letter was intended to clarify that it may utilize the remote disconnection functionality in a manner that is consistent with the Commission rules. Nonetheless, CSP affirms that it will follow all aspects of Rule 4901:1-18-05, O.A.C., absent a waiver and agrees not to seek a waiver of the rule before the end of 2011. (Second CSP Response at 4-6.)

The Commission is mindful that many customers may be apprehensive about various gridSMART technologies, particularly remote disconnection capabilities. We also have no intention of circumventing the consumer protections provided in Rule 4901:1-18-05, O.A.C., or similar provisions in the rules to be effective November 1, 2010. As such we confirm that CSP shall comply with the requirements of Rule 4901:1-18-05, O.A.C., as currently effective or similar provisions to be effective November 1, 2010. CSP may utilize the remote disconnection capabilities of gridSMART and shall not be required to implement any additional notice requirements to utilize the remote

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[11] See *In re Duke Energy Ohio, Inc.*, Case No. 10-249-EL-WVR, Entry at 7 (June 2, 2010); *In re Review of Chapters 4901:1-17 and 4901:1-18, O.A.C.*, Order at 4 (June 28, 2008).

disconnection capabilities provided all the other requirements of the rules in Chapter 4901:1-18, O.A.C, have been met.

OPAE requests that the gridSMART rate be stated as a dollar amount, as opposed to a percentage of base distribution rates, so customers can readily determine what gridSMART costs (OPAE comments at 4-5). CSP submits that the percentage increase rate design was used and approved in the ESP cases and is the appropriate, cost-based recovery mechanism. Further, CSP argues that OPAE's claim that a dollar amount rate would provide customers more transparency is speculative at best as a customer would still need to take the amount and calculate it by usage to obtain a dollar amount per month associated with the gridSMART rider. (CSP Reply at 9.)

The Commission recognizes that stating the gridSMART rider rate as a percentage of base distribution rates is consistent with the rate method set forth in the ESP case. However, it is equally important that customers understand the charges on their electric utility bill. To that end, the Commission directs CSP to revise the gridSMART rate to a be a fixed monthly per bill charge, consistent with the Commission's decision in *In re Duke Energy Ohio Inc.*, Case No. 09-543-GE-UNC, et al., Opinion and Order at 5-6 (May 13, 2010); and *In re FirstEnergy Companies*, Case No. 09-1820-EL-ATA, et al., Finding and Order at 9 (June 30, 2010).

It is, therefore,

ORDERED, That CSP is directed to file tariffs consistent with this finding and order. It is, further,

ORDERED, That CSP revise the gridSMART rate to a be a fixed monthly per bill charge. It is, further, ORDERED, That a copy of this Finding and Order be served upon all persons of record in this case.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Valerie A. Lemmie

Steven D. Lesser

Cheryl L. Roberto

GNS/dah

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Renée J. Jenkins
Secretary

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

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

OPINION AND ORDER

The Commission, considering the above-entitled applications and the record in these proceedings, hereby issues its opinion and order in this matter.

APPEARANCES:

Marvin I. Resnik and Steven T. Nourse, American Electric Power Service Corporation, One Riverside Plaza, Columbus, Ohio 43215, and Porter, Wright, Morris & Arthur, by Daniel R. Conway, 41 South High Street, Columbus, Ohio 43215, on behalf of Columbus Southern Power Company and Ohio Power Company.

Richard Cordray, Attorney General of the State of Ohio, by Duane W. Luckey, Section Chief, and Warner L. Margard, John H. Jones, and Thomas G. Lindgren, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of the Staff of the Public Utilities Commission of Ohio.

Janine L. Migden-Ostrander, the Office of the Ohio Consumers' Counsel, by Maureen R. Grady, Terry L. Etter, Jacqueline Lake Roberts, Michael E. Idzkowski and Richard C. Reese, Assistant Consumers' Counsel, 10 West Broad Street, Columbus, Ohio 43215-3485, on behalf of the residential utility consumers of Columbus Southern Company and Ohio Power Company.

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

Chester, Wilcox & Saxbe, LLP, by John W. Bentine, Mark S. Yurick, and Matthew S. White, 65 East State Street, Suite 1000, Columbus, Ohio 43215-4213, on behalf of The Kroger Company.

McNees, Wallace & Nurick, LLC, by Samuel C. Randazzo, Lisa G. McAlister, and Joseph M. Clark, 21 East State Street, 17th Floor, Columbus, Ohio 43215-4228, on behalf of Industrial Energy Users-Ohio.

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

Bell & Royer Co., LPA, by Barth E. Royer, 33 South Grant Avenue, Columbus, Ohio 43215-3927, on behalf of Ohio Environmental Council and Dominion Retail, Inc.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff, Mike Settineri and Betsy L. Elder, 52 East Gay Street, Columbus, Ohio 43216-1008, and Bobby Singh, Integrys Energy, 300 West Wilson Bridge Road, Worthington, Ohio 43085, on behalf of Integrys Energy.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff, Mike Settineri and Betsy L. Elder, 52 East Gay Street, Columbus, Ohio 43216-1008, and Cynthia A. Fonner, Constellation Energy Group, Inc., 550 West Washington Boulevard, Suite 3000, Chicago, Illinois 60661, on behalf of Constellation NewEnergy, Inc., and Constellation Energy Commodities Group, Inc.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff, Mike Settineri and Betsy L. Elder, 52 East Gay Street, Columbus, Ohio 43216-1008, on behalf of EnerNoc, Inc. and Consumer Powerline, Inc.

Schottenstein, Zox & Dunn Co., LPA, by Gregory H. Dunn, Christopher L. Miller, and Andre T. Porter, 250 West Street, Columbus, Ohio 43215, on behalf of the Association of Independent Colleges and Universities of Ohio.

Bricker & Eckler, Thomas J. O'Brien, 100 South Third Street, Columbus, Ohio, and Richard L. Sites, 155 East Broad Street, 15th Floor, Columbus, Ohio 43215-3620, on behalf of Ohio Hospital Association.

Bell & Royer Co., LPA, by Langdon D. Bell, 33 South Grant Avenue, Columbus, Ohio 43215-3927, and Kevin Schmidt, 33 North High Street, Columbus, Ohio 43215-3005, on behalf of Ohio Manufacturers' Association.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff and Stephen M. Howard, 52 East Gay Street, Columbus, Ohio 43216-1008, on behalf of Direct Energy Services, LLC.

McDermott, Will & Emery, LLP, by Grace C. Wung, 600 Thirteenth Street, N.W., Washington, D.C. 20005, on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc., LP, Macy's, Inc., and BJ's Wholesale Club, Inc.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff and Stephen M. Howard, 52 East Gay Street, Columbus, Ohio 43216-1008, on behalf of Ohio Association of School Business Officials, Ohio School Boards Association, and Buckeye Association of School Administrators.

Michael R. Smalz and Joseph E. Maskovyak, Ohio State Legal Services Association, 555 Buttles Avenue, Columbus, Ohio 43215, on behalf of Appalachian People's Action Coalition.

OPINION:

I. HISTORY OF PROCEEDINGS

On July 31, 2008, Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Companies) filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code. The application is for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code.

By entries issued August 5, 2008, and September 5, 2008, the procedural schedule in this matter was established, including the scheduling of a technical conference and the evidentiary hearing. A technical conference was held regarding AEP-Ohio's application on August 19, 2008. A prehearing conference was held on November 10, 2008, and the evidentiary hearing commenced on November 17, 2008, and concluded on December 10, 2008. The Commission also scheduled five local public hearings throughout the Companies' service area.

The following parties were granted intervention by entries dated September 19, 2008, and October 29, 2008: Ohio Energy Group (OEG); the Office of the Ohio Consumers' Counsel (OCC); Kroger Company (Kroger); Ohio Environmental Council (OEC); Industrial Energy Users-Ohio (IEU); Ohio Partners for Affordable Energy (OPAE); Appalachian People's Action Coalition (APAC); Ohio Hospital Association (OHA); Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. (Constellation); Dominion Retail, Inc. (Dominion); Natural Resources Defense Council (NRDC); Sierra Club - Ohio Chapter (Sierra); National Energy Marketers Association (NEMA); Integrys Energy Service, Inc. (Integrys); Direct Energy Services, LLC (Direct Energy); Ohio Manufacturers' Association (OMA); Ohio Farm Bureau Federation (OFBF); American Wind Energy Association, Wind on Wires, and Ohio Advance Energy (Wind Energy); Ohio Association of School Business Officials, Ohio School Boards Association, and Buckeye Association of School Administrators (collectively, Schools); Ormet Primary Aluminum Corporation (Ormet); Consumer Powerline; Morgan Stanley Capital Group Inc.; Wal-Mart Stores East, LP and Sam's East, Inc., Macy's, Inc., and BJ's Wholesale Club, Inc. (collectively, Commercial Group); EnerNoc, Inc.; and the Association of Independent Colleges and Universities of Ohio.

At the hearing, AEP-Ohio offered the testimony of 11 witnesses in support of the Companies' application, 22 witnesses testified on behalf of various intervenors, and 10 witnesses testified on behalf of Staff. At the local public hearings held in this matter, 124 witnesses testified. Briefs were filed on December 30, 2008, and reply briefs were filed on January 14, 2009.

A. Summary of the Local Public Hearings

Five local public hearings were held in order to allow CSP's and OP's customers the opportunity to express their opinions regarding the issues in this proceeding. The hearings were held in the evenings in Marietta, Canton, Lima, and Columbus. Additionally, an afternoon hearing was held in Columbus. At those hearings, public testimony was heard from 21 customers in Marietta, 21 customers in Canton, 17 customers in Lima, 25 customers at the afternoon hearing in Columbus and 40 customers at the evening hearing in Columbus. In addition to the public testimony, numerous letters were filed in the docket by customers stating concern about the applications.

The principal concern expressed by customers, both at the public hearings and in letters, was over the increases in customer rates that would result from the approval of the ESP applications. Witnesses stated that any increase in rates would negatively impact low-income customers, the elderly, and those on fixed incomes. Customers cited the recent downturn in the economy as the primary source of their apprehension. It was noted by many at the hearings that customers are also facing increases in other utility charges, gasoline, food, and medical expenses and that the proposed increases would cause undue hardship. On the other hand, some witnesses at the public hearings and in the letters filed in the docket acknowledged AEP-Ohio as a good corporate partner in their respective communities.

B. Procedural Matters

1. Motion to Strike

On January 7, 2009, AEP-Ohio filed a motion to strike a section of the brief jointly filed by OCC and Sierra (collectively, OCEA). More specifically, AEP-Ohio filed to strike the sentence starting on line 2 of page 63 ["In fact,"] through the first two lines of page 64, including footnotes 244 to 248. AEP-Ohio argues that the above-cited portion of OCEA's brief, regarding the deferral of fuel expenses and the carrying charges and the tax effect thereof, relies upon testimony offered by OCC witness Effron in the FirstEnergy Distribution Case.[1] AEP-Ohio notes that Mr. Effron was not a witness in this ESP proceeding and, therefore, was not available for the Companies, or any other party, to cross-examine. Accordingly, the Companies argue that consideration of Mr. Effron's testimony in this matter would be a denial of the Companies' due process rights, and request that the specified portion of OCEA's brief be stricken. On January 14, 2009, OCC filed a memorandum contra the motion to strike. OCC agreed to withdraw the second and third sentences on page 63, the quoted testimony of Mr. Effron on page 63, and footnotes 244 to 248 on pages 63 and 64. However, OCC contends that AEP-Ohio's

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1 *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and Toledo Edison Company*, Case No. 07-551-EL-AIR, et al. (FirstEnergy Distribution Case).

motion is overly broad and the remaining portion of the brief that AEP-Ohio seeks to strike is appropriate legal argument regarding deferrals on a net-of-tax basis and, therefore, should remain. AEP-Ohio filed a reply on January 16, 2009. AEP-Ohio first notes that because the memorandum contra was filed by OCC only and Sierra did not respond to the motion, it is not clear whether Sierra is also willing to withdraw the portions of the brief listed in the memorandum contra. AEP-Ohio also argues that the remaining portion of this particular argument in OCEA's brief should be stricken with the removal of the footnotes. With this removal, AEP-Ohio then argues that there is no longer any support in the brief for such arguments. By letter docketed January 22, 2009, Sierra confirmed that it joins OCC in OCC's withdrawal of the limited portions of the OCEA brief as stated by OCC in its January 14, 2009, reply.

The Commission grants, in part, and denies, in part, AEP-Ohio's motion to strike OCEA's brief. The Commission agrees with AEP-Ohio and OCC that the use of Mr. Effron's testimony filed in the FirstEnergy Distribution Case in this proceeding was inappropriate and, therefore, we accept OCC's and Sierra's withdrawal of that portion of their brief. As for the remaining portion of OCEA's brief that AEP-Ohio has requested to be stricken, we agree with OCC that the language that discusses the calculation of deferred fuel expenses on a net-of-tax basis could be construed to be legal argument on brief, which rationalized why the issue should be decided in OCEA's favor. Moreover, we can surmise that if OCEA had recognized its error in the drafting stage of the brief, that OCEA would have drafted similar legal arguments without referencing Mr. Effron's testimony. Accordingly, we will only strike the portions of OCEA's brief that OCC and Sierra have agreed to withdraw.

2. Motion for AEP-Ohio to Cease and Desist

On February 25, 2009, Integrys filed a motion with the Commission requesting that the Commission direct AEP-Ohio to cease and desist the Companies' refusal to process SSO retail customer applications to enroll in the Interruptible Load for Reliability (ILR) Program of PJM Interconnection, LLC (PJM). Integrys also filed a request for an expedited ruling; however, Integrys represented that counsel for AEP-Ohio objected to the expedited ruling request. Integrys is a registered curtailment service provider with PJM and as such receives notices from PJM and coordinates with retail customers to curtail load. Integrys argues that retail customer participation in PJM demand response programs was raised in the Companies' ESP application and has not yet been decided by the Commission. For this reason, Integrys contends that AEP-Ohio lacks the authority to refuse to process the ILR applications and the denial of the application violates the Companies' tariffs. Two other curtailment service providers in the AEP-Ohio service territory, Constellation and KOREnergy, Ltd., filed memoranda in support of Integrys' motion.[2]

On March 2, 2009, AEP-Ohio filed a memorandum contra the motion to cease and desist. AEP-Ohio affirms the arguments made in this proceeding to prohibit retail customers from participating in PJM's demand response programs. Further, AEP-Ohio argues, among other things, that despite the claims of Integrys andConstellation, AEP-Ohio is providing, in a timely manner, the load data required for customer enrollment in the PJM ILR program, informs the customer that AEP-Ohio is not consenting to the customer's participation in the program, and discloses that the matter is currently pending before the Commission.

On March 9, 2009, Integrys and Constellation filed a withdrawal of the motion to direct AEP-Ohio to cease and desist. The movants state that despite AEP-Ohio's assertions that the applicants were not eligible to participate in PJM's demand response programs, PJM rejected AEP-Ohio's opposition to the ILR applications and processed the ILR applications. Integrys and Constellation further state that, except for two pending applications, all their customers in the AEP-Ohio service territory have been certified for participation in the PJM programs.

As the parties acknowledge, this matter was presented for the Commission's consideration as part of the ESP application. The Commission, therefore, specifically addresses and discusses the issues raised concerning SSO retail customer participation in PJM demand response programs at Section VI.C of this opinion and order. Accordingly, we grant Integrys' and Constellation's request to withdraw their motion to cease and desist.

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 reviewing AEP-Ohio's application, the Commission is cognizant of the challenges facing Ohioans and the electric industry and will be guided by the policies of the state as established by the General Assembly in Section 4928.02, Revised Code, which was amended by Senate Bill 221 (SB 221).

Section 4928.02, Revised Code, states that it is the policy of the state, inter alia, to:

2 KOREnergy, Ltd., has not filed to intervene in this proceeding and, therefore, its memoranda in support will not be considered.

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

(2) Ensure the availability of unbundled and comparable retail electric service.

(3) Ensure diversity of electric supplies and suppliers.

(4) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand-side management (DSM), time-differentiated pricing, and implementation of advanced metering infrastructure (AMI).

(5) Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems in order to promote both effective customer choice and the development of performance standards and targets for service quality.

(6) Ensure effective retail competition by avoiding anticompetitive subsidies.

(7) Ensure retail consumers protection against unreasonable sales practices, market deficiencies, and market power.

(8) Provide a means of giving incentives to technologies that can adapt to potential environmental mandates.

(9) Encourage implementation of distributed generation across customer classes by reviewing and updating rules governing issues such as interconnection, standby charges, and net metering.

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

In addition, *SB 221* amended Section 4928.14, Revised Code, which now provides that on January 1, 2009, electric utilities must provide consumers 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. The law provides that electric utilities may apply simultaneously for both an

MRO and an ESP; however, at a minimum, the first SSO application must include an application for an ESP. Section 4928.141, Revised Code, specifically provides that an SSO 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 electric utility's rate plan. In the event an SSO is not authorized by January 1, 2009, Section 4928.141, Revised Code, provides that the current rate plan of an electric utility shall continue until an SSO is authorized under either Section 4928.142 or 4928.143, Revised Code.

AEP-Ohio's application in this proceeding proposes an ESP, pursuant to Section 4928.143, Revised Code. Paragraph (B) of Section 4928.141, Revised Code, requires the Commission to hold a hearing on an application filed under Section 4928.143, Revised Code, to send notice of the hearing to the electric utility, and to publish notice in a newspaper of general circulation in each county in the electric utility's certified territory.

Section 4928.143, Revised Code, sets out the requirements for an ESP. Under paragraph (B) of Section 4928.143, Revised Code, an ESP must include provisions relating to the supply and pricing of generation service. The plan, according to paragraph (B)(2) of Section 4928.143, Revised Code, may also provide for the automatic recovery of certain costs, a reasonable allowance for certain construction work in progress (CWIP), an unavoidable surcharge for the cost of certain new generation facilities, conditions or charges relating to customer shopping, automatic increases or decreases, provisions to allow securitization of any phase-in of the SSO price, provisions relating to transmission-related costs, provisions related to distribution service, and provisions regarding economic development.

The statute provides that the Commission is required to approve, or modify and approve the ESP, if 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. In addition, the Commission must reject an ESP that contains a surcharge for CWIP or for new generation facilities if the benefits derived for any purpose for which the surcharge is established are not reserved or made available to those that bear the surcharge.

The Commission may, under Section 4928.144, Revised Code, order any just and reasonable phase-in of any rate or price established under Section 4928.141, 4928.142, or 4928.143, Revised Code, including carrying charges. If the Commission does provide for a phase-in, it must also provide for the creation of regulatory assets by authorizing the deferral of incurred costs equal to the amount not collected, plus carrying charges on that amount, and shall authorize the deferral's collection through an unavoidable surcharge.

By finding and order issued September 17, 2008, in Case No. 08-777-EL-ORD (SSO Rules Case), the Commission adopted new rules concerning SSO, corporate separation, and reasonable arrangements for electric utilities pursuant to Sections 4928.06, 4928.14, 4928.17, and 4905.31, Revised Code. The rules adopted in the SSO Rules Case were subsequently amended by the entry on rehearing issued February 11, 2009.

B. <u>State Policy – Section 4928.02, Revised Code</u>

AEP-Ohio submits that, contrary to the views of the intervenors, Section 4928.02, Revised Code, does not impose additional requirements on an ESP and the ESP should not be modified or rejected because it does not satisfy all of the policies of the state. According to the Companies, "[t]he public interest is served if the ESP is more favorable in the aggregate than the expected results of an MRO" (Cos. Br. at 15).

OHA asserts that the Commission "must view the 'more favorable in the aggregate' standard through the lens of the overriding 'public interest,'" and that the public interest cannot be served if the result is not reasonable (OHA Br. at 10). OPAE/APAC seems to state that the ESP must be more favorable in the aggregate and comply with the state policy, but also recognizes that state policies are to be used to guide the Commission in its approval of an ESP (OPAE/APAC Br. at 3). OEG agrees that the policy objectives are required to be met prior to the approval of an ESP (OEG Br. at 1). The Commercial Group submits that costs must be properly allocated to ensure that the policies of the state are met, to improve price signals, and to ensure effective retail competition (Commercial Group Br. at 5).

In its reply brief, AEP-Ohio maintains that its proposed ESP is consistent with the policy of the state as delineated in Sections 4928.02(A) through (N), Revised Code, and is "worthy of approval, without modification" (Cos. Reply Br. a 7). According to the Companies, the ESP advances the general policy objectives of the policy of the state (Id. at 6-7). Furthermore, the Companies argue that the concerns raised by some intervenors regarding the impact of AEP-Ohio's ESP on the difficult economic conditions would have the Commission ignore the statutory standard for approving an ESP and, instead, establish rates based on the current economic conditions (Cos. Reply Br. at 7). While the Companies believe that aspects of the proposed ESP address these concerns (e.g., fuel deferrals), they argue that their SSO must be established in accordance with applicable ESP statutory provisions (Id.).

As explained above, and previously in our opinion and order issued in the FirstEnergy ESP proceeding,[3] the Commission believes that the state policy codified by the General Assembly in Chapter 4928, Revised Code, sets forth important objectives,

[3] *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company,* Case No. 08-935-EL-SSO, Opinion and Order at 12 (December 19, 2008) (FirstEnergy ESP Case).

which the Commission must keep in mind when considering all cases filed pursuant to that chapter of the code. As noted in the FirstEnergy ESP case, in determining whether the ESP meets the requirements of Section 4928.143, Revised Code, we take into consideration the policy provisions of Section 4928.02, Revised Code, and we use these policies as a guide in our implementation of Section 4928.143, Revised Code. Accordingly, we agree with AEP-Ohio and will use these policies as a guide in our decision-making in this case, just as we did in the FirstEnergy ESP Case (Cos. Reply Br. at 6).[4] The Commission has reviewed the ESP proposal presented by AEP-Ohio, as well as the issues raised by the various intervenors, and we believe that, with the modifications set forth herein, we have appropriately reached a conclusion advancing the public's interest.

C. Application Overview

In their application, the Companies are requesting authority to establish an SSO in the form of an ESP pursuant to the provisions of Sections 4928.141 and 4928.143, Revised Code. The proposed ESP is to be effective for a three-year period commencing January 1, 2009. According to the Companies, pursuant to the proposed ESP, the overall, estimated increases in total customer rates, including generation, transmission, and distribution, would be an average of 13.41 percent for CSP and 13 percent for OP in 2009, and 15 percent in 2010 and 2011 for both CSP and OP (Cos. Ex. 1, Exhibit DMR-1). The Companies also propose a 15 percent cap per year on the total allowable increases for each customer rate schedule should the actual costs be higher than expected, excluding transmission costs and costs associated with new government mandates (Cos. App. at 6).

III. GENERATION

A. Fuel Adjustment Clause (FAC)

The Companies contend that Section 4928.143(B)(2)(a), Revised Code, authorizes the implementation of a FAC mechanism to recover prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations (Cos. Ex. 7 at 4-7).

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4 Some intervenors recognize that the state policy objective must be used as a guide to implement the ESP provision (IEU Br. at 19; OPAE/APAC Br. at 3).

1. FAC Costs

The Companies proposed to include in the FAC mechanism types of costs recovered through the electric fuel component (EFC) previously used in Ohio[5] (Cos. Ex. 7 at 3-4). In addition to those types of costs, the Companies stated that Section 4928.143(B)(2)(a), Revised Code, provides for a broader cost-based adjustment mechanism that authorizes the inclusion of all prudently incurred fuel, purchased power, and environmental components (Id. at 4). Companies' witness Nelson itemized and described the accounts that the Companies proposed to include in their FAC mechanism (Id. at 5-7).

Staff, OCC, and Sierra support the FAC mechanism that will be updated and reconciled quarterly (Staff. Ex. 8 at 3-4; OCEA Br. at 47-48, 67-68; OCC Ex. 11 at 4-5, 31-40). Specifically, Staff witness Strom testified that the costs proposed to be recovered through the FAC mechanism are appropriate and recovery of those costs through a FAC mechanism is logical (Staff Ex. 8 at 3). OCC and Sierra also agree that Section 4928.143(B)(2)(a), Revised Code, authorizes the enactment of a FAC mechanism to automatically recover certain prudently incurred costs (OCEA Br. at 47), and OCC does not seem to oppose the list of categories of accounts proposed to be included in the FAC by Companies witness Nelson (OCC Ex. 11 at 18-20). Additionally, Staff recommended that annual reviews of the prudency and appropriateness of the accounting of FAC costs be conducted (Staff Ex. 8 at 3-4), and OCC recommended that an interest charge be paid to customers on any over-recovered fuel costs in a quarterly period until the subsequent reconciliation occurs, similar to the carrying charge for any under-recovery that she believed the Companies were proposing to collect[6] (OCC Ex. 11 at 4). Kroger and IEU, however, seem to state that a FAC mechanism cannot be established until a cost-of-service or earnings test is completed (Kroger Br. at 9-10; IEU Br. at 12-15). IEU also questioned the appropriate term of the proposed FAC mechanism (IEU Br. at 13; Tr. Vol. IX at 143-146).

The Commission believes that the establishment of a FAC mechanism as part of an ESP is authorized pursuant to Section 4928.143(B)(2)(a), Revised Code, to recover prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations. Given that the FAC mechanism is authorized pursuant to the ESP provision of SB 221, we will limit our authorization, at this time, to the term of the ESP.

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5 See Sections 4905.01(G), 4905.66 through 4905.69, and 4909.159, Revised Code (repealed January 1, 2001); Chapter 4901:1-11, Ohio Administrative Code (O.A.C.) (rescinded November 27, 2003).

6 In AEP's Brief, the Companies clarified that they did not propose to collect a carrying charge on any FAC under-recovery in one quarterly period until a reconciliation in the subsequent period occurred. The only carrying charge that they proposed was on the FAC deferrals that would not be collected until 2012-2018 (Cos. Br. at 27).

With regard to interest charges assessed on any over- or under-recoveries for FAC costs within the quarterly period until the subsequent reconciliation occurs, we agree with OCC witness Medine that symmetry should exist if interest charges were assessed on any under-recoveries (Tr. Vol. VI at 210). However, we do not conclude that any interest charges on either over- or under-recoveries are necessary as a deterrent to the creation of over- or under-recoveries as OCC witness Medine suggests (Id. at 210-211). As proposed by the Companies and supported by others, the FAC mechanism includes a quarterly reconciliation to actual FAC costs incurred, which will establish the new charge for the subsequent quarter. These quarterly adjustments combined with the annual review proposed by Staff to review the appropriateness of the accounting of the FAC costs and the prudency of decisions made are sufficient to control the over- or under-recoveries that may occur within a particular quarter. Therefore, we find that the FAC mechanism with quarterly adjustments as proposed by the Companies, as well as an annual prudency and accounting review recommended by Staff, is reasonable and should be approved and implemented as set forth herein.

(a) Market Purchases

As part of the FAC costs, the Companies proposed to purchase incremental power on a "slice of the system basis" equal to 5 percent of each company's load in 2009, 10 percent in 2010, and 15 percent in 2011 (Cos. Ex. 2-A at 21). The Companies argue that while these purchases will be included in the FAC mechanism, as the appropriate recovery mechanism for these costs, the purchases are permitted as a discretionary component of an ESP filing authorized by Section 4928.143(B)(2), Revised Code, which states: "The plan may provide for or include, without limitation, any of the following:" (emphasis added) (Cos. Br. at 37). To support its proposal, AEP-Ohio states that the purchases reflect the continued transition to market rates and represent an appropriate recognition of the Companies' incorporation of the loads of Ormet Primary Aluminum Company (Ormet) and the certified territory formerly served by Monongahela Power Company (MonPower) (Cos. Ex. 2-A at 21-22). The Companies further assert that, during the ESP, they should be able to continue to recover a market-based generation price for serving these loads, as was previously authorized by the Commission during the RSP period.

Staff supported market purchases sufficient to meet the additional load responsibilities that the Companies assumed for the addition of the former MonPower customers and Ormet to the Companies' system, which equals approximately 7.5 percent of the Companies' total loads (Staff Ex. 10 at 5). However, based on the size of the additional load assumed by the Companies, Staff only recommended that the incremental power purchases equal, on average, 5 percent of each company's load in 2009, 7.5 percent in 2010, and 10 percent in 2011 (Id.).

The Companies responded to Staff's reduction in the amount of market purchases by adding that the Companies also intended to utilize their proposed levels of market purchases to encourage economic development (Cos. Ex. 2-E at 7).

Various parties oppose the inclusion of incremental "slice of the system" power purchases in AEP-Ohio's ESP. OEG witness Kollen testified that the Commission should reject this provision of AEP-Ohio's ESP because the Companies have not demonstrated a need for the excess generation purchased on the market to meet its existing load, and such "purchases are not prudent because they will uneconomically displace lower cost Company owned generation and cost-based purchased power that is available to meet their loads" (OEG Ex. 3 at 3, 9-10). IEU witness Bowser agrees that this portion of the ESP should be rejected (IEU Ex. 10 at 9). Kroger witness Higgins also concurs, stating: "The *only* apparent purpose of these slice-of-system purchases is to serve as a device for increasing prices charged to customers" (Kroger Ex. 1 at 9). OCEA concurs with the testimony offered by these intervenor witnesses (OCEA Br. at 53-55). Intervenors also question this provision in light of the AEP Interconnection Agreement (OEG Ex. 3 at 10-14; OCEA Br. at 54-55).

Given that AEP-Ohio has explicitly stated that the purchased power is not a prerequisite for adequately serving the additional load requirements assumed by AEP-Ohio when adding Ormet and the MonPower customers to its system (Cos. Ex. 2-E at 7), the Commission finds that Staff's rationale for the support of the proposal, as well as the recommendation for a reduction in the amount of purchased power proposed to equal the additional load, fails. We struggle, along with the other parties, to find a rational basis to approve such a proposal in the absence of need. The Commission notes that while we appreciate AEP-Ohio's willingness and cooperation with regard to the inclusion of Ormet and MonPower customers into its system, we believe that the Companies have been able to prepare and plan for the additions to its system under the current regulatory scheme and have been compensated during the transitional period. As for the reliance on the market purchases to promote economic development, the Commission believes that this goal can be more appropriately achieved through other means as outlined in this opinion and order, the Commission's recently adopted rules, and SB 221. Accordingly, we find that AEP-Ohio's ESP shall be modified to exclude this provision.

(b) <u>Off-System Sales (OSS)</u>

Kroger and OEG contend that FAC costs must be offset by a credit for OSS margins, stating that other jurisdictions governing other operating companies of AEP Corporation require such an OSS offset to revenue requirements (Kroger Br. at 11-12; Kroger Ex. 1 at 3, 9, 10; OEG Br. at 10; OEG Ex. 3 at 14-15, 16-17). Kroger argues that it is incongruent to allow a rate increase based on certain costs without examining AEP-Ohio's net costs to determine that AEP-Ohio's costs have actually increased (Kroger Br. at 11-12). OEG notes that the Companies' profits for 2007 from off-system sales were $146.7 million for OP and $124.1 million for CSP (OEG Ex. 3 at 14). OEG reasons that because the cost of the power plants used to generate off-system sales are included in rates, all revenue from the power plants should be a rate credit (OEG Br. 10). OCEA raises similar arguments to those of OEG and Kroger in its brief (OCEA Br. at 57-59). More specifically, OCEA argues that the Companies' proposal to eliminate off-system sales expenses from Ohio ratepayers is not equivalent to providing customers the benefit of off-system sales margins. OCEA notes that, in other cases, the Commission has required electric utilities to share the benefits of off-system sales revenue with jurisdictional customers (OCEA Br. at 58-59).

Staff did not take a position in regard to the intervenors' arguments to offset FAC costs by the OSS margin. Staff, however, concluded that the costs sought to be recovered through the FAC are appropriate (Staff Ex. 10 at 4; Staff Ex. 8 at 3; Staff Br. at 2).

The Companies argue that an OSS offset to FAC charges is not required by Section 4928.143(B)(2)(a), Revised Code, or any other provision in SB 221 (Cos. Ex. 2-E at 8-9; Cos. Reply Br. at 12). The Companies also state that the regulatory or statutory regimes in other states have no bearing on Ohio or Ohio's statutory requirements (Id.). As to the other arguments raised by OEG and OCEA, the Companies argue that the intervenors' arguments ignore the fact that the Companies' ESP reduces the FAC and environmental carrying cost expenses for AEP-Ohio customers based on the calculation of the pool capacity payments in the FAC and use of the pool allocation factor (Cos. Ex. 7, Exhibits PJN-1, PJN-2, PJN-6 and PJN-8).

Upon a review of the record in this case, the Commission is not persuaded by the intervenors' arguments. We do not believe that the testimony presented offered adequate justification for modifying the Companies' proposed ESP to offset OSS margins from the FAC costs. Section 4928.143(B)(2)(a), Revised Code, specifically provides for the automatic recovery, without limitation, of prudently incurred costs for fuel, purchased power, capacity cost, and power acquired from an affiliate. As recognized by the Companies, the pertinent statutory provisions do not require that there be an offset to the allowable fuel costs for any OSS margins. Additionally, Ohio law governs the Companies' ESP application, and thus, we are not persuaded by the arguments of Kroger regarding how other jurisdictions handle OSS margins. Moreover, consistent with our discussion in Section VII of our opinion and order, we do not believe that OSS should be a component of the Companies' ESP, or factored into our decision in this proceeding. Intervenors cannot have it both ways: they cannot request that OSS margins be credited against the fuel costs (i.e., offset the expenses); and, at the same time, ask us to count the OSS margins as earnings for purposes of the significantly excessive earnings test (SEET) calculation.

(c) Alternate Energy Portfolio Standards (including Renewable Energy Credit program)

Section 4928.64, Revised Code, establishes alternative energy portfolio standards which consist of requirements for both renewable energy and advanced energy resources. Section 4928.64(B)(2), Revised Code, introduces specific annual benchmarks for renewable energy resources and solar energy resources beginning in 2009.

The Companies' ESP application included, as a part of the FAC costs, cost recovery for renewable energy purchases and renewable energy credits (RECs) with purchased power reflected in Account 555 and RECs reflected in Account 557 (Cos. Ex. 7 at 6-7, 14). The Companies stated that they plan to purchase almost all of the RECs required for 2009. The Companies further state that they will enter into renewable energy purchase agreements (REPAs) to meet compliance requirements for the remainder of the ESP period, for which they have already conducted a request for proposal (Cos. Ex. 9 at 10-11). The Companies also recognized that recovery of such costs to comply with Section 4928.64(E), Revised Code, is, as stated in the statute,avoidable. Therefore, the Companies explained that they intend to include all of the renewable energy costs within the FAC mechanism and not as part of any FAC deferral. The Companies, however, recognized that their request for proposal and procurement practices for renewable energy will be subject to a prudency review and the renewable purchases subject to a financial audit (Cos. Br. at 96-98).

Staff and OPAE/APAC express concern with the Companies' plan to include renewable energy purchases and RECs as a component of the FAC mechanism (Staff Ex. 4 at 6-7; Staff Br. at 4-5; OPAE/APAC Br. at 11).

The Commission notes that the renewable energy purchases and RECs requirements are based on Section 4928.64(E), Revised Code, and any recovery of such costs is, as the statute provides, bypassable. With the Companies' recognition that such costs must be accounted for separately from fuel costs, and is not to be deferred, the Commission finds that Staff's and OPAE/APAC's issue is adequately addressed. Accordingly, with that clarification, the Commission finds that this aspect of the Companies' ESP application is reasonable and should be adopted.

2. FAC Baseline

The Companies proposed establishing a baseline FAC rate by identifying the FAC components of the current SSO. The Companies started with the EFC rates that were unbundled as part of the electric transition plan (ETP) proceedings (those in effect as of October 5, 1999) (step #1), and then added calendar year 1999 amounts for the additional fuel, purchased power, and environmental accounts that are included in the requested

FAC mechanism for this proceeding (1999 data from FERC Form 1 and other financial records were used as the base period for the additional components that were not in the frozen EFC rates) (step #2) (Cos. Ex. 7 at 8). The Companies then adjusted the 1999 frozen EFC rates (step #1) and the 1999-level rates developed for the additional components (step #2) for subsequent rate changes (step #3) to get the base FAC component that is equal to the fuel-related costs presently embedded in the Companies' most recent SSO (i.e., the RSP) (Id.). The subsequent rate changes that occurred during the RSP period and reflected in step #3 of the Companies' calculation included annual increases of 7 percent for OP and 3 percent for CSP, an increase in CSP's generation rates for 2007 by approximately 4.43 percent through the Power Acquisition Rider, and a reduction in OP's base period FAC rate by the amount of the Gavin Cap and mine investment shutdown cost recovery component that was in OP's 1999 EFC rate given that the Regulatory Asset Charge (RAC) established in the ETP case expired (Id. at 9).

Staff argued that the actual costs should be used in determining the FAC baseline and, therefore, recommended using 2007 actual data, escalated by 3 percent for CSP and 7 percent for OP, as a reasonable proxy for 2008 (Staff Ex. 10 at 3-4). Staff explained that utilizing actual 2007 costs and updating them to 2008 is appropriate given that the resulting amounts should be the costs that the Companies are currently recovering for fuel-related costs (Id.). Additionally, Staff notes that this proposal produces a result that is very close to the result produced by utilizing the Companies' methodology (Staff Br. at 3).

OCC recommended the use of 2008 actual fuel costs to establish the FAC baseline, which will be reconciled to actual costs in the future FAC proceeding (OCC Ex. 10 at 11-14). OCC's witness testified that her concern is that if the FAC baseline is established too low, the base portion of the generation rates (the non-FAC portion) will be established too high (OCC Ex. 10 at 13). In its Brief, OPAE/APAC opposed the Companies' use of 1999 rates as the baseline and seems to support OCC's recommendation to use 2008 fuel costs (OPAE/APAC Br. at 11-12). The Companies' responded by explaining that they did not use 1999 rates as the baseline, rather the 1999 level was just the starting point to calculating the baseline (Cos. Reply Br. at 21). The Companies also stated that a variable baseline was not appropriate as it would result in a variable non-FAC generation rate as well since the non-FAC component of the current generation SSO was determined to be the residual after subtracting out the FAC component (Id.).

As noted by OCC's witness, the 2008 actual fuel costs were not known at the time of the hearing (OCC Ex. 10 at 14). Thus, the Companies and Staff proposed methodologies to obtain a proxy for 2008 fuel costs. While both had a different starting point to the calculation of the 2008 proxy, we agree that in the absence of known actual costs, a proxy is appropriate to establish a baseline. Therefore, based on the evidence presented, we agree with Staff's resulting value as the appropriate FAC baseline.

3. FAC Deferrals

The Companies proposed to mitigate the rate impact on customers of any FAC increases by phasing in their new ESP rates by deferring a portion of the annual incremental FAC costs during the ESP (Cos. App. at 4-5; Cos. Ex. 3 at 11; Cos. Ex. 1 at 13-15). The amount of the incremental FAC expense that would be recovered from customers would be limited so that total bill increases would not be more than 15 percent for each of the three years of the ESP (Id.). The 15 percent target for FAC does not include cost increases associated with the transmission cost recovery rider (TCRR) or with any new government mandates (the Companies' could apply to the Commission for recovery of costs incurred in conjunction with compliance of new government mandates, including any Commission rules imposed after the filing of the AEP-Ohio application (Cos. App. at 6)). The Companies proposed to periodically reconcile the FAC to actual costs, subject to the maximum phase-in rates (Cos. Ex. 1 at 14-15). Under the Companies' proposal, any incremental FAC expense that exceeds the maximum rate levels will be deferred. The Companies project the deferrals under the proposed ESP to be $146 million by December 31, 2011 for CSP and $554 million by December 31, 2011 for OP (Cos. Ex. 6, Exhibit LVA-1). If the projected FAC expense in a given period is less than the maximum phase-in FAC rates, the Companies proposed to give the Commission the option of charging the customer the actual FAC expense amount or increasing the FAC rates up to the maximum levels in order to reduce any existing deferred FAC expense balance (Id.). Any deferred FAC expense remaining at the end of 2011 would be recovered, with a carrying cost at the Weighted Average Cost of Capital (WACC), as an unavoidable surcharge from 2012 to 2018 (Id.).

As noted previously, Staff, OCC, and Sierra support the FAC mechanism that will be updated and reconciled quarterly (Staff. Ex. 8 at 3-4; OCC Ex. at 11 at 4-5, 31-40; OCEA Br. at 47-48, 67-68). Staff, OCC, and Sierra, however, oppose the creation of any long-term deferrals for fuel costs (Staff Ex. 10 at 5; OCEA Br. at 62). Similarly, the Commercial Group recommended that "customers pay the full cost of fuel during the ESP" (Commercial Group Ex. 1 at 9). Constellation argued that the deferral proposal should be rejected because it masks the true cost of the ESP generation, deferrals have the effect of artificially suppressing conservation, the carrying costs proposed by the Companies would be set at the Companies' cost of capital, which would include equity, and customers do not want to pay interest on any deferred amounts (instead, customers would rather pay when the costs are incurred so as to not pay the interest) (Constellation Br. at 8-9). The Schools also questioned the need for the phase-in of rates, as well as the avoidability of the surcharge that would be created to collect the deferred fuel costs, with carrying charges, from 2012 to 2018 (Schools Br. at 3).

If the Commission, however, authorizes such deferrals to levelize rates during the ESP period, Staff, OCC, and Sierra believe that the deferrals should be short-term deferrals that do not extend beyond the ESP period (Staff Ex. 10 at 5; OCEA Br. at 62). IEU also supports the use of a phase-in to stabilize rates, but does not believe that Section 4928.144, Revised Code, allows the deferrals to extend beyond the ESP term (IEU Br. at 27-29).

Furthermore, OCC opposed the Companies' use of WACC, stating that such an approach is not reasonable and results in excessive payments by customers (OCC Ex. 10 at 34). Through testimony, OCC asserts that the carrying charges on deferrals should be based on the current long-term cost of debt (OCC Ex. 10 at 34-35; Tr. Vol. VI at 157-158). However, in its joint brief, OCC seems to have modified its position and is now arguing that the carrying charges should be calculated to reflect the short-term actual cost of debt, excluding equity (OCEA Br. at 62). In reliance on OCC's testimony, Constellation submits that it is appropriate to use the long-term cost of debt (Constellation Br. at 8). The Commercial Group also opposed the use of WACC; instead, Commercial Group witness Gorman recommended that the Companies finance the FAC phase-in deferrals entirely with short-term debt given that the accruals are a temporary investment and not long-term capital (Commercial Group Ex. 1 at 9-11).

Additionally, the Commercial Group and OCC argued that the deferred fuel expenses should be calculated to reflect the net of applicable deferred income taxes (Commercial Group Ex. 1 at 9-10; OCEA Br. at 63). Commercial Group witness Gorman testified that if a company does not recover the fuel expense in the year that it was incurred, the company will reduce its current tax expense and record a deferred tax obligation. The deferred tax obligation would then represent a temporary recovery of the fuel expense via a reduction to the current income tax expense (Commercial Group Ex. 1 at 10). Commercial Group witness Gorman then goes on to recognize that the income tax will ultimately have to be paid after the incremental fuel cost is recovered from customers, but states that, while deferred, the company will partially recover its deferred fuel balance through the reduced income tax expense (Id.). To bolster their argument that deferred fuel expenses should be calculated on a net-of-tax basis, OCC and Sierra relied, in their brief, on a witness' testimony in an unrelated proceeding, which has been subsequently withdrawn as explained above. Neither OCC nor Sierra offered any record evidence to support its position.

AEP-Ohio, on the other hand, argued that the calculation of carrying charges for the deferrals should not be done on a net-of-tax basis. AEP-Ohio witness Assante testified that limiting the application of the carrying cost rate to a net-of-tax balance of FAC deferrals improperly utilizes a traditional cost-of-service ratemaking approach in a generation pricing proceeding (Tr. Vol. IV at 158-160). Additionally, while the Companies proposed the phase-in proposal to help mitigate increases and believe that their proposal is reasonable, in light of the opposition received from several parties, the Companies stated that they would accept a modification to their ESP that eliminated such deferrals (Cos. Reply Br. at 41-42).

To ensure rate or price stability for consumers, Section 4928.144, Revised Code, authorizes the Commission to order any just and reasonable phase-in of any electric utility rate or price established pursuant to 4928.143, Revised Code, with carrying charges, through the creation of regulatory assets. Section 4928.144, Revised Code, also mandates that any deferrals associated with the phase-in authorized by the Commission shall be collected through an unavoidable surcharge. Section 4928.144, Revised Code, does not, however, limit the time period of the phase-in or the recovery of the deferrals created by the phase-in through the unavoidable surcharge.

Contrary to OCC and others,[7] we believe that a phase-in of the increases is necessary to ensure rate or price stability and to mitigate the impact on customers during this difficult economic period, even with the modifications to the ESP that we have made herein. To this end, the Commission appreciates the Companies' recognition that over 15 percent rate increases on customers' bills would cause a severe hardship on customers. Nonetheless, given the current economic climate, we believe that the 15 percent cap proposed by the Companies is too high.[8] Therefore, we exercise our authority pursuant to Section 4928.144, Revised Code, and find that the Companies should phase-in any authorized increases so as not to exceed, on a total bill basis, an increase of 7percent for CSP and 8percent for OP for 2009, an increase of 6percent for CSP and 7percent for OP for 2010, and an increase of 6percent for CSP and 8percent for OP for 2011 are more appropriate levels.

Based on the application, as modified herein, the resulting increases amount to approximate overall average generation rates of 5.47 cents/kWh and 4.29 cents/kWh for CSP and OP, respectively in 2009; 6.07 cents/kWh and 4.75 cents/kWh for CSP and OP, respectively, in 2010; and 6.31 cents/kWh and 5.31 cents/kWh for CSP and OP, respectively, in 2011.

Any amount over the allowable total bill increase percentage levels will be deferred pursuant to Section 4928.144, Revised Code, with carrying costs. If the FAC expense in a given period is less than the maximum phase-in FAC rate established herein, the Companies shall begin amortization of the prior deferred FAC balance and increase the FAC rates up to the maximum levels allowed to reduce any existing deferred FAC expense balance, including carrying costs. As required by Section 4928.144, Revised Code, any deferred FAC expense balance remaining at the end of 2011 shall be recovered

7 See, e.g., OCC Reply Br. at 45-46; Constellation Br. at 6-9.

8 Numerous letters filed in the docket by various customers confirm our belief.

via an unavoidable surcharge. We believe that this approach balances our objectives of limiting the total bill increases that customers will be charged in any one year with minimizing the deferrals and carrying charges collected from customers.

Based on the record in this proceeding, we do not find the intervenors' arguments concerning the calculation of the carrying charges persuasive. Instead, for purposes of a phase-in approach in which the Companies are expected to carry the fuel expenses incurred for electric service already provided to the customers,[9] we find that the Companies have met their burden of demonstrating that the carrying cost rate calculated based on the WACC is reasonable as proposed by the Companies. As explained previously, Section 4928.144, Revised Code, provides the Commission with discretion regarding the creation and duration of the phase-in of a rate or price established pursuant to Sections 4928.141 through 4928.143, Revised Code. The Commission is not convinced by arguments that limit the collection of the deferrals to the term of the ESP. Limiting the phase-in to the term of the ESP may not ensure rate or price stability for consumers within that three-year period and may create excessive increases, which may defeat the purpose for establishing a phase-in. The limitation of any deferrals to the ESP term may also negate the cap established by the Commission herein to provide stability to consumers. Therefore, we find that the collection of any deferrals, with carrying costs, created by the phase-in that are remaining at the end of the ESP term shall occur from 2012 to 2018 as necessary to recover the actual fuel expenses incurred plus carrying costs.

Regarding OCC's, Sierra's, and the Commercial Group's recommendations that the tax deductibility of the debt rate be reflected in the carrying charges on a net-of-tax basis,[10] we have recently explained that this recommendation accounts for the deductibility of the debt rate, but does not account for the fact that the revenues collected are taxable.[11] If we were to adopt the net-of-tax recommendation, the Companies would not recover the full carrying charges on the authorized deferrals. We believe that this outcome would be inconsistent with the explicit directive of Section 4928.144, Revised

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9 We agree with the Companies that this decision is consistent with our decision in the recent TCRR and accounting cases with regard to the calculation based on the long-term cost of debt. See *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1202-EL-UNC, Finding and Order (December 17, 2008) and *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1301-EL-UNC, Finding and Order (December 19, 2008). However, we believe that, with regard to the equity component, these cases are distinguishable from the current ESP proceeding, where we are establishing the standard service offer and requiring the Companies to defer the collection of incurred generation costs associated with fuel over a longer period. We also believe that this decision is reasonable in light of our reduction to the Companies' proposed FAC deferral cap, which may have the effect of requiring the Companies to defer a higher percentage of FAC costs than what was otherwise proposed.

10 OCEA Br. at 63-64; Commercial Group Ex. 1 at 9-10.

11 *In re Ohio Edison Co., The Cleveland Electric Illuminating Co., Toledo Edison Co.*, Case No. 07-551-El-AIR, et al., Opinion and Order at 10 (January 21, 2009).

Code: "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." Therefore, we find that the carrying charges on the FAC deferrals should be calculated on a gross-of-tax rather than a net-of-tax basis in order to ensure that the Companies recover their actual fuel expenses. Accordingly, we modify the deferral provision of the Companies' ESP to lower the overall amount that may be charged to customers in any one year.

B. Incremental Carrying Cost for 2001-2008 Environmental Investment and the Carrying Cost Rate

A component of the non-FAC generation increase is the incremental, ongoing carrying costs associated with environmental investments made during 2001-2008. The Companies propose to include, as a part of their ESP, costs directly related to energy produced or purchased. While the Companies are not proposing to include the recovery of capital carrying costs on environmental capital investments in the FAC, the Companies are requesting recovery of carrying charges for the incremental amount of the environmental investments made at their generating facilities from 2001 to 2008. The Companies' annual capital carrying costs for the incremental 2001-2008 environmental investments not currently reflected in rates equals $84 million for OP and $26 million for CSP. The Companies' ESP includes capital carrying costs for 2001 through 2008 net of cumulative environmental capital expenditures for each company multiplied by the carrying cost rate.

Each company's capital expenditures in the ESP are determined by the expenditures made since the start of the market development period as offset by the estimate included in the Companies' rate stabilization plan (RSP) case, Case No. 04-169-EL-UNC, and the environmental expenditures included in the Companies' adjustments received in the RSP 4 Percent Cases[12] (Cos. Ex. 7 at 15-17, Exhibits PJN-8, PJN-12). The Companies calculated the carrying cost rate based on levelized investment and depreciation over the 25-year life of the environmental investment. CSP and OP utilized a capital structure of 50 percent common equity and 50 percent debt to calculate the carrying charges, asserting that such is consistent with the capital structure as of March 31, 2008, and consistent with the expected capital structure during the ESP period. Short-term debt and the Gavin Lease were excluded from OP's capital structure. AEP-Ohio asserts that such was the process in the RSP 4 Percent Cases. AEP-Ohio also argues that, for ratemaking purposes, the Gavin Lease is considered an operating lease as opposed to a component of rate base. Further, the Companies reason that the WACC incorporated a 10.5 percent ROE as used by the Commission in the proceeding to transfer

[12] *In re Columbus Southern Power Company and Ohio Power Company*, Case Nos. 07-1132-EL-UNC, 07-1191-EL-UNC, and 07-1278-EL-UNC (RSP 4 Percent Cases).

MonPower's certified territory to CSP (MonPower Transfer Case)[13] (Cos. Ex. 7 at 16-17, 19, Exhibit PJN-8, Exhibits PJN-10 - PJN-13; Cos. Ex. 7-B at 7).

Staff testified that the Companies should be allowed to recover carrying costs associated with capitalized investments to comply with environmental requirements made between 2001-2008 that are not currently reflected in rates (Staff Ex. 6 at 2, 4-5). Staff confirmed that AEP-Ohio's estimated revenue increases for incremental carrying costs associated with additional environmental investments in the amounts of $26 million for CSP and $84 million for OP are not currently reflected in rates (Id.).

OCEA and OEG oppose the Companies' request for recovery of environmental carrying charges on investments made prior to January 1, 2009. OEG contends that the rates in the RSP Case included recovery for environmental capital improvements made through December 31, 2008, as reflected in the RSP 4 Percent Cases. Further, OCEA and OEG argue that SB 221 only permits the recovery of carrying costs associated with environmental expenditures that are prudently incurred and that occur on or after January 1, 2009, pursuant to Section 4928.143(B)(2)(b), Revised Code (OCEA Ex. 10 at 32; OEG Ex. 3 at 21). Thus, OCEA reasons that approval of such expenditures necessitates an after-the-fact review, which cannot be considered in this proceeding. OEG, however, is not opposed to the Companies' increases due to environmental capital additions made after January 1, 2009, in the ESP in accordance with Section 4928.143(B)(2)(b), Revised Code (OEG Ex. 3 at 20). OEG and Kroger argue that the Companies' assertion that existing rates do not reflect environmental carrying costs ignores the Companies' non-environmental investment and the effects of accumulated depreciation and, therefore, according to OEG and Kroger, fails to demonstrate any net under-recovery of generation costs in total by the Companies (OEG Ex. 3 at 21; Kroger Ex. 1 at 10-11). OCEA and APAC/OPAE agree that the Companies have failed to demonstrate that they lack the earnings to make the environmental investments (OCEA Ex. 10 at 32; APAC/OPAE Br. at 5-6).

Further, OCEA asserts that there are several reasons that the Companies' attempt to recover environmental carrying cost during the ESP is unlawful. OCEA contends that it is retroactive ratemaking[14] and Senate Bill 3, which was the governing law from 2001 to 2005, included rate caps pursuant to Section 4928.34(A)(6), Revised Code, and the RSP, applicable to 2006 through 2008, included limitations on the rate increases. Therefore, the Companies can not collect now for costs incurred during those periods. Further, OCEA

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13 *In the Matter of the Transfer of Monongahela Power Company's Certified Territory in Ohio to the Columbus Southern Power Company*, Case No. 05-765-EL-UNC.

14 *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 25.

states that allowing for recovery of such environmental carrying costs would also violate the Stipulation and the Commission's order in the ETP case.[15]

OCEA argues that, should the Commission allow AEP-Ohio to recover carrying costs on environmental investments, the Companies' carrying charges should be based on actual investments made, not actual and forecasted environmental expenditures, and the carrying costs should be adjusted. More specifically, OCEA recommends that because the Companies failed to provide any support or explanation of the calculation of the property taxes or general and administrative components of the carrying cost calculation, the Commission should not grant recovery of these aspects of the Companies' request. Additionally, OCEA and IEU argue that the proposed carrying cost rates do not reflect actual financing for environmental investments, which could impact the calculation of the carrying cost rates (IEU Br. at 21-22, citing IEU Ex. 7 at 132-133; Tr. Vol. XI at 111-113; OCEA Br. at 71-72). The carrying cost rates, according to IEU and OCEA, should be revised to reflect actual financing, including the use of pollution control bonds that have been secured by the Companies (Id.). To support their argument, IEU and OCEA rely on Staff witness Cahaan who testified at the hearing that "if specific financing mechanisms can be identified that would be appropriate and applicable to the assets being financed, I see no reason why those shouldn't be specifically used"[16] (IEU Br. at 21-22; OCEA Br. at 72-73). However, Staff witness Cahaan also stated that "[A]t the time when we looked at the carrying cost calculations it seemed reasonable, given the cost of debt and cost of equity of the company,"[17] which is consistent with his prefiled testimony that said: "I have examined the carrying costs rates provided to Mr. Soliman and found them to be reasonable" (Staff Ex. 10 at 7).

OCEA also recommends that the carrying costs for deferrals of environmental costs be revised to reflect actual short-term cost of debt, as opposed to WACC as proposed by the Companies, and that the calculated carrying charges should not be based on the original cost of the environmental investment but at cost minus depreciation. Thus, OCEA argues that the Companies are seeking a return on and a return of their investment as would be the case under traditional ratemaking, but overstating the depreciation component. OCEA also advocates that the carrying cost rates, 13.98 percent for OP and 14.94 percent for CSP, are too high in light of the economic environment at this time (OCEA Br. at 73-74). Finally, OCEA urges the Commission to offset the Companies' request for carrying charges by the Section 199 provision of the Internal Revenue Code (Section 199). Section 199 allows the Companies to take a tax deduction for "qualified production activities income" equal to 6 percent in 2009 and 9 percent in 2010 and

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15 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order (September 28, 2000).

16 Tr. Vol. XII at 237.

17 Id.

thereafter. IEU, OEG, and OCEA request that the Commission adjust the carrying costs for the Section 199 deduction as the Commission has found appropriate in the Companies' 07-63 Case[18] and in the FirstEnergy ESP Case. OCEA argues that while Section 4928.143(B)(2)(a), Revised Code, allows the Companies to automatically recover the cost of federally mandated carbon or energy taxes, which will be passed on to customers, customers should be afforded the benefits of the Section 199 tax deduction (OCEA Br. at 74-75; IEU Br. at 21; IEU Ex. 10 at 6; OEG Ex. 3 at 23).

The Companies emphasize that their request for carrying costs is for the incremental carrying charges on the 2001-2008 investments that the Companies will incur post-January 1, 2009. AEP-Ohio explained that the carrying costs themselves are the costs that the Companies will incur after January 1, 2009, and, therefore, the Companies reason that the "without limitation" language in Section 4928.143(B)(2), Revised Code, supports their request (Tr. Vol. XIV at 93, 114). AEP-Ohio stresses that Section 4928.143(B)(2), Revised Code, is the basis for the carrying cost request as opposed to paragraph (B)(2)(a) of Section 4928.143, Revised Code, as OCEA and OEG claim and, therefore, the arguments as to retroactive ratemaking are misplaced (Cos. Reply Br. at 29-30). Further, the Companies insist that Section 4928.143(B)(2)(b), Revised Code, supports their request, as the carrying charges are necessary to recover the ongoing cost of investments in environmental facilities and equipment that are essential to keep the generation units operating. The Companies assert that the operating costs of their generation units remain well below the cost of securing the power on the market (Cos. Ex. 7-B at 7).

As to the claims that the carrying costs are overstated, the Companies claim that the levelized depreciation approach used by the Companies is better for customers than traditional ratemaking given the relative newness of the environmental investments (Tr. Vol. V at 55-56; Tr. Vol. VII at 22-23). The Companies also argue that the Companies' investments in environmental compliance equipment during 2001-2008 were not factored into the rates unbundled in 2000 and capped under the ETP case as alleged. The rate increase approved, as part of the RSP, and the RSP 4 Percent Cases did not, according to the Companies, provide recovery of the carrying costs to be incurred during the ESP period (Cos. Ex. 7, Exhibits PJN-8 - PJN-9 and PJN-12). The Companies reply that the intervenors' request to adjust carrying charges for the Section 199 deduction is flawed. AEP-Ohio states that the Section 199 deduction is not a reduction to the statutory tax rate used in the WACC, a fact which AEP-Ohio asserts has been recognized by FERC and the Financial Accounting Standards Board. The Companies further note that IEU witness Bowser indeed confirmed that Section 199 does not reduce the statutory tax rate (Tr. Vol. XI at 271-273). The Companies also argue, and IEU witness Bowser agreed, that the Section 199 tax deduction is applicable to AEP Corporation as a whole and not to each operating subsidiary. The Companies note, therefore, that any deduction available to

[18] *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 07-63-EL-UNC, Opinion and Order (October 3, 2007) (07-63 Case).

AEP-Ohio is reduced if one of the other AEP Corporation operating affiliates is not eligible for the Section 199 deduction (Cos. Br. 36; Tr. Vol. XI at 266-267). Accordingly, the Companies state that AEP-Ohio has not been able to take the full deduction (Tr. Vol. XIV at 115-117). Further, the Companies argue that the intervenors have misinterpreted the Commission's decision in the FirstEnergy ESP Case to imply that the Commission made an adjustment to account for the Section 199 deduction. For these reasons, the Companies request that the Commission reconsider adjusting carrying charges for the potential Section 199 deduction.

Upon review of the record, we agree with Staff that AEP-Ohio should be allowed to recover the incremental capital carrying costs that will be incurred after January 1, 2009, on past environmental investments (2001-2008) that are not presently reflected in the Companies' existing rates, as contemplated in AEP-Ohio's RSP Case. Further, the Commission finds that this decision regarding the recovery of continuing carrying costs on environmental investments, based on the WACC, is consistent with our decision in the 07-63 Case and the RSP 4 Percent Cases. Additionally, we agree with Staff that the levelized carrying cost rates proposed by AEP-Ohio are reasonable and, therefore, should be approved. We further find, as we concluded in the FirstEnergy ESP Case, that adequate modifications to the Companies' ESP application have been made in this order to account for the possibility of any applicable Section 199 tax deductions.

C. Annual Non-FAC Increases

The Companies proposed to increase the non-FAC portion of their generation rates by 3 percent for CSP and 7 percent for OP for each year of the ESP to provide a recovery mechanism for increasing costs related to matters such as carrying costs associated with new environmental investments made during the ESP period, increases in the general costs of providing generation service, and unanticipated, non-mandated generation-related cost increases. Specifically, as part of this automatic increase, the Companies intend to recover the carrying costs associated with anticipated environmental investments that will be necessary during the ESP period (2009-2011) (Cos. Br. at 27; Cos. Reply Br. at 46-49). The Companies argued that the annual increases are not cost-based and are avoidable for those customers who shop. The Companies also proposed two exceptions to the fixed, annual increases, one for generation plant closures and the other for OP's lease associated with the scrubber at the Gavin Plant, which would require additional Commission approval during the ESP. After establishing the FAC component of the current generation SSO to get a FAC baseline, the Companies determined that the remainder of the current generation SSO would be the non-FAC base component.

The intervenors oppose automatic annual increases in the non-FAC component of the generation rate, and argue that any generation increases should be cost-based (IEU Br.

at 24; OPAE/APAC Br. at 6; OEG Br. at 12; OCEA Br. 29-31). OEG contends that since the Companies have not provided any support for the automatic annual increases, which could result in total rate increases over the three-year period of $87 million for CSP and $262 million for OP, the annual increases should be disallowed (OEG Ex. 3 at 18-19); Similarly, Kroger argues that AEP-Ohio did not appropriately account for costs associated with the non-FAC component of the proposed generation rates (Kroger Br. at 14).

Staff opposes CSP's and OP's recommended annual, non-FAC increases of 3 and 7 percent, respectively (Staff Ex. 10 at 4). Instead, Staff stated that it believes a more appropriate escalation of the non-FAC generation component would be half of the proposed amounts; therefore, recommending annual increases of 1.5 percent for CSP and 3.5 percent for OP (Id.). Staff witness Cahaan rationalized the proposed reduction by stating that "an average of 5% for the two companies may have been a reasonable expectation of cost increases at the time that the ESP was contemplated, but not now. With the recent financial crises, we are entering a recessionary, and possibly a deflationary, period and any expectations of price increases need to be revised downward" (Id.). Furthermore, while recognizing that the ultimate balancing of interests lies with the Commission, Staff witness Cahaan testified that Staff's recommended reduction in the proposed increases was a reasonable balance between the Companies' obligation and costs to serve customers and the current economic conditions (Tr. Vol. XII at 211). The Companies rejected Staff's rationalization for the reduction in their proposed non-FAC increases (Cos. Reply Br. at 49). IEU also rejected Staff's rationalization for the reduction, arguing that no automatic increases are warranted (IEU Br. at 24).

Stating that it is in the public interest for the Companies to continue investing in environmental equipment and to be in compliance with current and future environmental requirements, Staff witness Soliman also recommended that AEP-Ohio be permitted to recover carrying costs for anticipated environmental investments made during the ESP period (Staff Ex. 6 at 5). Staff recommended that this recovery occur through a future proceeding upon the request of the Companies for recovery of additional carrying costs associated with actual environmental investment after the investments have been made (Staff Br. at 6-7). Specifically, Staff suggested that the Commission require the Companies to file an application in 2010 for recovery of 2009 actual environmental investment cost and annually thereafter for each succeeding year to reflect actual expenditures (Tr. Vol. XII at 132; Staff Ex. 10 at 7). OCEA seems to agree with Staff's recommendation (OCEA Br. at 71).

The Companies further respond that Section 4928.143, Revised Code, does not require that the SSO price be cost-based and, instead, Section 4928.143(B)(2)(e), Revised Code, authorizes electric utilities to include in their ESP provisions for automatic increases in any component of the SSO price (Cos. Reply Br. at 48-49).

The Commission finds Staff's approach with regard to the recovery of the carrying costs for anticipated environmental investments made during the ESP to be reasonable, and, therefore, we direct the Companies to request, through an annual filing, recovery of additional carrying costs after the investments have been made.

We also agree with Staff that the economic conditions must be balanced against the Companies' provision of electric service under an ESP. In balancing these two interests, as well as considering all components of the ESP, we believe that it is appropriate to modify this provision of the Companies' ESP and remove the inclusion of any automatic non-FAC increases. As recognized by several intervenors, the record is void of sufficient support to rationalize automatic, annual generation increases that are not cost-based, but that are significant, equaling approximately $87 million for CSP and $262 million for OP (see, i.e., OCEA Br. at 29-30, citing Tr. Vol. XIV at 208-209). We also believe the modification is warranted in light of the fact that we have removed one of the Companies' significant costs factored into establishing the proposed automatic increases. Accordingly, we find that the ESP should be modified to eliminate any automatic increases in the non-FAC portion of the Companies' generation rates.

IV. DISTRIBUTION

A. Annual Distribution Increases

To support initiatives to improve the Companies' distribution system and service to customers, the Companies proposed the following two plans, which will result in annual distribution rate increases of 7 percent for CSP and 6.5 percent for OP:

1. Enhanced Service Reliability Plan (ESRP)

The Companies proposed to implement a new, three-year ESRP pursuant to 4928.143(B)(2)(h), Revised Code,[19] which includes an enhanced vegetation initiative, an enhanced underground cable initiative, a distribution automation initiative, and an enhanced overhead inspection and mitigation initiative (Cos. Ex. 11 at 3). While noting that they are providing adequate and reliable electric service, the Companies justify the need for the ESRP by stating that customers' service reliability expectations are increasing, and in order to maintain and enhance reliability, the ESRP is required (Id. at 3, 8, 10-14). AEP-Ohio further states that the three-year ESRP, consisting of the four reliability

[19] On page 72 of its brief, the Companies rely on Section 4928.154(B)(2)(h), Revised Code, to support their request to receive cost recovery for the incremental costs of the incremental ESRP activities. We are assuming that the reference was a typographical error and that the Companies intended to cite to Section 4928.143(B)(2)(h), Revised Code (see Cos. Reply Br. at 50-51).

programs, is designed to modernize and improve the Companies' distribution infrastructure (Id.).

(a) Enhanced vegetation initiative

The Companies state that the purpose of this new initiative is to improve the customer's overall service experience by reducing and/or eliminating momentary interruptions and/or sustained outages caused by vegetation. The Companies proposed to accomplish this goal by balancing its performance-based approach to reflect a greater consideration of cycle-based factors (Id. at 26-28). The Companies state that under their proposed vegetation initiative, they will employ additional resources (approximately double the current number of tree crews in Ohio), employ greater emphasis on cycle-based planning and scheduling, increase the level of vegetation management work performed so that all distribution rights-of-way can be inspected and maintained, and utilize improved technologies to collect tree inventory data to optimize planning and scheduling by predicting problem areas before outages occur (Id. at 28-29).

(b) Enhanced underground cable initiative

The Companies state that the purpose of this initiative is to reduce momentary interruptions and sustained outages due to failures of aging underground cable. The Companies' plan to target underground cables manufactured prior to 1992 to replace and/or restore the integrity of the cable insulation (Id. at 31).

(c) Distribution automation (DA) initiative

The Companies explain that DA is a critical component of their proposed gridSMART distribution initiative that is described below. DA is an advanced technology that improves service reliability by minimizing, quickly identifying and isolating faulted distribution line sections, and remotely restoring service interruptions (Id. at 34-35).

(d) Enhanced overhead inspection and mitigation initiative

The Companies state that the purpose of this initiative is to improve the customer's overall service experience by reducing equipment-related momentary interruptions and sustained outages. The Companies intend to accomplish this goal through a comprehensive overhead inspection process that will proactively identify equipment that is prone to fail (Id. at 18). The Companies also state that the new program will go beyond the current inspection program required by the electric service and safety (ESSS) rules, which is a basic visual assessment of the general condition of the distribution facilities, by conducting a comprehensive inspection of the equipment on each structure via walking the circuit lines and physically climbing or using a bucket truck to inspect (Id. at 19). In conjunction with this program, AEP-Ohio proposes to focus on five targeted overhead asset initiatives, including cutout replacement, arrester replacement, recloser replacement, 34.5 kV protection, and fault indicator (Id. at 20-22).

Generally, numerous intervenors and Staff opposed the distribution initiatives and cost recovery of such initiatives through this proceeding. Many parties advocated for deferral of these distribution initiatives, and the ESRP as a whole, for consideration in a future distribution base rate case (Staff Br. at 7; Staff Ex. 1 at 6-7; OPAE/APAC at 19; IEU Br. at 25-26; Kroger Br. at 18; OHA Br. at 17; OMA Br. at 6). Further, OCEA argued that the Companies have not demonstrated that the ESRP is incremental to what the Companies are required to do and spend under the current ESSS rules and current distribution rates (OCEA Br. at 44; OCC Ex. 13 at 8-11). While supporting several aspects of the Companies' ESRP programs, Staff witness Roberts also questioned the incremental nature of the proposed ESRP programs (Staff Ex. 2 at 4-6, 13, 17, 18; Tr. Vol. VIII at 70-77).

The Commission agrees, in part, with Staff and the intervenors. The Commission recognizes that Section 4928.143(B)(2)(h), Revised Code, authorizes the Companies to include in its ESP provisions regarding single-issue ratemaking for distribution infrastructure and modernization incentives. However, while SB 221 may have allowed Companies to include such provisions in its ESP, the intent could not have been to provide a 'blank check' to electric utilities. In deciding whether to approve an ESP that contains provisions for distribution infrastructure and modernization incentives, Section 4928.143(B)(2)(h), Revised Code, specifically requires the Commission to examine the reliability of the electric utility's distribution system and ensure that customers' and the electric utilities' expectations are aligned, and to ensure that the electric utility is emphasizing and dedicating sufficient resources to the reliability of its distribution system. Given AEP-Ohio's proposed ESRP, the only way to examine the full distribution system, the reliability of such system, and customers' expectations, as well as whether the programs proposed by AEP-Ohio are "enhanced" initiatives (truly incremental), is through a distribution rate case where all components of distribution rates are subject to review. Therefore, at this time, the Commission denies the Companies' request to implement, as well as recover costs associated therewith, the enhanced underground cable initiative, the distribution automation initiative, and the enhanced overhead inspection and mitigation initiative. With regard to these issues, we concur with OHA: "The record in this case reflects the fact that the distribution prong of AEP's electric service deserves further Commission scrutiny – but not in the context of this accelerated ESP proceeding" (OHA Br. at 17).

Nonetheless, the Commission finds that AEP-Ohio has demonstrated in the record of this proceeding that it faces increased costs for vegetation management and that a specific need exists for the implementation of the enhanced vegetation initiative, as proposed as part of the three-year ESRP, to support an incremental level of reliability activities in order to maintain and improve service levels. The Companies' current approach to its vegetation management program is mostly reactive (Staff Ex. 2 at 10). While we recognize the difficulties that recent events have caused, we believe that it is important to have a balanced approach that not only reacts to certain incidents and problems, but that also proactively limits or reduces the impact of weather events or incidents. In addition to reacting to problems that occur, it is imperative that AEP-Ohio implements a cycle-based approach to maintain the overall system. To this end, the Companies have demonstrated in the record that increased spending earmarked for specific vegetation initiatives can reduce tree-caused outages, resulting in better reliability (Cos. Ex. 11 at 27-31). OCC witness Cleaver also recognized a problem with the current vegetation management program, and supported the adoption of a new, hybrid approach that incorporates a cycle-based tree-trimming program with a performance-based program (OCC Ex. 13 at 30, 35). Staff witness Roberts further supported the move to a new, four-year cycle-based approach and recommended that the enhanced vegetation initiative include the following: end-to-end circuit rights-of-way inspections and maintenance; mid-point circuit inspections to review vegetation clearance from conductors, equipment, and facilities; greater clearance of all overhang above three-phase primary lines and single-phase lines; removal of danger trees located outside of rights-of-ways where property owner's permission can be secured, and using technology to collect tree inventory data to optimize planning and scheduling (Staff Ex. 2 at 13).

The Commission is satisfied that the Companies have demonstrated in the record that the costs associated with the proposed vegetation initiative, included as part of the proposed three-year ESRP, are incremental to the current Distribution Vegetation Management Program and the costs embedded in distribution rates (Cos. Ex. 11 at 26-31). Specifically, the Companies proposed to employ additional resources in Ohio, place a greater emphasis on cycle-based planning and scheduling, and increase the level of vegetation management work performed (Id. at 28-29). Although OCC's witness questions the incremental nature of the costs proposed to be included in the enhanced vegetation initiative, OCC offered no evidence that the proposed initiative is already included in the current vegetation management program, and thus, is not incremental (OCC Ex. 13 at 30-36). Rather, OCC seems to quibble with the definition of "enhanced." OCC witness Cleaver stated: "I recommend that the Commission rule that the Company's proposed Vegetation Management Programs, while an improvement over its current performance based program, is *not an enhancement* but *rather a reflection of additional* tree trimming needed as a result of their prior program" (Id. at 35 (emphasis added)). Furthermore, we believe that the record clearly reflects customers' expectations as to tree-caused outages, service interruptions, and reliability of customers' service.[20] We also believe that, presently, those customer expectations are not aligned with the Companies' expectations. However, as required by Section 4928.143(B)(2)(h), Revised Code, we believe that the Companies' proposal for a new vegetation initiative more closely aligns

[20] A common theme from the customers throughout the local public hearings was that outages due to vegetation have been problematic.

the customers' expectations with the Companies' expectations as it relates to tree-caused outages, importance of reliability, and the increasing frustration surrounding momentary outages with the emergence of new technology.

Accordingly, in balancing the customers' expectations and needs with the issues raised by several intervenors, the Commission finds that the enhanced vegetation initiative proposed by the Companies, with Staff's additional recommendations, is a reasonable program that will advance the state policy. To this end, the Commission approves the establishment of an ESRP rider as the appropriate mechanism pursuant to Section 4928.143(B)(2)(h), Revised Code, to recover such costs. The ESRP rider initially will include only the incremental costs associated with the Companies' proposed enhanced vegetation initiative (Cos. Ex. 11 at 31, Chart 7) as set forth herein. Consistent with prior decisions,[21] the Commission also believes that, pursuant to the sound policy goals of Section 4928.02, Revised Code, a distribution rider established pursuant to Section 4928.143(B)(2)(h), Revised Code, should be based upon the electric utility's prudently incurred costs. Therefore, the ESRP rider will be subject to Commission review and reconciliation on an annual basis.

As for the recovery of any costs associated with the Companies' remaining initiatives (i.e., enhanced underground cable initiative, distribution automation initiative, and enhanced overhead inspection and mitigation initiative), the ESRP rider will not include costs for any of these programs until such time as the Commission has reviewed the programs, and associated costs, in conjunction with the current distribution system in the context of a distribution rate case as explained above. If the Commission, in a subsequent proceeding, determines that the programs regarding the remaining initiatives should be implemented, and thus, the associated costs should be recovered, those costs may, at that time, be included in the ESRP rider for future recovery, subject to reconciliation as discussed above.

2. GridSMART

The Companies propose, as part of their ESP, to initiate Phase 1 of gridSMART, a three-year pilot, in northeast central Ohio. GridSMART will include three main components, AMI, DA, and Home Area Network (HAN). The AMI system features include smart meters, two-way communications networks, and the information technology systems to support system interaction. AEP-Ohio contends that AMI will use internal communications systems to convey real-time energy usage and load information to both the customer and the company. According to the Companies, AMI will provide the capability to monitor equipment and convey information about certain malfunctions and operating conditions. DA will provide real-time control and monitoring of select

21 *In re Ohio Edison Co., The Cleveland Electric Illuminating Co., Toledo Edison Co.*, Case No. 08-935-EL-SSO, Opinion and Order at 41 (December 19, 2008).

electrical components with the distribution system, including capacitor banks, voltage regulators, reclosers, and automated line switches. HAN will be installed in the customer's home or business and will provide the customer with information to allow the customer to conserve energy. HAN includes providing residential and business customers who have central air conditioning with a programmable communicating thermostat (PCT) and a load control switch (LCS), which is installed ahead of a major electrical appliance and will turn the appliance on and off or cycle the appliance on and off. AEP-Ohio reasons that central air conditioners are typically the largest piece of electrical equipment in the home and will yield the most significant demand response benefit (Tr. Vol. III at 304). LCS will provide customers who have a direct load control or interruptible tariff the ability to receive commands from the meter and the option to respond and signal the appropriate action to the meter for confirmation. The Companies propose a phased-in implementation of Phase 1 gridSMART to approximately 110,000 meters and 70 distribution circuits in an approximately 100 square mile area within CSP's service territory (Cos. Ex. 4 at 9, 12-13; Tr. Vol. III at 303-304). The Companies further propose to extend the installation of DA to 20 circuits in areas beyond the gridSMART Phase 1 program. The Companies propose a phased-in approach to fully implement gridSMART throughout their service area over the next 7 to 10 years, if granted appropriate regulatory treatment. The Companies estimate the net cost of gridSMART Phase 1 to be approximately $109 million (including the projected net savings of $2.7 million) over the three-year period (Cos. Ex. 4 at 15-16, KLS-1). The rate design for gridSMART includes the projected cost of the program over the life of the equipment. The Companies have requested recovery during the ESP of only the costs to be incurred during the three-year term of the ESP (Cos. Ex. 1 at DMR-4). Thus, AEP-Ohio asserts that it is inappropriate to consider the long-term operational cost savings when the long-term costs of gridSMART have not been included in the ESP for recovery.

Although Staff generally supports the Companies' implementation of gridSMART, particularly the AMI and DA components, Staff raises a few concerns with this aspect of the Companies' ESP application. Staff is concerned that the overhead costs for meter purchasing is overstated and recommends that the overhead costs be reviewed before approval to ensure that the costs are not duplicative of the overhead meter purchasing costs currently recovered in the Companies' rates (Staff Ex. 3 at 3). Staff argues that there is no reason for the Companies to restrict the PCTs to customers with air conditioning only, and recommends that the device be offered to any customer that desires to own this type of thermostat to control air conditioning or other electrical appliances (Staff Br. at 12). Staff and OCC also argue that customers who have invested in advanced technological equipment for gridSMART will not benefit from dynamic pricing and time differentiated rates if the Companies do not simultaneously file tariffs for such services (Staff Ex. 3 at 5; OCEA Br. at 82). Staff recommends that the Companies offer some form of a critical peak pricing rebate for residential customers, and some form of hedged price for commercial customers for a fixed amount of the customers' demand (Staff Ex. 3 at 5).

Further, Staff argues that the Companies' gridSMART proposal does not contain sufficient information regarding any risk-sharing between the ratepayers and shareholders, operational savings, or a cost/benefit analysis, and states that AEP-Ohio did not quantify any customer or societal benefits of the proposed gridSMART initiative (Staff Br. at 12-13). Staff notes that according to the Companies, DA will not be implemented until 2011, the third year of the ESP, and that the ESP proposes to install DA beyond the Phase I gridSMART area (Tr. Vol. III at 246). Staff opposes DA outside of the Phase I area because the Companies' cannot estimate the expected reliability improvements associated with the installation of DA. Staff also argues that DA costs should be recovered through a DA rider. The cost of gridSMART, per AEP-Ohio's proposal, is to be recovered by adjusting distribution rates. Staff is opposed to increasing distribution rates in this proceeding (Staff Ex. 5 at 6). Instead, Staff recommends that a rider be established and set at zero. The Staff argues that a rider has several benefits over the proposed increase to distribution rates, including separate accounting for gridSMART costs, an opportunity to approve and update the plan annually, assurance that expenditures are made before cost recovery occurs, and an opportunity to audit expenditures prior to recovery. Finally, Staff also advocates that the Companies share the financial risk of gridSMART between ratepayers and shareholders, as there is a benefit to the Companies. Additionally, Staff questions whether gridSMART will meet minimum reliability standards. Lastly, Staff asserts that AEP-Ohio should conduct a study that quantifies both customer and societal benefits of its gridSMART plan (Staff Br. at 14).

OCC, Sierra, and OPAE/APAC argue that the Companies' ESP fails to demonstrate that its gridSMART program is cost-effective as required by Sections 4928.02(D) and 4928.64(E), Revised Code, and state that AEP-Ohio's assumption that the societal and customer benefits are self-evident is misplaced (OCEA Br. at 77-80; OPAE/APAC Br. at 17-18). OCC, Sierra, and OPAE/APAC note that there are a number of factors about the program that the Companies have not determined or evaluated, which are essential to the Commission's consideration of the plan. OCC, Sierra, and OPAE/APAC state that the Companies have failed to include any full gridSMART implementation plan or costs, the anticipated life cycle of various components of gridSMART, a methodology for evaluating performance of gridSMART Phase I, an estimate of a customer's bill savings, or the positive impact to the environment or job creation (OCEA Br. at 79-80; OPAE\APAC Br. at 17-18). Further, OCC's witness states that the ESP fails to acknowledge that full system implementation is required before many of the benefits of gridSMART can actually be realized (OCC Ex. 12 at 6). OCC recommends that Phase I have its own set of performance measures, a more detailed project plan, including budget, resource allocation, and life cycle operating cost projections for the full 7-10 year implementation period of gridSMART and beyond, and performance measures for the Commission's approval (OCC Ex. 12 at 18).

AEP-Ohio regards the Staff's proposal to offer PCTs to any customer as overly generous, particularly given that Staff is recommending that the rider be set initially at zero (Cos. Br. at 68-69). AEP-Ohio also submits that it has committed to offering new service tariffs associated with Phase I of gridSMART once the technology is installed and the billing functionalities available (Cos. Ex. 1 at 6; Tr. Vol. III at 304-305; Cos. Br. at 68-69). Further, regarding Staff's policy of risk-sharing, the Companies contend that the assertion that the gridSMART investment benefits CSP just as much as it does customers is not true and, given that the operational savings do not equal or exceed the cost of the program, is without any basis presented in the record. Thus, AEP-Ohio argues that discounting the net cost to be recovered by CSP is unfair and inappropriate (Cos. Reply Br. at 63-64). The Companies are unclear how the Staff expects to determine whether gridSMART meets the minimum reliability standards and contend that this issue was first raised in the Staff's brief. Nonetheless, the Companies argue that imposing reliability standards as to gridSMART Phase 1 is inappropriate, primarily because strict accountability for achieving the expected reliability impacts does not take into account the many dynamic factors that impact service reliability index performance. Moreover, accurate measurement and verification of the discrete impact of gridSMART deployment on a particular reliability index would be difficult. The Companies also explain that the expected reliability impacts provided to the Staff were based on good faith estimates of the full implementation of gridSMART Phase 1 as proposed by the Companies. Thus, the Companies would prefer the establishment of deployment project milestones as opposed to specific reliability impact standards.

Although the Companies maintain that their percentage of distribution increase is reasonable and an appropriate part of the ESP package, in recognition of Staff's preference for a distribution rider and to address various parties' concerns regarding the accuracy of AEP-Ohio's cost estimates for gridSMART Phase I, the Companies would agree to a gridSMART Phase I rider set at the 2009 revenue requirement subject to annual true-up and reconciliation based on CSP's prudently incurred net costs (Cos. Reply Br. at 70; Cos. Ex. 1, Exhibit DMR-4).

The Commission believes it is important that steps be taken by the electric utilities to explore and implement technologies, such as AMI, that will potentially provide long-term benefits to customers and the electric utility. GridSMART Phase I will provide CSP with beneficial information as to implementation, equipment preferences, customer expectations, and customer education requirements. A properly designed AMI system and DA can decrease the scope and duration of electric outages. More reliable service is clearly beneficial to CSP's customers. The Commission strongly supports the implementation of AMI and DA, with HAN, as we believe these advanced technologies are the foundation for AEP-Ohio providing its customers the ability to better manage their energy usage and reduce their energy costs. Thus, we encourage CSP to be more expedient in its efforts to implement these components of gridSMART. While we agree that additional information is necessary to implement a successful Phase I program, we do not believe that all information is required before the Commission can conclude that the program is beneficial to ratepayers and should be implemented. Therefore, we will approve the development of a gridSMART rider, as we agree with the Staff that a rider has several benefits over the proposed annual increase to distribution rates, including separate accounting for gridSMART, an opportunity to approve and update the plan each year, assurance that expenditures are made before cost recovery occurs, and an opportunity to audit expenditures prior to recovery. The Commission notes that recent federal legislation makes matching funds available to smart grid projects. Accordingly, the Companies' gridSMART proposal contained in its proposed ESP to recover $109 million over the term of ESP, should be revised to $54.5 million, which is half of the Companies' requested amount. Additionally, we direct CSP to make the necessary filing for federal matching funds under the American Recovery and Reinvestment Act of 2009 for the balance of the projected costs of gridSMART Phase I. The gridSMART rider shall be initially established at $33.6 million for the 2009 projected expenses subject to annual true-up and reconciliation based on the company's prudently incurred costs.

With the creation of the ESRP rider and the gridSMART rider, the Commission finds that annual distribution rate increases in the amounts of 7 percent for CSP and 6.5 percent for OP to recover the costs for the ESRP and gridSMART programs are unnecessary and should be rejected. Accordingly, the Commission finds that AEP-Ohio's proposed ESP should be modified to include the ESRP rider and the gridSMART rider, as approved herein, and to eliminate the annual distribution rate increases.

B. Riders

1. Provider of Last Resort (POLR) Rider

The Companies proposed to include in their ESP a distribution non-bypassable POLR rider (Cos. App. at 6-8). The POLR charge was proposed to collect a POLR revenue requirement of $108.2 million for CSP and $60.9 million for OP (Cos. Ex. 2-A at 34; Cos. Ex. 1, Exhibit DMR-5). The Companies stated that they have a statutory obligation to be the POLR,[22] and thus, the proposed POLR charge is based on a quantitative analysis of the cost to the Companies to provide to customers the optionality associated with POLR service (Cos. Ex. 2-A at 25-26). AEP-Ohio argued that this charge covers the cost of allowing a customer to remain with the Companies, or to switch to a Competitive Retail Electric Service (CRES) provider and then return to the Companies' SSO after shopping (Id.). To further support the proposed increase, the Companies added that their current POLR charge is significantly below other Ohio electric utilities' POLR charges (Cos. Ex. 2 at 8). The Companies utilized the Black-Scholes Model to calculate their cost of fulfilling

22 See Section 4928.141(A) and 4928.14, Revised Code.

the POLR obligation, comparing the customers' rights to "a series of options on power" (Cos. Br. at 43; Cos. Ex. 2-A at 31). AEP-Ohio listed the five quantitative inputs used in the Black-Scholes Model: 1) the market price of the underlying asset; 2) the strike price; 3) the time frame that the option covers; 4) the risk free interest rate; and 5) the volatility of the underlying asset (Id.). The Companies assert that the resulting POLR charge is conservatively low (Cos. Br. at 44).

The numerous intervenors and Staff opposed the level of POLR charge proposed by the Companies, as well as the use of the Black-Scholes Model to calculate the POLR charge (OPAE/APAC Br. at 14-17; OCC Ex. 11 at 8-14). Specifically, OCC and others questioned the use of the LIBOR rate as the input for the risk-free interest rate (Tr. Vol. X at 165-182, 188-189; Tr. Vol. XI at 166-182). Staff questioned the risk that the POLR charge was intended to compensate the Companies for, explaining that there are only two risks involved: one risk is the risk of customers returning to the SSO and the other risk is that the customers leave and take service from a CRES provider (migration risk) (Staff Ex. 10 at 6). Staff witness Cahaan testified that the risk associated with customers returning to the SSO could be avoided by requiring the customer to return at a market price, instead of the SSO rate, which would either be paid directly by the returning customer or any incremental cost of the purchased power could be flown through the FAC (Id.). Staff witness Cahaan admitted that if customers are permitted to return at the SSO rate, without paying the market price or without compensating the Companies for any incremental costs of the additional purchased power that they would be required to purchase, then the Companies would be at risk (Tr. Vol. XIII at 36-37). Thus, Staff witness Cahaan concluded that, if the risk of returning is addressed, then the migration risk is the only risk that should be compensated through a POLR charge (Id. at 7).

The Companies responded that their risk is not alleviated by customers agreeing to return at market price, arguing that future circumstances or policy considerations may require them to relieve customers of their promises to pay market price when circumstances change (Cos. Ex. 2-A at 27-30). AEP-Ohio's witness expressed skepticism as to a future Commission upholding such promises (Id). AEP-Ohio also opposed recovering any costs for market purchases incurred for returning customers through the FAC as an improper subsidization of those customers who chose to shop, and then return to the electric utility, by non-shopping customers (Cos. Ex. 2-E at 14-16). Furthermore, the Companies claim that their risk of being the POLR exists, regardless of historic or current shopping levels (Id.). Nonetheless, AEP witness Baker testified that, even adopting Staff witness Cahaan's theory that the Companies are only at risk for migration (the right of customers to leave the SSO), migration risk equals approximately 90 percent of the Companies' POLR costs pursuant to the Black-Scholes model (Tr. Vol. XIV at 204-205; Cos. Ex. 2-E at 15-16).

As the POLR, the Commission believes that the Companies do have some risks associated with customers switching to CRES providers and returning to the electric utility's SSO rate at the conclusion of CRES contracts or during times of rising prices. However, we agree with the intervenors and Staff that the POLR charge as proposed by the Companies is too high, but we do not agree that there is no risk or a very minimal risk as suggested by some. As noted by several intervenors and Staff, the risk of returning customers may be mitigated, not eliminated, by requiring customers that switch to an alternative supplier (either through a governmental aggregation or individual CRES providers) to agree to return to market price, and pay market price, if they return to the electric utility after taking service from a CRES provider, for the remaining period of the ESP term or until the customer switches to another alternative supplier. In exchange for this commitment, those customers shall avoid paying the POLR charge. We believe that this outcome is consistent with the requirement in Section 4928.20(J), Revised Code, which allows governmental aggregations to elect not to pay standby service charges, in exchange for agreeing to pay market price for power if they return to the electric utility. Therefore, based on the record before us, we conclude that the Companies' proposed ESP should be modified such that the POLR rider will be based on the cost to the Companies to be the POLR and carry the risks associated therewith, including the migration risk. The Commission accepts the Companies' witness' quantification of that risk to equal 90 percent of the estimated POLR costs,[23] and thus, finds that the POLR rider shall be established to collect a POLR revenue requirement of $97.4 million for CSP and $54.8 million for OP. Additionally, the POLR rider shall be avoidable for those customers who shop and agree to return at a market price and pay the market price of power incurred by the Companies to serve the returning customers. Accordingly, the Commission finds that the POLR rider, which is avoidable, should be approved as modified herein.

2. Regulatory Asset Rider

The Companies proposed to begin the recovery of a variety of regulatory assets that were authorized in various Commission proceedings regarding the Companies' electric transition plan (ETP), rate stabilization plan (RSP), line extension program, green pricing power program, and the transfer of the MonPower's service territory to CSP. In their application, the Companies proposed to begin the amortization of these regulatory assets in 2011 and complete the amortization over an eight-year period. The projected balances at the end of 2010 to amortize are $120.5 million for CSP and $80.3 million for OP. AEP-Ohio asserts that these projected balances, or the value on June 30, 2008, were not challenged by any party. To recover these regulatory assets, the Companies created a RAC rider to be collected from customers in 2011 through 2018. The rider revenues will be reconciled on an annual basis for any over- or under-recoveries.

23 See Cos. Ex. 1, Exhibit DMR-5.

Staff proposed that the eight-year amortization period proposal be deferred until the Companies' next distribution rate case where all components of distribution rates are subject to review (Staff Ex. 1 at 4). AEP-Ohio responded that SB 221 authorizes single-issue ratemaking related to distribution service, which is what it is proposing. AEP-Ohio also notes that the only opposition to the Companies' proposal is with regard to the collection of the historic regulatory assets, which was by Staff (Cos. Reply Br. at 94). The Companies submit that Staff's preference to deal with this issue in a distribution rate case is irrelevant and inconsistent with the statute.

The Commission finds that the Companies have not demonstrated that the creation of the RAC rider in its proposed ESP, as a single-issue ratemaking item for distribution infrastructure and modernization incentives, fulfills the requirements of SB 221 or advances the state policy. Therefore, the Commission finds that the RAC rider should not be approved in this proceeding. We note, however, that we agree with Staff that the consideration of the requested amortization of regulatory assets is more appropriate within the context of a distribution rate case where all distribution related costs and issues can be examined collectively. Accordingly, the Commission finds that AEP-Ohio's proposed ESP should be modified to eliminate the RAC rider.

3. Energy Efficiency, Peak Demand Reduction, Demand Response, and Interruptible Capabilities

(a) Energy Efficiency and Peak Demand Reduction

Section 4928.66, Revised Code, requires the electric utilities to implement energy efficiency programs that will achieve energy savings and peak demand programs designed to reduce the electric utility's peak demand. Specifically, an electric utility must achieve energy savings in 2009, 2010, and 2011 of .3 percent, .5 percent, and .7 percent, respectively, of the normalized annual kWh sales of the electric utility during the preceding three calendar years. This savings continues to rise until the cumulative savings reach 22 percent by 2025. Peak demand must be reduced by one percent in 2009 and by .75 percent annually until 2018.

CSP and OP include, as part of their ESP, an unavoidable Energy Efficiency and Peak Demand Reduction Cost Recovery Rider (EE/PDR rider). The estimated annual DSM program cost (including both EE and PDR) is to be trued-up annually to actual cost and compared to the amortization of the actual deferral on an annual basis via the EE/PDR rider (Cos. Ex. 6 at 47-48).

(b) Baselines and Benchmarks

In the ESP, the Companies have established the baselines for meeting the benchmarks for statutory compliance by weather normalizing retail sales, excluding economic development load, accounting for the load of former MonPower service territory and the Ormet/Hannibal Real Estate load, accounting for future load growth due to the Companies' economic development efforts, and accounting for increased load associated with the funds for economic development purposes pursuant to the order in Case No. 04-169-EL-ORD (RSP Order)[24] (Cos. Ex. 8 at 4; Cos. Ex. 2A at 46-51). The Companies contend that its process is consistent with Sections 4928.64(B) and 4928.66(A)(2)(a), Revised Code. The Companies request that the methodology be adopted in this proceeding so as to provide the Companies clear guidance with statutory compliance mandates. Further, the Companies reserve their right to request additional adjustments due to regulatory, economic, or technological reasons beyond the reasonable control of the Companies.

As to the calculation of the Companies' baseline, Staff asserts that the former MonPower load was acquired prior to the three-year period (2006 to 2008) and is not truly economic development. Therefore, Staff contends that the MonPower load is not a reasonable adjustment to the baseline. Staff suggests that the Companies' savings and peak demand reductions for 2009 be as set forth by Staff witness Scheck (Staff Ex. 3 at 6-8, Ex. GCS-1 and Ex. GCS-2). Staff recommends that CSP and OP make a case-by-case filing with the Commission to receive credit for the energy savings and peak demand reduction efforts of the electric utility's mercantile customers. Staff argues that because programs like PJM's demand response programs are not committed for integration into the electric utilities' energy efficiency and peak reduction programs, such credits should not count towards AEP-Ohio's annual benchmarks and retail customers who have such agreements should not receive an exemption from AEP-Ohio's energy efficiency cost recovery mechanism (Staff Br. at 17-19; Staff Ex. 3 at 6-11).

Kroger recommends an opt-out provision of the rider for non-residential customers that are above a threshold aggregate load (10 MW at a single site or aggregated at multiple sites) within the AEP-Ohio service territories. Kroger proposes that, at the time of the opt-out request, the customer would be required to self-certify or attest to AEP-Ohio that for each facility, or aggregated facilities, the customer has conducted an energy audit or analysis within the past three years and has implemented or plans to implement the cost-effective measures identified in the audit or analysis. Kroger argues that the unavoidable rider penalizes customers who have implemented cost efficient DSM measures. Kroger contends that this is consistent with the intent of Section 4928.66(A)(2)(c), Revised Code (Kroger Ex. 1 at 13-14).

IEU notes that the Commission has previously rejected a proposal similar to Kroger's opt-out proposal with a demand threshold for mercantile customers in Duke's

[24] *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 04-169-EL-ORD, Opinion and Order (January 26, 2005) (RSP Order).

ESP case.[25] IEU urges the Commission, consistent with Section 4928.66, Revised Code, and its determination in the Duke ESP case, to reject Kroger's request (IEU Reply Br. at 22).

The Commission concludes that the acquisition of the former MonPower load should not be excluded from baseline. The MonPower load was not a load that CSP served and would have lost, but for some action by CSP. Therefore, we find that the Companies' exclusion of the MonPower load in the energy efficiency baseline is inappropriate. The Commission does not believe that all economic development should automatically result in an exclusion from baseline. On the other hand, we agree with the Companies' adjustment to the baseline for the Ormet load. We note that the Companies and Staff agree that the impact of customer-sited specific DSM resources will be included in the Companies' compliance benchmarks and adjusted for any existing resources that had historic implication during the years 2006-2008. The Commission also recognizes that Staff and the Companies agree that the appropriate approach would be for the Companies to make case-by-case filings with the Commission to receive credit for contributions by mercantile customers.

In regards to Kroger's recommendation, for an opt-out process for certain commercial or industrial customers, the Commission finds Kroger's proposal, as advocated by Kroger witness Higgins, too speculative. It is best that the Commission determine the inclusion or exemption of a mercantile customer's DSM on a case-by-case basis. We note that Section 4928.66(A)(2)(c), Revised Code, provides, in pertinent part, the following:

> Any mechanism designed to recover the cost of energy efficiency and peak demand reduction programs under divisions (A)(1)(a) and (b) of this section may exempt mercantile customers that commit their demand-response or other customer-sited capabilities, whether existing or new, for integration into the electric distribution utility's demand-response, energy efficiency, or peak demand reduction programs, if the commission determines that that exemption reasonably encourages such customer to commit those capabilities to those programs.

This provision of the statute permits the Commission to approve a rider that exempts mercantile customers who commit their capabilities to the electric utility. However, the statute does not dictate a minimum consumption level. For these reasons, the Commission rejects Kroger's proposal.

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[25] *In re Duke Energy Ohio, Inc.*, Case No. 08-920-EL-SSO, et al., Opinion and Order (December 17, 2008) (Duke ESP Order).

(c) Energy Efficiency and Peak Demand Reduction Programs

The Companies propose ten energy efficiency and peak demand reduction programs that will be refined and supplemented at the completion of the Market Potential Study through the creation of a working collaborative group of stakeholders.

As part of the Companies' energy efficiency and peak demand reduction plan, the Companies propose to spend $178 million on the following programs: (1) Residential Standard Offer Program, Small Commercial and Industrial Standard Offer Program, Commercial and Industrial Standard Offer Program; (2) Targeted Energy Efficient Weatherization Program; (3) Low Income Weatherization Program; (4) Residential and Small Commercial Compact Fluorescent Lighting Program; (5) Commercial and Industrial Lighting Program; (6) State and Municipal Light Emitting Diode Program; (7) Energy Star® New Homes Program; (8) Energy Star® Home Appliance Program; (9) Renewable Energy Technology Program; (10) Industrial Process Partners Program (Cos. Ex. 4 at 20-22). OEG supports the Companies EE/PDR rider as a reasonable proposal (OEG Ex. 2 at 13). OPAE generally supports the Companies proposed programs as reasonable for low-income and moderate income customers. However, OPAE requests that the Companies be required to empower the collaborative to design appropriate programs, provide funding for existing programs that can rapidly provide energy efficiency and demand response reductions, and to retain a third-party administrator to manage program implementation (OPAE Ex. 1 at 16-17; OPAE/APAC Br. at 21-22).

Staff also generally approves of the Companies' demand-side management and energy efficiency programs. However, Staff notes that certain of AEP-Ohio's programs are expensive and should be required to comply with the Total Resources Cost Test (Staff Br. at 17-19; Staff Ex. 3 at 6-11).

OCC makes five specific recommendations (OCC Ex. 5 at 9). First, OCC contends that the Companies DSM programs for low-income residential customers are adequate but should be available to all residential customers in Ohio. Second, OCC recommends that AEP-Ohio work with Columbia Gas of Ohio, Inc., to develop a one-stop home performance program in year two of the ESP. Third, OCC recommends that programs for consumers above 175 percent of the federal poverty level should be competitively bid and customers charged for services according to a sliding fee scale based on income. Fourth, like Staff, OCC contends that all programs should be evaluated for cost-effectiveness pursuant to the Total Resource Cost Test. Finally, OCC expresses concern regarding the administrative costs of the programs, in comparison to energy efficiency programs offered by other Ohio utilities and recommends that the administrative cost of the DSM program (administrative, educational, and marketing expenses) be determined by the collaborative, and limited to 25 percent of the program costs to ensure that the majority of the program dollars reach the customers (Id.).

The Commission directs, as the Companies submit in their ESP, that the collaborative process be used to contain administrative cost of the EE/PDR programs and to ensure, with the possible exception of low-income weatherization programs, that all programs comply with the Total Resource Cost Test. We do not agree with OPAE/APAC that a third-party administrator is necessary to act as a liaison between the Companies and the collaborative. Thus, the Companies should proceed with the proposed EE/PDR programs proposed in its ESP as justified by the market project study and as refined by the collaborative.

(d) Interruptible Capacity

The Companies count their interruptible service towards their peak demand reduction requirements in accordance with Section 4928.66(A)(2)(b), Revised Code. More specifically, the Companies propose to increase the limit of OP's Interruptible Power-Discretionary Schedule (Schedule IRP-D) to 450 Megawatts (MW) from the current limit of 256 MW and to modify CSP's Emergency Curtailable Service (ECS) and Price Curtailable Service (PCS) to make the services more attractive to customers. The Companies request that the Commission recognize the Companies' ability to curtail customer usage as part of the peak demand reductions (Cos. Ex. 1 at 5-6).

Staff advocates that any credits awarded for the annual peak demand reduction targets for the Companies' interruptible programs should only apply when actual reductions occur (Staff Ex. 3 at 11). OCEA argues that interruptible load should not be counted toward AEP-Ohio's peak demand reduction as it is contrary to the intent of SB 221 to improve grid reliability and would be based on load under the control of the customer rather than AEP-Ohio. Further, OCEA argues that the Companies would reap an inequitable benefit from interruptible load (possibly in the form of off-system sales) that is not reduced at peak which would allow the Companies to sell the load or avoid buying additional power. OCEA contends that any such benefit is not passed on to customers (OCEA Br. at 102-103; Tr. Vol. IX at 68-69).

The Companies argue that capacity associated with interruptible customers should be counted toward compliance with the requirements of Section 4928.66, Revised Code, as the ability to interrupt is a significant demand reduction resource to AEP-Ohio. Further, the Companies state that interruptions have a real impact on customers and the Companies do not want to interrupt service when there is no system or market requirement to do so (Cos. Ex. 1 at 6). The Companies note that Section 4928.66(A)(1)(b), Revised Code, requires the electric utility to implement programs "designed to achieve" a specified peak demand reduction level as opposed to "achieve" a specified level of energy savings as required by Section 4928.66(A)(1)(a), Revised Code. Staff witness Scheck admits that the plain meaning of "designed to achieve" and "achieve" are different (Tr. Vol. VIII at 208). The Companies argue that the different language in the statutory requirements is intended to recognize the differences between energy efficiency programs and peak demand reduction programs. As such, the Companies contend that Staff's position is not supported by the language of the statute and it does not overcome the policy rationale presented by the Companies. The Companies also note that, in the context of integrated resource planning, interruptible capabilities are counted as capacity and evaluated in the need to plan for new power facilities. Finally, the Companies note that the Commission defines native load as internal load minus interruptible load.[26] For these reasons, the Companies contend that their interruptible capacity should be counted toward their compliance with the peak demand reduction benchmarks (Cos. Br. 114-115; Cos. Reply Br. at 90-93).

Further, the Companies claim that interruptible customers receive a benefit in the form of a reduced rate for taking interruptible service irrespective of whether their service is actually curtailed. AEP-Ohio notes that it includes such interruptible service as a part of its supply portfolio, unlike the PJM demand response programs, which is based on PJM's zonal load. Therefore, AEP-Ohio asserts there is no disparate treatment between counting interruptible capabilities as part of peak demand reduction compliance requirements and prohibiting retail participation in wholesale PJM demand reduction programs (Cos. Reply Br. at 90-91). Further, as to OCEA's claims regarding interruptible customer load, the Companies argue that the assertions are without merit or basis in the statute. The Companies argue that counting interruptible load fits squarely within the stated intent of the statute that programs be "designed to achieve" peak demand reduction and facilitates the ability to avoid the construction of new power plants. As to the customer's control of interruptible load argument, the Companies note that the customer has a choice to "buy through" to obtain replacement power at market prices to avoid curtailment and in such situations the Companies' supply portfolio is not affected. Regarding OCEA's assertion that the Companies might benefit from the associated interruption, AEP-Ohio acknowledges that off-system sales are indirectly possible, as are other circumstances, based on the market price. Nonetheless, AEP-Ohio argues that such does not alter the fact that AEP-Ohio's retail supply obligation is reduced and the supply portfolio is not accessed to serve the retail customer. Accordingly, AEP-Ohio asserts that interruptible tariff capabilities should count toward the Companies' peak demand reduction compliance requirements.

The Commission agrees with the Staff and OCEA that interruptible load should not be counted in the Companies' determination of its EE/PDR compliance requirements unless and until the load is actually interrupted. As the Companies recognize, it is imperative, with regard to the PJM demand response programs, that the Companies have

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26 See proposed Rule 4901:5-5-01(Q), O.A.C., *In the Matter of the Adoption of Rules for Alternative and Renewable Energy Technologies and Resources, and Emission Control Reporting Requirements, and Amendment of Chapters 4901:5-1, 4901:5-3, 4901:5-5, and 4901:5-7 of the Ohio Administrative Code, Pursuant to Chapter 4928, Revised Code, to Implement Senate Bill No. 221,* Case No. 08-888-EL-ORD (Green Rules).

some control or commitment from the customer to be included as a part of AEP-Ohio's Section 4928.66, Revised Code, compliance requirements.

Further, the Commission emphasizes that we expect that applications filed pursuant to Section 4928.66(A)(2)(b), Revised Code, to be initiated by the electric utility only when the circumstances are justified. At the time of such filing by an electric utility, the Commission will determine whether the electric utility's continued compliance is possible under the circumstances.

4. Economic Development Cost Recovery Rider and the Partnership with Ohio Fund

The Companies' ESP application includes an unavoidable Economic Development Rider as a mechanism to recover costs, incentives and foregone revenue associated with new or expanding Commission-approved special arrangements for economic development and job retention. The Companies propose quarterly filings to establish rates based on a percentage of base distribution revenue subject to a true-up of any under- or over-collection in subsequent quarterly filings. In addition, the Companies propose the development of a "Partnership with Ohio" fund from shareholders. The fund would consist of a $75 million commitment, $25 million per year of the ESP, from shareholders. The Companies' goal is for approximately half of the fund to be used to provide assistance to low-income customers, including energy efficiency programs for such customers, and the balance to be used to attract and retain business development within the AEP-Ohio service area (Cos. Ex. 1 at 12; Cos. Ex. 3 at 15-16; Cos. Ex. 6 at 49; Tr. Vol. III at 115-119).

OCC proposes that the Commission continue its policy of dividing the recovery of forgone revenue subsidies equally from AEP-Ohio's shareholders and customers or require shareholders to pay a larger percentage. Further, OCC expresses some concern that the rider may be used in an anti-competitive manner as it is not likely that incentives and/or discounts will be offered to shopping customers. To address OCC's anticompetitive concerns, OCC proposes that the Commission make the economic development rider avoidable or establish the charge as a percentage of the customer's entire bill rather than a percentage of distribution charges. OCC also recommends that all parties participate in the initial and annual review of the economic development contracts and that, at the annual review, if the customer has not fulfilled its obligation, the arrangement be cancelled, the subsidy paid back, and the Companies directed to credit the rider for the discounts (OCC Ex. 14 at 4-8; OCEA Br. at 104-106).

The Companies contend that Section 4905.31, Revised Code, as amended by SB 221, explicitly provides for the recovery of foregone revenues for entering into reasonable arrangements for economic development and, thus, OCC's recommendation to continue the Commission's previous policy is misplaced. Further, the Companies note that the

Commission's approval of any special arrangement will include a public interest determination. Thus, the Companies argue that OCC's recommendation for all parties to initially and annually review economic development arrangements is unnecessary, bureaucratic and burdensome, and should be rejected. The Companies contend that economic development and full recovery of the foregone revenue for economic development is consistent with SB 221 and a significant feature of the Companies' ESP, which should not be modified by the Commission (Cos. Br. at 132).

The Commission finds that OCC's concerns are unfounded and unnecessary at this stage. The Commission is vested with the authority to review and determine whether or not economic development arrangements are in the public interest. OCC's request is denied.

OPAE and APAC argue that the Companies have not provided any assurances that the $75 million will be spent from the Partnership with Ohio fund if the Commission modifies the ESP and fails to state how much of the fund will be spent on low-income, at-risk populations (OPAE/APAC Br. at 19-20). The Companies submit that, if the ESP is modified, they can then evaluate the modified ESP in its entirety to determine whether this fund proposal contained in the ESP requires elimination or modification (Tr. Vol. III at 137-138; Tr. Vol. X at 232-233).

While the Partnership with Ohio fund is a key component of the economic development proposal, in light of the modifications made to the ESP pursuant to this opinion and order, we find that the Companies' shareholders should fund the Partnership with Ohio fund, at a minimum of $15 million, over the three-year ESP period, with all of the funds going to low-income, at-risk customer programs. Accordingly, we direct AEP-Ohio to consult with Staff to administer the program established herein.

C. <u>Line Extensions</u>

In its ESP, AEP-Ohio proposes to modify certain existing line extension policies and charges included in its schedules (Cos. Ex. 10 at 5-14). Specifically, the Companies requested a modification to their definition of line extension and system improvements, a continuation of the up-front payment concept established in Case No. 01-2708-EL-COI,[27] an increase in the up-front residential line extension charges, implementation of a uniform, up-front line extension charge for all nonresidential projects, the elimination of the end use customer's monthly surcharge, and the elimination of the alternative construction option (Id. at 3-4, 6-7, 10-12).

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[27] *In the Matter of the Commission' s Investigation into the Policies and Procedures of Ohio Power Company, Columbus Southern Power Company, The Cleveland Electric Illuminating Company, Ohio Edison Company, The Toledo Edison Company and Monongahela Power Company Regarding the Installation of New Line Extensions*, Case No. 01-2708-EL-COI, et al., Opinion and Order (November 7, 2002).

Staff testified that distribution-related issues and costs, such as those related to line extensions, be examined in the context of a distribution rate case (Staff Ex. 13 at 4). IEU concurred with Staff's position (IEU Br. at 25). OCC also agreed and added that AEP-Ohio should be required to demonstrate in that rate proceeding that its costs related to line extensions have substantially increased, thereby justifying AEP-Ohio's proposed increase to the up-front residential line extension charges (OCEA Br. at 87).

Per SB 221, the Commission is required to adopt uniform, statewide line extension rules for nonresidential customers within six months of the effective date of the law. The Commission adopted such rules for nonresidential and residential customers on November 5, 2008.[28] Applications for rehearing were filed, which the Commission is still considering. Accordingly, the new line extension rules are not yet effective.

The Commission finds that AEP-Ohio has not demonstrated that its proposal to continue, in its ESP, its existing line extension policies regarding up-front payments, with modifications, is consistent with SB 221 or advances the policy of the state. Therefore, in light of the SB 221 mandate that the Commission adopt statewide line extension rules that will apply to AEP-Ohio, we do not believe that it makes sense to adopt a unique policy for AEP-Ohio at this time. As such, the Companies' ESP should be modified to eliminate the provision regarding line extensions, which would have the effect of also eliminating the alternative construction option as requested by the Companies. AEP-Ohio is, however, directed to account for all line extension expenditures, excluding premium services, in plant in service until the new line extension rules become effective, where the recovery of such will be reviewed in the context of a distribution rate case. The Companies may continue to charge customers for premium services pursuant to their existing practices.

V. TRANSMISSION

In its ESP, the Companies requested to retain the current TCRR, except the marginal loss fuel credit will now be reflected in the FAC instead of the TCRR. We concur with the Companies' request. We find the Companies' request to be consistent with our determination in the Companies' recent TCRR Case,[29] and thus, approve the TCRR rider as proposed by the Companies. Additionally, as contemplated by our prior order in the TCRR Case, any overrecovery of transmission loss-related costs, which has

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28 See *In the Matter of the Commission's Review of Chapters 4901:1-9, 4901:1-10, 4901:1-21, 4901:1-22, 4901:1-23, 4901:1-24, and 4901:1-25 of the Ohio Administrative Code*, Case No. 06-653-EL-ORD, Finding and Order (November 5, 2008), Entry on Rehearing (December 17, 2008) (06-653 Case).

29 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Adjust Each Company's Transmission Cost Recovery Rider*, Case No. 08-1202-EL-UNC, Finding and Order (December 17, 2008) (TCRR Case).

occurred due to the timing of our approval of the Companies' ESP and proposed FAC, shall be reconciled in the over/underrecovery process in the Companies' next TCRR rider update filing.

VI. OTHER ISSUES

A. Corporate Separation

1. Functional Separation

In its ESP application, AEP-Ohio requested to remain functionally separated for the term of the ESP, as was previously authorized by the Commission in the Companies' rate stabilization plan proceeding,[30] pursuant to Section 4928.17(C), Revised Code (Cos. App. at 14; Cos. Br. at 86). The Companies also requested to modify their corporate separation plan to allow each company to retain its distribution and, for now, transmission assets and that, upon the expiration of functional separation, the Companies would sell or transfer their generation assets to an affiliate (Id.).

Staff testified that the Companies' generating assets have not been structurally separated from the operating companies (Staff Ex. 7 at 2-3). Staff also recommended that, in accordance with the recently adopted corporate separation rules issued by the Commission in the SSO Rules Case,[31] the Companies should file for approval of their corporate separations plan within 60 days after the rules become effective. Furthermore, Staff proposes that the Companies' corporate separation plan should be audited by an independent auditor within the first year of approval of the ESP, the audit should be funded by the Companies, but managed by Staff, and the audit should cover compliance with the Commission's rules on corporate separation (Staff Ex. 7 at 3-4). No party opposed AEP-Ohio's request to remain functionally separate.

Accordingly, the Commission finds that, while the ESP may move forward for approval, as noted by Staff, in accordance with our recently adopted rules in the SSO Rules Case, the Companies must file for approval of their corporate separation plan within 60 days after the rules become effective.

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30 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 04-169-EL-UNC, Opinion and Order at 35 (January 26, 2005).

31 *In the Matter of the Adoption of Rules for Standard Service Offer, Corporate Separation, Reasonable Arrangements, and Transmission Riders for Electric Utilities Pursuant to Sections 4928.14, 4928.17, and 4905.31, Revised Code, as amended by Amended Substitute Senate Bill No. 221*, Case No. 08-777-EL-ORD, Finding and Order (September 17, 2008), and Entry on Rehearing (February 11, 2009) (SSO Rules Case).

2. Transfer of Generating Assets

The Companies request authorization for CSP to sell or transfer two recently acquired generating facilities (Waterford Energy Center and the Darby Electric Generating Station) that have not been included in rate base for ratemaking purposes and the costs of operating and maintaining the plants are not built into the current rates) (Cos. Ex. 2-A at 42; Cos. Ex. 2-E at 20). CSP purchased the Waterford Energy Center, a natural gas combined cycle power plant, on September 28, 2005, which has a generating capacity of 821 MW (Cos. App. at 14). On April 25, 2007, CSP purchased the Darby Electric Generating Station, a natural gas simple cycle generating facility, with a generating capacity of 480 MW and a summer capacity of approximately 450 MW (Id.). Although AEP-Ohio is requesting authority to transfer these generating assets pursuant to Section 4928.17(E), Revised Code, CSP has no immediate plans to sell or transfer the generating facilities. If AEP-Ohio obtains authorization to sell these generating assets through this proceeding, AEP-Ohio will notify the Commission prior to any such transaction (Id. at 15).

Through its application, the Companies also notify the Commission of their contractual entitlements/arrangements to the output from the Ohio Valley Electric Corporation generating facilities and the Lawrenceburg Generation Station that the Companies intend to sell or transfer in the future, but argue that any sale or transfer of those entitlements do not require Commission authorization because the entitlements do not represent generating assets wholly or partly owned by the Companies pursuant to Section 4928.17(E), Revised Code (Id.).

The Companies argue that, if the Commission does not grant authorization to transfer these plants or entitlements, then any expense related to the plants or entitlements not recovered in the FAC should be recovered in the non-FAC portion of the generation rate (Cos. Br. at 89; Cos. Ex. 2-E at 20-21). AEP-Ohio states that this rate recovery would include approximately $50 million of carrying costs and expenses related to the Waterford Energy Center and the Darby Electric Generating Station annually, and $70 million annually for the contract entitlements (Id.).

Staff witness Buckley testified that, while Staff does not necessarily disagree with the proposal to transfer the Waterford Energy Center and the Darby Electric Generating Station facilities, Staff believes that the transfers could have a potential financial and policy impact at the time of the transfer (Staff Ex. 7 at 3). Thus, Staff recommended that the Companies file a separation application, in accordance with the Commission's SSO rules, at the time that the transfer will occur (Id.). Several other parties agree that, in the absence of a current plan to sell or transfer, the Commission should not approve a future sale or transfer. Rather, the parties argue that the Companies should seek approval, pursuant to Section 4928.17(E), Revised Code, at the time of the actual sale or transfer (OCEA Br. at 100; IEU Br. at 26-27; OEG Br. at 16).

The Commission agrees with Staff and the intervenors that the request to transfer the Waterford Energy Center and the Darby Electric Generating Station facilities, as well as any contractual entitlements/arrangements to the output of certain facilities, is premature. AEP-Ohio should file a separate application, in accordance with the Commission's rules, at the time that it wishes to sell or transfer these generation facilities. The Commission, however, recognizes that these generating assets have not and are not included in rate base and, thus, the Companies cannot collect any expenses related thereto, even if the facilities or contractual outputs have been used for the benefit of Ohio customers. If the Commission is going to require that the electric utilities retain these generating assets, then the Commission should also allow the Companies to recover Ohio customers' jurisdictional share of any costs associated with maintaining and operating such facilities. Accordingly, we find that while the Companies still own the generating facilities, they should be allowed to obtain recovery for the Ohio customers' jurisdictional share of any costs associated therewith. Thus, we believe that any expense related to these generating facilities and contract entitlements that are not recovered in the FAC shall be recoverable in the non-FAC portion of the generation rate as proposed by the Companies. The Commission, therefore, directs AEP-Ohio to modify its ESP consistent with our determination herein.

B. Possible Early Plant Closures

The Companies include as a part of their application in these cases a request for authority to establish a regulatory asset to defer any unanticipated net cost associated with the early closure of a generating unit or units. The Companies assert that, during the ESP period, generating units may experience failures or safety issues that would prevent the Companies from continuing to cost-effectively operate the generation unit prior to the end of the depreciation accrual (unanticipated shut down) (Cos. App. at 18-19; Cos. Ex. 2-A at 51-52). The Companies request authority to include net early closure cost in Account 182.3, Other Regulatory Assets. In the event of an unanticipated shut down, the Companies state they will timely file a request with the Commission for recovery of such prudent early closure costs via a non-bypassable rider over a relatively short period of time. The Companies are requesting that the rider include carrying cost at the WACC rate (Cos. App. at 18-19; Cos. Ex 6 at 25-26). The Companies also request authority to come before the Commission to determine the appropriate treatment for accelerated depreciation and other net early closure costs in the event that the Companies find it necessary to close a generation plant earlier that otherwise expected (earlier than anticipated shut down) (Cos. Ex. 6 at 28).

OCEA posits that the Companies' request for accounting treatment for early plant closure is wrong and should be rejected. OCEA reasons that the plant was included in rate base under traditional ratemaking regulation to give the Companies the opportunity to earn a return on the investment and the Companies accepted the risk that the plant might not be fully depreciated when it was removed from service. OCEA asserts it is not appropriate to guarantee the Companies recovery of their investment. If the Commission determines to allow the Companies to establish the requested accounting treatment, OCEA asks that the Commission adopt the Staff's "offset" recommendation (OCEA Br. at 102).

Staff argues that the value of the generation fleet was determined in the Companies' ETP cases,[32] wherein, pursuant to the stipulation, AEP-Ohio agreed not to impose any lost generation cost on switching customers during the market development period. Staff notes that, although the economic value of the generation plants was never specifically addressed by the Commission, it is reasonable to assume that the net value of the Companies' fleet was not stranded. Accordingly, Staff opposes the Companies' requests to impose on customers the cost or risk of uneconomic plants without accounting for the offset of the positive economic value of the rest of the Companies' generation plants (Staff Ex. 1 at 8).

Based on the record in this proceeding, the Commission is not convinced that it is appropriate to approve the Companies' request for recovery of net cost associated with an unanticipated shut down. Despite the arguments of the Companies to the contrary, we are persuaded by the arguments of the Staff that there may be offsetting positive value associated with the Companies generation fleet. Accordingly, while we will grant the Companies the authority to establish the accounting mechanism to separate net early closure cost, the Companies must file an application before the Commission for recovery of such costs. Accordingly, this aspect of the Companies' ESP application is denied. As to the Companies' request for authority to file with the Commission to determine the appropriate treatment associated with an earlier-than-anticipated shut down, the Commission finds this aspect of the application to be reasonable and, accordingly, the request should be granted.

C. PJM Demand Response Programs

Through the ESP, the Companies propose to revise certain tariff provisions to prohibit customers receiving SSO from participating in the demand response programs offered by PJM, either directly or indirectly through a third-party. Under the PJM programs retail customers can receive payment for being available to curtail even if the

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32 *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case Nos. 99-1729-El-ETP and 99-1730-EL-ETP, Opinion and Order at 15-18 (September 28, 2000).

customer's service is not actually curtailed. AEP-Ohio argues that allowing its retail customers receiving SSO to also participate in PJM demand response programs is a no-win situation for AEP-Ohio and its other customers and inconsistent with the requirements of SB 221. The Companies contend that PJM demand response programs are intended to ensure the proper price signal to wholesale customers, not to address retail rate issues (Cos. Ex. 1 at 5-7). AEP-Ohio argues that retail customers should participate through AEP-Ohio-sponsored and Commission-approved programs. The Companies contend that FERC has granted state commissions, or- more precisely, the "relevant electric retail regulatory authority," the authority to preclude retail customer participation in wholesale demand response programs. *Wholesale Competition in Regions with Organized Electric Markets* (Docket Nos. RM07-19-000 and AD07-7-000), 125 FERC ¶ 61,071 at 18 CFR Part 35 (October 17, 2008) (Final Rule) (Cos. Br. at 119)

AEP-Ohio notes that it has consistently challenged retail customers' ability to participate in such programs and argued that the terms and conditions of its tariff prohibited such and, therefore, demand response retail participants should not be surprised by the Companies' position in this proceeding (Tr. Vol. IX at 212). AEP-Ohio argues that Ohio businesses participating in PJM's demand response programs have not invested their own capital or assets, taken any financial risk, or added any value to the services for which they are being compensated through PJM. The Companies assert, as stated by Staff witness Scheck, that the PJM demand response programs cost AEP-Ohio's other customers as the load of such PJM program participants continues to count toward the Companies' Fixed Resource Requirements (FRR) option and such cost is reflected in AEP-Ohio's retail rates (Tr. Vol. VIII at 165-166). Further, the PJM program participant/customer's ability to interrupt is of no use to AEP-Ohio, as the Companies claim that PJM's curtailment request is based on PJM's zonal load and not AEP-Ohio's peak load (Cos. Br. at 122-123).

The Companies reason that SB 221 includes a process whereby mercantile customer-sited resources can be committed to the utility to comply with the peak demand reduction benchmarks as set forth in Section 4928.66(A)(2)(d), Revised Code. Further, AEP-Ohio argues that it is unclear how the interruptible capacity of a customer participating in PJM's demand response program can count toward the Companies' benchmarks without being under the control of the Companies and "designed to achieve" peak demand reductions as required by the statue. As such, the Companies argue that, if participation in the PJM demand response program is allowed, PJM will be in direct competition with the electric distribution companies' efforts to comply with energy efficiency and peak demand reduction benchmarks and thus, render the mercantile customer commitment provisions largely ineffective. For these reasons, AEP-Ohio states that it should incorporate participation in PJM's demand response programs through AEP-Ohio and AEP-Ohio would then be in a position to pass some of the economic benefits associated with participation in PJM programs on to retail customers through complementary retail tariff programs and to pursue mercantile customer-sited arrangements to achieve benchmark compliance, thus allowing the Companies to avoid duplicate supply costs (Cos. Br. at 124-126).

This aspect of the Companies' ESP proposal is opposed by Integrys, OMA, Commercial Group, OEG, and IEU. Most of the intervenors contend that AEP-Ohio, in essence, considers retail customer participation in PJM programs the reselling of power provided to them by AEP-Ohio. Integrys makes the most comprehensive arguments opposing AEP-Ohio's request for approval to prohibit customer participation in the PJM demand response programs. Integrys argues that 18 C.F.R. 35.28(g) only permits this Commission to prohibit a retail customer's participation in demand response programs at the wholesale level through law or regulation. Section 18 C.F.R. 35.28(g) states:

> Each Commission-approved independent system operator and regional transmission organization must permit a qualified aggregator of retail customers to bid demand response on behalf of retail customers directly into the Commission-approved independent system operator's or regional transmission organization's organized markets, *unless the laws and regulations of the relevant electric retail regulatory authority expressly do not permit a retail customer to participate*. [Emphasis added.]

Thus, Integrys reasons that a ban on participation in wholesale demand response programs through AEP-Ohio's tariff is not equivalent to an act of the General Assembly or rule of the Commission. Accordingly, Integrys reasons that any attempt by the Commission to prohibit participation in this proceeding is beyond the authority granted by FERC and will be preempted. Further, Integrys and Constellation argue that AEP-Ohio has failed to state under what authority the Commission could bar customer participation in PJM's demand response and reliability programs. Constellation and Integrys posit that it is not in the public interest for the Commission to approve the prohibition from participation in such programs (Constellation Br. at 20-23; Constellation Ex. 2 at 18; Integrys Ex. 2 at 15; Integrys Br. at 2).

Even if the Commission concludes that it has the authority to grant AEP-Ohio's request to revise the tariff as requested, Integrys asserts that the Companies have not met their burden to justify prohibiting participation in PJM demand response programs. Integrys asserts that the request is not properly a part of the ESP applications and should have been part of an application not for an increase in rates pursuant to Section 4909.18, Revised Code. Nonetheless, Integrys concludes that under Section 4928.143 or Section 4909.18, Revised Code, the burden of proof is on the electric utility company to show that its proposal is just and reasonable.

The Companies, according to Integrys and the Commercial Group, have failed to present any demonstration that the Companies' programs are more beneficial to customers than the PJM programs. On the other hand, Integrys asserts that the PJM programs are more favorable to customers than the programs offered by AEP-Ohio as to notification, the number of curtailments per year, the hours of curtailments, payments and payment options, and penalties for non-compliance (Integrys Ex. 2 at 10-12; Commercial Group Br. at 9). In addition, certain interveners note, and the Companies agree, that PJM has not curtailed any customers since AEP-Ohio joined PJM (Tr. Vol. IX at 48). Furthermore, the intervenors contend that participation in the demand response programs provides improved grid reliability and improved efficiency of the market due to competition (Integrys Ex. 2 at 8).

Integrys also notes that the Ohio customers receive significant financial benefits from load serving entities beyond Ohio (Tr. Vol. IX at 52-52, 118). Integrys argues that AEP-Ohio wishes to ban customer participation in wholesale demand response programs to facilitate the increase in OSS of capacity to the benefit of the Companies' shareholders. Integrys reasons that because AEP-Ohio can count load enrolled in its interruptible service offerings as a part of the PJM ILR demand response program, the Companies will receive credit against its FRR commitment. The Companies, according to Integrys, hope that additional load will come from the customers currently participating in PJM's demand response programs in Ohio (Tr. Vol. IX at 53-58; Integrys Br. at 20-22). Integrys proposes, as an alternative to prohibiting customer participation in wholesale demand response programs, that the Commission count participation in the programs towards AEP-Ohio's peak demand reduction goals in accordance with the requirements of Section 4928.66, Revised Code. Integrys argues that the load can be certified, as it is today with the PJM demand response programs, or the electric services company could be required to register the committed load with the Commission.

Furthermore, Integrys reasons that the Commission can not retroactively interfere with existing contracts between customers and the customer's electric service provider in relation to the commitment contracts with PJM. With that in mind and if the Commission decides to grant AEP-Ohio's request to prohibit participation in wholesale demand response programs, Integrys requests that customers currently committed to participate in PJM programs for the 2008-2009 planning period and the 2009-2010 planning period be permitted to honor their commitments (Integrys Br. at 27-28).

Integrys argues that the Companies' claim that taking SSO and participating in a wholesale demand response program is a resale of power and a violation of the terms and conditions of their tariffs is misplaced. Integrys opines that there is no actual resale of energy, but, instead, there is a reduction in the customer's consumption of energy upon a call from the regional transmission operator (in this case, PJM). The customer is not purchasing energy from AEP-Ohio, so any energy purchased by AEP-Ohio can be transferred to another purchaser. Thus, Integrys asserts that AEP-Ohio's argument regarding participation in a wholesale demand response program is fiction and not based on FERC's interpretation of participation in such programs. Finally, Integrys contends that AEP-Ohio's proposal is a violation of Section 4928.40(D), Revised Code, as such prohibits electric utilities from prohibiting the resale of electric generation service.

The Commercial Group asserts, that because AEP-Ohio has not performed any studies or analyses, the Companies' assertion that wholesale demands response programs must be different from a demand response program offered by AEP-Ohio is unsupported by the record (Tr. Vol. IX at 47). The Commercial Group requests that the Companies be directed to design energy efficiency and demand response programs that incorporate all available programs (Commercial Group at Br. 9).

OEG argues that, to the extent there are real benefits to the Companies as well as to their retail customers in the form of improved grid reliability, AEP-Ohio should be required to offer PJM demand response programs to its large industrial customers by way of a tariff rider or through a third-party supplier (OEG Ex. 2 at 13). IEU adds that the Companies currently use the capabilities of their interruptible customers to assist the Companies in satisfying their generation capacity requirements to PJM. According to IEU, SB 221 gives mercantile customers the option of whether or not to dedicate their customer-sited capabilities to the Companies for integration into the Companies' portfolio (IEU Ex. 1 at 12).

Constellation argues that AEP-Ohio's proposal violates Section 4928.20, Revised Code, and the clear intent of SB 221. Further, Constellation argues that approving AEP-Ohio's request to prohibit Ohio businesses from conservation programs during this period of economic hardship is ill-advised, especially considering that other businesses with which Ohio businesses' must compete are able to participate in the PJM programs. As such, consistent with the Commission's decision in Duke's ESP case (Case No. 08-920-EL-SSO, et al.), Constellation encourages the Commission to reject AEP-Ohio's request to prohibit SSO customers from participating in PJM demand response programs and give Ohio's business customers all available opportunities to reduce demand, conserve energy, and invest in conservation equipment (Constellation Br. at 23). OMA supports the claims of Constellation (OMA Br. at 10).

First, we will address the claims regarding the Commission's authority, or as claimed by Integrys, the lack of authority, for the Commission to determine whether or not Ohio's retail customers are permitted to participate in wholesale demand response programs. The Commission finds that the General Assembly has vested the Commission with broad authority to address the rate, charges, and service issues of Ohio's public utilities as evidenced in Title 49 of the Revised Code. Accordingly, we consider this Commission the entity to which FERC was referring in the Final Rule when it referred to the "relevant electric retail regulatory authority." We are not convinced by Integrys' arguments that a specific act of the General Assembly is necessary to grant the Commission the authority to determine whether or not Ohio's retail customers are permitted to participate in the RTO's demand response programs.

Next, the Commission acknowledges that the PJM programs offer benefits to program participants. We are, however, concerned that the record indicates that PJM demand response programs cost AEP-Ohio's other customers as the load of AEP-Ohio's FRR and the cost of meeting that requirement is reflected in AEP-Ohio's retail rates. Finally, we are not convinced, as AEP-Ohio argues that a customer's participation in demand response programs is the resale of energy provided by AEP-Ohio. For these reasons, we find that we do not have sufficient information to consider both the potential benefits to program participants and the costs to Ohio ratepayers to determine whether this provision of the ESP will produce a significant net benefit to AEP-Ohio consumers. The Commission, therefore, concludes that this issue must be deferred and addressed in a separate proceeding, which will be established pursuant to a subsequent entry. Although we are not making a determination at this time as to the appropriateness of such a provision, we direct AEP to modify its ESP to eliminate the provision that prohibits participation in PJM demand response programs.

D. Integrated Gasification Combined Cycle (IGCC)

In Case No. 05-376-EL-UNC, the Commission concluded that it was vested with the authority to establish a mechanism for recovery of the costs related to the design, construction, and operation of an IGCC generating plant where that plant fulfills AEP-Ohio's POLR obligation and, therefore, approved the Phase I cost recovery mechanism included in the Companies' application.[33] Applications for rehearing of the Commission's IGCC Order were timely filed and by entry on rehearing issued June 28, 2006, the Commission denied each of the applications for rehearing (IGCC Rehearing Entry). Further, the IGCC Rehearing Entry conditioned the Commission's approval of the application, stating that: (a) all Phase I costs would be subject to subsequent audit(s) to determine whether such expenditures were reasonable and prudently incurred to construct the proposed IGCC facility; and (b) if the proposed IGCC facility was not constructed and in operation within five years after the date of the entry on rehearing, all Phase I charges collected must be refunded to Ohio ratepayers with interest.

In this ESP proceeding, AEP-Ohio witness Baker testified that, although the Companies have not abandoned their interest in constructing and operating an IGCC facility in Meigs County, Ohio, certain provisions of SB 221 are a barrier to construction and operation of an IGCC facility. As AEP-Ohio interprets SB 221, the Companies may be

33 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 05-376-EL-UNC, Opinion and Order (April 10, 2006) (IGCC Order).

required to remain in an ESP to assure an opportunity for cost recovery for an IGCC facility; the construction work in process (CWIP) provision which requires the facility to be at least 75 percent complete before it can be included in rate base; the limit on CWIP as a percentage of total rate base which the witness contends causes particular uncertainties since the concept of a generation rate base has no applicability under SB 221; and the effect of "mirror CWIP" (Cos. Ex. 2-A at 52-56). The Companies assert that not only are these barriers to the construction of an IGCC facility but also to any base load generation facility in Ohio. Nonetheless, the Companies state that they are encouraged by the fact that SB 221 recognizes the need for advanced energy resources and clean coal technology, such as an IGCC. Finally, the Companies' witness notes that, since the time the Companies proposed the IGCC facility, CSP has acquired additional generating capacity. According to Company witness Baker, the Companies hope to work with the Governor's administration, the General Assembly, and other interested parties to enact legislation that will make an IGCC facility in Meigs County a reality (Cos. Ex. 2-A at 55-56).

OCEA opines that SB 221 did not eliminate the existing requirement that electric utilities must satisfy to earn a return on CWIP and, since the Companies do not ask for the Commission to make any determination in this proceeding or at any definite time in the future as to the IGCC facility, the Commission should take no action on this issue (OCEA Br. at 98-99).

The Commission notes that the Ohio Supreme Court remanded, in part, the Commission's IGCC Order, for further proceedings and, accordingly, the matter is currently pending before the Commission. Further, as OCEA asserts, there does not appear to be any request from the Companies as to the IGCC facility in this proceeding. Accordingly, we find it inappropriate to rule, at this time, on any matter regarding the Meigs County IGCC facility in this proceeding. We will address the matter as part of the pending IGCC proceeding.

E. <u>Alternate Feed Service</u>

As part of the ESP, the Companies propose a new alternate feed service (AFS) schedule. For customers who desire a higher level of reliability, a second distribution feed, in addition to the customer's basic service, will be offered. Existing AEP-Ohio customers that are currently paying for AFS will continue to receive the service at the same cost under the proposed tariff. Existing customers who have AFS and are not paying for the service will continue to receive such service until AEP-Ohio upgrades or otherwise makes a new investment in the facilities that provide AFS to that customer. At such time, the customer will have 6 months to decide to discontinue AFS, take partial AFS, or continue AFS and pay for the service in accordance with the effective tariff schedule (Cos. Ex. 1 at 8). While OHA supports the implementation of an AFS schedule offering with clearly defined terms and conditions, OHA takes issue with two aspects of the AFS proposal. OHA witness Solganick testified that it is his understanding that the customer will have six months after the customer is notified by the company to make a decision (OHA Ex. 4 at 15). However, OHA witness Solganick advocated that six months was insufficient because critical-use customers, like hospitals, require more lead time to evaluate their electric supply infrastructure and needs (Id.). As such, he argued that 24 months would be more appropriate for planning purposes (Id.). Moreover, OHA argued that, because this issue involves the overall management and cost of operating AEP-Ohio's distribution system, the Commission should defer consideration of the proposed AFS until AEP-Ohio's next distribution rate case where there will be a more deliberate treatment of the issue as opposed to this 150-day proceeding (OHA Br. at 23). OHA believes that a distribution rate proceeding would better ensure that the underlying rate structure for AFS is correct, similar to the argument for deferring decision on other distribution rate issues presented in this ESP proceeding (Id.). Staff and IEU also agree that the issue should be addressed in a distribution rate case (Staff Ex. 1 at 4; IEU Ex. 10 at 11). However, IEU further recommends that the Commission deny the Companies' request because it is not based on prudently incurred costs (IEU Br. at 25-26).

The Companies retort that, while they may have some flexibility as to the notice provided customers, such notice is limited by the Companies' planning horizon for distribution facilities and the lead time required to complete construction of upgraded AFS facilities (Cos. Reply Br. at 122). The Companies reason that, while more than 6 months may be feasible, anything more than 12 months would not be prudent and, in certain rare circumstances, would not facilitate the construction of complex facilities (Id.). Nonetheless, the Companies stated that they will commit to 12 months notice to existing AFS customers for the need to make an election of service (Id.). However, the Companies vehemently opposed deferring approval of their proposed AFS schedule to some future proceeding, stating that the proposed AFS tariff codifies existing practices currently being addressed on a customer-by-customer contract addendum basis (Id.). Further, the Companies argue that IEU has not presented any basis to support the implication that the AFS schedule will recover imprudently incurred costs (Id. at 123). Thus, AEP-Ohio contends there is no good reason to delay implementation of the AFS schedule with the understanding that the Companies will provide up to 12 months notice to existing customers (Id. at 122-123).

As previously noted in this order in regards to other distribution rate issues, the Commission believes that the establishment of various distribution riders and rates, including the proposed new AFS schedule, is best reviewed in a distribution rate case where all components of distribution rates are subject to review.

F. Net Energy Metering Service

The Companies' ESP application includes several tariff revisions. More specifically, the Companies propose toeliminate the one percent limitation on the total rated generation capacity for customer-generators on the Companies' Net Energy

Metering Service (NEMS) and add a new Net Energy Metering Service for Hospitals (NEMS-H). The Companies note that, at the time the ESP application was filed, they had filed a proposed tariff modification to the NEMS and Minimum Requirements for Distribution System Interconnection and Standby Service in Case No. 05-1500-EL-COI.[34] The Companies state that upon approval of the modifications filed in 05-1500, the approved modifications will be incorporated into the tariffs filed in the ESP case (Cos. Ex. 1 at 8-9).

OHA identifies two issues with the Companies' proposed NEMS-H schedule. First, OHA asserts the conditions of service are unduly restrictive to the extent that NEMS-H requires the hospital customer-generator's facility must be owned and operated by the customer and located on the customer-generator's premises. OHA asserts that this requirement prevents hospitals from benefiting from economies of scale by utilizing the expertise of distributed generation or cogeneration companies, centralized operation and maintenance of such facilities, and shared expertise and expenses. Further, OHA asserts that the requirement that the facility be located on the hospital's premises is a barrier because space limitations and legal and/or financing requirements may suggest that a generation facility be located on property not owned by the hospital. OHA argues that the Companies do not cite any regulatory, operational, financial, or other reason why the ownership requirement is necessary. Therefore, OHA requests that the Commission delete this condition of service and require only that the hospital contract for service and comply with the Companies' interconnection requirements (OHA Ex. 4 at 8-10).

AEP-Ohio responds that the requirement that the generation facility be on-site and owned and operated by the customer is a provision of the currently effective NEMS schedule. Further, the Companies argue that economies of scale may be accomplished with multiple hospitals contracting with a third-party to operate and maintain the generation facilities of each hospital. Further, AEP-Ohio argues that there is no support for the claim that efficiencies can not be had if the hospital, rather than a third-party developer, is the ultimate owner of such facilities (Cos. Br. at 128). As to OHA's opposition to the requirement that the hospital own and operate the generation facility on its premises, AEP-Ohio contends that such is required based on the language in the definitions of a customer-generator, net metering system, and self-generator at Section 4928.02(A)(29) to (32), Revised Code (Cos. Reply Br. at 124-125).

Second, OHA argues that the payment for net deliveries of energy should include credits for transmission costs that are avoided and energy losses on the subtransmission and distribution systems that are avoided or reduced. Further, OHA requests that such payments for net deliveries should be made monthly without a requirement for the

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[34] *In the Matter of the Application of the Commission's Review to Provisions of the Federal Energy Policy Act of 2005 Regarding Net Metering, Smart Metering, Demand Response, Cogeneration, and Power Production*, Case No. 05-1500-EL-COI (05-1500).

customer-generator to request any net payment. The Companies propose to make such payment annually upon the customer's request (OHA Ex. 4 at 11-12). The Companies assert that OHA assumes that the customer-generator's activities will reduce transmission, subtransmission, and distribution line losses and there is no support for OHA's contention. Further, AEP-Ohio argues that annual payment is in compliance with Rule 4901:1-10-28(E)(3), Ohio Administrative Code (O.A.C.) (Cos. Reply Br. at 124). OHA witness Solganick conceded that the annual payment requirement is in compliance with the Commission's rule (Tr. Vol. X at 118-119).

Staff submits that the Companies' proposed NEMS-H tariff is premature given that requirements for hospital net metering are currently pending rehearing before the Commission in the 06-653 Case. Thus, Staff proposes, and OHA supports, that the Companies withdraw their proposed NEMS-H and refile the tariff once the new requirements are effective or with the Companies' next base rate proceeding, whichever occurs first (Staff Ex. 5 at 9; OHA Reply Br. at 9). AEP-Ohio argues that the status of the 06-653 Case should not postpone the implementation of one of the objectives of SB 221 and notes that, if the final requirements adopted in the 06-653 Case impact the Companies' NEMS-H, the adopted requirements can be incorporated into the NEMS-H schedule at that time.

As the Commission is in the process of determining the net energy meter service requirements pursuant to SB 221 in the 06-653 Case, the Commission finds AEP-Ohio's revisions to its net energy metering service schedules premature. Therefore, the Commission finds, as proposed by Staff and supported by OHA, the Companies should refile their net metering tariffs to be consistent with the requirements adopted by the Commission in the 06-653 Case or with the Companies' next base rate proceeding.

G. Green Pricing and Renewable Energy Credit Purchase Programs

OCEA proposes that the Commission order AEP-Ohio to continue, with the input of the DSM collaborative, the Companies' Green Pricing Program and to require the Companies to develop a separate residential and small commercial net-metering customer renewable energy credit (REC) purchase program. OCC witness Gonzalez recommended a market-based pricing for RECs. On brief, OCEA proposes an Ohio mandatory market-based rate for in-state solar electric application and a different rate for in-state wind and other renewable resources. OCEA asserts that the programs will assist customers with the cost of owning and using renewable energy and assist the Companies in meeting the renewable energy requirements (OCC Ex. 5 at 10-11; Tr. Vol. IV at 232-234; OCEA Br. at 97-98).

The Companies argue that, pursuant to the stipulation agreement approved by the Commission in Case No. 06-1153-EL-UNC,[35] the Green Pricing Program expired December 31, 2008. Further, the Companies note that the Commission approved the expiration of the Green Pricing Program by the Finding and Order issued in Case No. 08-1302-EL-ATA.[36] However, the Companies state that they intend to offer a new green tariff option during the ESP term (Cos. Ex. 3 at 13). Accordingly, the Companies request that the Commission OCEA's request to detail or adopt a new green tariff option at this time. In regards to OCEA's REC proposal, the Companies assert that the prescriptive pricing recommendation presented on brief is at odds with the testimony of OCC's witness. Further, the Companies note that OCC's witness acknowledged the administrative and cost-effective issues associated with the proposal. Thus, the Companies note that, as OCC's witness acknowledged, the proposal requires further study before being implemented.

While the Commission believes there is merit to green pricing and REC programs and, therefore, encourages the Companies to evaluate the feasibility and benefits to implementing such programs as soon as practicable , we decline to order the Companies to initiate such programs as part of this ESP proceeding, as it is not necessary that these optional requests be pursued by the Companies at this time. Accordingly, we find that it is unnecessary to modify AEP-Ohio's ESP to include any green pricing and REC programs, and we decline to do such modification at this time.

H. Gavin Scrubber Lease

The Companies note that in the Gavin Scrubber Case,[37] the Commission authorized OP to enter into a lease agreement with JMG Funding, L.P. (JMG) for a scrubber/solid waste disposal facilities (scrubber) at the Gavin Power Plant. Under the terms of the lease agreement, the agreement may not be cancelled for the initial 15-year term. After the initial 15-year period, under the Gavin lease agreement, OP has the option to renew or extend the lease for an additional 19 years. OP entered into the lease on January 25, 1995. Therefore, the initial lease period ends in 2010, and at that time, OP will have the option of renewing the Gavin scrubber lease for an additional 19 years, until 2029. On April 4, 2008, OP filed an application for authority to assume the obligations of JMG and restructure the financing for certain JMG obligations in the OP and JMG case.[38] In the OP and JMG case, the Commission approved OP's request subject to two conditions: OP must seek Commission approval to exercise the option to purchase the

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35 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 06-1153-EL-UNC (May 2, 2007).

36 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1302-EL-ATA (December 19, 2008).

37 *In re Ohio Power Company*, Case No. 93-793-EL-AIS, Opinion and Order (December 9, 1993).

38 *In re Ohio Power Company*, Case No. 08-498-EL-AIS, Finding and Order (June 4, 2008).

Gavin scrubbers or terminate the lease agreement; and OP must provide the Commission with details of how the company intends to incorporate the project into its ESP (Cos. Ex. 2-A at 56-58).

As part of the Companies' ESP application, OP requests authority to return to the Commission to recover any increased costs associated with the Gavin lease (Cos. Ex. 2-A at 56-58). The Companies state that a decision on the Gavin scrubber lease has not been made because the market value of the scrubbers and the analysis to determine the least cost option is not available at this time.

The Commission recognizes that additional information is necessary for the Companies to evaluate the options of the Gavin lease agreement and, to that end, we believe that AEP-Ohio should be permitted to file an application to request recognition of the Gavin lease at the time that it makes its decision as to purchasing or terminating the lease. Once the Companies have made their election, they should conduct a cost-benefit analysis and file it with the Commission prior to seeking recovery of any incremental costs associated with the Gavin scrubber lease.

I. <u>Section V.E (Interim Plan)</u>

The Companies assert that this provision is part of the total ESP package and should be adopted. The Companies requested that the Commission authorize a rider to collect the difference between the ESP approved rates and the rates under the Companies' current SSO for the length of time between the end of the December 2008 billing month and the effective date of the new ESP rates.

We find Section I.E of the proposed ESP to be moot with this opinion and order. The Commission issued finding and orders on December 19, 2008, and February 25, 2009, interpreting the statutory provision in Section 4928.14(C)(1), Revised Code, and approving rates for an interim period until such time as the Commission issues its order on AEP's proposed ESP.[39] Those rates have been in effect with the first billing cycle in January 2009. Consistent with Section 4928.141, Revised Code, which requires an electric utility to provide consumers, beginning on January 1, 2009, a SSO established in accordance with Section 4928.142 or 4928.143, Revised Code, and given that AEP-Ohio's proposed ESP term begins on January 1, 2009, and continues through December 31, 2011, we are authorizing the approval of AEP's ESP, as modified herein, effective January 1, 2009. However, any revenues collected from customers during the interim period must be recognized and offset by the new rates and charges approved by this opinion and order.

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39 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1302-EL-ATA, Finding and Order at 2-3 (December 19, 2008) and Finding and Order at 2 (February 25, 2009).

VII. SIGNIFICANTLY EXCESSIVE EARNINGS TEST (SEET)

Section 4928.143(F), Revised Code, requires that, at the end of each year of the ESP, the Commission shall consider if any adjustments provided for in the ESP:

> ...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.

AEP-Ohio's proposed ESP SEET process may be summarized as follows: The book measure of earnings for CSP and OP is determined by calculating net income divided by beginning book equity. The Companies then propose that the ROE for CSP and OP should be blended as the book equity amounts for AEP-Ohio is more meaningful since CSP and OP are supported by AEP Corporation. To develop a comparable risk peer group, including public utilities, with similar business and financial risk, AEP-Ohio's process includes evaluating all publicly traded U.S. firms. By using data from both Value Line and Compustat, AEP-Ohio applies the standard decile portfolio technique, to divide the firms into 10 different business risk groups and 10 different financial risk groups (lowest to highest). AEP-Ohio would then select the cell which includes AEP Corporation. To account for the fact that the business and financial risks of CSP and OP may differ from AEP Corporation, this aspect of the process is repeated for CSP and OP and taken into consideration in determining whether CSP's or OP's ROEs are excessive. The ESP evaluates business risk by using unlevered Capital Asset Pricing Model betas (or asset betas) and the financial risk by evaluating the book equity ratio. The Companies assert that the book equity ratio is more stable from year to year and, therefore, is considered by fixed-income investors and credit rating agencies. The ESP utilized two standard deviations (which is equivalent to the traditional 95 percent confidence level) about the mean ROEs of the comparable risk peer group and the utility peer group to determine the starting point for which CSP's or OP's ROE may be considered excessive (Cos. Ex. 5 at 13-42). Finally, AEP-Ohio advocates that the earnings for each year the SEET is applied should be adjusted to exclude the margins associated with OSS and accounting earnings for fuel adjustment clause deferrals for which the Companies will not have collected revenues (Cos. Ex. 2-A at 37-38; Cos. Ex. 6 at 16-17; Cos. Ex. 2 at 39-40).

OCC, OEG, and the Commercial Group each take issue with the development of the comparable firms and the threshold of significantly excessive earnings. Kroger and OCEA argue that the Companies' statistical process for determining when CSP and OP have earned significantly excessive earnings improperly shifts the burden of proof set forth in the statute from the company to other parties.

OCC witness Woolridge developed a proxy group of electric utilities to establish the business and financial risk indicators, then uses Value Line to develop a data base of companies with business and financial risk indicators within the range of the electric utility proxy group. Woolridge suggests computing the benchmark ROE for the comparable companies and adjusting the benchmark ROE for the capital structure of Ohio's electric utility companies and adjusting the benchmark by the FERC 150 basis points ROE adder to determine significantly excessive earnings (OCC Ex. 2 at 5-6, 20). AEP-Ohio argues that OCC's process is contrary to the language and spirit of Section 4928.143(F), Revised Code, as the statute requires the comparable firms include non-utility firms. The SEET proposed by OCC witness Woolridge results in the same comparable list of firms for each Ohio electric utility evaluated (Cos. Ex. 5-A at 5-6).

OEG proposes a method to establish the comparable group of firms by utilizing the entire list of publicly traded electric utilities in Value Line's Datafile,[40] and one group of non-utility firms. The comparable non-utility group is composed of Companies' with gross plant to revenue between 1.2 and 5.0, gross plant in excess of $1 billion and companies for which Value Line has a beta (OEG Ex. 4 at 4-6). OEG then calculates the difference in the average beta of electric utility group and the non-utility group and adjust it by the average historical risk premium for the period 1926 to 2008, which equals 7.0 percent to determine the adjustment to account for the reduced risk associated with utilities. Thus, for example, for the year 2007 OEG determined that the average non-utility earned return of 14.14 percent yields a risk-adjusted return of 12.82 percent. OEG then applies an adjustment to recognize the financial risk differences of AEP-Ohio to the utility and non-utility comparison groups. Finally, to determine the level at which earnings are "significantly excessive," OEG suggests an adder of the 200 basis points to encourage investments (OEG Ex. 4 at 7-9). OEG argues that the use of statistical confidence ranges as proposed by AEP-Ohio would severely limit any finding of excessive earnings as a two-tailed 95 percent confidence interval would mean that only 2.5 percent of all observations of all the sample company groups would be deemed to have excessive earnings. Further, OEG argues that as a statistical analysis the AEP-Ohio-proposed method eliminates most, if not all, of the Commission's flexibility to adjust to economic circumstances and determine whether the utility company's earnings are significantly excessive (OEG Ex. 4 at 9-10).

AEP-Ohio contends that OEG's SEET method fails to comply with the statutory requirements for the SEET, fails to control for financial risk of the comparable sample groups, fails to account for business risk and will, like the process proposed by OCC,

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40 OEG would eliminate one company with a significant negative return on equity for 2007.

produce the same comparable non-utility and utility group for each of the Ohio electric utilities (Cos. Ex. 5-A at 8-9).

The Commercial Group asserts that AEP-Ohio's proposed SEET methodology will produce volatile earned return on equity thresholds and, therefore, does not meet the primary objective of an ESP which is to stabilize rates and support the economic development of the state. Further, AEP-Ohio's SEET method, according to the Commercial Group, fails to compose a comparable proxy group with business risk similar to CSP and OP, including unregulated nuclear subsidiaries and deregulated generation subsidiaries. Thus, Commercial Group recommends a comparable group consist of publicly traded regulated utility companies as determined by the Edison Electric Institute (EEI). Commercial Group witness Gorman notes that using EEI's designated group of regulated entities and Value Lines earned return on common equity shows that the regulated companies had an average return on equity of approximately 9 percent for the period 2005 through 2008. Witness Gorman contends that over the period 2005 through 2008 and projected over the next 3 to 5 years, approximately 85 percent of the earned return on equity observations for the designated regulated electric utility companies will be at 12.5 percent return on equity or less. Therefore, Commercial Group recommends that the SEET test be based on the Commission-approved return on equity plus a spread of 200 basis points. Commercial Group witness Gorman reasons that the average risk, extreme risk and beta spread over AEP-Ohio's proxy group suggest that a 2 percent/200 basis points is a conservative determination of the excessive earnings threshold (Commercial Group Ex. 1 at 3, 12-17).

AEP-Ohio argues that the Commercial Group's proposed SEET fails to develop a comparable group as required by the SEET and ignores the fact that the rate of return is a forward-looking analysis and the SEET is retrospective. Thus, AEP-Ohio concludes that this method does not address the measurement of financial and business risk (Cos. Ex. 5-A at 9-10).

OCC opposes the exclusion of accounting earnings for fuel adjustment clause deferrals and the deduction of revenues associated withOSS, as OSS are not one-time write-offs or non-recurring items (OCC Ex. 2 at 21). OCC contends that revenues associated with the deferrals are reported during the same period with the Companies fuel-related expenses and to eliminate the deferrals, as AEP-Ohio proposes, would reduce the revenues for the period without deducting for the underlying expense (OCC Reply Br. 69-70). Similarly, Kroger proposes that AEP-Ohio credit the fuel adjustment clause for the margin generated by OSS and notes that AEP Corporation's West Virginia and Virginia electric distribution subsidiaries currently do so despite AEP-Ohio's assertion that such is in violation of federal law (Kroger Ex. 1 at 9).

Staff advocates a single SEET methodology for all electric distribution utilities as to the selection of comparable firms and, further, proposes a workshop or technical conference to develop the process to determine the "comparable group earnings" for the SEET. Staff witness Cahaan reasons that the SEET proposed by AEP-Ohio as a technical, statistical analysis, if incorrectly formulated shifts the burden of proof from the company to the other parties. Staff also contends that the Companies' SEET proposal is based upon a definition of significance which would create internal inconsistencies if applied to the statute. Further, Staff believes the "zone of reasonable" earnings can be framed by a return on equity with an adder in the range of 200 to 400 basis points. Further, Staff recognizes that if, as AEP-Ohio suggests, revenues from OSS are excluded from SEET, other adjustments would be required. Staff believes it would be unreasonable to predetermine those other adjustments as this time. Thus, Staff proposes that this proceeding determine the method of establishing the comparable group and specify the basis points that will be used to determine "significantly excessive earnings." Staff claims that under its proposed process, at the end of the year, the ROE of the comparable group could be compared to the electric utility's 10-K or FERC-1 and, if the electric utility's ROE is less than that of the sum of the comparable group's ROE plus the adder, it will be presumed that the electric utility's earnings were not significantly excessive. Further, Staff asserts that any party that wishes to challenge the presumption would be required to demonstrate otherwise. If, however, the electric utility's earned ROE is greater than the average of the comparable group plus the adder, the electric utility would be required to demonstrate that its earnings are not significantly excessive (Staff Ex. 10 at 8, 16, 19, 21-24, 26-27; Staff Br. at 27).

OCEA, OMA, and the Commercial Group recommend that the comparable firm process for the SEET be determined, as Staff proposes, as part of a workshop (OCEA Br. at 110; OMA Br. at 13; Commercial Group Br. at 9).

The Commission believes that the determination of the appropriate methodology for the SEET is extremely important. As evidenced by the extensive testimony in this case concerning the test, there are many different views concerning what is intended by the statute and what methodology should be utilized. However, as pointed out by several parties, whatever the ultimate determination of what the methodology should be for the test, the test itself will not be actually applied until 2010 and, as proposed by the Companies, will not commence until August 2010, after Compustat information is made publicly available (Cos. Ex. 5 at 11-12). Therefore, consistent with our opinion and order issued in the FirstEnergy ESP Case,[41] the Commission agrees with Staff that it would be wise to examine the methodology for the excessive earnings test set forth in the statute within the framework of a workshop. This is consistent with the Commission's finding that the goal of the workshop will be for Staff to develop a common methodology for the

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41 *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company,* Case No. 08-935-EL-SSO, Opinion and Order (December 19, 2008).

excessive earnings test that should be adopted for all of the electric utilities and then for Staff to report back to the Commission on its findings. Despite AEP-Ohio's assertions that FirstEnergy's ESP is no longer applicable since the FirstEnergy companies rejected the modified ESP, the Commission finds that a common methodology for significantly excessive earnings continues to be appropriate given that other ESP applications are currently pending and, even under AEP-Ohio's ESP application, the SEET information is not available until the July of the following year. Accordingly, the Commission finds that Staff should convene a workshop consistent with this determination. However, notwithstanding the Commission's conclusion that a workshop process is the method by which the SEET will be developed, we recognize that AEP-Ohio must evaluate and determine whether to accept the ESP as modified herein or reject the modified ESP and, therefore, require clarification of our decision as to OSS and deferrals (Cos. Reply Br. at 134). We find that a determination of the Companies' earnings as "significantly excessive" in accordance with Section 4928.143(F), Revised Code, necessarily excludes OSS and deferrals, as well as the related expenses associated with the deferrals, consistent with our decision regarding an offset to fuel costs for any OSS margins in Section III.A.1.b of this order. The Commission believes that deferrals should not have an impact on the SEET until the revenues associated with deferrals are received. Further, although we conclude that it is appropriate to exclude off-system sales from the SEET calculation, we do not wish to discourage the efficient use of OP's generation facilities and, to the extent that the Companies' earnings result from wholesale sources, they should not be considered in the SEET calculation.

VIII. MRO V. ESP

The Companies argue that "[t]he public interest is served if the ESP is more favorable in the aggregate than the expected results of an MRO" (Cos. Br. at 15). The Companies' further argue that the state policy set forth in Section 4928.02(A), Revised Code, is satisfied if the price for electric service, as part of the ESP as a whole, is more favorable than the expected results of an MRO (Id.). The Companies aver that not only is the SSO proposed under the ESP more attractive than the SSO resulting froman MRO, other non-SSO factors exist adding to the favorability of the ESP over the MRO (Cos. Ex. 2-A at 4, 8; Cos. Ex. 3 at 14-19). Specifically, AEP calculated the market price competitive benchmark for the expected cost of electricity supply for retail electric generation SSO customers in the Companies' service territories for the next three years as $88.15 per MWH for CSP and $85.32 per MWH for OP for full requirements service (Cos. Ex. 2-A at 5). These competitive benchmark prices were calculated by AEP using market data from the first five days of each of the first three quarters of 2008, and averaging the data (Id. at 15).

AEP-Ohio witness Baker then compared the ESP-based SSO with the MRO-based SSO, analyzing the following components: market prices for 2009 through 2011; the phase-in of the MRO over a period of time pursuant to Section 4928.142, Revised Code, at 10 percent, 20 percent, and 30 percent; the full requirements pricing components of the states of Delaware and Maryland; PJM costs; incremental environmental costs, POLR costs, and other non-market portions of an MRO-based SSO (Cos. Ex. 2-A at 3-17). AEP-Ohio witness Baker also considered non-SSO costs in the comparison, such as the distribution-related costs of $150 million for CSP and $133 million for OP (Id. at 16-17). AEP-Ohio concluded that the cost of the ESP is $1.2 billion and the cost of the MRO is $1.5 billion for CSP, while the cost of the ESP is $1.4 billion and the cost of the MRO is $1.7 billion for OP (Cos. Ex. 2-B, Revised Exhibit JCB-2). Therefore, AEP-Ohio states that the ESP for the Companies in the aggregate and for each individual company is clearly more favorable for customers, and would result in a net benefit to the customers under the ESP as compared to the MRO of $ 292 million for CSP and $262 million for OP (Id.; Cos. Br. at 135).

The Companies state that, in addition to the generation component, the ESP has other elements that, when taken in the aggregate, make the ESP considerably more favorable to customers than an MRO alternative (Cos. Ex. 2-A at 17-18). AEP-Ohio explains that the benefits in the ESP that are not available in an MRO, include: a shareholder-funded commitment focused on economic development and low-income customer assistance programs; price certainty and stability for generation service for a specified three-year period; and gridSMART and enhanced distribution reliability initiatives (Cos. Ex. 2-A at 17-18; Cos. Ex. 3 at 16-18; Cos. Br. at 135-137).

The Companies contend that once the Commission determines that the ESP is more favorable in the aggregate, then the Commission is required to approve the ESP. If the Commission determines that the ESP is not more favorable in the aggregate, then the Commission may modify the ESP to make it more favorable or it may disapprove the ESP application.

Staff states that, as a general principle, Staff believes that the Companies' proposed ESP is more favorable than what would be expected under an MRO (Staff Br. at 2). However, Staff explains that modifications to the proposed ESP are necessary to make the ESP reasonable (Id.). With Staff's proposed adjustments to the ESP rates, Staff witness Hess testified that the Companies' proposed ESP "results in very reasonable rates" (Staff Ex. 1 at 10). Furthermore, Staff witness Hess demonstrated, utilizing Staff witness Johnson's estimated market rates, that the ESP is more favorable in the aggregate as compared to the expected results of an MRO (Staff Ex. 1-A, Revised Exhibit JEH-1; Staff Br. at 26).

Several intervenors are critical of various components of AEP-Ohio's proposed ESP and thus conclude that the ESP, as proposed, is not more favorable in the aggregate and should be rejected or substantially modified, or that AEP-Ohio has failed to meet its burden of proof under the statute that the proposed ESP, in the aggregate, is more favorable than an MRO (OPAE Br. at 3, 22-23; OMA Br. at 3; Kroger Br. at 4; OHA Br. at 11; Commercial Group Br. at 2-3; OEG Br. at 2-3; Constellation Br. at 16-18). More specifically, OHA contends that the Commission must take into account all terms and conditions of the proposed ESP, not just pricing (OHA Br. at 8-9). OHA further explains that the Commission must weigh the totality of the circumstances presented in the proposed ESP with the totality of the expected results of an MRO (Id. at 9). OHA also states that the proposed ESP fails to mitigate the harmful effects of new regulatory assets, proposed deferrals, and rate increases on hospitals and, therefore, the ESP does not provide benefits that make it more favorable than a simple MRO (Id. at 11). IEU asserts that both the Companies' and Staff's comparison of the ESP to an MRO are flawed because the comparisons fail to reflect the projected costs of deferrals, assume the maximum blending percentages allowed under 4928.142, Revised Code, and fail to demonstrate the incremental effects of the maximum blending percentages on the FAC costs (IEU Br. at 33, citing Cos. Ex. 2-A, Staff Ex. 1, Exhibit JEH-1, Tr. Vol. XI at 78-82, and Tr. Vol. XIII at 87-88).

OCEA disputes the Companies' comparison of the ESP to the MRO, stating that the Companies have overstated the competitive benchmark prices (OCC Ex. 10 at 15; OCEA Br. at 19-24). Based on data from the fourth quarter 2008, and taking in consideration adjustments for load shaping and distribution losses, OCC calculates that the updated competitive benchmark prices should be $73.94 for CSP and $71.07 for OP (OCC Ex. 10 at 15-24). OCEA also questioned other underlying components of AEP witness Baker's comparison of the MRO to the ESP regarding the proposed ESP, as well as the exclusion of certain costs in the MRO calculation (Id. at 37-40). Nonetheless, OCEA ultimately concludes that AEP's ESP, if appropriately modified, is more favorable than an MRO (OCEA Br. at 19-24; OCC Ex. 10 at 39). Constellation also submits that the forward market prices for energy have fallen significantly since the Companies' filed their application and submitted their supporting testimony (Constellation Ex. 2 at 16).

Contrary to the position taken by Constellation and OCEA,[42] AEP-Ohio contends that the market price analysis supplied in support of the ESP does not need to be updated in order for the Commission to determine whether the ESP is more favorable that the expected result of the MRO. Furthermore, AEP-Ohio responds that the appropriate method is to look over a longer period of time, and not just focus on the recent decline in forward market prices. (Cos. Reply Br. at 130-131).

Contrary to arguments raised by various intervenors, AEP-Ohio avers that the legal standard to approve the ESP is not whether the Commission can make the ESP even more favorable, whether the rates are just and reasonable, whether the costs are prudently

[42] Constellation Br. at 17; OCEA Br. at 19-24.

incurred, whether the plan provisions are cost-based, or whether each provision of the plan is more favorable than an MRO (Cos. Reply Br. at 1-6). The Companies contend that the Commission only has authority to modify a proposed ESP if the Commission determines that the ESP is not more favorable than the expected results of an MRO (Id. at 4). As some intervenors have recognized,[43] the Commission does not agree that our authority to make modifications is limited to an after-the-fact determination of whether the proposed ESP is more favorable in the aggregate. Rather, the Commission finds that our statutory authority includes the authority to make modifications supported by the evidence in the record in this case. Based upon our opinion and order and using Staff witness Hess' methodology of the quantification of the ESP v. MRO comparison, as modified herein, we believe that the cost of the ESP is $673 million for CSP and $747 million for OP, and the cost of the MRO is $1.3 billion for CSP and $1.6 billion for OP.

Accordingly, upon consideration of the application in this case and the provisions of Section 4928.143(C)(1), Revised Code, the Commission finds that the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, as modified by this order, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

IX. CONCLUSION

The Commission believes that it is essential that the plan we approve be one that provides rate stability for the Companies, provides future revenue certainty for the Companies, and affords rate predictability for the customers. Upon consideration of the application in this case and the provisions of Section 4928.143(C)(1), Revised Code, the Commission finds that the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, as modified by this order, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. Therefore, the Commission finds that the proposed three-year ESP should be approved with the modifications set forth in this order. To the extent that intervenors have proposed modifications to the Companies' ESP that have not been addressed by this opinion and order, the Commission concludes that the requests for such modifications are denied.

Furthermore, the Commission finds that the Companies' should file revised tariffs consistent with this order, to be effective with bills rendered January 1, 2009. In light of the timing of the effective date of the tariffs, the Commission finds that the revised tariffs shall be approved upon filing, effective January 1, 2009, as set forth herein, and contingent upon final review by the Commission.

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[43] OEG Br. at 3.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

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

(2) On July 31, 2008, CSP and OP filed applications for an SSO in accordance with Section 4928.141, Revised Code.

(3) On August 19, 2008, a technical conference was held regarding AEP-Ohio's applications and on November 10, 2008, a prehearing conference was held in these matters.

(4) On September 19, 2008, and October 29, 2008, intervention was granted to: OEG; OCC; Kroger; OEC; IEU-Ohio; OPAE; APAC; OHA; Constellation; Dominion; NRDC; Sierra; NEMA; Integrys; Direct Energy; OMA; OFBF; Wind Energy; OASBO/OSBA/BASA; Ormet; Consumer Powerline; Morgan Stanley Capital Group Inc.; Commercial Group; EnerNoc, Inc.; and AICUO.

(5) The hearing in these proceedings commenced on November 17, 2008, and concluded on December 10, 2008. Eleven witnesses testified on behalf of AEP-Ohio, 22 witnesses testified on behalf of various intervenors, and 10 witnesses testified on behalf of the Commission Staff.

(6) Five local hearings were held in these matters at which a total of 124 witnesses testified.

(7) Briefs and reply briefs were filed on December 30, 2008, and January 14, 2009, respectively.

(8) AEP-Ohio's applications were filed pursuant to Section 4928.143, Revised Code, which authorizes the electric utilities to file an ESP as their SSO.

(9) The proposed ESP, as modified by this opinion and order, 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 Companies' application for approval of an ESP, pursuant to Sections 4928.141 and 4928.143, Revised Code, be modified and approved, to the extent set forth herein. It is, further,

ORDERED, That the Companies file their revised tariffs consistent with this opinion and order and that the revised tariffs be approved effective January 1, 2009, on a bills-rendered basis, contingent upon final review and approval by the Commission. It is further,

ORDERED, That each company is authorized to file in final form four complete, printed copies of its tariffs consistent with this opinion and order, and to cancel and withdraw its superseded tariffs. The Companies shall file one copy in this case docket and one copy in each Company's TRF docket (or may make such filing electronically, as directed in Case No. 06-900-AU-WVR). The remaining two copies shall be designated for distribution to Staff. It is, further,

ORDERED, That the Companies notify all affected customers of the changes to the tariff via bill message or bill insert within 45 days of the effective date of the tariffs. A copy of this customer notice shall be submitted to the Commission's Service Monitoring and Enforcement Department, Reliability and Service Analysis Division at least 10 days prior to its distribution to customers. It is, further, ORDERED, That a copy of this opinion and order be served on all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

KWB/GNS:vrm/ct

Entered in the Journal

MAR 18 2009

Reneé J. Jenkins
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

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

CONCURRING OPINION OF CHAIRMAN ALAN R. SCHRIBER

AND COMMISSIONER PAUL A. CENTOLELLA

We agree with the Commission's decision and write this concurring opinion to express additional rationales supporting the Commission's decision in two areas.

gridSMART Rider

The Order sets the initial amount to be recovered through the gridSMART rider based on the availability of federal matching funds for smart grid demonstrations and deployments under the American Recovery and Reinvestment Act of 2009. AEP-Ohio should promptly take the necessary steps to apply for available federal funding. Additionally, AEP-Ohio should work with staff and the collaborative established under the Order to refine its Phase 1 plan and initiate deployments in a timely and reasonable manner.

The foundation of a smart grid is an open-architecture communications system which, first, provides a common platform for implementing distribution automation, advanced metering, time-differentiated and dynamic pricing, home area networks, and other applications and, second, integrates these applications with existing systems to improve reliability, reduce costs, and enable consumers to better control their electric bills.

These capabilities can provide significant consumer and societal benefits. In the near term, participating consumers will have new capabilities for managing their energy usage to take advantage of lower power costs and reduce their electric bills. AEP-Ohio will be able to provide consumers feedback regarding their electric usage patterns and improved customer service. And, the combination of distribution automation and advanced metering should enable AEP-Ohio to rapidly locate damaged and degraded distribution equipment, reduce outages, and minimize the duration of any service interruptions. We expect that consumers will experience a material improvement in service and reliability.

SB 221 made it state policy to encourage time-differentiated pricing, implementation of advanced metering infrastructure, development of performance standards and targets for service quality for all consumers, and implementation of distributed generation. Section 4928.02 of the Revised Code. The Commission's Order advances these policies.

AEP-Ohio and its customers are likely to face significant challenges over the next decade from rising costs, requirements for improved reliability, and environmental constraints. Our Order will enable AEP-Ohio to take a first step in developing a modern grid capable of providing affordable, reliable, and environmentally sustainable electric service into the future.

PJM Demand Response Program

First, we wish to emphasize that the Commission supports demand response initiatives.

Second, it is essential that consumers benefit from demand response in terms of a reduction in the capacity for which AEP-Ohio customers are responsible. We encourage AEP-Ohio to work with PJM, the Commission, and interested stakeholders to ensure that predictable consumer demand response is recognized as a reduction in capacity that it must carry under PJM market rules.

Finally, consumers should have the opportunity to see and respond to changes in the cost of the power that they use. While an ESP may set the overall level of prices, consumers should have additional opportunities to benefit by reducing consumption when wholesale power prices are high. We would encourage the companies to work with staff to develop additional dynamic pricing options for commercial and industrial SSO customers who have the interval metering needed to support such rates. Such options should enable eligible consumers to directly manage risk and optimize their energy usage.

Alan R. Schriber

Paul A. Centolella

KWalton

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KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 1,273,337,766	$ 540,800,594	$ 137,576,878	$ 13,621,067	$ 182,715,055	$ 42,601,255
Production Demand - Inter	TPIS	PLPPDI	PPWDA	1,200,347,179	509,800,686	129,690,661	12,840,277	172,241,417	40,159,255
Production Demand - Peak	TPIS	PLPPDP	PPSDA	1,232,764,839	523,568,824	133,193,204	13,187,053	176,893,124	41,243,832
Production Energy - Base	TPIS	PLPPEB	E01	-	-	-	-	-	-
Production Energy - Inter	TPIS	PLPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TPIS	PLPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		PLPPT		$ 3,706,449,784	$ 1,574,170,104	$ 400,460,743	$ 39,648,397	$ 531,849,597	$ 124,004,341
					42.5%	10.8%	1.1%	14.3%	3.3%
Transmission Plant									
Transmission Demand - Base	TPIS	PLTRB	PPBDA	$ 190,095,928	$ 80,735,837	$ 20,538,780	$ 2,033,482	$ 27,277,435	$ 6,359,919
Transmission Demand - Inter	TPIS	PLTRI	PPWDA	179,199,201	76,107,877	19,361,451	1,916,918	25,713,831	5,995,354
Transmission Demand - Peak	TPIS	PLTRP	PPSDA	184,038,817	78,163,315	19,884,344	1,968,688	26,408,282	6,157,270
Total Transmission Plant		PLTRT		$ 553,333,946	$ 235,007,030	$ 59,784,574	$ 5,919,088	$ 79,399,548	$ 18,512,543
Distribution Poles									
Specific	TPIS	PLDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TPIS	PLDSG	NCPS	$ 151,352,471	$ 68,463,183	$ 20,989,527	$ 1,976,633	$ 23,177,701	$ 5,780,228
Distribution Primary & Secondary Lines									
Primary Specific	TPIS	PLDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPL	245,135,885	110,885,424	33,995,390	3,201,425	37,539,435	9,361,865
Primary Customer	TPIS	PLDPLC	YECust08	350,863,155	279,111,448	54,551,770	427,406	3,740,302	198,082
Secondary Demand	TPIS	PLDSLD	SICD	43,259,274	29,629,670	6,885,290	404,270	5,316,036	-
Secondary Customer	TPIS	PLDSLC	YECust07	61,917,027	49,298,390	9,635,271	75,491	660,635	-
Total Distribution Primary & Secondary Lines		PLDLT		$ 701,175,341	$ 468,924,932	$ 105,067,720	$ 4,108,592	$ 47,256,409	$ 9,559,947
Distribution Line Transformers									
Demand	TPIS	PLDLTD	SICD	$ 152,261,334	$ 104,288,691	$ 24,234,419	$ 1,422,926	$ 18,711,058	$ -
Customer	TPIS	PLDLTC	YECust07	130,279,646	103,728,766	20,273,578	158,841	1,390,043	-
Total Line Transformers		PLDLTT		$ 282,540,980	$ 208,017,456	$ 44,507,997	$ 1,581,766	$ 20,101,101	$ -
Distribution Services									
Customer	TPIS	PLDSC	C02	$ 87,334,885	$ 41,520,074	$ 27,249,219	$ 130,064	$ 1,495,512	$ -
Distribution Meters									
Customer	TPIS	PLDMC	C03	$ 69,210,278	$ 43,430,580	$ 15,833,937	$ 370,036	$ 4,646,207	$ 1,705,268
Distribution Street & Customer Lighting									
Customer	TPIS	PLDSCL	YECust04	$ 101,650,880	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 27,308,406	$ 212,382,992	$ 86,993,421	$ 27,261,917	$ 2,020,348	$ 657	$ 55,177
Production Demand - Inter	TPIS	PLPPDI	PPWDA	25,743,027	200,208,721	82,006,762	25,699,202	1,904,537	619	52,014
Production Demand - Peak	TPIS	PLPPDP	PPSDA	26,438,266	205,615,739	84,221,511	26,393,258	1,955,973	636	53,419
Production Energy - Base	TPIS	PLPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter	TPIS	PLPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TPIS	PLPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		PLPPT		$ 79,489,699	$ 618,207,452	$ 253,221,693	$ 79,354,378	$ 5,880,858	$ 1,913	$ 160,609
				2.1%						
Transmission Plant										
Transmission Demand - Base	TPIS	PLTRB	PPBDA	$ 4,076,858	$ 31,706,546	$ 12,987,202	$ 4,069,917	$ 301,617	$ 98	$ 8,237
Transmission Demand - Inter	TPIS	PLTRI	PPWDA	3,843,163	29,889,055	12,242,747	3,836,620	284,327	92	7,765
Transmission Demand - Peak	TPIS	PLTRP	PPSDA	3,946,955	30,696,266	12,573,385	3,940,236	292,006	95	7,975
Total Transmission Plant		PLTRT		$ 11,866,975	$ 92,291,867	$ 37,803,334	$ 11,846,773	$ 877,950	$ 286	$ 23,977
Distribution Poles										
Specific	TPIS	PLDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TPIS	PLDSG	NCPS	$ 3,428,302	$ 26,364,477	$ -	$ -	$ 1,166,261	$ 379	$ 5,781
Distribution Primary & Secondary Lines										
Primary Specific	TPIS	PLDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPL	5,552,600	42,700,851	-	-	1,888,918	614	9,363
Primary Customer	TPIS	PLDPLC	YECust08	91,065	111,006	-	-	12,578,235	665	53,176
Secondary Demand	TPIS	PLDSLD	SICD	803,610	-	-	-	219,134	71	1,193
Secondary Customer	TPIS	PLDSLC	YECust07	16,084	-	-	-	2,221,646	117	9,392
Total Distribution Primary & Secondary Lines		PLDLT		$ 6,463,359	$ 42,811,857	$ -	$ -	$ 16,907,933	$ 1,468	$ 73,125
Distribution Line Transformers										
Demand	TPIS	PLDLTD	SICD	$ 2,828,496	$ -	$ -	$ -	$ 771,296	$ 251	$ 4,198
Customer	TPIS	PLDLTC	YECust07	33,843	-	-	-	4,674,566	247	19,762
Total Line Transformers		PLDLTT		$ 2,862,340	$ -	$ -	$ -	$ 5,445,861	$ 498	$ 23,961
Distribution Services										
Customer	TPIS	PLDSC	C02	$ 27,712	$ -	$ -	$ -	$ 16,840,023	$ 1,088	$ 71,194
Distribution Meters										
Customer	TPIS	PLDMC	C03	$ 174,701	$ 1,233,917	$ 1,678,362	$ 61,662	$ -	$ 1,138	$ 74,470
Distribution Street & Customer Lighting										
Customer	TPIS	PLDSCL	YECust04	$ -	$ -	$ -	$ -	$ 101,650,880	$ -	$ -

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Kentucky Utilities Company
Meters Account 370
Determination of Meter Cost Allocation

Rate Class	Meter Unit Cost	13-mo Avg Number of Customers	Year-End Customers	Total Meter Cost	Meters Allocator
Residential	$ 62	420,348	419,902	$ 25,848,067	0.627516
General Service Secondary	$ 115	82,102	82,069	$ 9,423,698	0.228780
All Electric Schools	$ 343	640	643	$ 220,230	0.005347
Power Service Secondary	$ 491	5,633	5,627	$ 2,765,228	0.067132
Power Service Primary	$ 3,406	297	298	$ 1,014,904	0.024639
Time of Day Secondary	$ 759	137	137	$ 103,975	0.002524
Time of Day Primary Lines	$ 4,397	166	167	$ 734,376	0.017829
Time of Day Primary Substation	$ 4,397	-	-	$ -	0.000000
Retail Transmission Service	$ 28,540	36	35	$ 998,891	0.024250
Fluctuating Load Service	$ 36,699	1	1	$ 36,699	0.000891
Outdoor Lighting Rate ST & PO	$ -	169,645	170,307	$ -	0.000000
Lighting Energy Rate LE	$ 62	11	11	$ 677	0.000016
Traffic Lighting Rate TLE	$ 62	674	720	$ 44,321	0.001076
Total		679,690	679,917	$ 41,191,067	1.000000

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Table 8.(4)(a)-1
Kentucky Utilities Company / Louisville Gas and Electric Company
Resource Assessment and Acquisition Plan
Resource Capacity Available (MW)
At Summer Peak

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Forecasted Peak Load		7,278	7,364	7,450	7,536	7,623	7,663	7,721	7,780	7,839	7,893	7,948	8,003	8,059	8,115	8,171
Peak Reductions																
Existing DSM		275	275	275	275	275	275	275	275	275	275	275	275	275	275	275
Cumulative Incremental DSM		30	60	90	119	148	130	130	130	130	130	130	130	130	130	130
Total Demand	6,434	6,972	7,028	7,085	7,142	7,199	7,257	7,315	7,374	7,433	7,488	7,542	7,598	7,653	7,709	7,766
Capacity From:																
Existing Resources	7,918	7,904	7,876	7,859	7,859	7,859	7,859	7,859	7,859	7,859	7,859	7,859	7,859	7,859	7,859	7,859
Planned Resources	0	0	640	649	649	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,520	1,520	1,721	1,721
Firm Purchase (OVEC)	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155
Firm Purchases Non-Utility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Committed Capacity Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Retirements	0	0	724	724	724	724	724	724	724	724	724	724	724	724	724	724
Curtailable Customers	0	128	131	131	131	131	131	131	131	131	131	131	131	131	131	131
Total Supply*	8,073	8,187	8,078	8,070	8,070	8,740	8,740	8,740	8,740	8,740	8,740	8,740	8,941	8,941	9,142	9,142
16% Reserve Requirements	1,029	1,116	1,125	1,134	1,143	1,152	1,161	1,170	1,180	1,189	1,198	1,207	1,216	1,225	1,233	1,243
Excess (Deficit)	610	99	-75	-149	-215	389	322	254	186	118	54	-9	128	63	199	133
Reserve Margin (%)	25.5%	17.4%	14.9%	13.9%	13.0%	21.4%	20.4%	19.5%	18.5%	17.6%	16.7%	15.9%	17.7%	16.8%	18.6%	17.7%

* Table 8.(4)(a)-1 excludes any capacity additions for 2015 through 2017 as these additions have not been identified.
Note: In the peak demand forecast, DSM is applied using a mid-year methodology rather than a calendar-year methodology.
Note: 2013 peak load is from actual peak on 9/10/2013

Table 8.(4)(a)-2
Kentucky Utilities Company / Louisville Gas and Electric Company
Resource Assessment and Acquisition Plan
Resource Capacity Available (MW)
At Winter Peak

	2013/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
Forecasted Peak Load		6,176	6,266	6,307	6,356	6,429	6,449	6,532	6,551	6,583	6,612	6,650	6,708	6,779	6,809	6,825
Peak Reductions																
Existing DSM		141	141	141	141	141	141	141	141	141	141	141	141	141	141	141
Cumulative Incremental DSM		13	33	54	74	95	72	72	72	72	72	72	72	72	72	72
Total Demand	7,114	6,022	6,091	6,112	6,141	6,193	6,235	6,318	6,337	6,369	6,398	6,436	6,494	6,565	6,595	6,612
Capacity From:																
Existing Resources	7,977	7,941	7,912	7,906	7,906	7,906	7,906	7,906	7,906	7,906	7,906	7,906	7,906	7,906	7,906	7,906
Planned Resources	0	0	657	657	657	1,314	1,314	1,314	1,314	1,314	1,314	1,314	1,534	1,534	1,754	1,754
Firm Purchase (OVEC)	161	161	161	161	161	161	161	161	161	161	161	161	161	161	161	161
Firm Purchases Non-Utility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Committed Capacity Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Planned Retirements	0	0	732	732	732	732	732	732	732	732	732	732	732	732	732	732
Curtailable Customers	0	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131
Total Supply*	8,138	8,233	8,129	8,123	8,123	8,780	8,780	8,780	8,780	8,780	8,780	8,780	9,000	9,000	9,220	9,220
16% Reserve Requirements	1,138	1,116	1,125	1,134	1,143	1,152	1,161	1,170	1,180	1,189	1,198	1,207	1,216	1,225	1,233	1,243
Excess (Deficit)	-114	1,096	913	878	839	1,435	1,384	1,292	1,263	1,221	1,184	1,137	1,290	1,210	1,391	1,365
Reserve Margin (%)	14.4%	36.7%	33.5%	32.9%	32.3%	41.8%	40.8%	39.0%	38.6%	37.9%	37.2%	36.4%	38.6%	37.1%	39.8%	39.4%

* Table 8.(4)(a)-2 excludes any capacity additions for 2015 through 2017 as these additions have not been identified.
Note: In the peak demand forecast, DSM is applied using a mid-year methodology rather than a calendar-year methodology.
Note: 2013/14 winter peak load is from actual peak on 1/6/2014

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Cost Recovery Mechanisms for Smart Grid Investment.p
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Cost Recovery Mechanisms for Smart Grid Investment

Carl Peterson
Center for Business and Regulation
University of Illinois Springfield

Introduction

- Regulatory concepts for cost recovery
- Are smart grid investments different from other utility investments?
- Types of cost recovery mechanisms
  - Post test year
  - Test year
- Conclusions
  - How do cost mechanisms map to regulatory concepts?

Regualtory Concepts

- **Prudency of investments:** This can be broken down into **decisional prudence** i.e., was the decision to invest in smart grid reasonable given information known at the time and **operational prudence** i.e., did the utility build and deploy the investments in a timely and reasonable manner.
- **Used and useful**: Investments must be useful for the purpose it was intended once recovery of costs begin.
- **Equity in allocation of costs and risks** refers to the amount of risk (and in turn, cost) each side to the bargain must bear. Typically utility investments are undertaken as a need is identified and the cost to address that need is minimized.
- **Single Issue Ratemaking:** Utilities are generally required to "net" all costs and benefits of operation at the time rates are set to avoid cherry picking individual cost increases that may be offset by other cost decreases.
- **Regulatory lag:** This is the key incentive under traditional regulation for utilities to maintain efficient operation. Regulatory lag comes in two forms. The **administrative lag** refers to the time required to set rates. The **economic lag** refers to the time between rate setting procedures.

Additional Concepts for Smart Grid Investments

- Do the investments meet energy policy objectives for the state?
- Do the investments create a lasting value for consumers?
- Are the elements of the deployment plan reasonable for meeting energy policy objectives in a timely and cost effective manner?
- Does the process provide sufficient oversight and monitoring of deployment?

Are smart grid investments different?

- Replacing existing assets
- Uncertainties surrounding the business case
- The investment stream of costs and benefits may be substantially different from traditional utility investments.
- Public policy
- Smart grid investments are currently discretionary
- Smart grid investments require some public planning and monitoring

Types of Cost Recovery Mechanisms

- **Post test year ratemaking** includes any mechanism that adjusts rates outside the test year. This might include cost trackers, energy balancing accounts, certain types of surcharge mechanisms, some forms of performance based regulation.
- **Test year ratemaking** only allows cost and benefits to be changed within a test year (whether that is future, historic, or some combination of the two). These mechanisms include traditional regulation, regulatory assets, and some forms of performance based regulation.
- This dichotomy represents the two extremes of ratemaking for smart grid investment. One side the test-year based traditional ratemaking on the end of the spectrum is energy balancing accounts which track costs and revenues on a periodic (e.g., monthly) basis. All of the other mechanism fall somewhere between these two.

Post test year ratemaking
Energy balancing accounts

- Accounting mechanism that tracks the total revenue and cost for the project and records the net.
- Typically these mechanisms attempt to account for all revenues and costs associated with smart grid investments.
- Prudence often uses pre-approved through a planning docket that identifies the types of investments to be recovered
- After-the-fact reviews only occur in the case of excess expenditure
- Monitoring occurs through monthly reporting of the balancing account, but prudence reviews are limited to the accounting for costs.

Comments and examples

- This mechanism provides timely recovery of costs (at least those cost deemed appropriate for recovery).
- Prudency review is done prior to investment which removes the risk of after the fact reviews.
- Planning process can be significant and must be done for each set of smart grid costs.
- Example: Southern California Edison's SmartConnect program ($1.6B in smart meters and other AMI investment) First installations in fall 2009.

Post test year ratemaking
Surcharges/Riders

- Riders or surcharges can be devised in several different ways. The two main methods are **temporary surcharges** and **true-up riders**. Both of these mechanisms often begin with a forecast or a budget for capital and O&M annual amounts (and estimated savings).

Post test year ratemaking
Surcharges/Riders

- **Revenue level:** Typically these mechanisms attempt to account for all revenues and costs associated with smart grid investments.
- **Oversight:** Decisional prudence is often pre-approved, although operational prudence may be questioned in the following rate case.
- **Monitoring:** Monitoring occurs through annual or semiannual reporting. True-ups general occur annually.

Comments and examples

- Temporary Surcharges and true-up riders often differ in intent. For example, the temporary surcharge may be used to “get over the hump” of large meter investment.
- True-up riders may be aimed at longer term investments programs.
  - In place: Portland General Electric Smart Meter program (temporary surcharge); Oklahoma Gas and Electric (true up rider for Norman Smart City program);
  - Proposed: National Grid in New York (Surcharge); BG&E in Maryland (True up)

Post test year ratemaking
Performance based regulation

- **Targeted** programs are those that address performance standards either within traditional regulation or as part of one of the other methods of cost recovery.
  - TURN proposed a penalty mechanism for application to recovery of AMI costs for SCE. The CPUC ultimately decided against using such a method.
  - Investment milestones with tightened system reliability targets. Duke Energy in Ohio has a rider mechanism that includes milestone reporting and tightened reliability metrics. If milestones are met, but reliability is not, deployment can be stopped.

Post test year ratemaking
Performance based regulation

- **Comprehensive.**
  - **earnings sharing mechanisms** – often combined with traditional regulation e.g., PSCO “Smart City” program
  - **price (revenue) caps**, and
  - **multi-year rate plans**

Test Year Ratemaking

- **Traditional Regulation:** utilities propose investment in rate case with an up or down by the utility.
- **Regulatory Assets:** Costs and benefits are collected and accounted for by the utility, but not recovered until future rate case. This is proposed by the MD staff for the BG&E smart grid plan.

Conclusions

- Cost recovery mechanisms are as diverse as the states that use them.
- Some mechanisms include performance and review standards that exceed the standards applied in traditional regulation; others have been implemented to provide incentives for smart grid investment.

Conclusions

- Objectives matter: the problem being solve tends to dictate the solution.
- Post test year mechanisms appear to provide stronger oversight, monitoring, and timely cost recovery and can be designed to address particular issues (e.g., reliability issues) and recognize that smart grid investments are different that other utility investments.
- Test year based methods rely more on the traditional after the fact review and regulatory lag incentives and assume that any cost effective investment will be undertaken by the utility.

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Louisville Gas and Electric Company
Determination of Meter Allocation

	Meter Unit Cost	Forecasted Number of Customers	Total Meter Cost	Meters Allocator
Residential Rate RS	$ 63.93	364,109	$ 23,276,598	0.699920
General Service Rate GS	$ 151.28	45,237	$ 6,843,453	0.205780
Power Service Primary	$ 3,700.06	72	$ 266,404	0.008011
Power Service Secondary	$ 651.86	2,824	$ 1,840,954	0.055357
TOD Primary	$ 3,954.16	106	$ 417,164	0.012544
TOD Secondary	$ 702.69	276	$ 193,943	0.005832
Retail Transmission Service	$ 26,250.55	13	$ 341,257	0.010261
Special Contract #1	$ 3,954.16	1	$ 3,954	0.000119
Special Contract #2	$ 3,954.16	1	$ 3,954	0.000119
Street Lighting Rate (RLS, LS, DSK)	$ -	86,402	$ -	0.000000
Traffic Lighting Rate TLE	$ 63.93	165	$ 10,548	0.000317
Street Lighting Rate TLE	$ 63.93	905	$ 57,854	0.001740
		500,111	$ 33,256,085	1.000000
Total - per Plant Accounting			$ 39,970,580	

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AEP Application Case 14-192.pdf
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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application	)	
of Ohio Power Company	)	**Case No. 14-0192-EL-RDR**
to update its gridSMART Rider rates.	)	

APPLICATION

1. Ohio Power Company ("AEP Ohio" or the "Company) is an electric light company, as that term is defined in §§4905.03 and 4928.01(A) (7), Ohio Rev. Code.

2. In AEP Ohio's 2008 Electric Security Plan proceedings (*ESP I*) the Company proposed and was granted approval for gridSMART Phase I, a smart grid deployment program within AEP Ohio's service territory. In its Opinion and Order in the *ESP I* case, the Commission authorized AEP Ohio to establish a gridSMART rider, subject to annual reconciliation.[1]

3. By Order issued on August 8, 2012, the Commission approved, with certain modifications, AEP Ohio's modified *ESP II* application which included the continuation of the current gridSMART rider mechanism, subject to annual true-up and reconciliation based on the Company's prudently incurred costs.[2]

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[1] *In re AEP Ohio ESP I*, Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, Opinion and Order (March 18, 2009), at 37-38. A complete recounting of the gridSMART rider approval process was included in AEP Ohio's initial application to update its gridSMART rider, filed in Case No. 10-164-EL-RDR on February 11, 2010, and a subsequent amendment filed on July 21, 2010. On August 11, 2010, the Commission issued its Finding and Order in that case approving the gridSMART rider as a fixed monthly, per-bill charge.

[2] *In re AEP Ohio ESP II*, Case Nos. 11-346-EL-SSO et al., Opinion and Order (August 8, 2012) at 61-63.

4. On February 1, 2013, AEP Ohio filed its most recent application to update its gridSMART rider rates in Case No. 13-345-EL-RDR. During 2013, the Commission Staff conducted an audit of this docket and issued comments on August 2, 2013. The Company issued reply comments on August 23, 2013. As of the time of this filing, the Commission has not issued an order in the 13-345-EL-RDR docket. Therefore, the gridSMART rider rates approved by the Commission's December 12, 2012 Entry in case number 12-509-EL-RDR, which commenced with the first billing cycle of January 2013, remain in effect.

5. The Company hereby submits its 2014 gridSMART rider update application, reflecting actual project spending and recovery in 2013 and projected spending and revenue requirements through 2014.

6. As shown on Attachment 1, actual 2013 expenditures for the gridSMART program exceeded actual 2013 collections under the rider, resulting in an under recovery for 2013 of $12,209,432. Offsetting last year's under recovery with past years' net over recovery results in an under recovery to date of $10,225,704.

7. In the October 3, 2012, Opinion and Order in Case No. 12-509-EL-RDR, the Commission directed the Company to defer certain community energy storage charges to a future period. Those changes are included in this filing.

8. Attachment 2 contains a summary of gridSMART Phase 1 expense information and Attachment 3 contains the detail by project of gridSMART Phase 1 expenditures. The itemized detail for each charge and reimbursement

to date has been provided to the Commission Staff in each year of the audit as Staff 3-1 Attachment 1 and Staff 4-1 Attachment 1 for the 2009 expenditures, Staff 3-1 Attachment 1 for the 2010 expenditures, Staff 1-1 Attachment 1 for the 2011 expenditures and Staff 2-1 for the 2012 expenditures. The following table summarizes the data as ordered by Pacific Northwest National Laboratory (PNNL) expense, company expense and vendor in-kind contribution, as well as designation by the source of recovery of the expense (*e.g.*, American Recovery and Reinvestment Act or gridSMART rider).

Summary of AEP Ohio gridSMART Project Spend to Date

1	Total Expense (excludes 108 removal)	$	124,241,678
2	GS Reimbursements (ARRA funding)	$	(63,650,501)
3	Net	$	60,591,177
4	Remove Internal Labor	$	(4,732,462)
5	Add Incremental Labor	$	1,127,755
6	Add Loss on Removal of Meters	$	1,655,407
7	Recovered through GS Rider	$	58,641,877
8	Vendor In Kind	$	10,839,825
9	AEP In Kind	$	1,722,876
10	PNNL*	$	1,134,312
11	Total gridSMART Cost to date	$	137,938,691
12	Total ARRA to date	$	(63,650,501)
13	Total Rate Payer to date	$	58,641,877

* The Department of Energy reimburses the PNNL directly, so the Company is only providing the latest funds it has received. These funds are not requested in the gridSMART rider, nor does the Company receive any detail behind these expenditures.

9. Attached as Attachment 4 are revised tariff sheets 484-1 and 484-1D, reflecting the revised gridSMART Rider rates.

10. Because the authority to make this filing stems from the Commission's directives in the *ESP II* proceeding, AEP Ohio does not believe a hearing in this matter is necessary.

11. AEP Ohio's gridSMART rider has been previously approved as just and reasonable and is authorized as part of its current electric security plan. Therefore, AEP Ohio requests that the Commission approve this application.

Respectfully submitted,

/s/ Yazen Alami

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Counsel for Ohio Power Company

Attachment 1

2014 Ohio Power Company gridSMART Rider True-Up
Case No. 14-0192-EL-RDR

Line No.	2013 Over/(Under) Recovery		2013 Actual Spending	2013 Actual Carrying Charge	2013 Actual Revenue Requirement
1	O&M		$ 2,276,840		$ 2,276,840
2	Capital - 5 Year Life		$ 2,857,383	$ 6,056,646	$ 6,056,646
3	Capital - 7 Year Life		$ 3,261,405	$ 3,782,144	$ 3,782,144
4	Capital - 10 Year Life		$ (684,215)	$ 170,962.52	$ 170,963
5	Capital - 15 Year Life		$ 352,599	$ 23,417	$ 23,417
6	Capital - 30 Year Life		$ 97,619	$ 2,070,545	$ 2,070,545
7	Capital - 35 Year Life		$ 910	$ 66,957	$ 66,957
8	Capital - 40 Year Life		$ 187,690	$ 230,109	$ 230,109
9	Total Capital		$ 6,073,391	$ 12,400,780	$ 12,400,780
10	Total			2013 Actual Revenue Requirement	$ 14,677,620
11				2013 gridSMART Rider Collections	$ 2,468,188
12				2013 Over/(under) Recovery	$ (12,209,432)

Line No.	AEP Ohio- gridSMART 2014 Incremental Investment	2014 Estimated gridSMART Spending (a)			Carrying Charge Rate	2014 gridSMART Revenue Requirement
13	O&M	2,211,483				$ 2,211,483
14	Capital - 5 Year Life	-			31.29%	$ -
15	Capital - 7 Year Life	-			26.54%	$ -
16	Capital - 10 Year Life	-			21.07%	$ -
17	Capital - 15 Year Life	-			18.14%	$ -
18	Capital - 30 Year Life	-			14.95%	$ -
19	Capital - 35 Year Life	-			14.51%	$ -
20	Capital - 40 Year Life	-			14.19%	$ -
21	Total Capital	-		2014 Revenue Requirement		$ 2,211,483
22				Credit RR Captial Carrying Charge Adj		$ (7,324,644)
23				O&M Reclass		$ 12,305,642
24				Capital Carrying Costs		$ 9,878,514
25				Over/(Under) Recovery to Date		$ 1,983,728
26				Over/(Under) Recovery (From Above)		$ (12,209,432)
27			December 31, 2013 Base Distribution Rev	Total 2013 Revenue Requirement		$ 27,296,700
28		Residential	$ 392,898,753	Residential Revenue Requirement		$ 16,896,434
29		Non-Residential	$ 241,841,069	Non-Res Revenue Requirement		$ 10,400,266
30				Residential Customers @12/31/213	1,273,602	13.27
31				Non-Residential Customers @12/31/213	187,382	55.5
32				Residential Customers	Monthly Rate	$ 1.11
33				Non-Residential Customers	Monthly Rate	$ 4.63

(a) Estimated 2014 gridSMART O&M spending (Capital Spending ended at 12/31/2013)
(b) Captial Projects Reclassed to O&M. Carrying Charges credited from inception
(c) Capital Projects Reclassed to O&M
(d) Annual carrying charge rate times actual capital spending as of 12/31/2013 (Includes Reduced Carrying Charges for Captial Reclassed to O&M)
(e) gridSMART Over Recovery to date $1,983,728 (Actual 2009 over recovery of $7,936,573, plus 2010 under Recovery of $1,734,209, plus 2011 over recovery of $1,076,281 plus 2012 under recovery $5,294,916)

1/13/2014

OHIO gridSmart
Post Allocated Cost Summary By Program for Accounting's
"NET" Over/Under Revenue Recovery Adjustment
(Source: Transaction Universe)

Report includes Federal Stimulus dollars recovered from the DOE (cc 979)
Report excludes "In-Kind", "Project Compliance", "Write-Off" and "Non Service Corp O&M Internal Labor" expenses

			250 Ohio Power Co - Distribution						220 Columbus Southern Power - Dist						180 Ohio Power Co - Transmission
		Total	Capital	Removal	Other Bud Cat	Emp Benefits	O&M	Stores	Capital	Removal	Other Bud Cat	Emp Benefits	O&M	Stores	Capital
2013 (12) Dec	Expense	$2,159,007	$394,792	$4,003	$70,925		$1,689,287								
	Fed Stimulus Receipts	-$1,706,019	-$615,399	-$2,684	-$35,128		-$1,052,809								
	Net Expense	$452,988	-$220,606	$1,319	$35,798		$636,478								
2013 (11) Nov	Expense	$1,156,825	$705,338	$2,405	$0		$449,082								
	Fed Stimulus Receipts	-$348,278	-$276,597		-$334		-$71,346								
	Net Expense	$808,547	$428,741	$2,405	-$334		$377,736								
2013 (10) Oct	Expense	$731,845	$553,268		$0		$178,578								
	Fed Stimulus Receipts	$151,023	$150,739		$0		$284								
	Net Expense	$882,868	$704,007		$0		$178,861								
2013 (09) Sep	Expense	$677,012	$351,251		$0		$325,761								$0
	Fed Stimulus Receipts	-$735,917	-$192,202		$0		-$543,715								
	Net Expense	-$58,904	$159,049		$0		-$217,954								$0
2013 (08) Aug	Expense	$823,977	$650,471				$173,506								-$0
	Fed Stimulus Receipts														
	Net Expense	$823,977	$650,471				$173,506								-$0
2013 (07) Jul	Expense	$926,308	$588,806				$337,501								$0
	Fed Stimulus Receipts	-$531,938	-$676,083				$144,145								
	Net Expense	$394,370	-$87,277				$481,646								$0
2013 (06) Jun	Expense	$1,355,605	$1,011,286	$0	$0		$344,319								$0
	Fed Stimulus Receipts	$104,714	$415,614	$27	-$43		-$310,884								
	Net Expense	$1,460,319	$1,426,900	$27	-$43		$33,435								$0
2013 (05) May	Expense	$884,602	$539,823	$34	-$0		$344,745								
	Fed Stimulus Receipts	-$506,474	-$267,310		$0		-$239,164								
	Net Expense	$378,128	$272,513	$34	-$0		$105,581								
2013 (04) Apr	Expense	$619,993	$311,729		$0		$308,264								
	Fed Stimulus Receipts	$293,796	$184,803		$0		$108,993								
	Net Expense	$913,790	$496,532		$0		$417,257								
2013 (03) Mar	Expense	$1,923,827	$1,461,056		$0		$462,771								
	Fed Stimulus Receipts	-$1,784,522	-$1,358,687		-$3,468		-$422,367								
	Net Expense	$139,305	$102,369		-$3,468		$40,404								
2013 (02) Feb	Expense	$465,261	$41,254	$0	$6,937		$417,070								
	Fed Stimulus Receipts	-$452,457	-$239,339	$38,489	-$34,891		-$216,717								
	Net Expense	$12,804	-$198,085	$38,489	-$27,954		$200,353								
2013 (01) Jan	Expense	$770,343	$948,923	-$6,088	$0		-$172,492								
	Fed Stimulus Receipts	$809,951	$439,068	$0	$0		$370,883								
	Net Expense	$1,580,294	$1,387,991	-$6,088	$0		$198,392								
2013 Total	Expense	$12,641,220	$7,557,998	$364	$77,862		$4,858,392								$0
	Fed Stimulus Receipts	-$4,706,121	-$2,435,391	$35,832	-$73,865		-$2,232,697								
	Net Expense	$7,788,465	$5,122,607	$36,186	$3,997		$2,625,695								

OHIO gridSmart
Post Allocated Cost Summary By Program for Accounting's
"NET" Over/Under Revenue Recovery Adjustment
(Source: Transaction Universe)

Report includes Federal Stimulus dollars recovered from the DOE (cc 979)
Report excludes "In-Kind", "Project Compliance", "Write-Off" and "Non Service Corp O&M Internal Labor" expenses

			250 Ohio Power Co - Distribution						220 Columbus Southern Power - Dist						160 Ohio Power Co - Transmission
		Total	Capital	Removal	Other Bud Cat	Emp Benefits	O&M	Stores	Capital	Removal	Other Bud Cat	Emp Benefits	O&M	Stores	Capital
2012 (12) Dec	Expense	$2,293,419	$1,080,698	-$16,293	$0		$1,229,014								$0
	Fed Stimulus Receipts	-$1,819,106	-$1,108,838	$16,815	$0		-$727,084								
	Net Expense	$474,312	-$28,140	$522	$0		$501,930								$0
2012 (11) Nov	Expense	$1,034,624	$784,618	$0	$0		$250,006								$0
	Fed Stimulus Receipts	-$669,386	-$449,788	$4,188	$34,891		-$258,678								
	Net Expense	$365,238	$334,830	$4,188	$34,891		-$8,672								$0
2012 (10) Oct	Expense	$1,584,638	$933,358	$148,348	-$35,356		$538,289		$0	$0			$0		
	Fed Stimulus Receipts	$163,500	$103,458	$35,356	$0		$24,686								
	Net Expense	$1,748,138	$1,036,815	$183,704	-$35,356		$562,975		$0	$0			$0		
2012 (09) Sep	Expense	$1,240,221	$883,827	$54	$0		$356,340		-$0	$0					$0
	Fed Stimulus Receipts	-$1,428,565	-$1,129,309	-$609	$0		-$298,648								
	Net Expense	-$188,344	-$245,482	-$554	$0		$57,692		-$0	$0					$0
2012 (08) Aug	Expense	$1,411,385	$1,123,172	-$29,499	-$0		$317,711								$0
	Fed Stimulus Receipts	-$1,122,127	-$627,557		$0		-$494,570								
	Net Expense	$289,258	$495,615	-$29,499	-$0		-$176,859								$0
2012 (07) Jul	Expense	$1,263,288	$1,058,098	$0	$0		$205,191		$0						-$0
	Fed Stimulus Receipts	$339,084	$319,705	$0	$0		$19,379								
	Net Expense	$1,602,373	$1,377,803	$0	$0		$224,570		$0						-$0
2012 (06) Jun	Expense	$1,536,877	$1,193,002	$84,262	-$35,919		$295,532								$0
	Fed Stimulus Receipts	-$2,221,611	-$1,825,255	-$67,687	$35,356		-$364,026								
	Net Expense	-$684,734	-$632,253	$16,576	-$563		-$68,494								$0
2012 (05) May	Expense	$2,346,248	$1,902,584	-$51,970	$187		$495,447		-$0				$0		-$0
	Fed Stimulus Receipts	-$994,205	-$814,127	-$8,329	-$813		-$170,936								
	Net Expense	$1,352,043	$1,088,457	-$60,299	-$627		$324,512		-$0				$0		-$0
2012 (04) Apr	Expense	$1,854,926	$1,600,424	$15,942	$1,615	$0	$236,945		-$0	$0			$0		
	Fed Stimulus Receipts	$303,911	$219,650	-$0	$0	$0	$84,260								
	Net Expense	$2,158,837	$1,820,074	$15,942	$1,615	$0	$321,206		-$0	$0			$0		
2012 (03) Mar	Expense	$566,391	$27,906		$0		$240,384	$900	$144,398	$202,567	$3,996	$0	$46,240		
	Fed Stimulus Receipts	-$2,170,879					-$972,728		-$1,201,795	-$942	-$14,029	$500	$18,116		
	Net Expense	-$1,604,488	$27,906		$0		-$732,344	$900	-$1,057,397	$201,625	-$10,033	$500	$64,356		
2012 (02) Feb	Expense	$1,843,204	$21,212		-$0		$206,141	$2,251	$1,499,344	$106	$24,754		$89,398		
	Fed Stimulus Receipts	-$1,191,557					-$51,774		-$1,031,843	-$7,135	-$29,086		-$71,720		
	Net Expense	$651,646	$21,212		-$0		$154,366	$2,251	$467,502	-$7,029	-$4,331		$17,678		
2012 (01) Jan	Expense	$1,878,577	$15,623		-$0		$146,993	$1,350	$1,545,938	$11,709	$49,295		$107,669	$0	
	Fed Stimulus Receipts	$198,727							$182,456	$2,281			$15,574	-$1,584	
	Net Expense	$2,077,304	$15,623		-$0		$146,993	$1,350	$1,728,394	$13,989	$49,295		$123,243	-$1,584	
2012 Total	Expense	$19,138,114	$10,624,520	$150,845	-$69,473	$0	$4,517,994	$4,501	$3,189,681	$214,382	$78,045	$0	$243,304	$0	-$0
	Fed Stimulus Receipts	-$10,612,215	-$5,312,059	-$20,265	$69,433	$0	-$3,210,118		-$2,051,182	-$5,796	-$43,115	$500	-$38,030	-$1,584	
	Net Expense	$8,341,584	$5,312,461	$130,580	-$40		$1,307,876	$4,501	$1,138,499	$208,586	$34,930	$500	$205,274	-$1,584	-$0

			250 Ohio Power Co - Distribution						220 Columbus Southern Power - Dist						160 Ohio Power Co - Transmission
		Total	Capital	Removal	Other Bud Cat	Emp Benefits	O&M	Stores	Capital	Removal	Other Bud Cat	Emp Benefits	O&M	Stores	Capital
ACTUALS	Expense	121,808,571	$18,182,518	$151,199	$8,389	$0	$9,376,386	$4,501	$85,467,599	-$2,342,178	$78,045	$92,334	$10,762,340	$27,437	-$0
Project Life	Fed Stimulus Receipts	-$63,650,501	-$7,747,451	$15,567	-$4,431	$0	-$5,442,815		-$41,659,388	-$296,582	-$43,115	-$45,668	-$8,413,174	-$13,445	
To Date	Net Expense	$58,158,070	$10,435,068	$166,766	$3,958	$0	$3,933,571	$4,501	$43,808,211	-$2,638,760	$34,930	$46,667	$2,349,166	$13,992	-$0

OHIO gridSmart
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(Source: Transaction Universe)

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Report excludes "In-Kind", "Project Compliance", "Write-Off" and "Non Service Corp O&M Internal Labor" expenses

			220 Columbus Southern Power - Dist					
		Total	O&M	Capital	Removal	Other Bud Cat	Stores	Emp Benefits
2011 (12) Dec	Expense	$4,076,620	$366,979	$3,700,423	$5,068	$0	$3,151	
	Fed Stimulus Receipts	-$4,917,822	-$2,149,198	-$2,756,744	-$10,675	$0	-$905	
	Net Expense	-$841,902	-$1,782,219	$943,679	-$5,608	$0	$2,246	
2011 (11) Nov	Expense	$2,022,034	$425,902	$1,584,132	$10,200	-$0	$1,801	
	Fed Stimulus Receipts	-$2,700,353	-$1,876,945	-$817,384	-$5,345	$0	-$679	
	Net Expense	-$678,319	-$1,451,043	$766,748	$4,855	-$0	$1,122	
2011 (10) Oct	Expense	$2,585,416	$778,743	$1,799,704	$5,619	$0	$1,350	
	Fed Stimulus Receipts	$626,381	$192,496	$434,362	$0	$0	-$478	
	Net Expense	$3,211,798	$971,239	$2,234,065	$5,619	$0	$873	
2011 (09) Sep	Expense	$2,473,420	-$189,049	$2,641,284	$20,235	-$0	$950	
	Fed Stimulus Receipts	-$3,804,542	-$943,583	-$2,845,513	-$14,491	$0	-$955	
	Net Expense	-$1,331,122	-$1,132,632	-$204,228	$5,744	$0	-$5	
2011 (08) Aug	Expense	$4,056,743	$1,406,748	$2,644,866	$3,229	-$0	$1,900	$0
	Fed Stimulus Receipts	-$1,571,291	-$201,709	-$1,328,789	-$18,108	$0	-$679	-$22,006
	Net Expense	$2,485,452	$1,205,039	$1,316,078	-$14,880	$0	$1,221	-$22,006
2011 (07) Jul	Expense	$3,562,218	$503,468	$2,986,361	$27,028	-$0	$1,350	$44,011
	Fed Stimulus Receipts	$171,475	$1,104	$171,276	-$0	$0	-$905	
	Net Expense	$3,733,693	$504,572	$3,157,637	$27,028	-$0	$445	$44,011
2011 (06) Jun	Expense	$3,509,833	$384,729	$3,110,526	$12,777	$0	$1,801	
	Fed Stimulus Receipts	-$4,385,825	-$648,850	-$3,721,500	-$14,343	$0	-$1,131	
	Net Expense	-$875,992	-$264,121	-$610,975	-$1,565	$0	$669	
2011 (05) May	Expense	$5,314,475	$180,255	$5,122,000	$8,386	-$0	$2,926	
	Fed Stimulus Receipts	-$2,667,885	-$65,409	-$2,552,267	-$49,507	-$23	-$679	
	Net Expense	$2,646,590	$114,845	$2,570,641	-$41,121	-$23	$2,247	
2011 (04) Apr	Expense	$1,804,426	$192,683	$1,825,826	-$15,433	-$0	$1,350	
	Fed Stimulus Receipts	-$30,176	$32,352	-$61,663	-$661	$23	-$226	
	Net Expense	$1,774,250	$225,035	$1,564,163	-$16,094	$23	$1,124	
2011 (03) Mar	Expense	$5,108,067	$245,845	$4,900,157	-$40,260	-$0	$2,315	$0
	Fed Stimulus Receipts	-$4,580,403	-$362,903	-$4,118,302	-$96,377	$0	-$2,821	$0
	Net Expense	$527,664	-$117,058	$781,854	-$136,637	$0	-$506	$0
2011 (02) Feb	Expense	$3,383,964	$329,156	$2,942,704	$110,303	-$0	$1,801	$0
	Fed Stimulus Receipts	-$223,041	$19,361	-$213,114	-$26,884	-$0	-$2,404	$0
	Net Expense	$3,160,923	$348,517	$2,729,591	$83,418	-$0	-$603	$0
2011 (01) Jan	Expense	$1,967,170	$351,703	$1,698,540	-$95,023	$0	$1,949	
	Fed Stimulus Receipts	-$0	-$0			$0		
	Net Expense	$1,967,170	$351,703	$1,698,540	-$95,023	$0	$1,949	
2011 Total	Expense	$39,853,374	$4,077,160	$34,757,431	$52,128	-$0	$22,644	$44,011
	Fed Stimulus Receipts	-$24,083,181	-$6,003,283	-$17,809,638	-$236,393	-$0	-$11,861	-$22,006
	Net Expense	$15,770,193	-$1,926,123	$16,947,793	-$184,264	-$0	$10,782	$22,006

		250 Ohio Power Co - Distribution						130 Columbus Southern Power -Trans		160 Ohio Power Co - Transmission
		O&M	Capital	Removal	Other Bud Cat	Stores	Emp Benefits	Capital	Removal	Capital
2011 (12) Dec	Expense							$0		
	Fed Stimulus Receipts									
	Net Expense							$0		
2011 (11) Nov	Expense							-$0		
	Fed Stimulus Receipts									
	Net Expense							-$0		
2011 (10) Oct	Expense							$0		
	Fed Stimulus Receipts									
	Net Expense							$0		
2011 (09) Sep	Expense							$0		
	Fed Stimulus Receipts									
	Net Expense							$0		
2011 (08) Aug	Expense							$0		
	Fed Stimulus Receipts									
	Net Expense							$0		
2011 (07) Jul	Expense							$0		
	Fed Stimulus Receipts									
	Net Expense							$0		
2011 (06) Jun	Expense							-$0		
	Fed Stimulus Receipts									
	Net Expense							-$0		
2011 (05) May	Expense							$0		
	Fed Stimulus Receipts									
	Net Expense							$0		
2011 (04) Apr	Expense							-$0	$0	
	Fed Stimulus Receipts									
	Net Expense							-$0	$0	
2011 (03) Mar	Expense							$0	$0	
	Fed Stimulus Receipts									
	Net Expense							$0	$0	
2011 (02) Feb	Expense							$0	$0	
	Fed Stimulus Receipts									
	Net Expense							$0	$0	
2011 (01) Jan	Expense							$0	$0	
	Fed Stimulus Receipts									
	Net Expense							$0	$0	
2011 Total	Expense							-$0	$0	
	Fed Stimulus Receipts									
	Net Expense							-$0		

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(Source: Transaction Universe)

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Report excludes "In-Kind", "Project Compliance", "Write-Off" and "Non Service Corp O&M Internal Labor" expenses

			220 Columbus Southern Power - Dist						250 Ohio Power Co - Distribution						130 Columbus Southern Power -Trans		160 Ohio Power Co - Transmission
		Total	O&M	Capital	Removal	Other Bud Cat	Stores	Emp Benefits	O&M	Capital	Removal	Other Bud Cat	Stores	Emp Benefits	Capital	Removal	Capital
2010 (12) Dec	Expense	$3,631,184	$461,056	$3,001,268	$118,741	$0	$1,796	$48,323							-$0	-$0	
	Fed Stimulus Receipts	-$10,862,725	-$1,614,463	-$9,146,238	-$77,863	-$0	$0	-$24,161									
	Net Expense	-$7,231,541	-$1,153,407	-$6,144,970	$40,879	$0	$1,796	$24,161							-$0	-$0	
2010 (11) Nov	Expense	$1,452,704	$107,175	$1,170,574	$77,312	-$0	$1,642								-$0		
	Fed Stimulus Receipts	-$2,328,678	-$150,952	-$2,197,227	$28,501	$0											
	Net Expense	-$875,974	$37,223	-$1,020,653	$105,813	-$0	$1,642								-$0		
2010 (10) Oct	Expense	$4,127,587	$372,012	$3,781,777	-$27,556	-$0	$1,354								-$0		
	Fed Stimulus Receipts	-$418,289	-$469,505	$55,224	-$4,008	$0											
	Net Expense	$3,709,299	-$97,493	$3,837,001	-$31,564	-$0	$1,354								-$0		
2010 (09) Sep	Expense	$3,743,024	-$357,044	$4,165,744	-$65,675	-$0									-$0		
	Fed Stimulus Receipts																
	Net Expense	$3,743,024	-$357,044	$4,165,744	-$65,675	-$0									-$0		
2010 (08) Aug	Expense	$3,768,581	$893,863	$2,869,487	$5,231	$0									$0		
	Fed Stimulus Receipts	$0	$0	$0	$0	$0											
	Net Expense	$3,768,581	$893,863	$2,869,487	$5,231	$0									$0		
2010 (07) Jul	Expense	$2,815,059	$23,912	$2,772,575	$18,572	-$0									-$0		
	Fed Stimulus Receipts																
	Net Expense	$2,815,059	$23,912	$2,772,575	$18,572	-$0									-$0		
2010 (06) Jun	Expense	$1,841,944	$570,715	$1,306,823	-$35,594	$0									-$0		
	Fed Stimulus Receipts	-$10,639,292	-$127,941	-$10,510,328	-$1,024	$0											
	Net Expense	-$8,797,348	$442,775	-$9,203,505	-$36,618	$0									-$0		
2010 (05) May	Expense	$2,038,336	$437,693	$1,705,363	-$104,720	$0									-$0		
	Fed Stimulus Receipts	(na)	(na)	(na)	(na)	(na)									(na)		
	Net Expense	$2,038,336	$437,693	$1,705,363	-$104,720	$0									-$0		
2010 (04) Apr	Expense	$2,416,516	$1,050,881	$2,629,826	-$1,264,192	$0									$0		$0
	Fed Stimulus Receipts	(na)	(na)	(na)	(na)	(na)									(na)		(na)
	Net Expense	$2,416,516	$1,050,881	$2,629,826	-$1,264,192	$0									$0		$0
2010 (03) Mar	Expense	$3,631,925	$561,506	$3,580,755	-$510,337	-$0									-$0	$0	$0
	Fed Stimulus Receipts	(na)	(na)	(na)	(na)	(na)									(na)	(na)	(na)
	Net Expense	$3,631,925	$561,506	$3,580,755	-$510,337	-$0									-$0	$0	$0
2010 (02) Feb	Expense	$697,502	$542,301	$907,934	-$752,733	$0									$0	$0	$0
	Fed Stimulus Receipts	(na)	(na)	(na)	(na)	(na)									(na)	(na)	(na)
	Net Expense	$697,502	$542,301	$907,934	-$752,733	$0									$0	$0	$0
2010 (01) Jan	Expense	-$8,100,702	$324,567	-$8,357,817	-$67,452	$0									$0		-$0
	Fed Stimulus Receipts	(na)	(na)	(na)	(na)	(na)									(na)		(na)
	Net Expense	-$8,100,702	$324,567	-$8,357,817	-$67,452	$0									$0		-$0
2010 Total	Expense	$24,063,060	$5,078,639	$21,540,306	-$2,608,403	$0	$4,793	$48,323							$0	$0	-$0
	Fed Stimulus Receipts	-$24,248,984	-$2,371,660	-$21,798,568	-$54,394	-$0	$0	-$24,161									
	Net Expense	-$185,324	$2,706,778	-$258,260	-$2,662,797	$0	$4,793	$24,161							$0		-$0

OHIO gridSmart
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			220 Columbus Southern Power - Dist						250 Ohio Power Co - Distribution						130 Columbus Southern Power -Trans		160 Ohio Power Co - Transmission
		Total	O&M	Capital	Removal	Other Bud Cat	Stores	Emp Benefits	O&M	Capital	Removal	Other Bud Cat	Stores	Emp Benefits	Capital	Removal	Capital
2009 (12) Dec	Expense	$23,389,831	$319,020	$23,069,302	$1,510	-$0									-$0		-$0
	Fed Stimulus Receipts	(na)	(na)	(na)	(na)	(na)									(na)		(na)
	Net Expense	$23,389,831	$319,020	$23,069,302	$1,510	-$0									-$0		-$0
2009 (11) Nov	Expense	$1,328,667	$81,791	$1,247,158	-$293	$0									$0		$0
	Fed Stimulus Receipts	(na)	(na)	(na)	(na)	(na)									(na)		(na)
	Net Expense	$1,328,667	$81,791	$1,247,158	-$293	$0									$0		$0
2009 (10) Oct	Expense	$491,678	$64,350	$428,830	-$1,502										$0		
	Fed Stimulus Receipts	(na)	(na)	(na)	(na)										(na)		
	Net Expense	$491,678	$64,350	$428,830	-$1,502										$0		
2009 (09) Sep	Expense	$496,360	$33,364	$462,996		$0									$0		$0
	Fed Stimulus Receipts	(na)	(na)	(na)		(na)									(na)		(na)
	Net Expense	$496,360	$33,364	$462,996		$0									$0		$0
2009 (08) Aug	Expense	$76,346	-$198,841	$275,186											$0		$0
	Fed Stimulus Receipts	(na)	(na)	(na)											(na)		(na)
	Net Expense	$76,346	-$198,841	$275,186											$0		$0
2009 (07) Jul	Expense	$242,202	$95,982	$146,220											$0		-$0
	Fed Stimulus Receipts	(na)	(na)	(na)											(na)		(na)
	Net Expense	$242,202	$95,982	$146,220											$0		-$0
2009 (06) Jun	Expense	-$125,093	-$159,477	$34,384													
	Fed Stimulus Receipts	(na)	(na)	(na)													
	Net Expense	-$125,093	-$159,477	$34,384													
2009 (05) May	Expense	$537,951	$221,838	$316,113													
	Fed Stimulus Receipts	(na)	(na)	(na)													
	Net Expense	$537,951	$221,838	$316,113													
2009 (04) Apr	Expense	$1,776	$1,776														
	Fed Stimulus Receipts	(na)	(na)														
	Net Expense	$1,776	$1,776														
2009 (03) Mar	Expense	$2,497	$2,497														
	Fed Stimulus Receipts	(na)	(na)														
	Net Expense	$2,497	$2,497														
2009 (02) Feb	Expense	$323	$323														
	Fed Stimulus Receipts	(na)	(na)														
	Net Expense	$323	$323														
2009 (01) Jan	Expense	$816	$816														
	Fed Stimulus Receipts	(na)	(na)														
	Net Expense	$816	$816														
2009 Total	Expense	$28,443,131	$463,237	$25,980,179	-$285	$0									-$0		-$0
	Fed Stimulus Receipts																
	Net Expense	$28,443,131	$463,237	$25,980,179	-$285	$0									-$0		-$0
Project Life	Expense	109,299,255	10,762,340	85,467,500	-2,342,178	78,045	27,437	92,334	4,517,994	10,609,813	150,845	-69,473	4,501	0	0	0	-0
To Date	Fed Stimulus Receipts	-$58,944,380	-$8,413,174	-$41,659,388	-$296,582	-$43,115	-$13,445	-$45,668	-$3,210,118	-$5,312,059	-$20,265	$69,433		$0			
Total	Net Expense	$50,354,875	$2,349,166	$43,808,211	-$2,638,760	$34,930	$13,992	$46,667	$1,307,876	$5,297,754	$130,580	-$40	$4,501	$0	$0	$0	-$0

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	Project		Fed Stimulus Receipts	Project Life to Date Total (Net of Fed Stimulus Receipts)	Capital	Removal	Other Bud Cat	Emp Benefits	O&M	Stores
ACTUALS	00018777	OH gridSmart Bdgt Bucket	$0	$0	$0					
ACTUALS	DP9CO060A	CSP/Gahanna Sta AdaptiVolt	-$47,667	$611,301	$611,301					
ACTUALS	DP9CO060B	CSP/Gahanna D Line AdaptiVolt	-$130,496	$457,767	$459,168	$7,700	-$0		-$9,101	
ACTUALS	DP9CO060M	CSP/Blacklick Station IVVC	-$78,545	$170,600	$170,600					
ACTUALS	DP9CO060N	CSP/Blacklick Line IVVC	-$51,768	$58,931	$58,216	$715	$0			
ACTUALS	DP9CO060O	CSP/E Broad St Station IVVC	-$25,829	$420,556	$418,404	$2,152				
ACTUALS	DP9CO060P	CSP/E Broad St Line IVVC	-$65,376	$152,767	$153,195	-$428	-$0		$0	
ACTUALS	DP9CO060Q	CSP/Gahanna Sta GE CVVC	-$20,620	$237,596	$235,470	$2,126				
ACTUALS	DP9CO060R	CSP/Gahanna D Line IVVC	-$731,730	$583,009	$344,269		$0		$238,740	
ACTUALS	DP9CO060S	CSP/Karl Rd Station IVVC	-$75,944	$217,654	$215,895	$1,758				
ACTUALS	DP9CO060T	CSP/Karl Rd D Line IVVC	-$41,362	$44,872	$44,522	$233	$0		$117	
ACTUALS	DP9CO060U	CSP/Taylor Station IVVC	-$40,565	$42,449	$42,288	$162				
ACTUALS	DP9CO060V	CSP/Taylor Rd D Line IVVC	-$27,772	$28,911	$28,911		$0			
ACTUALS	GRHANOBIL	HAN No Bill	$0	$47,559	$41,065				$6,494	
ACTUALS	GRSHANIHD	1.1.5.3 Home Area Net - IHDs	-$53,669	$131,450	$95,069				$36,381	
ACTUALS	GRSHANLCS	1.1.5.3 Home Area Net - LCSs	-$15,084	$19,063	$7,693				$11,370	
ACTUALS	GRSHANPCT	1.1.5.3 Home Area Net - PCTs	-$925,333	$842,014	$312,726				$529,287	
ACTUALS	GSAMIINOP	1.1.3.3 AMI Interoperability	-$146,547	$182,142	$174,459				$7,683	
ACTUALS	GSAMIMTRS	1.1.5.2 gSmart AMI Meters	-$10,221,086	$8,846,658	$11,140,091	-$2,829,751			$536,318	
ACTUALS	GSAMISYS1	1.1.1.2 gSMART AMI IT Appl	-$2,280,711	$2,586,439	$1,918,164			$22,505	$645,770	
ACTUALS	GSAMITCOM	1.1.5.2 gSmart AMI TCom	-$1,682,750	$1,708,204	$1,683,761	$91	-$0	$24,161	$191	
ACTUALS	GSAMNOBIL	gSmart AMI Non-Billable		$36,602	$25,887				$10,715	
ACTUALS	GSBADM001	Data Management	-$2,285,901	$2,568,138	$1,715,308				$852,830	
ACTUALS	GSBADR001	Demand Response RTP/DA Mgn	-$6,664,695	$6,535,498	$6,035,973				$499,525	
ACTUALS	GSBADR002	Demand Response Battelle	-$1,709,023	$1,524,100	$1,522,449				$1,652	
ACTUALS	GSBADR003	Demand Response Reg-Rate		$23,458					$23,458	
ACTUALS	GSBADR005	Demand Response Security	-$6,083	$6,083					$6,083	
ACTUALS	GSBADR006	Demand Response Cust Engage	-$26,301	$57,205					$57,205	
ACTUALS	GSBADR007	Demand Response Process Def		$4,079					$4,079	
ACTUALS	GSBAMS001	Modeling and Simulation	-$557,994	$544,132	$544,244				-$113	
ACTUALS	GSBAMS002	Circuit Select-Implement 1182	$111,133	$73,786	$73,769				$17	
ACTUALS	GSBAMS003	Simulation Parametric Analysis	-$798,149	$792,197	$792,197				$0	
ACTUALS	GSBAMS004	Reporting & Deliverables 1312	-$466,240	$517,549	$517,549					
ACTUALS	GSBANOBIL	Battelle Assist No Bill		$15,356	$10,431				$4,925	
ACTUALS	GSBAPM001	Project Management and Suppor	-$1,066,249	$1,047,788	$1,031,441				$16,347	
ACTUALS	GSCENOBIL	CES No Bill		$4,651	$4,494				$156	
ACTUALS	GSCES0001	community energy storage (ces)	-$1,526,775	$1,993,430	$1,616,951	$52,984	$38,888		$283,933	$675
ACTUALS	GSCESOSTA	CES Morse Station	-$3,791	$4,308	$4,308					
ACTUALS	GSCOMM001	Commercialization	-$787	$24,851					$24,851	
ACTUALS	GSCON1221	1.2.2.1 Outreach & Education	-$2,532,275	$3,640,449					$3,640,449	
ACTUALS	GSCON1223	1.2.2.3 Cust Characterization	-$23,183	$162,127					$162,127	
ACTUALS	GSCSNOBIL	Cyber Security No Bill		$30,405	$25,939				$4,466	
ACTUALS	GSCSOC001	Cyber-Security Ops Center	-$2,026,807	$2,784,951	$2,737,971				$46,980	
ACTUALS	GSCUSTPMO	gridSMART Customer PMO	-$287	$31,911	$0				$31,911	
ACTUALS	GSCWEB001	Customer Web Portal	-$1,169,479	$1,112,516	$464,092				$648,424	
ACTUALS	GSDA31257	1.1.5.1 gSMART DA STA	-$112,275	$109,659	$109,659					
ACTUALS	GSDA31311	1.1.5.1 gSMART DA STA	-$21,664	$23,202	$23,202					
ACTUALS	GSDA31312	1.1.5.1 gSMART DA STA	-$108,326	$111,640	$110,996	$645				
ACTUALS	GSDA31313	1.1.5.1 gSMART DA STA	-$60,374	$64,103	$64,103					
ACTUALS	GSDA31314	1.1.5.1 gSMART DA STA	-$254,066	$276,540	$259,777	$16,763				

^ gridSmart Project Report 1.0 - Project Summary & Acctg Over Under.rep

OHIO gridSmart
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				Project Life to Date						
	Project		Fed Stimulus Receipts	Total (Net of Fed Stimulus Receipts)	Capital	Removal	Other Bud Cat	Emp Benefits	O&M	Stores
ACTUALS	GSDA31315	1.1.5.1 gSMART DA STA	-$243,968	$218,470	$203,573	$14,896				
ACTUALS	GSDA31316	1.1.5.1 gSMART DA STA	-$54,862	$55,311	$54,441	$871				
ACTUALS	GSDA31317	1.1.5.1 gSMART DA STA	-$31,839	$33,920	$33,920					
ACTUALS	GSDA31318	1.1.5.1 gSMART DA STA	-$847,650	$818,308	$747,567	$70,741				
ACTUALS	GSDA31319	1.1.5.1 gSMART DA STA	-$103,754	$96,438	$88,105	$8,333				
ACTUALS	GSDA31320	1.1.5.1 gSMART DA STA	-$284,418	$357,769	$329,172	$28,597				
ACTUALS	GSDA31321	1.1.5.1 gSMART DA STA	-$269,767	$263,605	$250,864	$12,741				
ACTUALS	GSDA31322	1.1.5.1 gSMART DA STA	-$57,015	$56,683	$54,462	$2,221				
ACTUALS	GSDA31323	1.1.5.1 gSMART DA STA	-$83,409	$82,513	$80,471	$2,042				
ACTUALS	GSDA31324	1.1.5.1 gSMART DA STA	-$164,576	$172,368	$171,893	$476				
ACTUALS	GSDA31780	1.1.5.1 gSMART DA STA	-$80,629	$85,626	$85,279	$347				
ACTUALS	GSDAA0005	1.1.5.x gSmart DA CKT	-$294,241	$350,106	$343,751	$5,128	$0		$1,228	
ACTUALS	GSDAA0009	1.1.5.x gSmart DA CKT	-$1,856,654	$1,966,657	$1,853,903	$87,665	-$0		$25,089	
ACTUALS	GSDAA0010	1.1.5.x gSmart DA CKT	-$140,713	$155,996	$148,725	$4,669	$1		$2,601	
ACTUALS	GSDAA0029	1.1.5.x gSmart DA CKT	-$214,087	$256,168	$265,344	-$638	-$0		-$8,538	
ACTUALS	GSDAA0039	1.1.5.x gSmart DA CKT	-$91,206	$104,010	$98,546	$5,762	-$0		$182	
ACTUALS	GSDAA0042	1.1.5.x gSmart DA CKT	-$754,875	$796,087	$778,543	$14,721	-$0		$2,823	
ACTUALS	GSDAA0045	1.1.5.x gSmart DA CKT	-$282,291	$313,901	$330,192	-$17,622	$0		$1,331	
ACTUALS	GSDAA0055	1.1.5.x gSmart DA CKT	-$135,558	$163,579	$164,001	-$601	-$0		$179	
ACTUALS	GSDAA0056	1.1.5.x gSmart DA CKT	-$432,485	$477,811	$465,120	$6,368	-$0		$6,323	
ACTUALS	GSDAA0058	1.1.5.x gSmart DA CKT	-$859,160	$872,001	$850,160	$15,995	-$0		$5,846	
ACTUALS	GSDAA0064	1.1.5.x gSmart DA CKT	-$124,955	$127,330	$126,076	$661	$0		$594	
ACTUALS	GSDAA0080	1.1.5.x gSmart DA CKT	-$246,577	$290,061	$289,801	-$30	$0		$290	
ACTUALS	GSDAA0097	1.1.5.x gSmart DA CKT	-$108,052	$123,380	$128,978	-$6,146	$0		$548	
ACTUALS	GSDAA0260	1.1.5.x gSmart DA CKT	-$302,865	$358,259	$361,028	-$7,561	-$0		$4,792	
ACTUALS	GSDAA0272	1.1.5.x gSmart DA CKT	-$90,922	$96,852	$94,781	$1,954	-$0		$117	
ACTUALS	GSDAA0365	1.1.5.x gSmart DA CKT	-$176,569	$190,914	$188,855	$1,617	-$0		$442	
ACTUALS	GSDAABLAN	1.1.5.x gSmart DA CKT	-$1,057,925	$1,666,916	$1,646,602	$4,178	$0		-$1,681	$17,818
ACTUALS	GSDAADENG	1.1.5.x gSmart DA CKT	-$1,626,758	$1,662,826	$1,641,659	$15,413			$5,754	
ACTUALS	GSDAAINOP	1.1.3.4 DA Interoperability	-$204,636	$283,927	$282,266				$1,661	
ACTUALS	GSDAASENG	1.1.5.1 gSMART DA STA	-$334,043	$350,317	$354,086	$40			-$3,809	
ACTUALS	GSDAASYS1	1.1.1.6.x Dist Rel Mgt Sys/App	-$1,660,940	$2,056,662	$1,403,620				$653,042	
ACTUALS	GSDANOBIL	gSmart Dist Auto Non-Billable		$3,428	$2,436				$993	
ACTUALS	GSDAPQVEW	1.1.5.1 gSMART PQ View	-$21,968	$40,450	$40,450					
ACTUALS	GSHANINOP	1.1.3.1 HAN Interoperability	-$390,638	$530,567	$527,001				$3,566	
ACTUALS	GSHANSYS1	gSMART HAN IT Appl	-$1,844,187	$2,211,879	$656,902				$1,554,978	
ACTUALS	GSINTE001	Interoperability	-$789,920	$860,114	$585,755				$274,359	
ACTUALS	GSMARTNAG	Oh gSmart NonAssoc A&G	-$1,277,928	-$93,301					-$93,301	
ACTUALS	GSOTNOBIL	gridSmart - Non-billable O&M		$133,675					$133,675	
ACTUALS	GSPHEV001	PHEV Plug-In Hybrid	-$640,252	$944,154	$227,223		$0		$716,932	
ACTUALS	GSPROCENG	OH gridSmart Process Re-Engr	-$2,017	$275,834					$275,834	
ACTUALS	GSPROCTRN	OH gridSmart Process Re-Train	-$102	$13,458					$13,458	
ACTUALS	GSREG1211	1.2.1.1 Reg-Build Busines Case		$24,628					$24,628	
ACTUALS	GSREG1212	1.2.1.2 Design Tariff	$0	$23,723					$23,723	
ACTUALS	GSREG1213	1.2.1.3 Seek Tariff Approval		$17,126					$17,126	
ACTUALS	GSSMAP001	Smart Appliance	-$85,583	$91,977	$35,136				$56,840	
ACTUALS	GSSTAINOP	1.1.3.2 Int Gateway IntrOper	-$157,296	$210,173	$184,669				$25,504	
ACTUALS	GSSTNOBIL	gSmart Sta Auto Non-Billable		$700	$700					
ACTUALS	GSVICM001	Vendor In-Kind Contributions	-$5,822,772	$5,032,634					$5,032,634	
ACTUALS	GSVINOBIL	Vendor In-Kind No Bill		-$10,855,406					-$10,855,406	
ACTUALS	ITUOP0400	Meter Data Management-AEPSC	-$162	$6,978					$6,978	

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				Project Life to Date						
Project			Fed Stimulus Receipts	Total (Net of Fed Stimulus Receipts)	Capital	Removal	Other Bud Cat	Emp Benefits	O&M	Stores
ACTUALS	ITUOP0402	CUST OPS gridSMART-CSP-D	-$65,373	$1,762,619	$1,762,619					
ACTUALS	ITUOP0493	ENMAC/Distribution Automation		$10,619					$10,619	
ACTUALS	ITUOP0809	Com Cust Prgm & Outage Sys Bri	-$209	$2,114	$0				$2,114	
ACTUALS	ITUOP0833	ENMAC CSP	-$21,393	$212,452	$212,452					
ACTUALS	ITUOP0880	DOE Doc Mgmt Compliance	-$26,758	$18,759	$17,912				$846	
ACTUALS	ITUOP0995	Utilities System Integration		$22,681					$22,681	
ACTUALS	ITUOP1006	gridSMART Implementation-CSP	-$198,995	$86,534	$86,534					
ACTUALS	ITUOP1008	gridSMART Implementation-OPCC	-$119,195	-$50,104	-$50,104					
ACTUALS	ITUOP1018	Common Cust Sys Enhance-CSP	-$108,583	$81,637	$81,637					
ACTUALS	ITUOP1020	Common Cust Sys Enhance-OPC		$5,471	$5,471					
ACTUALS	ITUOP1030	Utilities Sys Integration-CSP	$4,600	$142,720	$142,729					
ACTUALS	ITUOP1032	Utilities Sys Integration-OPCO		-$18,033	-$18,033					
ACTUALS	ITUOP1251	UIQ Upgrade		$11,877					$11,877	
Total			-$63,650,601	$58,158,070	$54,243,279	-$2,471,995	$38,888	$46,667	$6,282,738	$18,493

OHIO POWER COMPANY

3rd ~~2nd~~ Revised Sheet No. 484-1D
Cancels 2nd ~~1st~~ Revised Sheet No. 484-1D

P.U.C.O. NO. 20

OAD – gridSMART RIDER
(Open Access Distribution – gridSMART Rider)

Effective ~~with the first billing cycle of January, 2013~~______________, all customer bills subject to the provisions of this Rider, including any bills rendered under special contract, shall be adjusted by the monthly gridSMART charge. This Rider shall be adjusted periodically to recover amounts authorized by the Commission.

Residential Customers	$~~0.10~~ 1.11/month
Non-Residential Customers	$~~0.42~~ 4.63/month

Filed pursuant to Order dated ~~December 12, 2012~~ __________ in Case No. ~~13-0345~~-EL-RDR

Issued: ~~December 21, 2012~~__________ Effective: ~~Cycle 1 January 2013~~__________

Issued by
Pablo Vegas, President
AEP Ohio

OHIO POWER COMPANY

Attachment 4 Page 2
3rd ~~2nd~~ Revised Sheet No. 484-1
Cancels 2nd ~~1st~~ Revised Sheet No. 484-1

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KWalton

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	: : :	**Case No. 2014-00371**
IN THE MATTER OF: THE APPLICATION OF LOUISVILLE GAS & ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	: : :	**Case No. 2014-00372**

DIRECT TESTIMONY AND EXHIBITS

OF

PAUL A. COOMES

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

MARCH, 2015

DIRECT TESTIMONY OF PAUL A. COOMES

Q. Please state your name, address, and profession.

A. My name is Paul A. Coomes. My address is 3604 Trail Ridge Road, Louisville KY 40241. I am a consulting economist. I have a Ph.D. in economics from the University of Texas. I am also an emeritus professor of economics at the University of Louisville.

Q. Have you testified before the Kentucky Public Utility Commission?

A. Yes, I have testified and submitted testimony several times before the Kentucky Public Service Commission to present studies I have performed for utilities, and utility customers such as the Kentucky Industrial Utility Customers, Inc. ("KIUC").

Q. What is the purpose of your testimony?

A. I am providing testimony in support of a study that I conducted entitled, *The Differential Economic Importance and Electricity Usage of Industries in Kentucky (March 4, 2015).* This study attempts to quantify the economic impact of Kentucky's industrial sector compared to other Kentucky industries and is attached to my Direct Testimony as Attachment 1. My study demonstrates that the most important industries, in terms of economic growth, are those that export their goods and services to customers around the US and the world. Firms in these industries bring new dollars into Kentucky and thereby lift firms in other linked industries, as well as the incomes of Kentucky households. As household incomes grow, so do sales and employment in support industries (and governments) that provide goods and services to local households. The export-based industries are the engines of growth, and therefore have been the target of economic development agencies, while retail and most service businesses are essentially captive and require no special incentives to operate in the state.

Q. Can you explain why economists and economic development agencies value export-based industries more than businesses that service the local population?

A. Economists and economic development agencies value export-based industries because they have large "employment multipliers", thereby lifting economic activity in other industries and raising household incomes statewide. They also usually provide many high paying direct jobs because, say, a sophisticated manufacturing plant requires skilled workers and highly sought-after plant managers. North American Stainless, for example, not only employs 1,300 highly-trained steel workers at its factory in Ghent, Kentucky, but also employs hundreds of people (engineers, accountants, attorneys, executives, etc.) at its on-sight office complex.

Q. What is an "employment multiplier"?

A. An employment multiplier is one of the measures used to determine the impact a particular industry will have upon a regional economy when it arrives or departs. In its simplest terms, the employment multiplier measures the indirect and induced jobs created (or lost) in the area for each direct job at a facility. Direct jobs are related to the specific industry, while indirect jobs are those that support the industry. Induced jobs are those that are a result of direct/indirect employee's spending money in the community. Generally, industries with a higher multiplier are more desirable.

Q. What is an "export industry" and why are they so important to a local economy?

An "export industry" is a business that primarily sells its goods or products outside of the area in which it is located. The importance of export industries can be easily illustrated with a real-world example. Consider the difference between a store like Target that sells household goods to local residents, and a manufacturing plant like Georgetown's Toyota that makes Camrys and sells them around the world. Regional economists classify businesses like Toyota as export industries, as they serve primarily out-of-state customers. Businesses like Target serve the residential market, and their sales ebb and flow with the population and their disposable incomes. Toyota's sales bring new dollars into the state, where they are used to purchase goods and services to make the cars, and to pay their employees. Those employees, and the employees of their suppliers, spend their paychecks on many local goods and services, thus lifting the economy further.

By contrast, Target provides clothing and other merchandise in return for the disposable incomes of residents, absorbing not adding dollars to the economy. If Toyota were to close its Kentucky plant, disposable incomes of Kentuckians would fall predictably. If a Target were to close, other stores like Kohl's or perhaps smaller locally owned businesses would expand to meet the demand and there would be no net impact on the economy.

Additionally, while a business like Target may have many direct employees at a local store it does not necessarily increase the net employment or net wages in a local area. When a Target moves into an area it often displaces smaller businesses that are not able to compete with the lower prices and wider selection offered by such a larger retailer.

Q. Do states compete for export industries?

A. Yes, state and local governments, as well as private economic development groups, use a lot of resources to help spawn, grow, retain, and attract firms in export industries. Common tools include tax incentives, land assembly, public infrastructure investments, and worker training programs. Most industries that export their product out of state could feasibly locate in a number of other states, and hence companies are in a position to negotiate public incentives in return for locating in a given state. The calculation from the public side is that the other jobs and taxes generated by an exporting firm (and its vendors and their employees) more than offset any incentives granted to the firm. By contrast, retail and personal service industries are rarely subsidized because they essentially have no choice of location. If they want to sell groceries, cars, haircuts and dental services to Kentucky residents they will have to set up business in Kentucky.

Q. How do you identify businesses that have large employment multipliers?

A. Since no person or agency knows the customer (or vendor) base for all Kentucky companies, I rely on well-developed theories and models to predict the relative economic importance of different industries in the state. As explained in my attached Report, the most richly developed and widely used regional modeling system is called *Implan*.[1] I have recently constructed a custom *Implan* model of Kentucky. The model begins with national input-output tables, essentially detailed production recipes for everything in the economy, and is calibrated to Kentucky using detailed county-level data on employment and wages for 470 industries. It is capable of predicting how a change in activity in any industry impacts output, employment, wages and other variables in all the other

[1] For a description and documentation of the IMPLAN modeling system, see http://implan.com/v3/

industries. The modeling system is the primary tool used to evaluate economic development incentives around Kentucky.

Q. Can you summarize the results of the Implan modeling system that you customized for Kentucky?

A. I used the *Implan* model of Kentucky to identify 83 industries that have significant levels of employment *and* have relatively high interindustry job multipliers. These 83 industries, directly employ 276,000 persons (out of 2.4 million total statewide in all industries), but their impact on the economy is much greater than just their direct employment. Most of the industries listed are classified as manufacturing.

My report shows that petroleum refineries, animal processing, chemical manufacturing, iron and steel manufacturing, paper mills and automobile manufacturing have high employment multipliers, that is they have deep supplier linkages with other industries around Kentucky. One conclusion supported by this report is that a fraction of industries in Kentucky directly or indirectly support most of the employment in the state.

Q. How important is reliable, low-cost electricity to export-based industries?

A. Low and reliable electricity costs are very important to Kentucky export-based industries. Kentucky's historically low electricity costs are one of the factors that has attracted energy-intensive businesses such as aluminum and steel manufacturers, auto-makers, chemical manufacturers and paper mills. This is reflected in public economic data. Kentucky ranks third highest among states in terms of electricity purchases per manufacturing employee, and ranks first in kilowatt-hour purchases per dollar of manufacturing shipments. My attached Report illustrates the differential economic importance of various industries in Kentucky.

Q. How do the conclusions reached in your Report relate to KU and LG&E's request to increase electric base rates by a total of $184 million?

A. While I do not have any specific recommendation regarding the level of rate increase the Commission should approve for the Companies, the Commission should be mindful of the economic impact that large rate increases may have on the energy-intensive export industries that are engines of the Kentucky economy. Low industrial electric rates helped to attract these manufacturers to Kentucky and maintaining low electric rates is important to both retain and attract new manufacturers to the Commonwealth.

Q. Does this conclude your testimony?

A. Yes.

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ATTACHMENT 1

OF

PAUL A. COOMES

The Differential Economic Importance and Electricity Usage of Industries in Kentucky

a report for the
Kentucky Industrial Utility Customers

by
Paul Coomes, Ph.D.
Consulting Economist
March 4, 2015

Economic activity in Kentucky is classified under hundreds of different industries, but some are much more important than others in terms of overall growth and prosperity in the state. The most important industries, in terms of economic growth, are those that export their goods and services to customers around the US and the world. Firms in these industries bring new dollars into Kentucky and thereby lift firms in other linked industries, as well as the incomes of Kentucky households. As household incomes grow, so do sales and employment in retail and service industries (and governments) that provide goods and services to households. The export-based industries are the engines of growth, and hence the target of economic development agencies, while the retail and service industries are essentially captive and require no special incentives to operate in the state.

From this perspective, the most important industries are in the manufacturing, distribution, mining and agricultural sectors, and the least important industries are those in the retail, financial services, real estate, health care, legal, education and personal services sectors. In terms of export-based industries with significant employment in Kentucky, those with the greatest spin-off impacts are nearly all manufacturers: petroleum refining, beef and pork slaughtering and processing, animal food, organic chemicals, milk production, tobacco products, aluminum, trucks, iron and steel, soap, paper, automobiles and trucks, plastics, distilleries, inorganic chemicals, poultry, sawmills, and motor vehicle parts.

These important industries are also among the largest consumers of electricity in Kentucky. Primary aluminum producers, for example, spend around $137,000 per employee on electricity, whereas the typical retail or service business spends only a few hundred dollars per employee annually on electricity – primarily for lighting and air conditioning, rather than for the production processes. Indeed, Kentucky has a strong presence of many of the most energy-intensive industries in the United States, attracted here partly because of our historically competitive electricity rates. I have identified at least ten key manufacturing industries in Kentucky that purchase more than $20,000 of electricity per employee. These industries also have large employment multipliers, thereby lifting economic activity in other industries and raising household incomes statewide. Kentucky ranks third highest among states in terms of electricity purchases per manufacturing employee, and ranks first in kilowatt hour purchases per dollar of manufacturing shipments. In this report I organize the most recent data to illustrate the differential economic importance of various industries in Kentucky[1].

Example: Toyota vs. Target

It is not well understood among the public that certain industries in Kentucky are much more important than others in terms of our economic prosperity. I will explore this in some detail later in the report, but the basic idea can be illustrated with a simple example.

Consider the difference between a store like Target that sells apparel to local residents, and a plant like Georgetown's Toyota that makes Camrys and sells them around the world. Toyota's sales bring new dollars into the state, where the company purchases goods and services to make the cars, and to pay their employees. Those employees spend their paychecks on many local goods and services, thus lifting the economy further. By contrast, Target provides clothing and other merchandise in return for the disposable incomes of residents, absorbing not adding dollars to the economy. If Toyota were to close its Kentucky plant, disposable incomes of Kentuckians would fall predictably. If a Target were to close, other stores like Kohl's would expand to meet the demand and there would be no net impact on the economy.

Regional economists classify businesses like Toyota as export industries, as they serve primarily out-of-state customers. Businesses like Target serve the residential market, and their sales ebb and flow with the population and their disposable incomes. Hence, state and local governments, as well as private economic development groups, use a lot of resources to help spawn, grow, retain, and attract firms in export industries. Common tools include tax incentives, land assembly, public infrastructure investments, and worker training programs. Most industries that export their product out of state could feasibly locate in a number of other states, and hence companies are in position to negotiate public incentives in return for locating in a given state. The calculation from the public side is that the other jobs and taxes generated by an exporting firm (and its vendors and their employees) more than offset any incentives granted to the firm. By contrast, retail and personal service industries are rarely subsidized because they essentially have no choice of location. If they want to sell groceries, cars, haircuts and dental services to Kentucky residents they will have to set up business in Kentucky.

The distinction between firms that export and firms that just sell to residents is not always so clear. Humana, for example, has a huge national business but also sells health insurance

[1] This updates my report of April, 2010, using fresh detailed economic data and models that have become available over the last several years.

services to Kentuckians. Some of our major law firms have specialty practices that attract national clients, thus bringing new dollars into our regional economy, even though the bulk of their revenues are from serving local companies and households. Kentucky's hotels and restaurants serve a mixture of destination tourists and convention-goers, pass-through interstate travelers, family visitors, business travelers, and local residents.

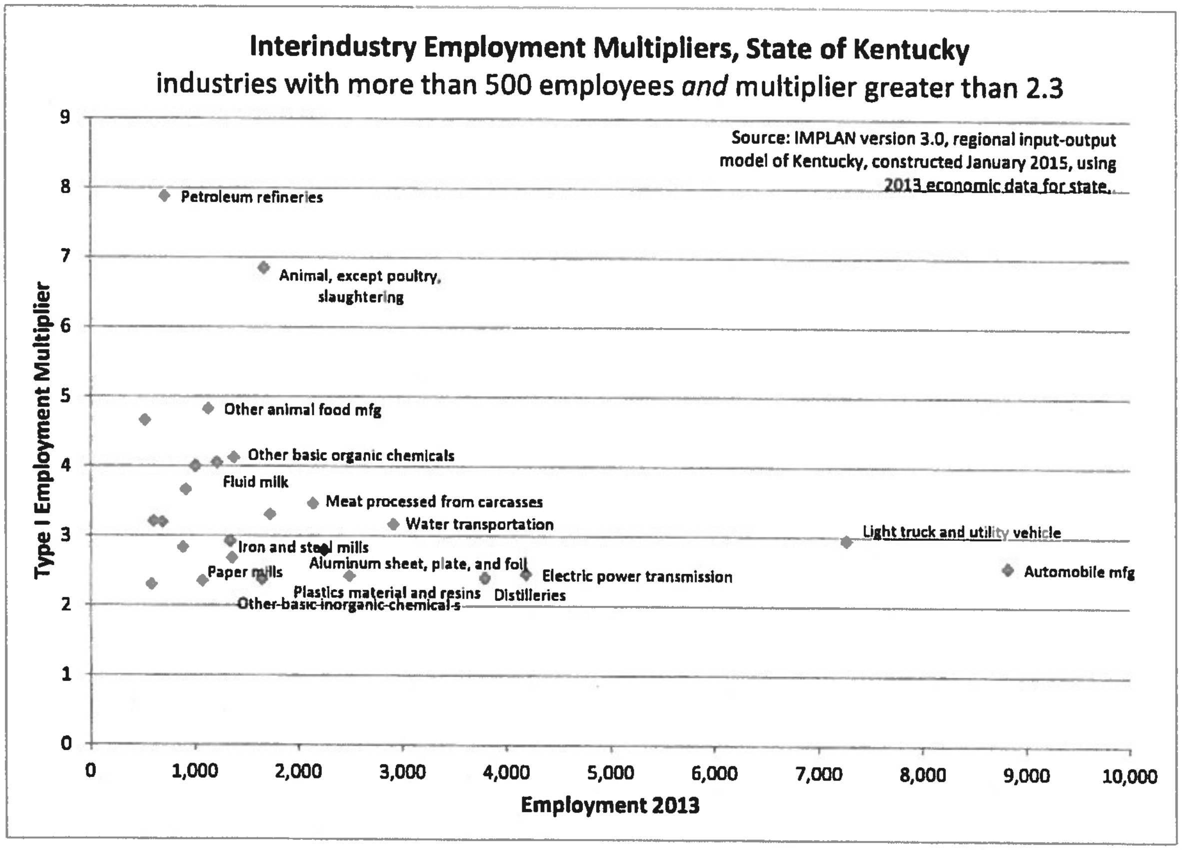
No person or agency knows the customer (or vendor) base for all Kentucky companies, and hence we rely on well-developed theories and models to predict the relative economic importance of different industries in the state. Probably the most richly developed and widely used regional modeling system is Implan, which came out of research at the University of Minnesota[2]. I have recently constructed a custom Implan model of Kentucky. The model begins with national input-output tables, essentially detailed production recipes for everything in the economy, and is calibrated to Kentucky using detailed county-level data on employment and wages for 470 industries. It is capable of predicting how a change in activity in any industry impacts output, employment, wages and other variables in all the other industries. The modeling system is the primary tool used to evaluate economic development incentives around Kentucky.

[2] For a description and documentation of the IMPLAN modeling system, see http://implan.com/v3/

Employment Linkages by Industry

I have used the Implan modeling system to organize detailed economic estimates on industrial activity in Kentucky. I sorted the estimates to reveal which industries have the most employment and which have the most employment spinoff impacts. As a measure of spinoff, I use what are called 'Type I employment multipliers'. These measure how much total employment in Kentucky would rise per new job in the reference industry, due to vendor linkages among industries. The Type I multipliers exclude the additional household spending impacts (Type II), and allow us to focus clearly on industrial linkages that drive the overall economy.

I started by plotting employment and the inter-industry job multipliers for all 470 industries represented in the Implan model. Then I zoomed in on industries that have significant employment *and* have relatively high job multipliers. I looked for the top 25 industries in terms of job multipliers, screening for those with more than 500 employees. This filtering clearly reveals the relative economic importance of industries in Kentucky. Note that the industries with the highest job multipliers are mostly in manufacturing. One can see that auto and truck manufacturing have the highest inter-industry employment multipliers, reflecting their deep linkages with suppliers in the state. Steel, aluminum, chemicals, paper, and distilled spirits manufacturing also stand out. Meat processing and other food production have strong linkages



with the rest of the economy as, for example, livestock require grain and hay which is grown in the state, which in turn requires purchases of farm equipment, fertilizer, trucks, banking, insurance, and so on.

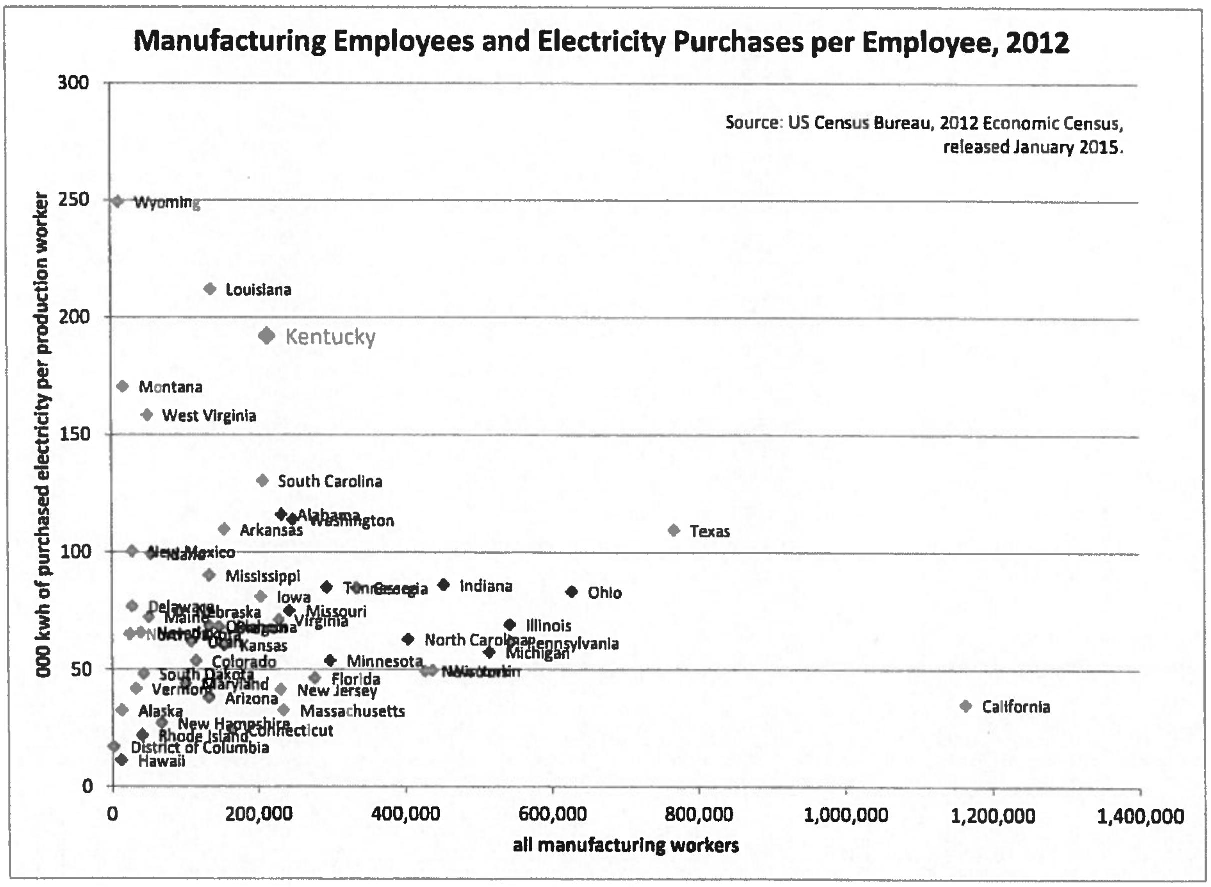
A larger list of export-based industries with greater than 500 employees and with an employment multiplier above 1.65 is provided in Appendix A. There are 83 industries, directly employing 276,000 persons (out of 2.4 million total statewide in all industries), that meet these criteria. Most of the industries listed are classified as manufacturing. The highest job multiplier is for petroleum refineries, followed by beef and pork slaughtering, federal electric utilities, other animal manufacturing, and tobacco products manufacturing. By contrast, industries with very large employment tend to have relatively low employment multipliers: insurance, R&D, wholesalers, banking, and home construction. These industries mainly purchase intermediate products made elsewhere. That is, compared to the manufacturing industries, they do not need to purchase of lot of materials in Kentucky to support their output. For example, consider an insurance operation. Insurance is by nature an intangible item, not requiring a lot of physical inputs to production. An insurance company employee is basically using a computer and a set of rules to match insurance buyers (those avoiding risk) with investors (those taking risk). Insurance agents often do not even have an office, and they purchase very little from other regional businesses in the course of selling a policy. Real estate firms and agents, with an interindustry employment multiplier of 1.48, are similar. The real estate industry is one of the largest employers in Kentucky, supporting about 70,000 jobs, but is generally not bringing new dollars into the state. Rather, the industry primarily absorbs dollars by providing a service to households and firms statewide.

The reader should not focus so much on the magnitudes of the industry multipliers as on the ranking of the multipliers. For example, it is unlikely that the true (unknown) employment multiplier for petroleum refining is as high as 7, but it is likely that the industry has one of the highest job multipliers in Kentucky. Given the measurement challenges inherent in these regional analyses, the input-output modeling tools can generate extremely high (unrealistic) multipliers, especially for smaller industries with strong linkages to the rest of the economy. The main conclusion supported by this list is that a fraction of industries in Kentucky directly or indirectly support most of the employment in the state.

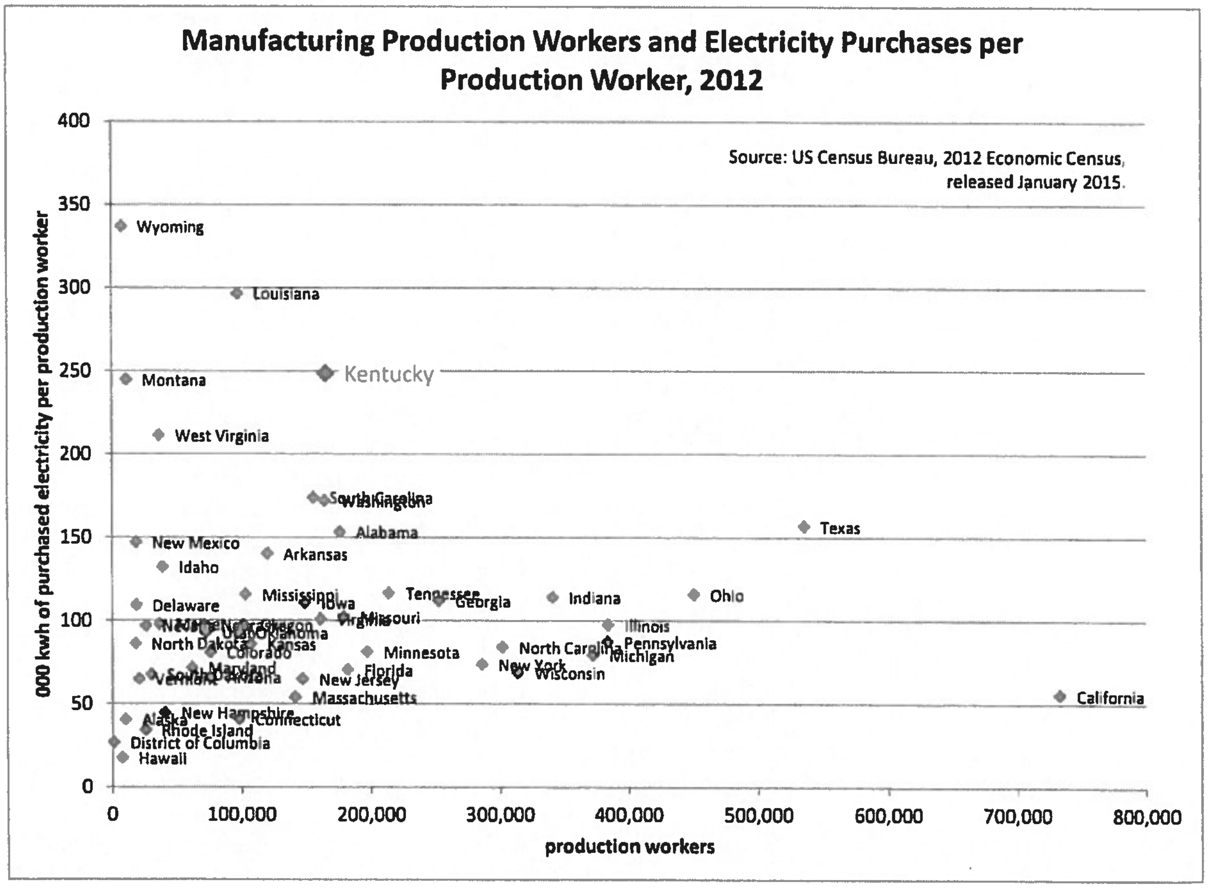
Energy-Intensiveness of Industries

Many of the industries I identify as having great employment impacts in Kentucky also are among the most energy-intensive. Whereas a household or a small business may spend a few thousand dollars annually on electricity and natural gas, an aluminum smelter, for example, will purchase tens of millions of dollars of electricity. Larger retail and commercial firms, hospitals, and the like purchase energy for heating, air conditioning and lighting, with annual energy expenditures per employee of perhaps a few hundred dollars. Many manufacturing operations use energy as part of their production processes, and companies producing aluminum may purchase over one hundred thousand dollars of electricity per employee annually.

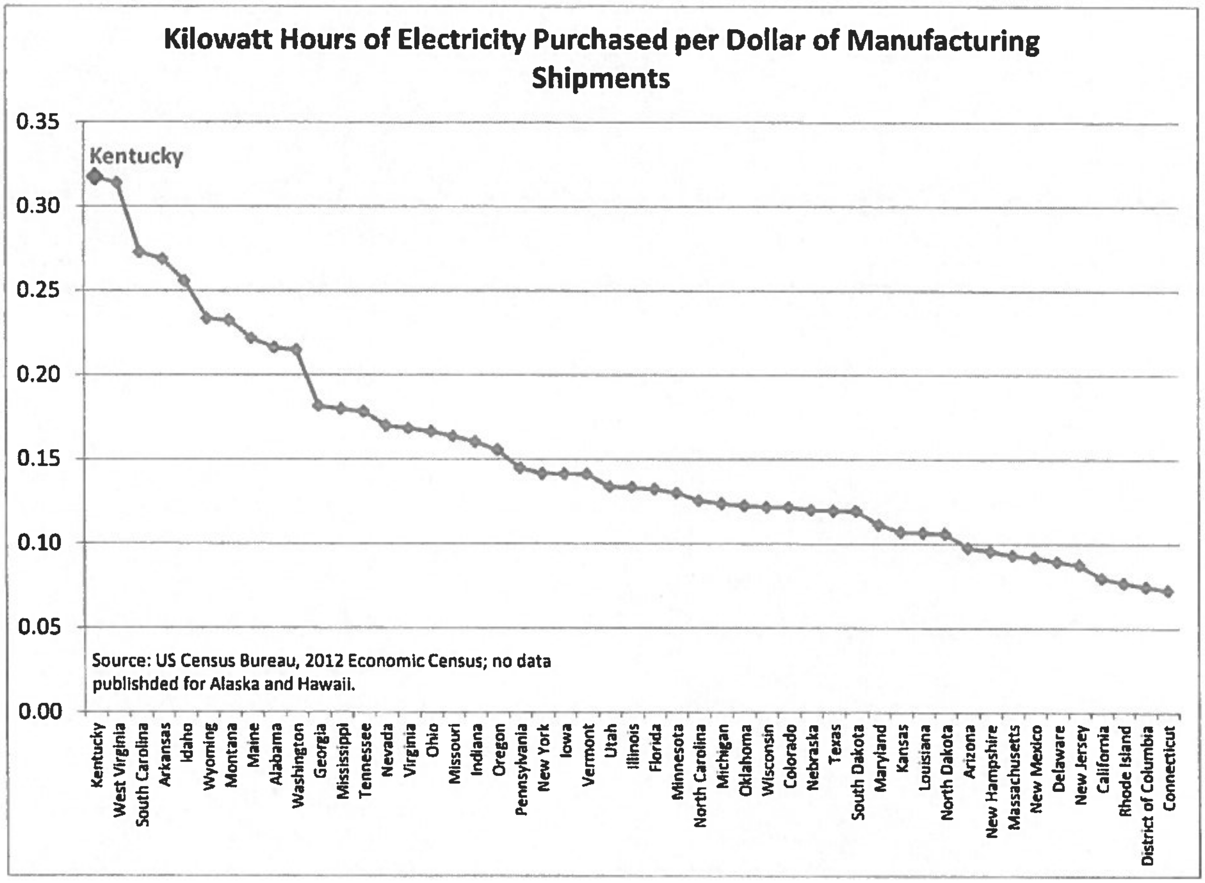
Indeed, the recently released 2012 Census of Manufacturers shows that Kentucky has one of the most energy-intensive portfolios of manufacturing industries in the US. The next chart plots electricity purchases per employee against total manufacturing employment in each state. Kentucky had 214,000 manufacturing employees, ranking 21st highest. However, Kentucky manufacturing firms purchased 192,200 kilowatt hours per employee, ranking 3rd highest. Moreover, Kentucky has many more manufacturing employees than the two states with higher electricity intensity – Wyoming and Louisiana.



The pattern holds up when we zoom in on just production workers in manufacturing, as opposed to the total. Note that managers, engineers, lawyers, accountants, and other office-oriented employees of a manufacturing firm get counted in federal statistics under the manufacturing industry. For example, perhaps half the employees at Louisville's Appliance Park are now white collar workers. The Census Bureau provides separate estimates for production workers versus all employees, and these are shown for all states in the accompanying chart. Kentucky had 165,000 production workers, with an average of 248,600 kilowatt hours per employee. Again, Kentucky ranks 3rd in electricity intensity per employee. And Kentucky ranks 4th highest in the concentration of production workers, with 77 percent of all manufacturing employees engaged in production. California, by contrast, has the most manufacturing employees, but ranks 46th in the share that are production workers (at 63 percent), reflecting the high degree of management, research, development, and other professional jobs associated with the technology industries located there.



One further way to sort the data is to look at the quantity of electricity purchased by manufacturers divided by the value of their shipments. Here Kentucky ranks highest among US states, with 0.32 kilowatt hours per dollar of shipments. Clearly, Kentucky has an extremely energy-intensive portfolio of manufacturing industries.



The Census Bureau does not publish state-level data on electricity usage for detailed manufacturing industries. However, they do publish details for 365 industries at the national level, and we can see that Kentucky has a disproportionate concentration of industries that are energy intensive. In Appendix B I display the top 50 manufacturing industries nationally, in terms of electricity purchases per employee, and also show purchases per business establishment for these detailed industries. The listing is particularly interesting since many of the top energy using industries are prominent in Kentucky. The highest electricity purchases per employee ($136,566) are in the primary aluminum industry, and Kentucky represents a large share of this national industry[3]. Other prominent Kentucky industries in the list include petroleum refining, steel, secondary aluminum, paperboard, soybean processing, plastics, wood

[3] According to the US Geological Survey, the two Kentucky smelters (at Hawesville and Sebree) accounted for 17 percent of the primary aluminum capacity of the US in 2013: 457 thousand metric tons out of a total of 3,500 metric tons. See Table 2, 2013 *Minerals Yearbook*, http://minerals.usgs.gov/minerals/pubs/commodity/aluminum/myb1-2013-alumi.pdf

pulp, paper, and aluminum sheet, plate, and foil. These industries all purchase more than $8,000 of electricity per employee. And a majority purchase more than $1 million in electricity per plant. Indeed, access to Kentucky's historically inexpensive electricity is the reason many of these industries are located in the state.

Other examples, drawn from our list of high employment multipliers above, illustrate the distinction between a manufacturing operation and a service operation. The average electricity purchases annually for a poultry processing plant purchases is over $800,000, for a fluid milk plant over $500,000, and for a meat processing plant over $230,000, driven largely by their massive refrigeration requirements. The average petroleum refinery purchases $15.9 million per year in electricity. The average truck manufacturing plant purchases $2.6 million in electricity annually, automobile manufacturing plants purchase $1.2 million, and motor vehicle parts plants purchase $225,000.

Finally, I have matched across the three databases to see what particular industries stand out in Kentucky. That is, what detailed industries have (a) large employment in Kentucky, (b) high Kentucky employment multipliers, and (c) high national electricity purchases per employee. The top ten industries are shown in the table below, ranked by their employment multiplier. The list includes petroleum and chemical manufacturing, food processing, and metal production.

Industries with Significant Employment, Dense Industry Linkages, and High Electricity Purchases

Industry description	Kentucky Employment	Kentucky Employment multiplier - Type I (interindustry)	Purchases of Electricity per Employee, US
Petroleum refineries	717	7.877	$44,577
Other basic organic chemical mfg	1,383	4.123	$40,894
Rendering and meat byproduct processing	915	3.664	$9,049
Secondary smelting and alloying of aluminum	604	3.201	$15,564
Iron and steel mills and ferroalloy mfg	1,346	2.920	$28,593
Aluminum sheet, plate, and foil mfg	2,249	2.794	$15,438
Plastics material and resin mfg	2,488	2.427	$19,433
Other basic inorganic chemical mfg	1,654	2.374	$40,894
Rolled steel shape mfg	932	2.247	$9,118
Alumina refining and primary aluminum production	1,454	2.028	$136,566

Sources: employment and employment multipliers from Implan model discussed above. Electricity purchases per employee from the 2012 Economic Census.

Conclusion

I have documented the relative economic importance of manufacturing operations in Kentucky, due to the fact that they bring in new dollars to the state by exporting products around the world, and also to the dense linkages with supporting industries. I have also shown that many important manufacturing industries in Kentucky purchase large amounts of electricity as part of their production processes. Indeed, as a whole, Kentucky has the most electricity-intensive manufacturing sector of any state.

Appendix A

Industries with Dense Industry Linkages and Significant Employment, Kentucky 2013		
Industry description	Employment	Employment multipler - Type I (interindustry)
Petroleum refineries	717.2	7.877
Animal, except poultry, slaughtering	1,678.2	6.848
Other animal food mfg	1,132.4	4.822
Internet publishing and broadcasting and web search portals	522.2	4.658
Other basic organic chemical mfg	1,382.6	4.123
Fluid milk mfg	1,217.5	4.052
Tobacco product mfg	1,006.8	4.000
Rendering and meat byproduct processing	915.4	3.664
Meat processed from carcasses	2,140.9	3.464
Wireless telecommunications carriers (except satellite)	1,734.5	3.305
Secondary smelting and alloying of aluminum	604.0	3.201
Roasted nuts and peanut butter mfg	688.9	3.190
Water transportation	2,910.9	3.167
Light truck and utility vehicle mfg	7,262.0	2.950
Iron and steel mills and ferroalloy mfg	1,346.1	2.920
Soap and other detergent mfg	887.7	2.832
Aluminum sheet, plate, and foil mfg	2,249.3	2.794
Paper mills	1,363.5	2.686
Automobile mfg	8,819.6	2.562
Electric power transmission and distribution	4,187.9	2.458
Plastics material and resin mfg	2,488.1	2.427
Distilleries	3,791.2	2.398
Other basic inorganic chemical mfg	1,653.6	2.374
Bottled and canned soft drinks & water	1,074.3	2.352
Tire mfg	582.6	2.303
Construction machinery mfg	940.5	2.275
Construction of other new residential structures	15,747.5	2.270
Rolled steel shape mfg	932.0	2.247
Poultry processing	5,243.0	2.209
Other federal government enterprises	1,825.6	2.204
Sawmills	2,725.2	2.197
Data processing, hosting, and related services	7,216.8	2.195
Other local government enterprises	13,955.9	2.146
Insurance carriers	23,157.6	2.118
Book publishers	575.6	2.101
Motor vehicle gasoline engine and engine parts mfg	2,488.3	2.087
Sanitary paper product mfg	876.7	2.061
Oilseed farming	1,973.7	2.035
Alumina refining and primary aluminum production	1,453.7	2.028

Appendix A (cont)

Industries with Dense Industry Linkages and Significant Employment, Kentucky 2013

Industry description	Employment	Employment multipler - Type I (interindustry)
Other financial investment activities	5,841.1	2.024
Federal electric utilities	839.0	2.021
Motor vehicle transmission and power train parts mfg	1,696.9	2.004
Adhesive mfg	628.6	2.001
Computer storage device mfg	534.1	1.999
Periodical publishers	621.0	1.997
All other food mfg	1,927.6	1.974
Radio and television broadcasting	3,536.1	1.964
Dry pasta, mixes, and dough mfg	846.4	1.958
Farm machinery and equipment mfg	639.9	1.954
Construction of new multifamily residential structures	2,454.9	1.949
Copper rolling, drawing, extruding and alloying	1,377.3	1.945
Other miscellaneous chemical product mfg	674.9	1.939
Tobacco farming	994.7	1.914
Maintenance and repair construction of residential structures	7,021.8	1.903
Wired telecommunications carriers	8,228.0	1.868
Flat glass mfg	679.5	1.866
Iron and steel forging	1,199.6	1.855
Electronic computer mfg	1,115.8	1.838
Other motor vehicle parts mfg	7,660.2	1.834
Paint and coating mfg	1,110.1	1.817
Motor vehicle steering, suspension (except spring), brake systems mfg	7,349.6	1.814
Veneer and plywood mfg	650.5	1.795
Insurance agencies, brokerages, and related activities	18,331.5	1.788
Pump and pumping equipment mfg	530.6	1.771
Other major household appliance mfg	2,135.3	1.765
Frozen specialties mfg	2,354.0	1.754
Electric lamp bulb and part mfg	2,165.9	1.749
Cookie and cracker mfg	2,484.8	1.743
Paperboard container mfg	2,918.8	1.743
Canned fruits and vegetables mfg	1,034.5	1.741
Motor vehicle electrical and electronic equipment mfg	1,603.2	1.740
Scientific research and development services	17,731.4	1.739
Aircraft mfg	1,608.7	1.734
Custom computer programming services	10,532.6	1.733
Iron, steel pipe and tube mfg from purchased steel	612.3	1.731
Ready-mix concrete mfg	1,481.9	1.711
Rail transportation	3,982.3	1.697
Independent artists, writers, and performers	582.4	1.690
Fluid power pump and motor mfg	615.0	1.688
Motor vehicle seating and interior trim mfg	4,279.4	1.681
Grain farming	11,514.7	1.667
Industrial truck, trailer, and stacker mfg	860.5	1.656
subtotal	276,456.6	

Appendix B

2012 NAICS code	Meaning of 2012 NAICS code	Purchased Electricity per Employee	Purchased Electricity per Establishment
Top 50 US Manufacturing Industries, Electricity Purchases per Employee and Establishment, 2012			
331313	Alumina refining and primary aluminum production	$136,566	$27,827,698
325120	Industrial gas manufacturing	$107,318	$2,320,566
322122	Newsprint mills	$94,956	$20,811,167
325193	Ethyl alcohol manufacturing	$60,392	$2,818,395
311221	Wet corn milling	$48,797	$5,152,855
327310	Cement manufacturing	$45,403	$2,367,347
325110	Petrochemical manufacturing	$44,577	$6,890,321
325180	Other basic inorganic chemical manufacturing	$40,894	$2,367,321
331410	Nonferrous metal (except aluminum) smelting and refining	$38,904	$2,058,345
324110	Petroleum refineries	$37,241	$15,870,589
325311	Nitrogenous fertilizer manufacturing	$31,094	$921,211
322130	Paperboard mills	$30,295	$6,820,538
331110	Iron and steel mills and ferroalloy manufacturing	$28,593	$7,365,553
311212	Rice milling	$28,475	$1,672,388
325194	Cyclic crude, intermediate, and gum and wood chemical manufacturing	$24,618	$1,616,209
327410	Lime manufacturing	$23,158	$1,096,239
321219	Reconstituted wood product manufacturing	$20,899	$1,269,288
311224	Soybean and other oilseed processing	$20,361	$1,042,624
325211	Plastics material and resin manufacturing	$19,433	$1,133,238
322121	Paper (except newsprint) mills	$17,780	$6,605,726
311211	Flour milling	$17,095	$605,480
325130	Synthetic dye and pigment manufacturing	$16,198	$952,654
327213	Glass container manufacturing	$15,841	$3,838,100
331314	Secondary smelting and alloying of aluminum	$15,564	$750,000
325312	Phosphatic fertilizer manufacturing	$15,522	$1,287,156
331315	Aluminum sheet, plate, and foil manufacturing	$15,438	$2,487,728
327993	Mineral wool manufacturing	$15,087	$768,896
325220	Artificial and synthetic fibers and filaments manufacturing	$15,074	$1,656,893
327211	Flat glass manufacturing	$14,393	$2,154,746
312112	Bottled water manufacturing	$14,057	$419,832
327420	Gypsum product manufacturing	$13,619	$485,570
325199	All other basic organic chemical manufacturing	$13,181	$1,049,450
326160	Plastics bottle manufacturing	$12,514	$897,514
313110	Fiber, yarn, and thread mills	$12,211	$943,250
327992	Ground or treated mineral and earth manufacturing	$12,203	$348,821
313230	Nonwoven fabric mills	$11,971	$837,954
322110	Pulp mills	$10,951	$2,460,129
325212	Synthetic rubber manufacturing	$10,925	$535,781
335991	Carbon and graphite product manufacturing	$10,692	$617,231
332431	Metal can manufacturing	$10,653	$1,076,901
331511	Iron foundries	$9,936	$959,392
324121	Asphalt paving mixture and block manufacturing	$9,801	$102,102
312113	Ice manufacturing	$9,786	$105,741
326113	Unlaminated plastics film and sheet (except packaging) manufacturing	$9,354	$573,254
324199	All other petroleum and coal products manufacturing	$9,145	$287,819
331221	Rolled steel shape manufacturing	$9,118	$358,220
327212	Other pressed and blown glass and glassware manufacturing	$9,080	$305,527
311613	Rendering and meat byproduct processing	$9,049	$387,213
325613	Surface active agent manufacturing	$8,778	$329,363
331420	Copper rolling, drawing, extruding, and alloying	$8,641	$746,843

Source: US Census Bureau, 2012 Economic Census, Table EC123111: Manufacturing: Industry Series: Detailed Statistics by Industry for the United States: 2012

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Kentucky Utilities Company
Meters Account 370
Determination of Meter Cost Allocation

Rate Class	Meter Unit Cost	Forecasted Number of Customers	Total Meter Cost	Meters Allocator
Residential	$ 65	35,890	$ 2,319,029	0.621463
General Service Single Phase	$ 75	5,305	$ 397,126	0.106423
General Service Three Phase	$ 285	1,639	$ 467,171	0.125194
All Electric Schools Single Phase	$ 131	28	$ 3,687	0.000988
All Electric Schools Three Phase	$ 689	21	$ 14,646	0.003925
Power Service Secondary	$ 624	375	$ 234,267	0.062780
Power Service Primary	$ 3,593	14	$ 51,651	0.013842
Time of Day Secondary	$ 843	52	$ 43,446	0.011643
Time of Day Primary	$ 4,981	23	$ 114,762	0.030754
Retail Transmission Service	$ 31,308	3	$ 78,269	0.020975
Fluctuating Load Service	$ 39,752	0	$ 3,313	0.000888
Outdoor Lighting Rate ST & PO	$ -	14,040	$ -	0.000000
Lighting Energy Rate LE	$ 65	0	$ 22	0.000006
Traffic Lighting Rate TLE	$ 65	65	$ 4,178	0.001120
Total		57,455	$ 3,731,567	1.000000

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company to Initiate Phase 2 of its gridSMART Project and to Establish the gridSMART Phase 2 Rider	)))))	Case No. 13-1939-EL-RDR

STIPULATION AND RECOMMENDATION

I. Introduction

Rule 4901-1-30, Ohio Administrative Code (OAC), provides that any two or more parties to a proceeding may enter into a written or oral stipulation concerning the issues presented in such a proceeding. This document sets forth the understanding and agreement of the parties who have signed below (Signatory Parties) and jointly recommend that the Public Utilities Commission of Ohio (Commission) approve and adopt this Stipulation and Recommendation (Stipulation) without modification, which resolves all of the issues raised in the above-captioned proceeding involving Ohio Power Company (AEP Ohio or the Company).

This Stipulation is the product of lengthy, serious, arm's-length bargaining among the Signatory Parties (all of whom are capable, knowledgeable parties). All parties to this proceeding were invited to discuss and negotiate this Stipulation, and it was openly negotiated with all parties. This Stipulation is supported by adequate data and information. As a package, the Stipulation benefits customers and the public interest, provides direct benefits to residential and low-income customers, and represents a just and reasonable resolution of all issues in this proceeding. The Stipulation violates no regulatory principle or practice and complies with and promotes the policies and requirements of Title 49 of the Ohio Revised Code. This Stipulation represents an accommodation of the diverse interests represented by the Signatory Parties and, though not binding, is entitled to careful consideration by the Commission. For purposes of resolving the issues raised by this proceeding, the Signatory Parties stipulate, agree, and recommend as set forth below.

II. Signatory Parties

This Stipulation is entered into by the Staff of the Public Utilities Commission of Ohio (Staff), Direct Energy Business, LLC and Direct Energy Services, LLC (collectively, Direct Energy), Interstate Gas Supply Inc. (IGS), , the Ohio Hospital Association (OHA), Environmental Defense Fund, and Ohio Environmental Council, and AEP Ohio.[1] The Signatory Parties agree to fully support the adoption of the Stipulation without modification in this proceeding.

III. Background

WHEREAS, AEP Ohio is an electric utility and an electric distribution utility as those terms are defined in Section 4928.01, Revised Code, and an electric utility operating company subsidiary of American Electric Power Company, Inc.

WHEREAS, the Commission in its August 8, 2012, Opinion and Order in the Company's second electric security plan proceedings directed AEP Ohio to continue its gridSMART Phase 1 project and to initiate Phase 2 of the gridSMART project. *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 No. 11-346-EL-SSO, et al., Opinion and Order at 62 (August 8, 2012). The Commission's order further directed the Company to file its proposed expansion of the gridSMART project – gridSMART Phase 2 – as part of a new gridSMART application. *Id.*

[1] For purposes of this Stipulation, Staff is considered a party in accordance with OAC 4901-1-10(C).

WHEREAS, on September 9, 2013, AEP Ohio commenced this proceeding by filing an application proposing the initiation of Phase 2 of the gridSMART project and establishment of the gridSMART Phase 2 rider as the mechanism for recovering gridSMART project investment beyond Phase 1.

WHEREAS, on December 14, 2015, a Joint Stipulation and Recommendation Agreement in the Purchase Power Agreement (PPA) proceedings, Case Numbers 14-1693-EL-RDR *et al.*, ("PPA Stipulation") was filed by AEP Ohio and several Signatory Parties that includes provisions related to the gridSMART Phase 2 docket.

WHEREAS, on March 31, 2016, the Commission issued an Opinion and Order modifying and adopting the PPA Stipulation; that decision is subject to rehearing and is not yet a final order. Accordingly, as further referenced below, the commitments from the PPA Stipulation that are incorporated in this Stipulation are dependent upon the Commission issuing a final order in the PPA proceedings adopting the PPA Stipulation without material modification.

WHEREAS, AEP Ohio and the Staff agreed to support Sierra Club's full intervention in this case if the Commission adopts the PPA Stipulation without material modification.

WHEREAS, AEP Ohio's gridSMART Phase 2 Proposal takes into account the Grid Modernization plan outlined in the PPA Stipulation Section III.A.15.G (page 29) which is fully consistent with this Stipulation.

WHEREAS, the Signatory Parties agree on how to resolve the issues presented in this proceeding, as reflected in their recommendations set forth below.

WHEREAS, the Signatory Parties believe that this Stipulation represents a fair and reasonable solution to all of the issues raised in this proceeding.

NOW, THEREFORE, the Signatory Parties stipulate, agree, and recommend that the Commission should issue its Opinion and Order in this proceeding accepting and adopting without modification this Stipulation and relying upon its provisions as the basis for resolving all issues raised by this proceeding.

IV. Recommendations

The Signatory Parties recommend that the Commission find as follows:

1. The Company shall be granted a limited approval of recovery of reasonable costs to complete the following:

A. BUSINESS CASE DEVELOPMENT

i. The Company submitted its Business Case for gridSMART Phase 2 as Attachment A to its Application in this case, which demonstrated a benefit-cost ratio of 2.8 on a cash basis and 2.0 on a net present value basis. Based on additional compromises agreed to by the Company in the context of this Stipulation (operational cost savings credit, additional VVO deployment etc.), the benefit-cost ratio remains the same even with additional investment. Moreover, as provided below, there will be a formal evaluation of benefits to be reported which will serve to further illustrate the benefits associated with the proposed implementation. Accordingly, the Signatory Parties agree that no further Business Case development is needed.

B. PHASE 2 FEASIBILITY AND SELECTION STUDIES

i. Engineering feasibility and selection studies will be completed for distribution automation circuit reconfiguration (DACR) and advanced meter infrastructure (AMI) scopes of work as originally proposed in the Company's application.

ii. The Company will use best efforts for completion and submittal of the feasibility and selection studies within one year of approval of the Stipulation.

iii. The Company shall also provide deployment selection detail and documentation to show how to select deployment activities that result in the maximum customer and company benefits for the technologies proposed in the original scope of the Phase 2 application.

iv. The primary purpose of the finalized feasibility and selection studies in parallel to deployment is to fully document the circuit selection process including examination of the expected reliability considerations associated with DACR.

C. DEPLOYMENT OF AMI AND DACR TECHNOLOGIES

i. The Company shall be authorized to move forward with deployment of AMI meters and DACR while the feasibility and selection studies are being finalized.

   a. AMI deployment shall be the approximately 894,000 AMI meters proposed in the Application. The Company shall initiate efforts to develop the needed systems and/or processes to provide the customers and the CRES providers with customer interval data. The Company agrees, where possible, to develop the systems and/or processes to provide the customers and CRES with interval data using a phase-in approach and to transfer as much data as possible to the customers and the CRES through the various implementation stages.

   b. DACR deployment shall involve a total of 250 circuits as referenced in the Application. The Company shall consider prioritizing those circuits that have adequate circuit ties or are adjacent to other circuits and have a history of appearing on the AEP Ohio Rule 11 Report (worst performing circuit list) in recent years. The Company shall determine the location of DACR technology deployment based on these and other relevant criteria and will work with the Staff to obtain their input regarding which Rule 11 circuits will yield maximum customer reliability benefits for the 250 circuits. The Company's selection and scheduling of the 250 circuits will be finalized after considering the Staff's input regarding the above factors.

   c. The AMI deployment is expected to take approximately forty-eight months from approval of the Stipulation. The DACR deployment is expected to take approximately seventy-two months from approval of the Stipulation.

D. FULL SYSTEM FEASIBILITY STUDY

i. In conjunction with the Phase 2 feasibility and selection studies described in Section B above, the Company shall conduct a feasibility study that encompasses all circuits and all meters to determine the full extent of cost justified future possible deployments of AMI, DACR, and VVO (including Volt-Amp Reactive power and Conservation Voltage Reduction technology). The VVO cost/benefit study shall be broken down by distribution circuit and substation, to determine the total amount of investment which would be cost-effective.

ii. Any additional future deployments of smartgrid technology beyond what is outlined in Section IV.1.C and IV.3 will be determined through a potential new gridSMART Phase 3 rider filing based upon completion of Phase 2including a cost/benefit study and a proposal for seeking cost recovery of deployment of all cost-effective Volt/Var technology. Nothing herein requires the Company to wait until after Phase 2 is completed to begin planning or filing for such additional future deployments. AEP Ohio agrees not to seek any additional incentive for installing the equipment or shared savings for any resulting energy savings.[2] If the filing is approved, the Company agrees to develop a deployment schedule and deploy the equipment in a timely manner.

2. Distribution Automation Circuit Reconfiguration (DACR) Reliability Improvement

The Company will annually report its performance improvements to the Staff for Phase 2 circuits equipped with DACR for more than six months. Annual reports will be submitted by August 15 based on the prior period ending June 30. The first report will occur when there are at least ten circuits that have had DACR technology installed for at least six months. The Company commits to achieve a 3-year average annual SAIFI improvement of 15.8%, excluding major events, on the aggregated performance of that group of circuits. In other words, the performance metric is expected to show that SAIFI performance (based on a 3-year rolling average) for the group of circuits that have had DACR technology installed for at least six months is 15.8% better than SAIFI performance on the same group of circuits would have been without DACR. This performance metric shall continue to be calculated annually through 2021. Since reliability improvement has many factors outside of the Company's control, the Company will have a secondary metric regarding successful operation of the DACR systems to be used if the SAIFI savings target is not reached. For this secondary metric, the Company expects to achieve a 80% successful operation of the DACR systems (based on a 3-year rolling average) for the aggregate of circuits equipped with DACR more than six months. The secondary metric will only be evaluated if the group of circuits experienced an average of at least 15 reconfigurable events per year and will incorporate factors agreed to by Staff and the Company. If the minimum requirement of 15 reconfigurable events is triggered for a particular year, that year will be excluded from the 3-year rolling average calculations and an additional historical year will instead be included (*i.e.*, an additional year preceding the earliest year that was otherwise to be included in the 3-year rolling average calculation). If neither measure is met, the Company must submit to Staff the reasons both measures were not met as well as an action plan in order to meet the measures the following year. If the commitment is missed 2 years in a row, the Company is required to file a report explaining its failure and show cause as to why the misses should not constitute a violation of the Stipulation; thereafter, the Commission can determine whether the Company has violated the Stipulation.

3. <u>Volt VAR Optimization (VVO)</u>

The Signatory Parties agree that the Company will move forward with a 160-circuit capital deployment of VVO with the costs to be recovered under the gridSMART Phase II rider with no shared savings and no incentive ROE.[3] The Company will make additional recoverable capital investments for any cost disallowed by a final Commission order so that the total capital investment is at least $20M (the Company reserves its normal rights to rehearing and appeal for any disallowance order). The parties agree that any lost distribution residential revenues

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[2] This is commitment arose as part of the PPA Stipulation and is dependent upon that agreement being adopted by the Commission through a final order without material modification.

[3] This is commitment arose as part of the PPA Stipulation and is dependent upon that agreement being adopted by the Commission through a final order without material modification. If the Stipulation is terminated, the Company will make a $20 million investment in lieu of the 160-circuit commitment, subject to the remaining terms of this paragraph.

associated with the VVO deployment shall be recovered through the current decoupling pilot approved in Case 11-351-EL-AIR or another mechanism if that pilot ends prior to the filing of a base distribution case post installation of VVO. The parties agree that another mechanism will be implemented for the Company to recover any lost distribution revenue associated with demand-metered commercial and industrial class customers. The parties agree that the proposed VVO investment in this paragraph resolves the Company's outstanding obligation for renewable or similar investment associated with the 2009 SEET case (Case No.10-1261-EL-UNC). All of the Signatory Parties recommend the Commission's adoption of the entire Stipulation including this paragraph as the order in this case and agree to affirmatively support the same. All Signatory Parties agree that the Commission can decide, based on an appropriate procedure established to consider this issue, whether to adopt this paragraph as part of the order in this case or sever the provision from the Stipulation. The Signatory Parties agree that rejection of the entire paragraph by the Commission would not constitute a modification of the Stipulation that could trigger withdrawal under Paragraph V.3 below, but a partial adoption or partial rejection does constitute a modification that could trigger a withdrawal.

AEP Ohio will prioritize deployment timelines for Company selected circuits with OHA members for any Volt-Var Optimization deployments over the term of the Affiliate PPA, when determining the implementation plan. AEP will work with OHA and the Staff to determine which circuits will be prioritized taking into account the benefit to the circuit in comparison to others and construction/staging considerations.

The VVO deployment is expected to take approximately seventy-two months from approval of the Stipulation.

AEP Ohio shall keep the equipment operational during the useful life of the equipment and shall file annual reports with the Commission stating the amount of energy reductions, peak demand reduction, and monetary savings and greenhouse gas emission reductions resulting from this equipment.

4. **<u>gridSMART Collaborative</u>**

The Company shall establish a gridSMART Collaborative process, separate from the existing EE/PDR Collaborative, to advise on the benefit analysis, structure of time of use rate offerings, provide deployment updates, review customer enrollment activities, annually report the level of customer savings being achieved, discuss customer and CRES access to interval data, discuss possible ways for customers to connect in-home technologies with real time electric usage data, and review the performance and environmental metrics. The gridSMART Collaborative shall be established and administered monthly through the project deployment timeframe for all stakeholders.

5. **<u>Time Differentiated Rates and other gridSMART Tariffs</u>**

A. The Company agrees to work with the Staff and Competitive Retail Electricity Suppliers (CRES) to administer a Time-of-Use (TOU) Transition plan. The CRES agree to develop similar programs to the Company's SMART Shift (2-tier Time of Use), SMART Shift Plus (3-tier TOU plus Critical Peak Pricing), and SMART Cooling (Thermostat) programs within 6 months of the Stipulation being adopted, using the same on-off peak meter program structure. Costs associated with the TOU plan and interval data portal will be recovered through the gridSMART rider; if the Company through its own fault departs significantly from the timelines outlined in this section, the Commission can consider reducing recovery of such costs.

B. The TOU Transition plan will include the following steps:

i. DEVELOP THE SYSTEM AND PROCESSES (6 months)

Within approximately 6 months of an approved Stipulation Order, the Company will complete the development of the necessary systems and processes to enable CRES TOU programs similar to the existing gridSMART TOU and Consumer Programs. As part of the transitional period, the gridSMART project shall include the capability of the Company to provide rate ready and bill ready billing for time of use rates offered by CRES providers that meet the same criteria of AEP Ohio's SMART Shift and SMART Shift plus. In addition, the Company will support bill ready billing for customers on CRES Smart Cooling programs, where compliance and customer credit calculations will be performed by the CRES. The monthly billing cycle totals per period (*i.e.*, on-peak and off-peak) will be provided to CRES providers within the time windows required by CRES providers for bill-ready and rate-ready billing. The Company shall continue to gather CRES input associated with these systems/processes. The Company will work with the CRES providers offering these programs and engage them in testing through the development effort. The Company shall build its systems and/or processes to allow for CRES Settlement via actual load data for TOU customers. The Company will add an AMI flag to the enrollment list to allow the CRES providers to be able to market to the gridSMART customers with an AMI meter.

ii. CUSTOMER COMMUNICATIONS (6 months)

After completion of the development of the system, the Company will disseminate customer communications to aid customers in moving to the CRES with similar program options. These communications will inform the customer of similar CRES programs for the customer to switch to if they so desired and will be administered over a timeframe of approximately six months. The Company agrees to seek input from interested parties in the gridSMART Collaborative to develop the plan and customer communications during the System Development and Customer Communications Phases.

iii. TOU COMPETITIVE REVIEW

Consistent with the Commission's Finding and Order in Case No. 12-3151-EL-COI, the Company shall agree to propose, within 90 days following the adoption of this Stipulation by the Commission, a simple two-tier, non-technology TOU rate reflecting default load auction prices for these AMI customers to be used as specified below only if the CRES TOU market has not evolved to be "sufficiently competitive" after the Customer communication phase.

C. Within 90 days after commissioning the necessary systems and engaging the customers (approximately three months after the systems and processes and customer communications steps are both completed), the Company and Staff will coordinate to file a report containing the latest data available concerning CRES TOU offerings. Within 90 days after the report is filed, the Commission will either determine if the CRES TOU market is "sufficiently competitive" or establish a process for reaching that determination. If the CRES TOU offers are deemed "sufficiently competitive", the Company's simple AMI TOU tariff filing will be dismissed and the Company's pending application requesting to withdraw its existing experimental TOU tariffs (Case No. 13-1937-EL-ATA) will be deemed approved and such tariffs will be discontinued. The Company will work with customers who have not enrolled in a CRES TOU to transition them to a program of their choice including CRES TOU or the Company's non-TOU SSO. Until such time that the Commission makes a ruling under this paragraph regarding the sufficiency of competitive CRES TOU offers, the Company's 13-1937 filing will be held in abeyance. If the Commission deems that the CRES programs are not sufficiently competitive, the Commission shall grant the Company's 13-1937 application and adopt the Company's newly-proposed AMI TOU program only for as long as it takes the market to develop. The Company will work with the customers that remain on the gridSMART TOU programs to transition them to the new TOU or to a CRES TOU offer or the Company's non-TOU SSO. Once the Commission subsequently determines that the CRES TOU offers are sufficiently competitive, the Company's AMI TOU tariffs will be discontinued and any remaining customers will be transitioned to a program of their choice including CRES TOU or the Company's non-TOU SSO.

D. The Company agrees to develop a CRES AMI interval data portal. The Company will target completion of the CRES AMI interval data portal in approximately 24 months after approval of the Stipulation. After completion of the CRES AMI interval data portal, CRES providers will have the opportunity to offer more strategic and competitive TOU options and programs. The Company shall build its system and/or processes to allow for CRES Settlement via actual load data after completion of the CRES AMI interval data portal for all CRES TOU customers. The Company will install Zigbee or other similar communication module within the AMI meters to facilitate program offerings with in-home technologies.

6. **Rider Recovery Mechanism**

Costs incurred for the gridSMART Phase 2 project shall be recovered through a rider rate filed quarterly with automatic approval 30 days after the filing unless otherwise determined by the Commission. These costs will be subject to an annual audit for prudency and no carrying charges will be imposed on over/under recoveries due to quarterly collections. The costs will be allocated and recovered from customers in the same manner as gridSMART Phase 1.

By Order issued in the ESP III (Case No. 13-2385-EL-SSO et al. February 25, 2015 Opinion and Order at 50-52) the Commission granted the Company's request to continue the gridSMART rider with certain modifications as proposed by the Company. Consistent with the Commission's directive in the ESP II (Case No. 11-346-EL-SSO Jan. 30, 2013 Entry on Rehearing at 53.), the Company, within 90 days after the expiration of ESP II, was required to file an application for review and reconciliation of the final year of the gridSMART Phase 1 rider (this was filed in Case No. 15-1513-EL-RDR). Additionally, in the ESP III Order the Commission approved AEP Ohio's request to transfer the approved capital cost balance into the DIR, and to also transfer any unrecovered O&M balance into the gridSMART Phase 2 rider, after the Commission has reviewed and reconciled gridSMART Phase 1 costs. Therefore, upon a

Commission Order in this case, the Company will move the approved gridSMART Phase 1 assets to the DIR and file for any unrecovered O&M expenses in a gridSMART Phase 2 rider application.

Because meters are capitalized at the time of purchase, the value of uninstalled gridSMART meters authorized for recovery through this Rider shall on average include only the aggregate supply necessary for approximately three months of meter deployment activity. Uninstalled meters in excess of this limitation will not be eligible for recovery through any other rider.

Concurrent with the inclusion of costs in the gridSMART Phase 2 rider, a credit reflecting projected operational cost savings will be incorporated so that it offsets the costs otherwise recovered through the rider (*i.e.*, the Company will recover costs through the rider that are net of the operational cost savings credit). This initial cost savings credit will flow back $400,000 per quarter starting in the fourth quarter of the first year and will not be adjusted or reconciled during the time it will be in effect, which will extend until the Commission adopts a new operational cost savings credit as described below.

The Commission Staff may retain an external consultant to review the Phase 1 and Phase 2 operational benefits of the gridSMART project. The consultant shall be selected by and be under the direction of Staff. The cost for the consultant and the Company's incremental resources to manage and support the consultants including data requests and other efforts associated with this review shall be paid by the Company and be fully recoverable through the Phase II rider, subject to prudence review.

The consultant will evaluate and recommend an ongoing level of operational benefits to be achieved and recognized in rates as part of the annual rider filing, to the extent such operational savings are not already reflected in rates. The Consultant shall complete this review using the AEP Ohio specific staffing situation and operational processes, where applicable, rather than using generalized industry standard data for these operational benefits. After this assessment is made, the Company and interveners shall endeavor to reach agreement on whether the recommended level of benefits should be adopted or modified. If an agreement cannot be reached, the Commission shall establish a process for the Company and intervenors to advocate their positions regarding the estimated level of benefits to be netted against gridSMART costs in this proceeding. Upon adoption by the Commission of a new operational cost savings credit, the Company's gridSMART Phase 2 riders shall reflect the net amount of prudently-incurred costs reduced by an amount equal to the value of the operational benefits as adopted by the Commission.

7. **Accounting**

The accounting life of all AMI meters will be 15 years instead of 7 years. 22,000 additional AMI meters that were deployed in order to perfect the Phase 1 pilot project, as well as all replacement and in stock AMI meters will be moved to the gridSMART Phase 2 rider for recovery upon approval of this Stipulation. The Company will retire the existing meters through the normal course of business which will be included in the DIR rider, and any undepreciated amount for the retired meters will be accorded standard accounting treatment and included in the calculation of the accumulated depreciation reserve for distribution and general plant in the next base distribution case. If during the Phase 2 meter rollout, the difference between the actual and theoretical reserve, as provided to Staff annually, becomes a negative 5% of the original cost on that same study, the Company will file, within two years, a base distribution case unless mutually agreed by the Company and Staff and approved by the Commission that a base case is not necessary.

Consistent with the Commission's February 25, 2015 Opinion and Order in the *ESP III* case (Page 52), the Company will file its final reconciliation for the gridSMART Phase 1 Rider to transfer the approved capital cost balance into the DIR and unrecovered O&M into the gridSMART Phase 2 Rider.

8. Cybersecurity

The Company agrees to brief the Commission and a limited number of key Staff on cybersecurity issues annually, including smart grid cybersecurity matters addressed in NIST Interagency Report 7628 Revision 1.

9. Historical Usage Data

The Company will provide historical usage data in a manner similar to the existing presentation on the AEP Supplier data website today for Commercial and Industrial customers (15 minute intervals). Data is "bill quality" (scrubbed).

10. Billing Data for Customers on CRES TOU or Other Smart Meter-Enabled Products

The Company agrees to provide AMI interval data to CRES via CRES Web Portal daily using 15 minute intervals. The release of the customer interval data shall be in accordance with the rules adopted by the Commission in Case No. 12-2050-EL-ORD on May 28, 2014. The Company shall continue to gather CRES input associated with these systems/processes and shall develop target timelines for implementation. Before the web portal goes "live" the Company will work with Staff to confirm that disclosure of granular residential customer usage data through the web portal only occurs with customer consent, consistent with Ohio Adm. Code 4901:1-10-24. The Company will use reasonable efforts to develop this functionality in a timely manner.

11. "One Day Delay" (between bill cycles) Data

AEP Ohio will make AMI data available to CRES providers as close to day-after load as possible, presenting the data on the Ohio CRES Portal for download.

12. Use of Actual Data for Residential and Commercial Customer PLCs and NSPL Calculations

For customers with AMI meters, AEP Ohio plans to utilize AMI interval data to not only calculate yearly transmission and capacity (NSPL and PLC) "tags," but also to perform final PJM 60 day settlement for customers on CRES TOU rates or DLC programs.

13. Audit Review and Data Measures

The Company will continue the same review process from Phase 1 - annual physical audit, financial audit and review of costs recovered through the rider. The Company will file quarterly updates in a single docket created for each calendar year and the annual review connected to that year shall occur in the same docket. In conjunction with the next six annual rider filings, the Company will also report the Non-financial Metrics, as shown in Attachment 1 for the prior calendar year.

14. Air Emissions Benefits

AEP Ohio agrees to work with stakeholders to develop a method to quantify the air emissions benefits from the program (resulting from any VVO efficiency gains, fewer truck rolls and time-based rate plans, etc.). The parties will use their best efforts to obtain approvals for using these air emissions benefits for compliance toward the new 111(d) rules for greenhouse gas emissions from fossil fuel plants. AEP Ohio also agrees to work with a third party to: (a) quantify the operational impacts of distributed generation on its distribution system; (b) identify additional changes needed for the distribution system to accommodate greater penetration of distributed generation; and (c) share its non-confidential findings with stakeholders. AEP Ohio will update and file the estimated cost of third party work, which will be fully recoverable through the Phase II rider, subject to audit and review.

AEP Ohio will use its best efforts to seek approval for the energy and peak demand reductions to be used as a compliance tool under the Clean Power Plan.

15. Peak Demand Reported to PJM as a result of VVO

Any approved VVO installations will be reflected in AEP Ohio's forecasts for demand. Currently, VVO is not eligible for bidding into the PJM Capacity Auction. AEP Ohio agrees to bid those resources into PJM if allowed in future rules and will support efforts to include those resources in new PJM rules. If VVO is permitted to be bid into PJM Capacity Auctions and the Company is successful in its bid, a plan will be developed for allocation of the incremental revenues received and any associated risks.

16. Green Button

AEP Ohio agrees to provide residential and small business customers with access to Green Button Download. Customers will be informed of this tool as part of the post-AMI meter installation communications. The Company agrees to continue to monitor the implementation costs and associated customer benefits of Green Button Connect. Later, if the benefits appear to exceed the implementation costs, the Company agrees to discuss possible implementation of Green Button Connect with the gridSMART Collaborative.

17. Prepaid Metering

AEP Ohio agrees to work with the Staff and interested parties within the gridSMART Collaborative to identify any legal and regulatory barriers for an EDU or CRES pilot prepaid metering program that customers could opt-into. Any future opportunity to move forward with Prepaid Metering would address consumer protections.

18. Customer Web Portal

The Company agrees to maintain a customer web portal that is customer-focused and displays the customer's AMI interval usage data. The Company shall use reasonable efforts to display this usage data the day after. The Company agrees to gather input on the customer web portal from the gridSMART Collaborative.

V. Procedural Matters

1. This Stipulation is submitted for purposes of this proceeding only. Except for purposes of enforcement of the terms of this Stipulation, this Stipulation (including the information and data contained therein or attached) shall not be cited as precedent in any future proceeding for or against any Signatory Party. The circumstances of this case are unique; thus, using the terms of this Stipulation in any other case is inappropriate and undermines the willingness of the parties to compromise. This Stipulation is a reasonable compromise involving a balancing of competing positions and it does not necessarily reflect the position that one or more of the Signatory Parties would have taken if these issues had been fully litigated. This Stipulation recognizes that each Signatory Party may disagree with individual provisions of this Stipulation, but also recognizes that the Stipulation has value as a whole. Upon filing the Stipulation and consistent with any procedural schedule established in this case, the Company will file testimony supporting the Stipulation.

2. The Signatory Parties will support the Stipulation if the Stipulation is contested, and no Signatory Party will oppose an application for rehearing designed to defend the terms of this Stipulation. If the Stipulation is adopted by the Commission, the Signatory Parties will support the Stipulation in appeal of the decision.

3. The settlement agreement embodied in this Stipulation was reached only after negotiations between the Company, Staff, and intervenors, and it reflects a bargained compromise involving a balancing of competing interests. Because the Stipulation is an

integrated settlement, it is expressly conditioned upon the Commission adopting the same in its entirety without material modification. Except as provided in Paragraph IV. 3, rejection of all or any part of the Stipulation and Recommendation by the Commission will be deemed to be a material modification for purposes of this provision. Upon the Commission's issuance of a decision that does not adopt this Stipulation in its entirety without material modification, or the alternative proposal, if one is submitted, a Signatory Party may withdraw from the Stipulation by filing a notice with the Commission within thirty days after the Commission's decision. Upon the filing of a notice of termination and withdrawal, the Stipulation shall immediately become null and void. In such event, this proceeding shall go forward from the procedural point at which the Stipulation was filed, and the parties will be afforded the opportunity to present evidence through witnesses, to cross-examine all witnesses, to present rebuttal testimony, and to brief all issues which shall be decided based upon the record and briefs, as if this Stipulation had never been executed.

April 4, 2016

Steven T. Nourse
On behalf of Ohio Power Company

Werner L. Margard / by STN per authority

Werner L. Margard, III
On behalf of the Staff of the Public Utilities Commission of Ohio

Mark A. Whitt / by STN per authority

Mark A. Whitt
On behalf of Direct Energy

Matthew S. White / by STN per authority

Matthew S. White
On behalf of Interstate Gas Supply, Inc.

Richard L. Sites / by STN per authority

Richard L. Sites
On behalf of the Ohio Hospital Association

Scott J. Casto / by STN per authority

Scott J. Casto
On behalf of FirstEnergy Solutions Corp.[4]

Trent A. Dougherty / by STN per authority

Trent A. Dougherty
On behalf of the Ohio Environmental Council

John J. Finnigan / by STN per authority

John J. Finnigan
On behalf of the Environmental Defense Fund

[4] FirstEnergy Solutions Corp. is a non-opposing party and is not a Signatory Party for purposes of the Stipulation.

Attachment 1

Non-financial Metrics	Baseline Pre Phase I	Current	2016	2017	2018	2019
# of Certified Meters						
Average System Voltage						
# of Manual Meter Reads						
# of Non-Pay Disconnects						
# of Meter Readers, Expressed in FTEs						
# of Smart Meters Failed						
# of Customer Minutes Saved From Self Healing Events						
# of AMI Power Theft Cases Billed						
# of Call Center Calls						
MW and MWh saved - VVO						
# of Estimated Bills						
# of Meters Salvaged or Transferred						
Reduction in Greenhouse Gas from VVO (estimate)						

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

CONSIDERATION OF THE IMPLEMENTATION OF SMART GRID AND SMART METER TECHNOLOGIES	)))	CASE NO. 2012-00428

INDEX

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

CONSIDERATION OF THE IMPLEMENTATION OF SMART GRID AND SMART METER TECHNOLOGIES	)))	CASE NO. 2012-00428

ORDER

BACKGROUND

By Order dated October 1, 2012, the Commission initiated this administrative proceeding to consider the implementation of Smart Grid and Smart Meter technologies, and time-of-use, or dynamic, pricing ("Opening Order"). The Opening Order provided that this administrative proceeding would also include a determination as to whether the Smart Grid Investment Standard and the Smart Grid Information Standard as set forth in the Energy Independence and Security Act of 2007 ("EISA 2007") should be adopted.[1] In particular, the purpose of the instant administrative matter would address all aspects of a Smart Grid system from hardware and software issues to reliability improvement, cost recovery issues, and dynamic pricing. All of Kentucky's jurisdictional electric

[1] The EISA 2007 Smart Grid Investment Standard and the Smart Grid Information Standard were part of standards considered by the Commission in Case No. 2008-00408, *Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007* (Ky. PSC Oct. 6, 2011). The Commission, however, ultimately deferred consideration of these two standards until the completion of this administrative proceeding.

utilities[2] and the five largest jurisdictional gas utilities[3] ("Gas LDCs") were made parties to this proceeding.

The Opening Order also incorporated into the record of this matter certain documents which had been filed in Administrative Case No. 2008-00408 and a report, along with supporting documents, developed by the Kentucky Smart Grid Roadmap Initiative.[4] The Opening Order also established a procedural schedule for the processing of this administrative proceeding. The procedural schedule provided deadlines for, among other things, the filing of individual or joint testimony, two rounds of discovery, and two informal conferences.

The following parties petitioned for and were granted intervention in this proceeding: the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); and the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG").

Joint testimonies were filed by Big Rivers and its three distribution cooperative members; EKPC and its 16 distribution cooperative members; LG&E and KU; and

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[2] The jurisdictional electric utilities are Big Rivers Corporation ("Big Rivers"), Big Sandy Rural Electric Cooperative Corporation, Blue Grass Energy Cooperative Corporation, Clark Energy Cooperative, Inc., Cumberland Valley Electric, Inc., Duke Energy Kentucky, Inc. ("Duke Kentucky"), East Kentucky Power Cooperative, Inc. ("EKPC"), Farmers Rural Electric Cooperative Corporation, Fleming-Mason Energy Cooperative, Inc., Grayson Rural Electric Cooperative Corporation, Inter-County Energy Cooperative Corporation, Jackson Energy Cooperative, Jackson Purchase Energy Corporation, Kenergy Corp., Kentucky Power Company ("Kentucky Power"), Kentucky Utilities Company ("KU"), Licking Valley Rural Electric Cooperative Corporation, Louisville Gas and Electric Company ("LG&E"), Meade County Rural Electric Cooperative Corporation, Nolin Rural Electric Cooperative Corporation, Owen Electric Cooperative, Salt River Electric Cooperative Corporation, Shelby Energy Cooperative, Inc., South Kentucky Rural Electric Cooperative Corporation, and Taylor Rural Electric Cooperative Corporation.

[3] The Gas LDCs are Atmos Energy Corporation ("Atmos"), Columbia Gas of Kentucky, Inc. ("Columbia"), Delta Natural Gas Company ("Delta"), Duke Kentucky, and LG&E.

[4] *See* Opening Order, Appendix A.

Atmos, Columbia, and Delta. Individual testimonies were filed by Duke Kentucky, Kentucky Power, and CAC.

An informal conference was conducted on April 19, 2013, to discuss the need for, and feasibility of, uniform standards for Smart Grid Investment and Smart Grid Information; to identify the process for determining reasonable standards and programs for the implementation of Smart Grid Investment, Smart Grid Information, reliability improvements, and dynamic pricing; and to assess the willingness of all parties to work in a collaborative manner to identify such reasonable standards and programs. Discussions at the April 19, 2013 informal conference resulted in an agreement among the parties to engage in a collaborative effort to address the issues raised in this administrative proceeding. On May 20, 2013, the parties to this proceeding, with the exception of KIUC, submitted Joint Comments setting forth a recommendation of the topics the collaborative would address, a proposed schedule going forward, and the manner in which the intervening parties and Commission Staff would participate in the collaborative process. The Joint Comments also recommended that the Commission not require adoption of the Smart Grid Investment Standard and the Smart Grid Information Standard.

On July 17, 2013, the Commission issued an Order in this proceeding requiring the parties to collaboratively address the following topics: 1) EISA 2007 Smart Grid Information and Smart Grid Investment Standards; 2) customer privacy; 3) opt-out provisions; 4) cybersecurity; 5) customer education; 6) dynamic pricing; 7) advanced metering infrastructure ("AMI") and automated meter reading ("AMR") deployment; 8) cost recovery for smart technology deployments; and 9) participation by natural gas companies in the electric Smart Grid. In addition, the Commission found that those topics should include issues relating to the recovery of costs of obsolete equipment.

The parties, with the exception of KIUC, implemented the collaborative process by holding monthly meetings to discuss each of the nine topics. The meetings began in August 2013 and concluded in June 2014. The collaborative effort culminated with the filing of a report on June 30, 2014, of the jurisdictional electric utilities and the Gas LDCs (collectively "Joint Utilities") addressing in detail and containing findings and recommendations on each of the nine issues referenced above. The report also contained comments from the AG and the CAC.

Finding that additional discovery was needed to further develop the record on the complex issues addressed by the June 30, 2014 report ("Report"), the Commission established a supplemental procedural schedule that provided for two rounds of discovery and set a hearing date. On November 25, 2014, after additional discovery was conducted, the Commission issued an Order finding that the record has been sufficiently developed for the Commission to render a decision based on the evidentiary record without the need for a formal hearing. The November 25, 2014 Order then established a deadline for the parties to this proceeding to, either individually or jointly, notify the Commission in writing whether the formal hearing should be held as scheduled or whether the matter could be submitted to the Commission for a determination based on the evidentiary record. In the event the parties recommended that no formal hearing be held, the November 25, 2014 Order established a deadline allowing the parties an opportunity to submit a brief, either individually or jointly. The November 25, 2014 Order also scheduled two dates for a meeting in which the

Commission would take public comments. The first public meeting was conducted on December 16, 2014, and the second on December 17, 2014.

On December 3, 2014, the parties to this matter submitted a joint statement stating their belief that a formal hearing for this matter was not necessary and that the case could be submitted to the Commission for a decision based upon the existing evidentiary record.

On February 27, 2015, the Joint Utilities filed a brief unanimously recommending that the EISA 2007 Smart Grid Investment and Smart Grid Information Standards should not be adopted by the Commission. The Joint Utilities assert that adopting the former standard would require them to make uneconomical investments, and adopting the latter standard would be largely redundant, while potentially stifling useful innovation in smart-technology proposals. The brief further summarized the Joint Utilities' positions on the nine issues that were addressed in their Report.

DISCUSSION

EISA 2007 Smart Grid Information Standard

The Joint Utilities state in the Report that they continue to believe that "[e]ach utility's unique circumstances and the pace of technological change make it unnecessary, and likely counterproductive, to impose uniform, one-size-fits-all standards, such as the EISA 2007 Smart Grid Information and Investment Standards."[5] The Joint Utilities state that the better approach is to use the Commission's existing authority to ensure the prudence of utility operations and investments.[6]

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[5] Report at 6.

[6] *Id.*

The EISA 2007 Smart Grid Information Standard for electric utilities requires that electric suppliers provide to purchasers of electricity direct access to time-based wholesale and retail price information, purchaser usage information, updates of price and usage information, day-ahead projections, and information concerning sources of generation, including associated greenhouse gas emissions.

This standard also requires electric utilities to provide consumers access to their customer-specific information at any time through the Internet and by other means elected by the utility, with other interested persons able to access only non-customer specific information.[7]

The Joint Utilities unanimously recommend that the Commission not adopt the EISA 2007 Smart Grid Information Standard. They state that adoption of the standard would require utilities to make uneconomical investments to provide customers direct access to a wide array of information, including price and usage information, without considering the costs or benefits of the provision of the information.[8]

Kentucky is not a restructured state in which customers may select an electricity supplier other than their incumbent utility, nor may customers utilize the services of aggregators.[9] The Joint Utilities point out that time-based or time-of-use ("TOU") pricing programs are currently voluntary and are not widely available to all customers.[10]

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[7] Opening Order at 4–5.

[8] Report at 77.

[9] Aggregators are entities that bring together, and negotiate on behalf of, large groups of consumers for reduced rates for goods or services or improved terms and/or conditions of service, especially in the energy sector

[10] Report at 78.

With regard to customer-specific information and privacy issues, the Joint Utilities state that they each have an internal customer privacy policy or practice currently in effect,[11] and that there does not appear to be a need to adopt this standard or develop a similar standard at this time.

As previously stated, the Joint Utilities recommend that the Commission continue to use its existing review processes and authority to ensure that utilities are providing customers with the information they need in economical ways. They believe that this will allow the Commission to continue to have oversight over the information provided to customers, yet still recognize each utility's individual characteristics, including the utility's unique costs and benefits of providing various information in certain ways to each utility's customers.[12] The Joint Utilities identified a list of terms and substantive items which they believe the Commission may consider useful when reviewing Smart Grid or customer privacy proposals.[13]

The AG states that he does not oppose the "economical use of smart technologies,"[14] but agrees with the Joint Utilities that the Commission should not adopt the EISA 2007 Smart Grid Information Standard.[15] The CAC provided no comments regarding the Smart Grid Information Standard.[16]

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[11] *Id.* at 11.

[12] *Id.* at 78.

[13] *Id.* at 1.

[14] *Id.* at 80.

[15] *Id.*

[16] *Id.*

The Commission will not require adoption of the EISA 2007 Smart Grid Information Standard or a similar standard. We will, however, require the utilities to provide certain basic information to their customers. Customers should be able to access their own information at any time through the internet or by other cost-effective means of communication selected by the utility. At a minimum, customers should be able to access historical information regarding their electricity or natural gas usage, expressed in each utility's respective billing units, as well as the customers' current applicable tariff rate. Additionally, the utilities should endeavor to provide customers this information in as close to real time as practical.

In addition, the Commission accepts the Joint Utilities proposal to adopt the "voluntary-checklist approach"[17] set forth in the Customer Privacy section of the Report. The Commission's decision is discussed in further detail in the Customer Privacy section later in this Order.

EISA 2007 Smart Grid Investment Standard

The EISA 2007 Smart Grid Investment Standard for electric utilities provides that each state consider requiring electric utilities to demonstrate that certain factors with regard to investing in a Smart Grid system were considered before the utilities invested in non-advanced grid technologies.

The standard also requires each state to consider rate recovery of Smart Grid capital expenditures, operating expenses, and other costs related to the deployment of Smart Grid technology, including a reasonable return on the capital expenditures, as

[17] *Id*. at 15.

well as recovery of the remaining book value of obsolete equipment replaced with Smart Grid deployment.[18]

As previously stated, the Joint Utilities do not support the adoption of the EISA Smart Grid Investment Standard, but rather believe that the Commission should exercise its existing authority to review Smart Grid investments.[19]

Based on the testimony and the responses to data requests in this case, most electric utilities have migrated to AMR or AMI meters and functionality, or are in the process of doing so.

Additionally, the electric utilities' systems include Smart Grid technologies such as Distribution Automation ("DA") features, volt/volt-ampere-reactive ("volt/var") programs and Supervisory Control and Data Acquisition ("SCADA") systems.

As the Joint Utilities note, they have all deployed smart technologies, but in different ways and degrees.[20] The record reflects that the Joint Utilities have adequately demonstrated that system investments are tied to issues relating to cost and how to incorporate components that are compatible with the current distribution system. They have also demonstrated that they are attempting to improve system reliability as they make investment decisions.

Although not stated directly in the Report, the Joint Utilities imply that adoption of the EISA 2007 Smart Grid Investment Standard would require them to seek a certificate of public convenience and necessity ("CPCN") for Smart Grid investments. In the

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[18] Opening Order at 4.

[19] Report at 6.

[20] *Id.* at 77.

discussion in the Cost Recovery section of the Report, the Joint Utilities argue that, while CPCN proceedings may be needed for some smart technology deployment, CPCN authorization is not necessary for all smart technology investment.[21]

The AG concurs with the Joint Utilities that the Commission should not adopt the EISA 2007 Smart Grid Investment Standard. CAC provided no comments with regard to the adoption of this standard.

The Commission believes that the record in this case demonstrates that the deployment of Smart Grid technology, whether in the form of smart meters or DA, varies from utility to utility, as are the reasons for the investment decisions that are made. Some of the investments in existing Smart Grid technology were made after the utilities had obtained a CPCN, and some were not. The Commission has not found any of the investments to be unreasonable.

While the Commission supports the intent of the EISA 2007 Smart Grid Investment Standard, we will not require its adoption. The Commission does not find it practical for each jurisdictional utility to be required to obtain a CPCN for every Smart Grid or meter investment decision. The Commission does find that each of the Joint Utilities should develop internal procedures and policies regarding Smart Grid investments. Such procedures and policies should include a description of their systems, their planning goals, and explanations of how such investments will be considered. This will be discussed in more detail in the discussion of Distribution Smart Grid Components.

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[21] *Id.* at 76.

In support of our decision, the Commission notes the steps the distribution cooperatives take in developing their Construction Work Plans ("CWPs"). The CWPs set forth straightforward design criteria and explain the basis for each project included therein.

With regard to CPCNs, the Commission finds it appropriate for jurisdictional electric utilities to obtain CPCNs for major AMR or AMI meter investments and distribution grid investments for DA, SCADA or volt/var resources. In the past, when addressing requests for CPCNs for AMR and AMI meters, the Commission has noted its concern regarding a number of meter related issues such as cost, compatibility with current system equipment and software, and unplanned obsolescence.

Customer Privacy

In the Executive Summary of the Report ("Executive Summary"), the Joint Utilities take the position that it is not necessary for the Commission to mandate a new customer privacy standard that includes the customer data provisions of the EISA 2007 Smart-Grid Information Standard.[22]

In their Report, the Joint Utilities propose a list of terms and substantive items for utilities to consider when reviewing customer privacy policies and practices.[23] The Joint Utilities state that the Commission may find this information "useful when addressing smart-grid or other customer-privacy-related utility proposals."[24] According to the Joint Utilities, this voluntary checklist approach will ensure that utilities have the flexibility they

[22] *Id.* at 1 and 9–16.

[23] *Id.*

[24] *Id.* at 1–2 and 9.

need to continue to provide safe, reliable, and economical service while protecting their customers' privacy.[25] As previously stated, the Joint Utilities noted in their Report that each member of the Joint Utilities has a voluntary customer privacy policy or practice in force.[26] In their brief, the Joint Utilities state that federal and state legal protections are already in place concerning customer information and that government and industry groups are working to develop even more robust voluntary standards for utilities.[27] In addition, the Joint Utilities state that Kentucky's utilities have gone beyond the legal requirements to ensure that only appropriate use is made of customer information.[28] The Joint Utilities, therefore, assert that a new mandatory customer privacy standard, including the requirements set forth by the EISA 2007 Smart Grid Information Standard, is unnecessary.[29]

The AG recommends that the Commission adopt a statewide mandated customer privacy standard. The AG further recommends that the standard provide for significant civil penalties for non-compliance and include a universal opt-in policy that would prevent a utility from disclosing consumer information unless the customer elects to allow such disclosure.[30]

CAC states that it supports utilities' efforts to maintain customer privacy. However, CAC believes that aggregated customer information is often helpful to it in its

[25] *Id.* at 15.

[26] *Id.* at 11.

[27] Brief of the Joint Utilities (filed Feb. 27, 2015) at 6.

[28] *Id.*

[29] *Id.*

[30] Report at 2 and 15.

effort to provide assistance to low-income customers in paying their bills and in its mission as an advocate for low-income customers. CAC believes that information should be readily available to it for these purposes and in regulatory proceedings. Also, since utilities benefit from its low-income assistance, CAC recommends that the utilities absorb the costs of providing this information.[31]

The Commission agrees that each utility should have a customer privacy policy and will accept the proposal set forth in the Report. Although the Commission will not mandate the adoption of a particular standard, the Commission finds that each utility should formalize its customer privacy policy and include it as part of its internal procedures. Each utility should incorporate appropriate items from Section VI and Section VII of the Customer Privacy section of the Report.[32] The Commission also finds that each utility's customer privacy policy (or a descriptive summary of that policy) should be available on the utility's website. Through independent research of the websites of the jurisdictional electric utilities, the Commission notes that each investor-owned utility ("IOU") has an established privacy policy accessible via its website, but only a few of the cooperatives have a privacy policy available on their websites.

Also, aggregated customer information should be available to CAC to assist it in its effort to provide assistance to low-income customers in paying their bills and in its mission as an advocate for low-income customers. That information, however, should be provided only at the request of CAC after it provides a reasonable basis for requesting the information.

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[31] *Id.* at 2.

[32] *Id.* at 11–14.

The Commission finds the AG's recommendation to adopt a statewide privacy standard that provides for civil penalties and requires opt-in to be inappropriate. If necessary, utility customers may seek civil penalties through individual court actions. Further, the Commission believes that the utilities' existing customer privacy policies should be sufficient to address any issues regarding the use of their individual information, and that aggregate information provided to entities such as CAC will be to the benefit, rather than the detriment, of utility customers.

Opt-Out

In the Executive Summary, the Joint Utilities state that requiring utilities to offer opt-out from smart meters "has potentially significant cost and operational impacts for utilities and customers"[33] and that such requirements are generally not beneficial.[34] They further note that allowing a customer to opt out of using a smart meter will inhibit the customer's ability to participate in and obtain timely information about usage.[35] The Joint Utilities recommend that the Commission evaluate the issue of opting out on a case-by-case basis.[36]

The Joint Utilities state that the two primary objections some customers raise about smart meters are that smart meters will adversely affect their health and that smart meters invade their privacy.[37] In the Report, the Joint Utilities provide a brief

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[33] *Id.* at 2.

[34] *Id.*

[35] *Id.* at 26.

[36] *Id.* at 2.

[37] *Id.* at 17.

rebuttal to each concern.[38] In addition, the Commission notes that the AG states that very few independent scientific results have been produced demonstrating that smart meters are either unsafe or dangerous to human health.[39]

To support their argument regarding the potential negative effects of allowing customers to opt out of smart meters, the Joint Utilities cite some of the potential costs and operational impacts in the Report.[40]

In addition to the information provided in the Report, the Commission notes the issues identified in Farmers RECC's response to a Staff data request regarding the impact of opt-outs from AMI deployment:

- Metering: A utility would be required to purchase special meters that would not have the current AMI capability.

- Billing: A utility would be required to establish special meter reading routes and cycles to accommodate opt-out customers. Additional administrative time and other costs would be incurred to manage the billing for these customers.

- Manual meter reading: A utility would incur additional costs to dispatch meter readers to travel to, and read the meter of, each opt-out customer.

- Outage notification: Information on whether opt-out customers were being affected by service outages would also be limited to either the customer notifying the utility or through a personal visit.

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[38] *Id.* at 17–18.

[39] *Id.* at 27.

[40] *Id.* at 20–23.

- Voltage/Current system modeling: Opt-out customers would be more difficult to include in these types of studies due to the lack of data.

- System reliability/Blinks: Opt-out customers would no longer be a part of this trouble-shooting capability, as no data could be supplied from their meters.[41]

The Joint Utilities state that they did not address AMR metering in the Report.[42] AMR meters only allow for one-way communication, and the Joint Utilities have defined the term "smart meter" as a meter that allows two-way communication. Therefore, AMR meters would not fall within their definition of a "smart meter." However, the Joint Utilities contend that no opt-out should be allowed for AMR meters and state that a number of utilities have already deployed AMR systems.[43]

The Joint Utilities oppose opt-outs of any kind for digital meters with no communications capabilities because such meters function in a manner essentially identical to older electromechanical meters. They do not believe electromechanical meters are being manufactured domestically today.[44] Therefore, they state that any opt-out from a non-communicating digital meter is impracticable at best.[45]

The AG recommends that both technical and informational opt-out should be available to customers, where infrastructure allows.[46]

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[41] Farmer's response to Commission Staff's Request for Information (Ky. PSC Sept. 18, 2014), Item 10.

[42] Report at 17.

[43] *Id.*

[44] *Id.* at 18.

[45] *Id.*

[46] *Id.* at 27–28.

CAC recommends that if a utility offers opt-out alternatives, customers should not be penalized for choosing to opt out.[47] In addition, CAC believes that the ability of utilities with smart meter deployments to instantaneously remotely disconnect customers could potentially have negative consequences for low-income customers which should be mitigated.[48]

Due to the potential negative impact on the operational benefits of a Smart Grid, the Commission does not support meter opt-outs, whether they be from digital, AMR or AMI meters. However, almost all of the public comments submitted in this proceeding address concerns with smart meters from either a health or privacy perspective. Therefore, the Commission accepts the Joint Utilities' recommendation to consider opt-out on a case-by-case basis (or more precisely, on a utility-by-utility basis). Each utility will be able to determine the need for an opt-out provision and petition the Commission for consideration. The Commission believes that each utility can best determine the need for an opt-out provision and whether that the proposed opt-out provision will apply to digital, AMR, or AMI meters will be at the utility's discretion.

The Commission finds that any opt-out provision should require those customers that opt out to bear the cost related to that decision — through a one-time fee and/or a monthly charge, as appropriate.

<u>Customer Education</u>

The Joint Utilities believe that customer education will increase the success of smart meter deployment. They recommend that each utility deploying smart meters consider using some of the customer-education topics that are addressed in the

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[47] *Id.* at 2 and 28.

[48] *Id.* at 28.

Report.[49] However, most utilities have already migrated to AMR or AMI meters, so initial education efforts for smart meter deployment have, for the most part, already been made.

The Joint Utilities state that customer education on the benefits of smart technology is critical to gaining customer acceptance and use of Smart Grid technology.[50] In addition, they state that customer education tends to increase the benefits from Smart Grid investment, consistent with the Smart Grid Investment Standard's consideration of cost effectiveness.[51]

The Joint Utilities cite the customer education efforts undertaken by Duke Energy, American Electric Power ("AEP") (the parent company of Kentucky Power), and Owen Electric.[52] In addition, the Joint Utilities cite various topics and communication channels that the utilities may utilize for customer-education purposes.[53]

In his testimony, the AG acknowledges the need for customer education but does not include any additional comments in the Report. CAC recommends that customer education should be mandatory as smart meters are deployed.[54]

It is evident from the testimony, responses to data requests, and the Report that utilities are already engaging in customer education concerning safety and some Smart Grid efforts. However, the Commission is uncertain as to the structure of each utility's

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[49] *Id*. at 3.

[50] *Id*. at 29.

[51] *Id*. at 35.

[52] *Id*. at 29–31.

[53] *Id*. at 31–35.

[54] *Id*. at 36.

customer-education policy or practice. The Commission, therefore, has determined that each utility should formalize its customer-education policy or practice with regard to Smart Grid and smart meters as part of its internal procedures manual.

At a minimum, the policy should address the appropriate education activities for deployment of smart meters and other Smart Grid components (including DA, volt/var and SCADA). The requirement will allow each utility to develop educational materials that apply to its own system.

Dynamic Pricing[55]

In the Report's Executive Summary, the Joint Utilities state that their collective experience is that residential dynamic pricing programs have had low participation and have sometimes resulted in energy-consumption increases.[56] The Joint Utilities contend that they should not be required to create and offer dynamic rate offerings, but should be allowed to do so voluntarily, subject to Commission approval.[57]

As defined in the Report, dynamic pricing refers to pricing that varies according to the time at which the energy is consumed, is normally tied to energy prices in the wholesale market or to system peaks, and is delivered to customers through time-based rates or tariffs.[58] The Report describes several forms of dynamic pricing, including time-

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[55] In the Opening Order establishing this case, dynamic pricing was defined to include time-of-use pricing, critical peak pricing, real-time pricing, and credits for consumers with large loads that enter into pre-established peak load reduction agreements that reduce a utility's planned load capacity obligations. *See* further definition in the Appendix to this Order.

[56] Report at 3.

[57] *Id.*

[58] *Id.* at 37.

of-use ("TOU") or time-of-day ("TOD") pricing, both variable and fixed critical-peak pricing ("CPP"), peak-time rebate ("PTR") and real-time pricing ("RTP").[59] [60]

Although there has not been significant customer participation, several utilities continue to offer some form of dynamic pricing options, such as on peak/off peak TOD rates. The Joint Utilities provide a discussion of the experiences of Duke Energy, the parent company of Duke Kentucky, in North Carolina, South Carolina, and Ohio, and the experiences of Kentucky Power, KU/LG&E, Owen Electric and Jackson Energy.[61] In addition, the Report lists the residential dynamic pricing programs available in Kentucky[62] and those offered by AEP and Duke Energy in other jurisdictions.[63]

The Report also includes a discussion of issues that need to be addressed when considering dynamic pricing. The rate and tariff issues include: opt-in/opt-out, rate structure, contract terms, waiting periods to switch rates, complexity, criteria for participation and hold-harmless trial periods.[64] Also discussed in the Report are technology considerations that the customer and utility must address, customer education and marketing. Other considerations, including cost, equity, and economic justification, are also discussed.[65]

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[59] *Id.* at 37–38.

[60] Some utilities, such as AEP, do not consider TOD rates to be dynamic pricing.

[61] Report at 38–41.

[62] *Id.*, Appendix B at 85–86.

[63] *Id.*, Appendix C at 87.

[64] Report at 41–42.

[65] *Id.* at 42–43.

Noting that the results of dynamic pricing are mixed at best, the AG states that the Commission should not require mandatory residential TOU rates and that such rates should be no more than an option for residential ratepayers.[66] In the Report, the AG also adopted all of the positions set forth by CAC.[67]

According to CAC, the potential impact on low-income customers is a concern because these customers typically do not fully understand the complexities of dynamic pricing or they lack the technology to fully take advantage of such rates. As a result, participation in dynamic-pricing programs could inadvertently result in higher bills. CAC therefore recommends that dynamic pricing should not be required for residential customers and that efforts should be undertaken to prevent any inadvertent increases in bills for low-income customers who may choose to take advantage of voluntary pricing options. CAC also states that the rates of customers not participating in dynamic pricing should not be negatively impacted by dynamic pricing offerings.[68]

The Commission is on record as noting its consistent support of dynamic pricing. At one point in Administrative Case 2008-00408, the Commission stated its hope to ultimately develop some dynamic pricing options for utility customers. In its Opening Order initiating this case, the Commission likewise stated its intent to consider issues relating to dynamic pricing. However, the Joint Utilities argue that utilities should not have an obligation to create dynamic rate offerings, but should have the option to do so

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[66] *Id.* at 3 and 44.

[67] *Id.*

[68] *Id.* at 3–4 and 45. As noted earlier, a definition of each form of dynamic pricing can be found in the Appendix to this Order.

subject to Commission approval. The AG and CAC support this position. All parties agree that customer participation in dynamic pricing should be voluntary.

The Commission believes that a strong economic argument cannot currently be made for mandatory dynamic pricing tariffs in Kentucky, and there is uncertainty what impact dynamic pricing tariffs may have on energy consumed or on utility revenues. However, the Commission notes that its general intent is to incentivize consumers to decrease usage, move usage to off-peak hours, and/or reduce energy bills, all of which will likely reduce a utility's revenues.

The Commission, therefore, will not require that a broad array of dynamic pricing proposals be developed. The Commission strongly encourages the jurisdictional electric utilities to develop some pilot programs for consideration. It seems appropriate, at a minimum, that the jurisdictional electric utilities could develop and offer "on-peak/off-peak" TOD tariffs (including seasonal TOD tariffs). In fact, TOU and TOD rates are currently offered by some of Kentucky's jurisdictional electric utilities, as reflected in Appendix B of the Report.

The Commission finds that any dynamic pricing offering should be voluntary for customer participation, and efforts should be made to mitigate negative impacts on low-income customers through customer education or any other reasonable and cost-effective method.

<u>Distribution Smart Grid Components</u>

The Joint Utilities state that distribution Smart Grid components can provide benefits to customers and add value to utilities' distribution systems.[69] However, they

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[69] *Id.* at 4.

cite a number of items which can impact customers that utilities should consider before investing in Smart Grid systems.[70] These items include technological obsolescence, prepaid metering, and remote connection and disconnection of utility service.[71] The Joint Utilities contend that adding more regulation such as that represented by the EISA 2007 Smart Grid Investment Standard is unnecessary.[72] They claim that the Commission already has the authority through review of base rates, CPCN authority, and other mechanisms to ensure that utilities make prudent investments.[73]

As technologies have demonstrated value or have been determined to be advisable, the Joint Utilities have deployed smart technologies in their distribution systems.[74] Currently, all of the Joint Utilities have deployed some form of Smart Grid technology.[75]

A summary example of some Smart Grid deployment discussed in the report includes:

- Kentucky Power has deployed AMR, DA — Circuit Reconfiguration, Volt/VAR Optimization, and SCADA.[76]

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[70] *Id.*

[71] *Id.*

[72] *Id.* at 4 and 56.

[73] *Id.*

[74] *Id.* at 46.

[75] *Id.* at 47.

[76] *Id.* at 47–48.

- Duke Kentucky has installed four self-healing systems as part of its normal reliability improvement process.[77]

- LG&E and KU have deployed four SCADA systems (KU, LG&E electric, LG&E gas, and downtown Louisville), and have installed about 90,000 AMR meters (electric and gas) across their service territories. LG&E is currently deploying approximately 1,500 AMI meters and related infrastructure in its downtown Louisville network as part of a project to gather enhanced engineering information for network planning.[78]

- Jackson Purchase Energy Corporation has illustrated the value of Smart Grid deployments in its system with DA and Voltage Conservation.

- Other smart technology components that are utilized include:
  - Switches and valves (Duke Kentucky);
  - Voltage stabilization (Kentucky Power);
  - Meters (Duke Kentucky); and
  - Communications and SCADA (LG&E/KU).[79]

- 15 distribution cooperatives offer prepaid metering as a voluntary option to their consumers.[80]

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[77] *Id.* at 48.

[78] *Id.*

[79] *Id.* at 52–53.

[80] *Id.* at 48–49.

The AG did not comment on Smart Grid components. CAC states that it is open to "fair and limited"[81] prepaid metering, but notes its concerns with prepaid metering and remote disconnection.[82]

As the Commission stated earlier, its findings and the requirements set forth in this section are coupled with the decision regarding the EISA 2007 Smart Grid Investment Standard. The Commission will require that each of the jurisdictional electric utilities develop internal procedures regarding Smart Grid investments that include a description of their systems, their planning goals, and an explanation of how such investments will be considered a Smart Grid plan.

Requiring each utility to develop a Smart Grid plan should not be burdensome. As noted earlier, the steps the distribution cooperatives take in developing their CWPs set forth straightforward design criteria and explain the basis for each project included in the CWP. The Commission will not apply the formal CPCN process to each utility investment decision, but needs to ensure that the jurisdictional electric utilities define and develop a strategy that can guide their investment decisions. Until recently, the distribution cooperatives were required to submit their CWPs for Commission review and receive a CPCN before starting construction. The IOUs have not been subjected to that requirement. As such, they have invested in AMR and AMI meters, DA, SCADA and other Smart Grid deployment without prior Commission oversight. With the deployment of smart technology that may directly impact the service provided to

[81] *Id.* at 57.

[82] *Id.*

customers becoming more prevalent, the Commission believes that a requirement to develop internal procedures regarding Smart Grid investment is reasonable.

Cybersecurity

In the Executive Summary of the Report, the Joint Utilities state that all stakeholders' interests are aligned and that utilities should take reasonable measures to prevent cyber-attacks. However, they state that existing mandatory and voluntary cybersecurity standards, frameworks, and guidelines are sufficient, and that adding regulations or rules serves to weaken utilities' ability to thwart cyber-attacks. They state that the focus should be on the ability to evolve with emerging threats and not on compliance with cybersecurity standards. They believe an effective cybersecurity process is one that is continuously evolving based on emerging threat intelligence. As a result, they assert that additional requirements at the state level are not necessary or advisable.[83]

As the Joint Utilities note, some members are subject to mandatory cybersecurity standards to protect the Bulk Electric System.

These include the Critical Infrastructure ("CIP") Standards developed by the North American Electric Reliability Corporation ("NERC"), approved by the Federal Energy Regulatory Commission ("FERC"), and administered and enforced by NERC and its regional entities, including the SERC Reliability Corporation ("SERC").[84] [85]

[83] *Id.* at 4.

[84] *Id.* at 59.

[85] SERC has jurisdiction over all of Kentucky except the easternmost portion, which is under the jurisdiction of the Reliability First Corporation.

The Joint Utilities cite and discuss the eight CIP standards that apply to cybersecurity,[86] as well as the voluntary cybersecurity guidelines developed by the National Institute of Standards and Technology.[87]

The Joint Utilities also provide a discussion of the tools that comprise the "Guide to Developing a Cyber Security and Risk Mitigation Plan," developed by the National Rural Electric Cooperatives Association and the Cooperative Research Network ("CRN"). The purpose of the CRN guide is to enable cooperatives to strengthen their security posture and allow for continuous improvement.[88]

Finally, the Joint Utilities cite the "Cyber Security Risk Assessment and Risk Mitigation Plan Review for the Kentucky Public Service Commission" ("Guernsey Report") that shows that oversight activities are being conducted for utilities not subject to mandatory requirements.[89]

The Guernsey Report offered a focused assessment and general guidance on areas of utility operations that may be susceptible to cyber threats for Kentucky's smaller electric cooperatives and other similarly situated entities. Although participation in the Guernsey cybersecurity assessment was voluntary and limited to only six electric cooperatives, the intent was to develop a document that could be a starting point for further evaluation and improvement of utility operations. Twenty one topical areas were identified in the Guernsey Report for the purpose of evaluating the general effectiveness of utility operations and identifying opportunities for improvement in mitigating cyber

[86] Report at 59–60.

[87] *Id.* at 60–61.

[88] *Id.* at 61.

[89] *Id.* at 62.

risks. Since release of the Guernsey Report, the Kentucky Association of Electric Cooperatives has spearheaded a workgroup to further develop operating procedures and work practices to address cybersecurity threats for its membership.

The Joint Utilities state that none of its group takes cybersecurity lightly.[90] However, they argue that more requirements may be counterproductive because cyber-attacks are constantly evolving and a focus on compliance could create a false sense of security.[91]

The AG recommends that the Commission require compliance with the mandatory and voluntary standards, guidelines and resources cited in the Report.[92] The AG also recommends that the Joint Utilities use the best foreseeable measures possible to secure their cybersecurity.[93] To support its position, the AG cites comments from several cybersecurity experts and from a Chairman's forum on cybersecurity hosted by the Commission.[94] CAC states that utilities should work diligently to take reasonable measures to prevent and defeat cyber-attacks.[95]

The Commission agrees with the Joint Utilities that a mature, effective cybersecurity process is one that is continuously evolving to address new cyber threats. However, the Commission believes that each utility should have some form of cybersecurity plan in place beyond the FERC or NERC mandatory standards.

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[90] *Id.* at 63.

[91] *Id.* at 62.

[92] *Id.* at 5 and 64.

[93] *Id.*

[94] *Id.* at 63–64.

[95] *Id.* at 5 and 64.

Therefore, the Commission will require that the Joint Utilities develop internal procedures addressing cybersecurity.

Having met with representatives of each of Kentucky's major jurisdictional electric, gas, and water utilities to discuss cybersecurity, the Commission is generally aware of the effort the Joint Utilities have taken (and are taking) to address cyber threats.[96] Each utility particularly cited the confidential and sensitive nature of their plans to address cyber issues. Given the sensitivity of cybersecurity concerns, the utilities should be allowed to keep their procedures confidential.

The Commission, therefore, will not require each utility's actual internal procedure be filed; rather each utility will be required to certify the development of cybersecurity procedures. The utilities will then be required to make a presentation describing their procedures to the Commission (and the AG, should he wish to attend). In addition, the Joint Utilities will be required to continue to make cybersecurity presentations every two years to the Commission through the Track Meeting process.

All utilities are advised to develop, maintain and enforce a management approved written cybersecurity policy that addresses known and reasonably foreseeable cybersecurity risks. The policy and any subsequent procedures developed should incorporate essential elements of each utility's system that may be susceptible to cyber threats in conjunction with plans for hazard mitigation, emergency response and recovery and other relevant continuity of service arrangements.

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[96] The AG was invited and participated in person or by phone in each meeting.

Cost Recovery

The Joint Utilities state that since each utility is deploying smart technology "under different circumstances, in different ways, at different paces, and to different extents,"[97] there cannot be one specific approach to addressing cost recovery.[98] The Joint Utilities believe that all the utilities should be able to propose, and the Commission should consider, any form of cost recovery including traditional base rates, existing cost recovery mechanisms (e.g., demand-side management riders), and new riders or surcharge mechanisms.[99] They also believe that utilities proposing smart technology deployments that necessitate retiring existing utility assets with unrecovered book life should take the cost of those retirements into account in their cost-benefit analyses and be able to recover that cost if the deployment is prudent.[100] Finally, the Joint Utilities state that additional proceedings or criteria for Smart Grid deployments are unnecessary because existing cost recovery and other review proceedings and mechanisms are sufficient.[101]

In the Report, the Joint Utilities state that there must be reasonable assurance of cost recovery of prudent investments and of the remaining book costs of replaced equipment for utilities to invest in Smart Grid technologies to improve the service and information their customers receive.[102] They state that there is nothing novel about this

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[97] Report at 5.

[98] *Id.*

[99] *Id.* at 5 and 70.

[100] *Id.*

[101] *Id.*

[102] *Id.* at 70.

concept, whether for smart technologies or other utility investments.[103] The Joint Utilities cite the manner in which they have been allowed to recover smart technology costs in Kentucky and other jurisdictions in which they operate.[104] In particular, they discuss the cost recovery authorized for Taylor County RECC, Shelby Energy, and South Kentucky RECC for major meter change outs.[105]

The AG does not oppose the economical and cost-effective investment in smart technologies, but reserves judgement on his ultimate position based on a case-by-case review of cost recovery requests as they occur. CAC provided no comments on this topic.[106]

The Commission is sensitive to the Joint Utilities' concern regarding the cost recovery of reasonable smart technology investment and recovery of the remaining cost of replaced facilities and equipment. The Commission currently has the authority to reasonably address smart technology investment issues, and we conclude that the requirement to develop internal procedures regarding Smart Grid investment will assist both the utilities and the Commission in addressing cost-recovery concerns. To the extent that investments are in accordance with a Commission-approved internal Smart Grid investment policy, there should be a strong presumption that the investment was reasonable. Therefore, except for the development of an internal Smart Grid investment policy, the Commission will not impose any additional review of such

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[103] *Id.*

[104] *Id.* at 70–74.

[105] *Id.* at 71–73.

[106] *Id.* at 5 and 76.

investments. Smart Grid investments will therefore be treated like any other investment or expense.

How Natural Gas Companies Might Participate in Electric Smart Grid

The Joint Utilities state that Kentucky's Gas LDCs have pioneered deployment of automated and smart technologies because they have deployed SCADA in their distribution systems and AMR in meter reading for many years.[107] They assert that the Gas LDCs have already achieved associated efficiencies and that they have less to gain from smart technology deployment than the electric utilities.[108]

Neither the AG nor CAC provided any comments with regard to this issue in the Report.

The Commission recognizes that Smart Grid and smart meter issues are predominantly confined to the electric industry. We also agree that operational savings from further Smart Grid investment is not likely to be achieved by the Gas LDCs. The Commission further notes that, with one exception, the Gas LDCs do not offer TOU or dynamic pricing structures.[109]

The Commission will require the Gas LDCs to comply with the customer privacy, consumer education, and cybersecurity internal procedures requirements contained herein. The broad issues in these three areas apply to both electric and gas utilities.

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[107] *Id.* at 6 and 64.

[108] *Id.*

[109] LG&E's TS-2 transportation service reduces the transportation rate to commercial and industrial customers by $.50 per Mcf during the months of April through October.

SUMMARY OF FINDINGS

1. Neither the EISA 2007 Smart Grid Information Standard nor the Smart Grid Investment Standard should be adopted.

2. The Joint Utilities should provide customers access to historical information regarding their energy use and tariff rate and should endeavor to provide this information to customers in as close to real-time as practical. Furthermore, the Joint Utilities should provide aggregated information to CAC upon its reasonable request.

3. The Joint Utilities should develop internal procedures governing customer privacy, customer education, and cybersecurity as set forth in this Order.

4. Within 60 days of the date of this Order, the Joint Utilities should file with the Commission their internal procedures governing customer privacy and customer education.

5. Within 60 days of the date of this Order, the Joint Utilities should certify to the Commission that they have developed internal cybersecurity procedures.

6. Dynamic pricing requirements should not be mandated, but the jurisdictional electric utilities should strongly consider the development of voluntary pilot programs and tariffs.

7. Provisions allowing customers to opt out of smart meter deployments should be considered as they are proposed by individual utilities.

8. The jurisdictional electric utilities should be required to develop internal procedures regarding Smart Grid investments to include but not be limited to a

description of their systems, their planning goals, and explanations of how such investments will be considered.

9. The jurisdictional electric utilities should identify Smart Grid investments in each rate case.

10. Utility investments in Smart Grid and unrecovered book value of replaced equipment should be treated like any other investment or expense, and afforded full rate recovery following a request for recovery, discovery, and Commission approval, if reasonable.

IT IS HEREBY ORDERED that:

1. Neither the EISA Smart Grid Information Standard nor the EISA 2007 Smart Grid Investment Standard shall be adopted.

2. The Joint Utilities shall develop policies and procedures that provide customers access to historical information regarding their energy use and tariff rate and shall endeavor to provide this information to customers in as close to real-time as practical. Furthermore, the Joint Utilities shall provide aggregated information to CAC upon its reasonable request.

3. The Joint Utilities shall develop internal policies and procedures governing customer privacy, customer education, and cybersecurity as set forth in this Order.

4. Within 60 days of the date of this Order, the Joint Utilities shall file with the Commission their internal procedures governing customer privacy and customer education.

5. Within 60 days of the date of this Order, the Joint Utilities shall certify to the Commission that they have developed internal cybersecurity procedures.

6. The jurisdictional electric utilities shall not be required to develop Dynamic Pricing programs and tariffs, but they are encouraged to do so.

7. Customer participation in any Dynamic Pricing program or tariff shall be voluntary.

8. Provisions allowing customers to opt out of smart meter deployments shall be considered as they are proposed by individual utilities.

9. The jurisdictional electric utilities shall be required to develop internal policies and procedures regarding Smart Grid investments as described in this Order.

10. Within 60 days of the date of this Order, the jurisdictional electric utilities shall file with the Commission their internal procedures regarding Smart Grid investments.

11. The jurisdictional electric utilities shall identify Smart Grid investments in each rate case.

12. Utility investments in Smart Grid and unrecovered book value of replaced equipment shall be treated like any other investment or expense, and afforded full rate recovery following a request for recovery, discovery, and Commission approval, if reasonable.

13. Any documents filed in the future pursuant to ordering paragraphs 4, 5, and 10 herein shall reference this case number and shall be retained in the utility's general correspondence file.

14. The Executive Director is delegated authority to grant reasonable extensions of time for the filing of any documents required by this Order upon the showing of good cause for such extension.

15. This case is hereby closed and removed from the Commission's docket.

By the Commission

ENTERED

APR 13 2016

KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Aaron D. Greenwell

Acting Executive Director

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2012-00428 DATED APR 13 2016

Dynamic Pricing defined:[110]

Dynamic pricing refers to pricing that varies according to the time at which the energy is consumed. It is normally tied directly or indirectly to prices in the wholesale market or to system conditions (peaks) and normally is delivered to a customer via time-based rates or tariffs. There are several different kinds of dynamic pricing.

A. Time-of-Use ("TOU") or Time-of-Day ("TOD") — TOU or TOD rates typically divide a day into two or three groups of hours that have different rates associated with them. For example, a utility might divide the day into peak, intermediate, and off-peak rates, with different hours assigned to each rate, e.g., late evening through early morning would typically be off-peak hours. Each day may have one or two peak periods and may have as many as three intermediate periods. The hours assigned to each pricing period may change seasonally, as well; for example, a summer-peaking utility may have summer TOU periods and different non-summer TOU periods. The rates associated with each period might also change seasonally.

TOU or TOD rates may vary by season, but typically the design is predictable and easy for the customer to understand. Because these rates do not reflect varying cost conditions, they are ordinarily characterized as having little dynamism.

B. Critical-Peak Pricing ("CPP") — There are two types of CPP rates: variable and fixed. Fixed CPP rates are identical to TOU rates with the added feature that during certain days of the year, which are prescribed by tariff, there are a relatively small number of critical-peak hours that have a markedly higher rate than the standard TOU peak rate. Like TOU rates, fixed CPP rates do not reflect varying cost conditions, making them equally lacking in dynamism as TOU rates. Variable CPP rates, however, add an element of dynamism that TOU and fixed CPP rates do not have because the critical-peak periods are not established by tariff; rather, the implementing utility typically may call a critical peak no more than a certain number of times for certain maximum durations during a year, and may do so on an established amount of notice to customers, usually anywhere from half an hour to several hours.

C. Peak-Time Rebate ("PTR") — PTR rates usually involve establishing a baseline amount of usage for a customer or group of customers and then rewarding those customers with rebates for using less than the baseline amount of energy during peak periods. As with CPP rates, the peaks can be established by tariff or can be called by the utility upon established notice to customers.

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[110] Report at 37–38.

D. Real-Time Pricing ("RTP") — RTP rates are the most dynamic of the dynamic-pricing options. Under RTP, customers pay rates linked to the hourly market price for electricity. Customers typically receive hourly prices on a day-ahead or hour-ahead basis.

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

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

OPINION AND ORDER

Table of Contents

The Commission, having considered the above-entitled application, and the record in these proceedings, hereby issues its Opinion and Order in these matters.

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Thompson Hine, LLP, by Philip B. Sineneng, 41 South High Street, Suite 1700, Columbus, Ohio 43215, on behalf of Duke Energy Retail Sales, LLC and Duke Energy Commercial Asset Management, Inc.

Mark A. Hayden, Jacob A. McDermott, and Scott J. Casto, FirstEnergy Service Company, 76 South Main Street, Akron, Ohio 44308, and Latham & Watkins LLP, by David L. Schwartz, 555 Eleventh Street, NW, Suite 1000, Washington, D.C. 20004-1304, on behalf of FirstEnergy Solutions Corporation.

Bell & Royer Co., LPA, by Barth E. Royer, 33 South Grant Avenue, Columbus, Ohio 43215-3927, and Gary A. Jeffries, Dominion Resources Services, Inc., 501 Martindale Street, Suite 400, Pittsburgh, Pennsylvania 15212-5817, on behalf of Dominion Retail, Inc. d/b/a Dominion Energy Solutions.

Whitt Sturtevant, LLP, by Mark A. Whitt and Andrew J. Campbell, 88 East Broad Street, Suite 1590, Columbus, Ohio 43215, and Vincent Parisi and Lawrence Friedeman, 6100 Emerald Parkway, Dublin, Ohio 43016, on behalf of Interstate Gas Supply, Inc.

Joseph M. Clark, 21 East State Street, 19th Floor, Columbus, Ohio 43215, on behalf of Direct Energy Services, LLC and Direct Energy Business, LLC.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff, Stephen M. Howard, Michael J. Settineri, and Gretchen L. Petrucci, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, on behalf of Constellation NewEnergy, Inc. and Exelon Generation Company, LLC.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff, Stephen M. Howard, and Gretchen L. Petrucci, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, on behalf of Retail Energy Supply Association.

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

Michael R. Smalz, Ohio Poverty Law Center, 555 Buttles Avenue, Columbus, Ohio 43215-1137, on behalf of Appalachian Peace and Justice Network.

Trent Dougherty, 1207 Grandview Avenue, Suite 201, Columbus, Ohio 43212, and John Finnigan, 128 Winding Brook Lane, Terrace Park, Ohio 45174, on behalf of Ohio Environmental Council and Environmental Defense Fund.

Robert Kelter and Madeline Fleisher, 1207 Grandview Avenue, Suite 201, Columbus, Ohio 43212, on behalf of Environmental Law & Policy Center.

Samantha Williams, 20 North Wacker Drive, Suite 1600, Chicago, Illinois, 60606, on behalf of Natural Resources Defense Council.

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

Bricker & Eckler, LLP, by J. Thomas Siwo, 100 South Third Street, Columbus, Ohio 43215-4291, on behalf of Paulding Wind Farm II LLC.

Kevin R. Schmidt, 88 East Broad Street, Suite 1770, Columbus, Ohio 43215, on behalf of Energy Professionals of Ohio.

OPINION:

I. HISTORY OF THE PROCEEDINGS

Ohio Power Company d/b/a AEP Ohio (AEP Ohio or the Company)[1] is a public utility as defined in R.C. 4905.02 and an electric utility as defined in R.C. 4928.01(A)(11), and, as such, is subject to the jurisdiction of this Commission.

On December 20, 2013, AEP Ohio filed an application for a standard service offer (SSO) pursuant to R.C. 4928.141. The application is for approval of an electric security plan (ESP) in accordance with R.C. 4928.143. As proposed, AEP Ohio's ESP would commence on June 1, 2015, and continue through May 31, 2018, and will be referred to herein as ESP 3. According to the application, for all customer classes, customers are expected to experience average annual rate changes ranging from -27 percent to 6 percent during the ESP period. The application proposes the recovery of other costs through various riders during the term of the ESP. In addition, the application contains provisions addressing distribution service, economic development, alternative energy resource requirements, and energy efficiency requirements.

By Entry issued on December 27, 2013, a technical conference regarding AEP Ohio's application was scheduled, which occurred on January 8, 2014. By Entry issued on January 24, 2014, the procedural schedule in these matters was established. A prehearing conference was held on May 27, 2014, and the evidentiary hearing commenced on June 3, 2014, and concluded on June 30, 2014. The Commission also scheduled five local public hearings throughout AEP Ohio's service territory. AEP Ohio filed proof of publication of notice of the local public hearings on June 4, 2014.

The following parties were granted intervention by Entries dated April 21, 2014, and May 21, 2014: Industrial Energy Users-Ohio (IEU-Ohio); Ohio Consumers' Counsel (OCC); Ohio Energy Group (OEG); Dominion Retail, Inc. d/b/a Dominion Energy Solutions (Dominion); Duke Energy Ohio, Inc. (Duke); Ohio Hospital Association (OHA); Duke Energy Retail Sales, LLC (DERS); Duke Energy Commercial Asset Management, Inc. (DECAM); Interstate Gas Supply, Inc. (IGS); Ohio Manufacturers' Association Energy Group (OMAEG); FirstEnergy Solutions Corp. (FES); Ohio Partners for Affordable Energy (OPAE); The Kroger Company (Kroger); The Dayton Power and Light Company (DP&L); Environmental Defense Fund (EDF); Ohio Environmental Council (OEC); Direct Energy Services, LLC and Direct Energy Business, LLC (jointly, Direct Energy); Appalachian Peace and Justice Network (APJN); Retail Energy Supply Association (RESA); Constellation

[1] On March 7, 2012, the Commission approved and confirmed the merger of Columbus Southern Power Company (CSP) into Ohio Power Company (OP). *In re Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2376-EL-UNC, Entry (Mar. 7, 2012).

NewEnergy, Inc. and Exelon Generation Company, LLC (jointly, Constellation); Environmental Law & Policy Center (ELPC); Wal-Mart Stores East, LP and Sam's East, Inc. (jointly, Walmart); Natural Resources Defense Council (NRDC); Border Energy Electric Services, Inc. (Border Energy); EnerNOC, Inc. (EnerNOC); Paulding Wind Farm II LLC (Paulding II); and Energy Professionals of Ohio (EPO). On October 3, 2014, Border Energy filed a notice of withdrawal from these proceedings.

At the evidentiary hearing, AEP Ohio offered the direct testimony of 12 witnesses in support of the Company's application, while 2 witnesses offered rebuttal testimony on behalf of the Company. Additionally, 21 witnesses testified on behalf of various intervenors and 13 witnesses testified on behalf of Staff. At the local public hearings held in these matters, a total of 11 witnesses testified. Briefs and reply briefs were filed on July 23, 2014, and August 15, 2014, respectively. At AEP Ohio's request, an oral argument regarding the Company's proposed power purchase agreement (PPA) rider was held before the Commission on December 17, 2014.

A. Summary of the Local Public Hearings

Five local public hearings were held in order to allow AEP Ohio's customers the opportunity to express their opinions regarding the issues in these proceedings. Four evening hearings were held in Columbus, Lima, Canton, and Marietta. An afternoon hearing was also held in Columbus. At these hearings, public testimony was heard from individuals on behalf of the Discovery District Civic Association; Allen Economic Development Group; Lima/Allen County Chamber of Commerce; Sprinkler Fitters Local Union 669 and the Lima Building and Construction Trades Council; Columbus/Central Ohio Building and Construction Trades Council; United Way of Central Ohio; YWCA Columbus; Timken Company (Timken); Parkersburg-Marietta Building and Construction Trades Council; Appalachian Partnership for Economic Growth; and Lawrence County Emergency Management Agency. In addition to the public testimony, numerous letters were filed by customers raising concerns in response to AEP Ohio's ESP application, most of which convey opposition to the Company's proposed PPA rider, although a few of the letters address the Company's recent storm damage recovery rider (SDRR) proceeding. *In re Ohio Power Company*, Case No. 12-3255-EL-RDR (*Storm Damage Case*), Opinion and Order (Apr. 2, 2014).

At each of the local public hearings, witnesses testified in support of AEP Ohio's ESP application. In particular, witnesses testified on behalf of various non-profit organizations and community groups that value AEP Ohio's charitable support of their organizations. These witnesses emphasized that AEP Ohio maintains a positive corporate presence in the local community and promotes economic development endeavors throughout the Company's service territory. Members of local unions and building and construction trades councils also testified in support of AEP Ohio's proposed ESP, explaining that it would not only allow the Company to retain jobs, but also create new jobs as the Company continues to expand its infrastructure throughout the region. Finally, Timken's representative expressed support for certain aspects of AEP Ohio's ESP application and opposition to others, consistent with OEG's position in these proceedings, and concluded by urging the Commission to consider the impact of the proposed ESP on large energy-consuming customers such as Timken.

B. Procedural Matters

On May 6, 2014, OCC and IEU-Ohio filed motions for protective order with respect to the confidential versions of the direct testimony of James F. Wilson (OCC Ex. 15) and Kevin M. Murray (IEU-Ohio Ex. 1A), respectively. On May 8, 2014, OEG filed a confidential version of Exhibit AST-2, as an exhibit to the testimony of Alan S. Taylor (OEG Ex. 3A). On May 9, 2014, AEP Ohio filed a motion for protective order seeking protection of the confidential versions of the direct testimony of Mr. Wilson and Mr. Murray, as well as Mr. Taylor's Exhibit AST-2. AEP Ohio contends that the redacted testimony and exhibit constitute competitively sensitive and proprietary trade secret information. Specifically, AEP Ohio notes that the redactions pertain to the Company's cost and earnings forecast related to its ownership interest in the Ohio Valley Electric Corporation (OVEC) and the projected future performance of the assets. AEP Ohio asserts that the information is the product of original research and development, has been kept confidential, and, as a result, retains substantial economic value to the Company by being kept confidential. According to AEP Ohio, public disclosure would enable third parties to gain information about the costs and operations of the OVEC assets that may impair the Company's ability to sell their output at the best price and weaken the benefits of the proposed PPA rider, thereby harming the Company and its customers.

Following a review of the documents filed under seal, the attorney examiners requested, at the outset of the evidentiary hearing, that AEP Ohio coordinate with OCC, IEU-Ohio, and OEG to redact only the confidential trade secret information in the testimony and supporting exhibits and to file the revised documents by June 6, 2014. Consistent with the attorney examiners' ruling, revised public versions of the testimony of OCC witness Wilson and IEU-Ohio witness Murray were filed on June 6, 2014. On June 18, 2014, a revised public version of OEG witness Taylor's Exhibit AST-2 was filed.

On October 14, 2014, AEP Ohio filed a second motion for protective order, seeking to protect Company Exhibits 8A and 10, OCC Exhibits 4 and 16, IEU-Ohio Exhibit 8, and OMAEG Exhibit 3, which were admitted into the record during the evidentiary hearing; the confidential portions of the hearing transcripts (Volume III); and, again, the confidential portions of the direct testimony of OCC witness Wilson, IEU-Ohio witness Murray, and OEG witness Taylor. AEP Ohio explains that most of the confidential information constitutes market price projections and unit-specific cost estimates that are used to model unit dispatch scenarios, while other confidential information relates to the Company's existing coal contracts. AEP Ohio asserts that public disclosure of the confidential information would disadvantage the Company and its generation affiliates, because it would enable competitors and potential suppliers to learn the structure and sources of the Company's market price projections, unit-specific cost expectations, and proprietary coal contract terms. AEP Ohio also notes that it has provided redacted public versions of the confidential hearing transcripts and exhibits. No memoranda contra were filed with respect to any of the motions for protective order.

The Commission finds that the information that is the subject of the motions for protective order filed by AEP Ohio, OCC, and IEU-Ohio constitutes confidential and proprietary trade secret information. We, therefore, find that the motions for protective order filed by AEP Ohio, OCC, and IEU-Ohio are reasonable and should be granted. Pursuant to Ohio Adm.Code 4901-1-24(F), AEP Ohio Exhibits 8A and 10, OCC Exhibits 4 and 16, IEU-Ohio Exhibit 8, and OMAEG Exhibit 3; the confidential portions of the hearing transcripts (Volume III); and the confidential versions of the direct testimony of OCC witness Wilson, IEU-Ohio witness Murray, and OEG witness Taylor shall be granted protective treatment for 24 months from the date of this Opinion and Order. Any request to extend the protective order must be filed at least 45 days in advance of the expiration date.

II. DISCUSSION

A. Applicable Law

R.C. Chapter 4928 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 reviewing AEP Ohio's application, the Commission is cognizant of the challenges facing Ohioans and the electric industry and is guided by the policies of the state as established by the General Assembly in R.C. 4928.02, as amended by Amended Substitute Senate Bill 221 (SB 221).

In addition, SB 221 enacted R.C. 4928.141, which provides that, beginning on January 1, 2009, electric utilities must provide consumers 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 service. R.C. 4928.143 sets out the requirements for an ESP. Pursuant to R.C. 4928.143(B)(1), an ESP must include provisions relating to the supply and pricing of generation service. The ESP, according to R.C. 4928.143(B)(2), may also provide for the automatic recovery of certain costs, a reasonable allowance for certain construction work in progress, an unavoidable surcharge for the cost of certain new generation facilities, charges relating to certain subjects that have the effect of stabilizing or providing certainty regarding retail electric service, automatic increases or decreases in components of the SSO price, provisions to allow securitization of any phase-in of the SSO price, provisions relating to transmission-related costs, provisions related to distribution service, and provisions regarding economic development. R.C. 4928.143(C)(1) provides that the Commission is required to approve, or modify and approve, the ESP, if 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 R.C. 4928.142.

B. Analysis of the Application

1. Power Purchase Agreement Rider

(a) AEP Ohio

In this ESP, AEP Ohio requests approval of a non-bypassable PPA rider to be used as a hedge against future market volatility, in order to stabilize customer rates. Initially, the proposed PPA rider would be based solely on AEP Ohio's OVEC contractual entitlement from the Kyger Creek and Clifty Creek generating stations, although the Company seeks to reserve the opportunity to include additional PPAs in the rider. As proposed, AEP Ohio's OVEC contractual entitlement, including energy, capacity, and ancillaries, would be sold into the PJM Interconnection, LLC (PJM) market and, after deducting all associated costs from the revenues, the proceeds from the OVEC contractual entitlement, whether a credit or a debit, would accrue to Ohio ratepayers. AEP Ohio submits that selling the OVEC entitlement into the PJM market eliminates any adverse impact on the SSO auctions and does not affect the opportunity of competitive retail electric service (CRES) providers to compete for customers. OVEC's costs, according to AEP Ohio witnesses Vegas and Allen, are relatively stable, in comparison to the wholesale power market, and rise and fall in a manner that is counter-cyclical to the market, thereby creating the PPA rider's hedging effect for ratepayers. AEP Ohio proposes that the PPA rider would be adjusted annually to reconcile projected expenses and revenues with actual data. AEP Ohio also notes, regarding the possible expansion of the PPA rider, that the Company is only considering the inclusion of future PPAs with its affiliates. (Co. Ex. 1 at 8; Co. Ex. 2 at 13; Co. Ex. 7 at 8-10; Co. Ex. 8B; Tr. I at 26, 110-111; Co. Br. at 22-24.)

AEP Ohio proposes to provide the projected expenses and revenues to be used to populate the PPA rider shortly after a Commission decision regarding this ESP or early in the first quarter of 2015. However, AEP Ohio also provided an estimated rate impact for the OVEC portion of the PPA rider during the course of the hearing. Initially, on cross-examination, AEP Ohio witness Vegas testified that $52 million was a reasonable estimate of the net cost of the PPA rider, over the three-year term of the ESP, based on the latest available OVEC cost data (OMAEG Ex. 3; Tr. I at 110; Tr. II at 498, 507-508). Later, during his cross-examination, AEP Ohio witness Allen testified to an $8.4 million estimated net benefit, during the term of the ESP, based, in part, on achievement of cost reductions associated with OVEC's LEAN initiative (Tr. II at 484-486, 506; Co. Ex. 8B). Specifically, AEP Ohio estimates the PPA rider to be a $6.2 million cost in year one, a $2.8 million benefit in year two, and an $11.8 million benefit in year three, for a total PPA mechanism benefit of $8.4 million. According to AEP Ohio's estimate, the hedge would equate to an average credit of seven cents per megawatt-hour (MWh) over the term of the ESP. (Co. Ex. 33 at 9-10; Tr. II at 484-485, 508, 552, 569-570; Tr. XIII at 3257-3258.)

AEP Ohio explained that OVEC was originally formed in 1952 by investor-owned utilities, known as sponsoring companies, to provide electricity to a uranium enrichment facility located near Portsmouth, Ohio. AEP Ohio further explained that OVEC's contract with the federal government to supply electricity was terminated in 2003. Since the termination of the contract with the federal government, AEP Ohio, as a sponsoring company of the OVEC facilities, is entitled to 19.93 percent of OVEC's power participation benefits and requirements under the Amended and Restated Inter-Company Power Agreement (ICPA) executed by the sponsoring companies, effective August 11, 2011, through June 30, 2040. (Co. Ex. 7 at 8-10; Co. Br. at 22-24.)

AEP Ohio acknowledges that the Commission approved, in Case No. 12-1126-EL-UNC and Case No. 11-346-EL-SSO, et al., the Company's corporate separation plan, which authorized the transfer of the Company's generation assets to AEP Generation Resources, Inc. (AEP Genco). *In re Ohio Power Company*, Case No. 12-1126-EL-UNC (*Corporate Separation Case*), Finding and Order (Oct. 17, 2012), Entry on Rehearing (Apr. 24, 2013); *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 11-346-EL-SSO, et al. (*ESP 2 Case*), Opinion and Order (Aug. 8, 2012) at 59-60, Entry on Rehearing (Jan. 30, 2013) at 61-65. Under the ICPA, AEP Ohio states that consent must be obtained from all of the other sponsoring companies before the Company can transfer its OVEC contractual entitlement to AEP Genco in a manner that would relieve the Company from ongoing liabilities. Despite a guaranty from AEP Ohio's parent corporation, the sponsoring companies did not give their consent and, therefore, the Company filed an application with the Commission for approval to amend its corporate separation plan to permit the Company to continue to hold its interest in OVEC. The Commission granted AEP Ohio's application to amend its corporate separation plan, subject to certain conditions. *Corporate Separation Case*, Finding and Order (Dec. 4, 2013) at 9, Entry on Rehearing (Jan. 29, 2014). Thus, AEP Ohio reasons that the Company is exempted from transferring its OVEC entitlement. Furthermore, AEP Ohio offers that the sponsoring companies withheld their consent for the transfer because AEP Genco's credit rating is lower than the Company's. Since the credit rating comparison continues to be true, AEP Ohio has not again attempted to secure the consent of the sponsoring companies. AEP Ohio witness Vegas also noted that the Commission indicated that it would consider any rate related implications of the transfer of the OVEC contractual entitlement in a future ESP proceeding. (Tr. I at 23-25; Co. Br. at 24-25.)

AEP Ohio argues that R.C. 4928.143(B)(2)(a) and (B)(2)(d) permit the Commission to approve the PPA rider as a provision of the ESP. AEP Ohio points out that R.C. 4928.143(B)(2)(d) permits the Commission to adopt, as a component of an ESP, terms, conditions, or charges that relate to default service or address bypassability or non-bypassability, as the statute is not expressly limited to non-shopping customers. AEP Ohio avers that its analysis of R.C. 4928.143(B)(2)(d) is consistent with the *ESP 2 Case*. *ESP 2 Case*, Entry on Rehearing (Jan. 30, 2013) at 14-16. Furthermore, AEP Ohio reasons that the PPA rider may also be considered a limitation on customer shopping, given that, as proposed by the Company, the rider would provide a generation hedge for shopping customers. Similarly, AEP Ohio notes that R.C. 4928.143(B)(2)(a) is not limited to SSO service and specifically permits the Commission to approve an ESP that includes affiliate PPAs.[2] AEP Ohio reasons that R.C. 4928.143(B)(2)(d) could be invoked, if necessary, in conjunction with R.C. 4928.143(B)(2)(a), to approve a non-bypassable PPA rider. AEP Ohio also finds support for its proposal in R.C. 4928.143(B)(2)(e), which permits automatic increases or decreases in any component of the SSO price, and R.C. 4928.143(B)(2)(i), which permits economic development, job retention, and energy efficiency programs as a component of an ESP. (Co. Br. at 27-30; Co. Reply Br. at 21-23.)

AEP Ohio notes that the Commission has previously held that the OVEC costs were prudent. *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-917-EL-SSO, et al. (*ESP 1 Case*), Opinion and Order (Mar. 18, 2009) at 14-15, 51-52. As such, AEP Ohio submits that there is no need to review the prudence of the OVEC contract's terms and conditions. Noting that the OVEC contractual entitlement extends through 2040, AEP Ohio requests that the Commission make two assurances regarding the PPA mechanism. First, AEP Ohio requests that the Commission reiterate and confirm, in these proceedings, a commitment to be bound by the prudence of the OVEC contract for the full term of the contract through 2040. With the Commission's commitment in place, AEP Ohio's intention would be to continue to include the OVEC contract in the PPA rider beyond the term of the ESP to the same extent that the Commission commits, up-front, to the hedging arrangement. Second, AEP Ohio requests that the Commission assure that any future PPA to be included in the PPA rider is subject to a one-time, up-front prudence review for the full term of the PPA. (Tr. I at 121, 150-151, 264; Co. Br. at 30-33.)

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2 AEP Ohio considers OVEC an affiliate in this context since the Company has an ownership interest, and OVEC and the Company share corporate resources.

(b) Intervenors and Staff

OEG, the only intervenor to endorse the adoption of a PPA mechanism, supports the proposed PPA rider in concept and recommends certain modifications to protect customers and increase the value of the hedge. OEG interprets R.C. 4928.143(B)(2)(d) to permit the adoption of the PPA rider as a financial limitation on customer shopping that has the effect of stabilizing or providing certainty regarding retail electric service. To improve the projected benefit of the PPA rider, OEG recommends that the PPA mechanism be effective for 9.5 years, June 2015 through December 2024, and subject to an annual true-up, with the last true-up to occur during 2024 based on end of year expenses and revenues for 2023. Based on OEG's projections of market prices and OVEC costs, OEG estimates that the modified PPA mechanism's net benefit would be $70 million. Further, OEG recommends that AEP Ohio retain 10 percent of the PPA rider, in order to ensure that the Company's interests are aligned with the interests of its customers, and to incent the Company to keep OVEC's costs as low and its revenues as high as possible. The balance, 90 percent of the PPA credit or charge, would accrue to AEP Ohio's customers. OEG also recommends that the PPA rider incorporate a levelization mechanism to bring the rider more in line with a market-neutral hedge for the 9.5 year period. Finally, OEG proposes that large, business-savvy customers, with more than 10 megawatts (MW) of load per single site, be permitted to opt out of the PPA rider and self-insure. (OEG Ex. 3 at 16-20; Tr. XI at 2557, 2603-2604; OEG Br. at 4-5, 13-17.)

OEG offers several grounds for endorsing the PPA mechanism. OEG reasons that, with its recommendations, the PPA rider would supplement the staggering and laddering auction process preferred by Staff for non-shopping customers as well as provide a measure of protection for shopping customers. While acknowledging that there is no certainty whether the PPA rider would be a credit or a charge, OEG asserts that the most reliable and recent evidence indicates that the PPA rider would be a credit, particularly over a period longer than three years. While severe weather increases electricity prices, OEG submits that the converse is not true, to the same extent, when weather is mild. Accordingly, OEG reasons that the benefits of the PPA rider would increase when severe weather affects the market, while there would be no corresponding risk that the PPA rider would prevent customers from experiencing low electricity prices when the weather is mild. Further, OEG predicts that the retirement of generation capacity in the PJM region will increase price volatility in the market in the short- and long-term. According to OEG, Staff's philosophical opposition to the PPA rider is not good policy for the state. OEG explains that what are referred to as market based rates are really PJM-administered market prices and, by transitioning AEP Ohio to market prices for generation, the Commission's regulatory authority is relinquished to PJM and the Commission's ability to protect Ohio's electric consumers is limited. (Co. Ex. 33 at 10; Tr. II at 480; Tr. XI at 2539, 2557; OEG Br. at 4, 6, 12.)

The many remaining intervenors that take a position on the PPA rider oppose AEP Ohio's proposal for a variety of reasons. As noted by OEG, Staff contests AEP Ohio's PPA mechanism as a step backwards in the Commission's goal to transition the Company to a fully competitive market with market based pricing. Staff emphasizes that the transition to a fully competitive market was a significant, non-quantifiable benefit of the *ESP 2 Case*. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 76. Staff submits that the PPA proposal would provide AEP Ohio a guaranteed revenue stream for its generation assets, including a return on equity (ROE) for the Company and the other OVEC sponsoring companies. RESA asserts that the proposed PPA rider violates the state's electric restructuring paradigm as set forth in R.C. 4928.03, which limits the electric distribution utility to supplying only non-competitive utility service except where a customer is not supplied by a competitive supplier, and frustrates the Commission's intent to make AEP Ohio financially responsible for OVEC. (Staff Ex. 18 at 7-9; Tr. I at 29-30; Tr. II at 556; Tr. XIII at 3217; Staff Br. at 2-5; RESA Br. at 27-28.)

Staff's perspective, according to AEP Ohio, ignores the concept of rate stability and is not based on any rate impact analysis performed by Staff or projections of the market price under Staff's preferred auction approach. AEP Ohio argues that Staff's policy is in stark contrast to the ESP statute and hybrid regulatory approach adopted in SB 221. AEP Ohio interprets SB 221 to permit cost based rate adjustments as opposed to mandating market based prices. AEP Ohio advocates that the PPA rider can co-exist with the competitive bid procurement (CBP) based SSO process. (Tr. XII at 2907, 2947; Co. Reply Br. at 33-35.)

OCC submits that AEP Ohio has not met its burden of proof to demonstrate that it could not transfer its interest in OVEC. OCC notes that, after the OVEC sponsoring companies denied AEP Ohio's request to transfer its share of OVEC to AEP Genco, the Company has not made any further attempts to transfer or divest its interest in OVEC, because, as Company witness Vegas recalls, the majority of sponsoring companies withheld their consent to transfer. Observing that the denial of the transfer of OVEC likely came from a number AEP Ohio's affiliates, OCC asks the Commission to consider the PPA rider in light of the Company's failure to continue to pursue the consent of the sponsoring companies or other means to transfer its OVEC interest and, therefore, reject the PPA rider proposal. (Tr. I at 22; OCC Br. at 39-42.)

OMAEG and Constellation assert that AEP Ohio incorrectly characterizes the Commission's decision, in the *Corporate Separation Case*, to allow the Company to retain its OVEC contractual entitlement (OMAEG Br. at 15; Constellation Br. at 28). OCC also interprets the conditions imposed on AEP Ohio to apply only while the Company holds the OVEC interest (OCC Br. at 38). AEP Ohio retorts that nothing in the *Corporate Separation Case* indicates that the authorization to retain the OVEC contractual entitlement is temporary or that the Company has a continuing duty to pursue transfer or divestiture.

OCC's interpretation, according to AEP Ohio, is inconsistent with the straightforward language in the *Corporate Separation Case*. (Co. Reply Br. at 16-21.)

Staff notes that, if the PPA rider is adopted, the Commission's oversight would be severely limited, if not non-existent. Staff reasons that the OVEC contract is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) and that the Commission would not have the ability to directly disallow any imprudent costs that may be assessed to AEP Ohio's customers, without first seeking relief at FERC. Staff emphasizes that, to challenge certain costs in the PPA rider, the Commission would need to file a complaint with FERC and sustain a heightened burden of proof to establish that the PPA costs were unreasonable. *NRG Power Mktg., LLC v. Maine Pub. Util. Comm.*, 558 U.S. 165, 130 S. Ct. 693 (2010). (Staff Br. at 7-8.)

In response, AEP Ohio argues that the Commission would have the ability to review and approve the Company's decision to enter into the PPA, abundant data and visibility into the underlying costs related to the Company's implementation of the PPA, financial auditing rights relating to costs being passed through retail rates, and the authority to disallow costs caused by imprudent actions of the Company under the contract. Further, AEP Ohio notes that, while Staff admits that the Commission currently reviews the prudency of OVEC's costs under the fuel adjustment clause (FAC) mechanism, neither Staff nor any other intervenor has explained how the same OVEC costs would not be reviewable by the Commission if the costs are recoverable under the PPA rider. AEP Ohio implies that the Commission's review of OVEC costs via the PPA rider would be similar to its review of FERC-approved transmission costs through the transmission cost recovery rider (TCRR). However, AEP Ohio proceeds to reason that the Commission implicitly passed on the prudency of the OVEC contract when the Commission approved recovery of the OVEC costs as a component of SSO rates in the *ESP 1 Case*. *ESP 1 Case*, Opinion and Order (Mar. 18, 2009). AEP Ohio also argues that the Commission would not lose its authority to review the appropriateness of the Company's decisions and the rights available to the Company under the OVEC contract. *Pike County Light & Power Co. v. Penn. Pub. Util. Comm.*, 77 Pa Commw. 268, 465 A.2d 735 (Pa. Commw. Ct. 1983). Thus, AEP Ohio concludes that Staff is incorrect that the Commission's authority would be limited or non-existent if the PPA mechanism is approved. (Tr. I at 32-33; Co. Reply Br. at 39-49.)

IEU-Ohio asserts that the PPA mechanism is preempted by the Federal Power Act (FPA). IEU-Ohio reasons that the FPA preempts the Commission from the field of wholesale electric sales, including the price at which electricity is sold at wholesale. *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467 (4th Cir. 2014) (*Nazarian*); *PPL EnergyPlus, LLC v.*

Hanna, 977 F. Supp.2d 372 (D. N.J. 2013) (*Hanna*)[3]. (IEU-Ohio Br. at 20-24.) *Nazarian* and *Hanna*, as interpreted by AEP Ohio, concern the lack of authority of state utility commissions to regulate the wholesale price of power and to require local utilities to enter into wholesale arrangements. In contrast, AEP Ohio avers that it is the party that initiated these proceedings, proposed the PPA rider, and voluntarily entered into the contract with OVEC - a contract that has been regulated and approved by FERC for years. Accordingly, AEP Ohio reasons that the PPA rider is distinguishable from *Nazarian* and *Hanna* and that the PPA mechanism does not conflict with federal law. (Co. Reply Br. at 40, 53-54.)

IEU-Ohio also argues that approval of the PPA mechanism would exceed the Commission's jurisdiction. IEU-Ohio notes that the OVEC contractual entitlement will be offered, as the Commission ordered, into the PJM wholesale market and will not be used to provide energy or capacity to AEP Ohio's retail customers. *Corporate Separation Case*, Finding and Order (Dec. 4, 2013) at 8-9. To the extent that the PPA rider would adjust AEP Ohio's compensation for the OVEC contractual entitlement via the rider's charge or credit, IEU-Ohio argues that approval of the rider is beyond the Commission's jurisdiction, which does not extend to the adjustment of the Company's compensation for wholesale electric services. (IEU-Ohio Br. at 20.) Constellation also reasons that the proposed PPA rider violates FERC Order 697 regarding affiliate transactions (Constellation Br. at 6-9, citing *In re Edgar Electric Energy Co.*, 55 FERC ¶ 61,382). AEP Ohio responds that Constellation's claims ignore relevant FERC rulings and fail to recognize that OVEC submitted to and satisfied, to the extent applicable, FERC Order 697 (Co. Reply Br. at 40, 55-57).

A variety of intervenors, including IEU-Ohio, OEC, EDF, OHA, and OCC, claim that the PPA mechanism is not authorized under any provision of R.C. 4928.143(B)(1) or (B)(2). R.C. 4928.143(B)(1) permits an ESP to include provisions relating to the supply and pricing of electric generation service, while R.C. 4928.143(B)(2)(a) permits an electric distribution utility to recover prudently incurred costs associated with purchased power supplied under the SSO, including purchased power from an affiliate. The intervenors argue that the OVEC generation will not be bid into the auctions to serve the SSO load of AEP Ohio's customers. Thus, the intervenors reason that the PPA rider does not meet the express requirements of R.C. 4928.143(B)(1) or (B)(2)(a). (Co. Ex. 7 at 10; IEU-Ohio Br. at 8-9; OCC Br. at 44-46; OEC/EDF Br. at 12-13; OHA Br. at 9-10.) OMAEG and EPO come to the same conclusion, focusing on R.C. 4928.143(B)(2)(a). The intervenors emphasize that, as AEP Ohio acknowledges, the energy and capacity associated with the OVEC contractual entitlement will be bid into the PJM market, not supplied to SSO customers. (EPO Br. at 5; OMAEG Br. at 15-16.)

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3 Following the hearing and submission of the parties' briefs in these ESP proceedings, the United States Court of Appeals for the Third Circuit affirmed the district court's judgment in *Hanna*. *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241 (3d Cir. 2014).

Evaluating the proposed PPA rider under the statutory requirements of R.C. 4928.143(B)(2)(b) and (B)(2)(c), the intervenors conclude that the rider fails. R.C. 4928.143(B)(2)(b) permits recovery of costs associated with the construction of an electric generating facility or environmental expenditures for such facility on or after January 1, 2009. R.C. 4928.143(B)(2)(c) permits the recovery of costs through a non-bypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, sourced by a competitive bid process, and newly used and useful on or after January 1, 2009. IEU-Ohio, OEC, EDF, and ELPC address the failure of the OVEC generation and the associated PPA rider to comply with R.C. 4928.143(B)(2)(b) and (B)(2)(c), because the OVEC facilities have been in service since the 1950s and were not sourced through a competitive bid process, and there has not been any demonstration of need by AEP Ohio. Accordingly, IEU-Ohio, OEC, EDF, and ELPC assert that the PPA rider does not comply with the requirements of R.C. 4928.143(B)(2)(b) or (B)(2)(c) to be a provision of the ESP. (IEU-Ohio Br. at 9; OEC/EDF Br. at 13-16; ELPC Br. at 6-8, 15-17.)

R.C. 4928.143(B)(2)(d) authorizes the Commission to approve terms, conditions, or charges of an ESP that relate to limitations on customer shopping and default service, among other services, that have the effect of stabilizing or providing certainty regarding retail electric service. Several of the intervenors note that the PPA rider, by AEP Ohio's own admission, is not related to any limitation on customer shopping, standby service, supplemental power, or back-up power, as required by R.C. 4928.143(B)(2)(d). IEU-Ohio reasons that the PPA rider has no relation to bypassability of generation-related costs, as the rider is proposed to be non-bypassable, nor has any relation to carrying costs, amortization periods, accounting, or deferrals. As such, IEU-Ohio and OCC argue that the PPA rider is not related to any kind of service or accounting issues that may be authorized pursuant to the requirements of R.C. 4928.143(B)(2)(d). (OCC Ex. 15A at 29-32; Tr. II at 566-567; IEU-Ohio Br. at 9-11; OCC Br. at 45-46.)

In response, AEP Ohio asserts that the intervenors are incorrectly relating the delivery of electrons generated at OVEC with whether the proposed PPA rider is a generation service. AEP Ohio witness Allen specifically made the distinction, according to the Company, on cross-examination. AEP Ohio argues that the impact of the PPA rider is as a generation service that affects the SSO by stabilizing the SSO generation rate. AEP Ohio reasons that nothing in the language of R.C. 4928.143(B)(2)(d) requires a stability charge to be directly tied to the costs for the delivery of electricity, as is evident from the Commission's approval of the retail stability rider (RSR) in the *ESP 2 Case*. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 26-38, Entry on Rehearing (Jan. 30, 2013) 61-65. (Co. Ex. 7 at 9-11; Tr. I at 265; Tr. II at 747; Co. Reply Br. at 23-25.)

Further, OCC and IEU-Ohio offered testimony, with which several other intervenors agree, that the PPA rider is not likely to provide customers stability or certainty. The intervenors challenge the likelihood that the PPA mechanism would stabilize customer rates, given the wide range of estimates offered into evidence. Staff notes that, by AEP Ohio's own admission, $52 million is a reasonable estimate of the net cost of the PPA rider, over the three-year term of the ESP, although, during the course of the hearing, the Company estimated a net benefit of $8.4 million for the ESP term. IEU-Ohio, however, estimates that the PPA rider would cost $82 million and OCC projects a cost of $116 million over the full term of the ESP. (Co. Ex. 33 at 9-10; IEU-Ohio Ex. 1B at 10-12; IEU-Ohio Ex. 8; OCC Ex. 15A at 7, 9, 25; OCC Ex. 17; Tr. I at 110.) OCC developed its calculation utilizing AEP Ohio's initial projection of a PPA cost of $52 million and adjusted the estimate to account for an increase in demand charges to be billed to the Company by OVEC and to eliminate the LEAN initiative cost reductions. Noting that AEP Ohio's estimated $52 million cost was based on forward market prices from September 2013, OCC also adjusted the analysis for forward market prices known through early May 2014, revised the OVEC pricing point, and adjusted OVEC generation output to be more in line with recent historical performance. OCC asserts that AEP Ohio's OVEC generation output was not highly correlated with the energy price and that there does not appear to be a basis for the Company's forecast of a significant increase in OVEC's generation in 2016 through 2018, in comparison to recent years or the expectations for 2015. For these reasons, OCC contends that its analysis of the PPA rider cost is likely conservative. (OCC Ex. 15A at 13-18, 21-23, 26, Attach. JFW-2; OCC Ex. 17; OCC Br. at 54-62, 64-65.) IEU-Ohio increased AEP Ohio's initial projection of $52 million to $82 million by eliminating the LEAN initiative cost reductions (IEU-Ohio Ex. 1B at 10-12). EPO submits that the customer benefit of the proposed PPA rider, whether by AEP Ohio or as amended by OEG, is uncertain, and EPO and OMAEG believe the benefit, at best, will be unnoticeable on customer bills (EPO Br. at 3, 5-8; OMAEG Br. at 17).

AEP Ohio and OEG argue that IEU-Ohio's forecast of the PPA cost is based on the most out-of-date information offered by the Company and eliminates the projected LEAN initiative cost savings. In response to OCC, AEP Ohio and OEG retort that OCC's projections are overstated, because they are not based on the most recent version of OVEC cost projections or market prices, use a single price for all generation, and arbitrarily reduce the projected output of the OVEC units. (Co. Ex. 33 at 6-10; IEU-Ohio Ex. 1B at 11-12; OCC Ex. 15A at 7; OCC Ex. 17; OEG Br. at 15; Co. Br. at 58-59.)

AEP Ohio also submits that the record evidence supports that the PPA mechanism would promote rate stability in four ways. First, AEP Ohio notes that the PPA rider would produce a credit or charge based on the differential between its market proceeds and OVEC costs, which would counteract market volatility. Second, during periods of extreme weather, AEP Ohio believes that the PPA rider credit would increase and help to offset price spikes by a factor of ten times more than the price decreases associated with mild weather. Third, AEP Ohio asserts that there would be a compounding effect of the PPA rider benefit when high market prices are sustained, because the OVEC units would be dispatched more consistently. Finally, AEP Ohio reasons that, because OVEC is a long-term commitment by the Company, the PPA rider would provide long-term rate stability for customers, unlike any other rate stability option currently available. Acknowledging that the annual reconciliation component of the PPA rider may not be counter-cyclical to market prices, like the rider itself would be, AEP Ohio contends that customers would nevertheless receive the same benefit of the rider over time. If the annual reconciliation component of the PPA rider is a particular concern, AEP Ohio proposes that the Commission order more frequent updates of the rider or a levelization approach. (Co. Br. at 43-52; Co. Reply Br. at 25-26, 29-30.)

IEU-Ohio, Staff, and other intervenors argue that OVEC's generation costs are highly dependent on weather, output, economic conditions, and energy prices. Staff points out that the PPA rider would be greatly dependent on the stability of OVEC costs, which could increase significantly over the next few years as a result of additional capital expenditures, increases in coal prices, and environmental regulations. Numerous intervenors submit that, in light of the conflicting PPA estimates presented, and given that future costs are unknown, including OVEC costs, the Commission cannot reasonably conclude that the PPA mechanism would stabilize rates for AEP Ohio's customers. Noting that AEP Ohio's OVEC contractual entitlement represents approximately five to six percent of the Company's total connected load, Staff, RESA, OHA, IEU-Ohio, OCC, and Constellation, among other intervenors, surmise that the impact of the PPA rider credit, based on the Company's projected $8.4 million net benefit, would be de minimis, insignificant, and unnoticeable from the average customer's perspective. Furthermore, RESA points out that fixed price contract customers and customers with existing financial hedges do not need the rate stabilization allegedly offered by the PPA rider. (IEU-Ohio Ex. 1B at 9-11, Ex. KMM-3 at 2; OCC Ex. 15A at 13; Tr. I at 152-153; Tr. II at 480, 552; Staff Br. at 21-24; RESA Br. at 30-31; Constellation Br. at 15-16; OHA Br. at 8; IEU-Ohio Br. at 25, 28; OCC Br. at 55.)

Staff prefers the practice of staggering and laddering SSO auctions as a more successful means of addressing market volatility for SSO customers, and asserts that shopping customers have market based options to address volatility, including fixed price contracts with CRES providers. Staff notes that, as AEP Ohio admits, very few large customers buy electric service on an index tied to PJM's market price, as such large customers are likely sufficiently sophisticated to secure hedges or call options to mitigate market volatility. Staff also argues that, despite any implications to the contrary, the PPA rider would not address electric reliability concerns. According to Staff, the Commission has better tools than the proposed PPA rider to address potential electric reliability concerns, such as the authority to approve a non-bypassable rider to fund the construction of a new generating facility. (Staff Ex. 18 at 7; Tr. XII at 2853; Tr. XIII at 3084; Staff Br. at 5-6, 9-10.)

R.C. 4928.143(B)(2)(e) permits the ESP to include automatic increases or decreases in any component of the SSO price. IEU-Ohio reasons that, by the very design of the PPA rider, as proposed by AEP Ohio or OEG, the rider does not automatically increase or decrease any component of the SSO price. For that reason, IEU-Ohio concludes that R.C. 4928.143(B)(2)(e) cannot be a basis for approving the PPA rider. (IEU-Ohio Br. at 11-12; IEU-Ohio Reply Br. at 7-11.)

Further, several intervenors, including IEU-Ohio, OCC, IGS, ELPC, RESA, and Constellation, contend that the proposed PPA rider would impede the state policy expressed in R.C. 4928.02(H), violate R.C. 4928.17, and constitute an anticompetitive subsidy, particularly given that AEP Ohio's customers would be ensuring recovery of the cost of generation with a return on and of the Company's investment in OVEC. *Elyria Foundry Co. v. Pub. Util. Comm.*, 114 Ohio St.3d 305, 2007-Ohio-4164, 871 N.E.2d 1176. Constellation also contends that the PPA rider would skew the competitive wholesale market for power. (IEU-Ohio Br. at 9, 13-15; OEC/EDF Br. at 13-16; Constellation Br. at 6-8; IGS Br. at 17; ELPC Br. at 6-8, 15-17; RESA Br. at 29-30; OCC Br. at 46, 53, 70.)

AEP Ohio states that the intervenors' arguments are based on the flawed premise that the PPA rider would be a distribution charge. AEP Ohio declares that the PPA rider would not be a distribution charge, because it does not involve distribution service. The PPA rider would be, according to AEP Ohio, a generation-related charge and, therefore, there is no support for the intervenors' arguments that the PPA rider would violate R.C. 4928.02(H). AEP Ohio notes that Constellation witness Campbell agreed that the PPA rider would be a generation-related rider that would recover generation-related costs. (Tr. VII at 1623-1624; Co. Reply Br. at 35-37.)

Kroger and IEU-Ohio contend that the PPA rider would permit AEP Ohio to recover the Company's generation costs for OVEC after the permissible period for transition cost recovery has ended, as resolved by the Commission in Case No. 99-1729-EL-ETP, et al. *In re Columbus Southern Power and Ohio Power Company*, Case No. 99-1729-EL-ETP, et al., Opinion and Order (Sept. 28, 2000) at 10-18. Further, OMAEG, IEU-Ohio, and OCC argue that approving AEP Ohio's request for a PPA rider would violate R.C. 4928.38. (OMAEG Br. at 16; Kroger Br. at 3; IEU-Ohio Br. at 15-18; OCC Br. at 53.)

In its reply brief, AEP Ohio avers that the view that the proposed PPA rider violates R.C. 4928.38 or is an untimely attempt to collect transition revenues is misguided. In sum, AEP Ohio submits that stranded generation costs under R.C. 4928.38 were measured based on a long-term view of the cost over the life of the unit. AEP Ohio argues that, in these proceedings, the only evidence of record regarding the long-term costs and benefits of the OVEC units demonstrates a long-term benefit. Further, AEP Ohio notes that the Commission rejected similar arguments regarding transition costs in the *ESP 2 Case* and requests that the Commission again reject such arguments. *ESP 2 Case*, Opinion and Order

(Aug. 8, 2012) at 32. (OMAEG Ex. 3; OEG Ex. 3 at 16, Ex. AST-2; Tr. II at 506-507; Tr. XI at 2557, 2604; Co. Reply Br. at 38-39.)

OEC, EDF, EPO, Constellation, IGS, ELPC, RESA, and IEU-Ohio opine that the PPA rider is an attempt by AEP Ohio to increase customers' electric bills to pay for aging coal plants and to insulate the Company's shareholders from the risks of the competitive market and the costs of future carbon restraints and environmental regulations on electric generating units (IGS Ex. 1 at 5-6; OEC/EDF Br. at 16; EPO Br. at 2; Constellation Br. at 12-13; IGS Br. at 16; ELPC Br. at 11-12; RESA Br. at 30; IEU-Ohio Br. at 33). Constellation adds that the competitive retail market in Ohio offers electric customers another less expensive way to stabilize electric rates - a fixed price contract (Constellation Ex. 2; Constellation Br. at 10, 16). AEP Ohio responds that, based on data from the Commission's Apples to Apples website, CRES providers are not offering long-term contracts to residential customers, as the majority of the available offers are for 12 months or less. AEP Ohio opines that there is volatility for customers as they transition from one fixed price contract to the next. For that reason, AEP Ohio concludes that the PPA mechanism would benefit shopping customers as well as SSO customers. Noting that Staff's policy of staggering and laddering auctions follows the market, AEP Ohio argues that the PPA rider would grant to customers 100 percent of the differential between OVEC costs and market prices, without an additional premium or upcharge. AEP Ohio concludes that relying on the SSO auctions and fixed price offers from CRES providers, as the sole means to mitigate market volatility, would impose artificial, unjustified, and unreasonable limitations on the Commission's available tools to promote price stability. (Co. Ex. 33 at Ex. WAA-R3 and WAA-R4; Co. Reply Br. at 29.)

(c) Conclusion

The Commission has given thorough consideration to AEP Ohio's request for approval of the PPA rider, which, as proposed by the Company, would flow through to customers, on a non-bypassable basis, the net benefit or cost from the Company's sale of its OVEC contractual entitlement into the PJM market less all associated costs. AEP Ohio also seeks approval of its plan to petition the Commission, during the ESP term, to include the net benefit or cost of additional PPAs or similar products in the PPA rider.[4] The primary purpose of the PPA rider, according to AEP Ohio, would be to provide a financial hedge against market volatility, as a type of insurance that would allow customers to take advantage of market opportunities while providing added price stability. AEP Ohio also asserts that the PPA rider would afford the state of Ohio considerable flexibility in formulating a strategy for complying with forthcoming federal environmental regulations, as well as enable the Company to continue to provide, on an annual basis, over $40 million

[4] On October 3, 2014, in Case No. 14-1693-EL-RDR, et al., AEP Ohio filed an application to include an affiliate PPA with AEP Genco in the PPA rider.

in economic benefits to OVEC's six-county region and over $100 million in economic benefits to the state. (Co. Ex. 1 at 8; Co. Ex. 2 at 13; Co. Ex. 7 at 8-11; Tr. I at 127.) In reviewing AEP Ohio's proposed PPA rider and the considerable evidence of record offered by the Company, Staff, and intervenors with regard to the proposal, the Commission has been guided by two key considerations, specifically whether the PPA rider may be authorized under R.C. 4928.143(B)(1) or (B)(2) and, if so, whether the Company's proposal would provide the purported benefits or otherwise further the policy of the state.

Initially, the Commission must determine whether the proposed PPA mechanism may be considered a permissible provision of an ESP, in accordance with R.C. 4928.143(B)(1) or (B)(2). The Commission has the authority to approve, as a component of an ESP, only items that are expressly listed in the statute. *In re Columbus S. Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655. AEP Ohio focuses primarily on R.C. 4928.143(B)(2)(d) as its statutory basis for the PPA mechanism, but the Company also offers R.C. 4928.143(B)(2)(a), (B)(2)(e), and (B)(2)(i) as justification for approval of the rider.

Under R.C. 4928.143(B)(2)(d), the Commission can approve, as a component of an ESP, terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service. Thus, considering the plain language of the statute, we find that there are three criteria with which the PPA mechanism must comply. Specifically, an ESP component approved under R.C. 4928.143(B)(2)(d) must first be a term, condition, or charge; next, relate to one of the enumerated types of terms, conditions, and charges; and, finally, have the effect of stabilizing or providing certainty regarding retail electric service. *See, e.g., ESP 2 Case*, Entry on Rehearing (Jan. 30, 2013) at 15-16; *In re Dayton Power and Light Company*, Case No. 12-426-EL-SSO, et al. (*DP&L ESP Case*), Opinion and Order (Sept. 4, 2013) at 21-22.

The Commission finds that the first requirement of R.C. 4928.143(B)(2)(d) is met, as the PPA rider would consist of a charge incurred by customers under the ESP. The PPA rider, as proposed by AEP Ohio, would appear as a charge on customer bills, and there is no dispute among the parties on this point. Although AEP Ohio projects that the PPA rider would provide a net credit over the course of the ESP term, the Company estimates that the rider would result in a net charge to customers in the first year of the ESP (Co. Ex. 8B). Thus, the record indicates that the PPA rider would, at times, consist of a charge to customers.

Taking the requirements of R.C. 4928.143(B)(2)(d) somewhat out of turn, the Commission will next address the third criterion, which is whether the PPA charge would have the effect of stabilizing or providing certainty regarding retail electric service. We find that the PPA rider, as a financial hedging mechanism, is proposed to have the effect of stabilizing or providing certainty regarding retail electric service. AEP Ohio witness Vegas explained that the PPA rider would smooth out fluctuations in market prices, because the rider would rise or fall in a way that is opposite of the wholesale market. Specifically, because AEP Ohio claims that OVEC's mostly fixed costs are relatively stable in comparison to market based costs, the PPA rider would produce a credit when OVEC's costs are below wholesale market prices, while the rider would produce a charge when OVEC's costs are above wholesale market prices. The PPA rider, therefore, is intended to mitigate, by design, the effects of market volatility, providing customers with more stable pricing and a measure of protection against substantial increases in market prices.

AEP Ohio acknowledges that, as proposed, the PPA rider would have a reconciliation component to true up actual historical costs and revenues and that the one-year lag associated with the true-up process may mean that the reconciliation component does not always operate in the opposite direction of current market prices. AEP Ohio points out, however, that the regulatory lag inherent in the annual true-up process would not alter the fundamental operation of the PPA rider. At its core, the PPA rider is expected to move in the opposite direction of wholesale market prices, causing a rate stabilization effect. As AEP Ohio witness Allen explained, the PPA rider, including only the OVEC contractual entitlement, would mitigate $0.35/MWh of a $5.00/MWh change in market prices, or 7 percent of that change. (Co. Ex. 1 at 8; Co. Ex. 2 at 13; Co. Ex. 7 at 9-11; Co. Ex. 33 at 3, Ex. WAA-R2; OEG Ex. 3 at 13-14; Tr. I at 28, 173, 265; Tr. II at 517-518, 567, 658; Tr. III at 747; Tr. XI at 2451-2452, 2573.) Although several intervenors dispute the value of the proposed hedging mechanism and its use as a means to promote rate stability, there is no question that the PPA rider would produce a credit or charge based on the difference between wholesale market prices and OVEC's costs, offsetting, to some extent, the volatility in the wholesale market. The impact of the PPA rider would be reflected as a charge or credit for a generation-related hedging service that stabilizes retail electric service, by smoothing out the market based rates paid by shopping customers to their CRES providers, as well as the market based rates paid by SSO customers, which are determined by a series of auctions that reflect the prevailing wholesale prices for energy and capacity in the PJM markets. Because AEP Ohio has demonstrated that the proposed PPA rider would, in theory, have the effect of stabilizing or providing certainty regarding retail electric service, the Commission finds that the third criterion of R.C. 4928.143(B)(2)(d) has been met.

Finally, to meet the second requirement of R.C. 4928.143(B)(2)(d), the proposed PPA charge must relate to at least one of the following: 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. AEP Ohio concedes that the PPA mechanism has no connection to standby, back-up, or supplemental power service, carrying costs, amortization, and accounting or deferrals. AEP Ohio argues, however, that the PPA mechanism relates to default service, addresses bypassability, and may be considered a limitation on customer shopping. (Co. Br. at 27-30; Co. Reply Br. at 21-23.)

The Commission finds that R.C. 4928.143(B)(2)(d) authorizes electric utilities to include, in an ESP, terms related to "bypassability" of charges to the extent that such charges have the effect of stabilizing or providing certainty regarding retail electric service. *DP&L ESP Case*, Opinion and Order (Sept. 4, 2013) at 21. As discussed above, both shopping and SSO customers may benefit from the PPA rider because it would have a stabilizing effect on the price of retail electric service, irrespective of whether the customer is served by a CRES provider or the SSO. Therefore, the Commission agrees with AEP Ohio that the proposed PPA rider, if approved, should be non-bypassable, as authorized by the second criterion of R.C. 4928.143(B)(2)(d). However, we also agree with Staff that, since nearly any charge may be bypassable or non-bypassable, "bypassability" alone is insufficient to fully meet the second criterion of R.C. 4928.143(B)(2)(d).

Nonetheless, the Commission agrees with AEP Ohio and OEG that the proposed PPA rider is a financial limitation on customer shopping for retail electric generation service. Although the proposed PPA rider would impose no physical constraints on shopping, the rider does constitute, as OEG witness Taylor explained, a financial limitation on shopping that would help to stabilize rates (Tr. XI at 2539, 2559). Under AEP Ohio's PPA rider proposal, shopping customers will still purchase all of their physical generation supply from the market through a CRES provider. Although the proposed PPA rider would have no impact on customers' physical generation supply, the effect of the PPA rider is that the bills of all customers would reflect a price for retail electric generation service that is approximately 5 percent based on the cost of service of the OVEC units and 95 percent based on the retail market. Effectively, then, the proposed PPA rider would function as a financial restraint on complete reliance on the retail market for the pricing of retail electric generation service. As several of the intervenors note, AEP Ohio witness Allen did, at one point, testify that he believes that the PPA rider, as proposed, is not a limitation on customer shopping (Tr. II at 566). It is not clear from Mr. Allen's testimony, however, whether he specifically considered whether the PPA rider constitutes a financial, rather than physical, limitation on customer shopping and, in any event, the Commission is not bound to rely on his testimony. We are persuaded by OEG witness Taylor's testimony that the PPA rider constitutes a financial limitation on customer shopping that is intended to stabilize rates (Tr. XI at 2539, 2559). Further, we note that, in light of our determination that the PPA rider is a financial limitation on customer shopping pursuant to R.C. 4928.143(B)(2)(d), it is unnecessary to reach the argument related to "default service." Accordingly, we find that the second criterion of R.C. 4928.143(B)(2)(d) is satisfied.

Having determined that R.C. 4928.143(B)(2)(d) provides the requisite statutory authority, we next consider, based on the record evidence, whether AEP Ohio's PPA rider proposal is reasonable and whether customers would, in fact, sufficiently benefit from the rider's financial hedging mechanism. At the outset, the Commission notes again that the power generated by the OVEC units will not be used to supply electricity to AEP Ohio's SSO customers. AEP Ohio repeatedly emphasized, consistent with the Commission's directives in the *Corporate Separation Case*, that the OVEC facilities will not be used to provide any generation service to the Company's customers (Co. Ex. 1 at 8; Co. Ex. 2 at 13; Co. Ex. 7 at 10; Tr. II at 540, 567). Rather than provide a physical hedge (i.e., providing generation), the OVEC units, in conjunction with the PPA rider, are intended to function purely as a financial hedge against market price volatility. Although AEP Ohio and OEG argue that the PPA rider would protect customers from price volatility in the wholesale market, there is no question that the rider would impact customers' rates through the imposition of a new charge on their bills. What is unclear, based on the record evidence, is how much the proposed PPA rider would cost customers and whether customers would even benefit from the financial hedge.

During the course of the hearing, the Commission was presented with several different PPA rider scenarios based on differing data inputs and assumptions. Initially, AEP Ohio provided three separate projections to the parties during discovery (OMAEG Ex. 3), all of which are reasonable estimates, according to Company witness Vegas, including an estimated $52 million net cost for the three-year term of the ESP (Tr. I at 110). AEP Ohio witness Allen explained that the primary difference in the Company's initial projections is the vintage of the forecast data used in each analysis. During his cross-examination, Mr. Allen further explained that he updated the most current of the three projections to incorporate the latest data available at the time of the hearing, with the result being an estimated $8.4 million net credit over the ESP term. AEP Ohio, therefore, concludes that a net credit of $8.4 million is the best evidence of the projected rate impact of the PPA rider during the ESP term. (OMAEG Ex. 3; Co. Ex. 8B; Tr. I at 110, Tr. II at 484-486, 498, 506-508.) In currently projecting a net credit, AEP Ohio relied, in part, on LEAN initiative cost reductions and other projected savings, such as from a severance program, which the Company valued at $10 million in determining the OVEC demand charge component of its PPA rider estimate of $8.4 million (Co. Ex. 8B; IEU-Ohio Ex. 1B at 10-11, KMM-9; Tr. II at 501-502, 648). The intervenors, however, paint a much different picture, with IEU-Ohio and OCC estimating that the PPA rider would result in a net cost of $82 million and $116 million, respectively, over the ESP term (IEU-Ohio Ex. 1B at 11-12; OCC Ex. 15A at 7; OCC Ex. 17). Initially, OEG projected, with its recommended modifications to the PPA rider in place, that the rider would result in a net benefit of $49 million, but only over a more than nine-year period, which would extend well beyond the ESP term. Like AEP Ohio, OEG updated, at the time of the hearing, its estimated net benefit to $70 million for that same extended period of time. (OEG Ex. 3 at 16; Tr. XI at 2557, 2603-2604.)

It is undisputed that all of these projections are based on data assumptions that attempt to predict OVEC's costs and revenues, as well as PJM prices for energy and capacity, over the three-year period of the ESP and beyond. In light of the uncertainty and speculation inherent in the process of projecting the net impact of the proposed PPA rider, which is evident in AEP Ohio's own projections ranging from a $52 million net cost to an $8.4 million net benefit, the Commission is unable to reasonably determine the rate impact of the rider.

Although the magnitude of the impact of the proposed PPA rider cannot be known to any degree of certainty, the Commission agrees with OCC, IEU-Ohio, and other intervenors that the evidence of record reflects that the rider may result in a net cost to customers, with little offsetting benefit from the rider's intended purpose as a hedge against market volatility. On balance, the record reflects that, during the three-year period of the ESP, the PPA rider would, in all likelihood, result in a net cost to customers and that, only over a longer timeframe, would customers perhaps benefit from a credit under the rider. AEP Ohio, however, proposes a three-year ESP term and seeks to reserve the right to terminate the ESP after two years, as discussed further below. Although AEP Ohio witness Vegas testified, on cross-examination, that the Company would be willing to consider a PPA rider that extends beyond the ESP term, he acknowledged that the Company is not actually requesting that the Commission approve the rider for a period longer than the ESP term. Mr. Vegas also admitted that AEP Ohio maintains the discretion to determine whether to propose to continue any of its riders in a future ESP application. (Co. Ex. 1 at 1, 15; IEU-Ohio Ex. 1B at 11-12; OCC Ex. 15A at 7; OCC Ex. 17; OMAEG Ex. 3; OEG Ex. 3 at 16; Tr. I at 121, 150-152.) It is, therefore, evident from AEP Ohio's testimony that the Company has made no offer to ensure that customers receive the alleged long-term benefits of the PPA rider or even a commitment or any type of proposal to continue the rider in subsequent ESP proceedings.

The Commission must base our decision on the record before us. *Tongren v. Pub. Util. Comm.*, 85 Ohio St.3d 87, 706 N.E.2d 1255 (1999). With that in mind, we are not persuaded that the PPA rider proposal put forth by AEP Ohio in the present proceedings would, in fact, promote rate stability, as the Company claims, or that it is in the public interest. There is considerable uncertainty with respect to pending PJM market reform proposals, environmental regulations, and federal litigation, as AEP Ohio acknowledges, and, in light of this uncertainty, the Commission does not believe that it is appropriate to adopt the proposed PPA rider at this time. Also, as Staff and several intervenors point out, there are already existing means, such as the laddering and staggering of SSO auction products and the availability of fixed price contracts in the market, that provide a significant hedge against price volatility (Co. Ex. 33 at 2-3, WAA-R3; Staff Ex. 18 at 10-11; Tr. XII at 2933-2934; Tr. XIII at 3084, 3141, 3279-3280, 3284-3285).

In sum, the Commission is not persuaded, based on the evidence of record in these proceedings, that AEP Ohio's PPA rider proposal would provide customers with sufficient benefit from the rider's financial hedging mechanism or any other benefit that is commensurate with the rider's potential cost. We conclude that AEP Ohio has not demonstrated that its PPA rider proposal, as put forth in these proceedings, should be approved under R.C. 4928.143(B)(2)(d). Nevertheless, the Commission does believe that a PPA rider proposal, if properly conceived, has the potential to supplement the benefits derived from the staggering and laddering of the SSO auctions, and to protect customers from price volatility in the wholesale market. We recognize that there may be value for consumers in a reasonable PPA rider proposal that provides for a significant financial hedge that truly stabilizes rates, particularly during periods of extreme weather. (Co. Ex. 9; Co. Ex. 32 at 5-7; Staff Ex. 18 at 10; Tr. II at 518-519; Tr. III at 745-746.) As we have consistently emphasized in AEP Ohio's prior ESP proceedings, rate stability is an essential component of the ESP. *See, e.g., ESP 1 Case,* Opinion and Order (Mar. 18, 2009) at 72; *ESP 2 Case,* Opinion and Order (Aug. 8, 2012) at 32, 77.

Accordingly, the Commission authorizes AEP Ohio to establish a placeholder PPA rider, at an initial rate of zero, for the term of the ESP. We note that the Commission has, on prior occasions, approved a zero placeholder rider within an ESP. *ESP 2 Case,* Opinion and Order (Aug. 8, 2012) at 24-25; *In re Duke Energy Ohio, Inc.,* Case No. 08-920-EL-SSO, et al., Opinion and Order (Dec. 17, 2008) at 17; *In re Ohio Edison Co., The Cleveland Elec. Illuminating Co., and The Toledo Edison Co.,* Case No. 08-935-EL-SSO, et al., Second Opinion and Order (Mar. 25, 2009) at 15. The Commission emphasizes that we are not authorizing, at this time, AEP Ohio's recovery of any costs through the placeholder PPA rider. Rather, AEP Ohio will be required, in a future filing, to justify any requested cost recovery. All of the implementation details with respect to the placeholder PPA rider will be determined by the Commission in that future proceeding. In its filing, AEP Ohio should, at a minimum, address the following factors, which the Commission will balance, but not be bound by, in deciding whether to approve the Company's request for cost recovery: financial need of the generating plant; necessity of the generating facility, in light of future reliability concerns, including supply diversity; description of how the generating plant is compliant with all pertinent environmental regulations and its plan for compliance with pending environmental regulations; and the impact that a closure of the generating plant would have on electric prices and the resulting effect on economic development within the state. The Commission also reserves the right to require a study by an independent third party, selected by the Commission, of reliability and pricing issues as they relate to the application. AEP Ohio must also, in its PPA rider proposal, provide for rigorous Commission oversight of the rider, including a proposed process for a periodic substantive review and audit; commit to full information sharing with the Commission and its Staff; and include an alternative plan to allocate the rider's financial risk between both the Company and its ratepayers. Finally, AEP Ohio must include a severability provision that recognizes that all other provisions of its ESP will continue, in the event that the PPA rider is invalidated, in whole or in part at any point, by a court of competent jurisdiction.

The Commission finds that our adoption of a PPA rider, to the limited extent set forth herein, is consistent with the state policy specified in R.C. 4928.02 and, in particular, with our obligation under R.C. 4928.02(A) to ensure the availability to consumers of reasonably priced retail electric service. In response to the arguments raised by various intervenors that the PPA rider would violate R.C. 4928.02(H), which requires the Commission to ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies, we find that, contrary to intervenors' claims, the rider would not permit the recovery of generation-related costs through distribution or transmission rates. As discussed above, the PPA rider, whether charge or credit, would be considered a generation rate. For that same reason, we do not find applicable the Commission's past decision to deny AEP Ohio's request for recovery of certain plant closure costs. *In re Ohio Power Company,* Case No. 10-1454-EL-RDR, Finding and Order (Jan. 11, 2012). In that case, AEP Ohio sought approval of a plant closure cost recovery rider, which the Company specifically classified as a non-bypassable distribution, not generation, rider that would have collected the generation-related costs associated with the closure of Sporn Unit 5. Neither do we agree with the assertion that the PPA rider would permit AEP Ohio to collect untimely transition costs in violation of R.C. 4928.38. As discussed above, the PPA rider constitutes a rate stability charge related to limitations on customer shopping for retail electric generation service and may, therefore, be authorized pursuant to R.C. 4928.143(B)(2)(d), although, on other grounds, we do not find it reasonable to approve the PPA rider as proposed by AEP Ohio in these proceedings. Some of the parties have also raised the issue of federal preemption. The Commission declines to address constitutional issues raised by the parties in these proceedings, as, under the specific facts and circumstances of these cases, such issues are best reserved for judicial determination.

Finally, the Commission notes that our decision not to approve, at this time, AEP Ohio's recovery of any costs, including OVEC costs, through the PPA rider is based solely on the record in these proceedings, and does not preclude the Company from seeking recovery of its OVEC costs in a future filing. Further, despite AEP Ohio's contention to the contrary, it was not the Commission's intent, in the *Corporate Separation Case,* to exempt the Company from further pursuing the divestiture or transfer of the OVEC contractual entitlement. The Commission recognized that, given the sponsoring companies' denial of the proposed transfer to AEP Genco, AEP Ohio would likely continue to hold its ownership interest in OVEC beyond December 31, 2013, which was the expected completion date of the Company's corporate separation. In light of the need to facilitate the timely completion of the corporate separation, the Commission approved AEP Ohio's request to retain the OVEC contractual entitlement, until it could be transferred to AEP Genco or otherwise divested, or until otherwise ordered by the Commission. *Corporate*

Separation Case, Finding and Order (Dec. 4, 2013) at 9. To the extent that it is necessary to do so, the Commission clarifies that our intent in the *Corporate Separation Case* was not to direct or encourage AEP Ohio to forgo any further efforts to transfer or divest its OVEC interest. Accordingly, we direct AEP Ohio to continue to pursue transfer of the OVEC contractual entitlement to AEP Genco or to otherwise divest the OVEC asset. AEP Ohio should file a status report regarding the transfer of the OVEC asset, in the docket of the *Corporate Separation Case*, by June 30 of each year of the ESP, with the first such filing to occur by June 30, 2015.

2. Competitive Bid Procurement Process

AEP Ohio proposes to utilize full auction based pricing for its SSO customers beginning in June 2015 and continuing through the full term of the ESP. In its application, AEP Ohio notes that the delivery point for the auction is specified as the AEP Load Zone established in PJM, which is the point at which all load in the Company's service territory is priced. AEP Ohio further notes that, in the future, it may be appropriate to request that PJM establish an AEP Ohio Aggregate pricing point that would be used to settle the Company's load and serve as the new delivery point in the SSO agreement. According to AEP Ohio, in the event a new pricing point is established, the SSO agreement will be revised accordingly and potential bidders will be provided sufficient notice. (Co. Ex. 1 at 7.)

AEP Ohio witness LaCasse testified that, through the CBP process, the Company will procure full requirements service for its SSO customers, including energy, capacity, ancillary services, and certain transmission services. According to Dr. LaCasse, AEP Ohio will divide the SSO load into a number of tranches, each representing a fixed percentage of the SSO load requirements to be served by the wining bidders, which are referred to as SSO suppliers and will be paid, for each MWh of SSO load served, the auction clearing price times a seasonal factor. Dr. LaCasse explained that there will likely be 100 tranches, each representing one percent of the SSO load, although the auction manager, in agreement with Staff, can increase the tranche size if it is necessary to maintain bidder interest in the face of customer migration. In terms of the auction schedule, AEP Ohio proposes to procure approximately two-thirds of its SSO supply on a 12-month term basis and to procure the remainder on a 24-month term basis, with each contract synchronized to the PJM planning year, starting on June 1 and ending on May 31. In advance of the start of the supply period on June 1 of each year, AEP Ohio proposes to conduct two auctions, one in September and another in March, with each auction designed to procure the same products at two different points in time. Specifically, under AEP Ohio's proposal, the Company would hold six auctions over the term of the ESP, with the first two auctions offering both 12-month and 24-month products and the final four auctions offering a single 12-month product, in order to ensure that all of the SSO supply would terminate at the end of the ESP term. Dr. LaCasse explained that AEP Ohio's proposed auction structure is consistent with the practice of other electric distribution utilities in Ohio, while also striking an appropriate balance between the risk of exposure to market conditions and the risk of decreasing bidder interest and increasing administrative cost. Dr. LaCasse added that the proposed clock auction format, which proceeds in a series of rounds, is consistent with the CBP rules adopted in Case No. 12-3254-EL-UNC and is broadly similar to the format used by the other electric distribution utilities in Ohio. (Co. Ex. 15 at 9-15, 18.)

AEP Ohio proposes a two business day window during which the Commission would review the auction results, which could be rejected if a specific CBP rule is violated in such a manner so as to invalidate the auction, or if any of the following criteria are not met: the auction was oversubscribed on the basis of the indicative offers received; there were four or more bidders; and no bidder won more than 80 percent of the tranches available at the start of the auction. In the event that there are unfilled tranches in an auction or there is a supplier default, AEP Ohio proposes to implement a contingency plan, which generally calls for procuring any needed supply through the next available auction under the CBP, or, if necessary, through PJM-administered markets. Dr. LaCasse provided a number of documents in support of AEP Ohio's CBP proposal, including the Master SSO Supply Agreement, Bidding Rules, Glossary, Communications Protocols, Alternate Guaranty Process, Part I Application, Part II Application, and Associated Bidder Rules and Protocols. (Co. Ex. 15 at 4-5, 29, 32, Ex. CL-2 to CL-9; Co. Ex. 15A.)

Staff recommends that AEP Ohio's proposed SSO auction structure be modified to reduce customers' exposure to uncertainty and potential rate volatility in 2017 and 2018, in light of the Company's plan to restrict its initial auctions to products that terminate on or before May 31, 2017, in conjunction with the Company's request to reserve the right to terminate the ESP after two years. Staff witness Strom testified that AEP Ohio's proposal has an inadequate amount of product blending and may expose customers to price spikes. As a means to provide more price stability for SSO customers, Mr. Strom recommends that the Commission reject AEP Ohio's early termination proposal; adopt Staff's alternative product mix in order to increase auction blending and eliminate 100 percent termination of auction products; and adopt a five-year ESP term. Mr. Strom further recommends that the Commission require AEP Ohio to propose its next SSO well in advance of the termination of ESP 3, which would enable the Company to blend its last procurements for ESP 3 with the initial procurements for the next SSO. In terms of AEP Ohio's proposed CBP process, Mr. Strom testified that the Commission's ability to reject the auction results should not be limited to the criteria identified by Company witness LaCasse. Staff recommends that the Commission clarify that it will ultimately determine the criteria used to determine whether the auction results should be rejected and that it retains the right to modify and alter the load cap or any other feature of the CBP process for future auctions. (Staff Ex. 16 at 2-6, Ex. RWS-1; Tr. IX at 2245-2250; Staff Br. at 63-67.) AEP Ohio replies that its proposed criteria are reasonable, consistent with prior auctions, and intended to ensure certainty for bidders (Co. Reply Br. at 13-14).

Like Staff, OCC argues that AEP Ohio's proposal relies too much on one-year products, which may result in higher prices for consumers and greater rate volatility. OCC witness Kahal recommends that a 50/50 mix of one- and two-year products be offered in the fifth and sixth auctions. Alternatively, Mr. Kahal proposes that AEP Ohio be required to procure SSO supply through a 50/50 mix of one- and two-year products in each of the six auctions. (OCC Ex. 13 at 49-53; OCC Br. at 118-119; OCC Reply Br. at 104-106.) Constellation supports AEP Ohio's proposed CBP process and schedule, but notes that it is not opposed to amendment of the auction schedule to provide for some auctioned tranches of a three-year duration (Constellation Br. at 24-25).

In response to Staff's and OCC's concerns, AEP Ohio responds that there is no evidence that rate volatility will be materially increased by the Company's laddering proposal, which would reasonably provide for the termination of the auction products' terms at the end of its ESP. With respect to Staff witness Strom's proposal to extend the ESP term to five years, AEP Ohio points out that Mr. Strom did not take into account the impact of his proposal on any other aspect of the ESP, such as whether the distribution investment rider (DIR) should be continued for five years, and the fact that a prospective significantly excessive earnings test (SEET) review would be required under R.C. 4928.143(E) during the fourth year of the ESP. AEP Ohio adds that the proposal is unnecessary, given that Mr. Strom appeared to recognize that there are other mechanisms available to mitigate his concerns, such as through a requirement that the Company propose its next SSO sufficiently far in advance that the final procurements in this ESP can be blended with the initial procurements of the subsequent SSO. (Staff Ex. 16 at 4; Tr. IX at 2257, 2262-2263; Co. Br. at 12-14; Co. Reply Br. at 12-13.) Staff replies that the Commission has numerous available ways in which to modify AEP Ohio's proposed auction schedule to increase the laddering of auction products in order to reduce customers' exposure to rate volatility (Staff Reply Br. at 47-48).

IGS argues that AEP Ohio's SSO is not a non-discriminatory, comparable, and unbundled service, which is counter to R.C. 4928.02(A) and (B) and has harmed competition in Ohio to the detriment of customers. Specifically, IGS asserts that the SSO receives favored regulatory treatment and is subsidized by AEP Ohio's distribution ratepayers, because significant costs supporting the SSO are recovered through distribution rates. IGS adds that AEP Ohio's proposed wholesale auction process will not resolve problems with limited customer engagement and the failed development of a robust retail electric market for the residential class in particular. IGS, therefore, recommends that the Commission direct AEP Ohio to charge SSO suppliers a retail price adjustment (RPA) fee designed to recover the costs incurred to make the SSO available, which would then be returned to all distribution ratepayers. IGS asserts that the

Commission should establish a proceeding in which to determine the actual and avoided costs related to the SSO that would make up the RPA fee. Alternatively, IGS proposes that AEP Ohio be required to conduct a retail auction in which suppliers would bid for the right to serve SSO customers directly. IGS believes that a retail auction would generate significant revenues that should be used to offset AEP Ohio's deferrals. IGS concludes that either option would benefit customers, encourage customer engagement in the retail electric market, and further state policy by offering a non-discriminatory, comparable, and unbundled SSO price. (IGS Ex. 2 at 5-22; Tr. III at 909-912; Tr. VII at 1807-1808; IGS Br. at 3-15.)

AEP Ohio contends that the recommendations put forth by IGS are contrary to R.C. 4928.141, which requires the Company to provide an SSO to all consumers, while there is no statutory basis for the proposed RPA fee. AEP Ohio adds that IGS offered the same proposals in Case No. 12-3151-EL-COI, which were rejected by the Commission. *In re Comm. Investigation of Ohio's Retail Elec. Serv. Market*, Case No. 12-3151-EL-COI (*CRES Market Case*), Finding and Order (Mar. 26, 2014) at 19. AEP Ohio concludes that, because the Company's SSO is the default service for non-shopping customers, the recommendations of IGS should again be rejected. (Co. Br. at 14-15; Co. Reply Br. at 14-15.) OCC also urges the Commission to reject IGS' recommendations. Specifically, OCC contends that the recommendations are contrary to R.C. 4928.02 and 4928.141; are not supported by any evidence; and would erode the value of the SSO as a market based alternative and increase its price for consumers. (OCC Br. at 123-125; OCC Reply Br. at 80-81.) Like OCC, OPAE and APJN encourage the Commission to reject IGS' recommendations, which, according to OPAE and APJN, are an attempt to undermine the SSO as a competitive option (OPAE/APJN Br. at 48-50; OPAE/APJN Reply Br. at 27-29). IGS responds that its RPA and retail auction proposals are consistent with Ohio law; would lower costs for customers; and enable the retail electric market to continue to evolve following the significant changes that have occurred since AEP Ohio's prior ESP proceedings (IGS Reply Br. at 4-8).

In addition to its recommendations regarding the auction process and schedule, Staff recommends that an AEP Ohio settlement zone be established in PJM, as soon as practicable, for the purpose of pricing SSO load and that the Company be directed to work with Staff in the process. Staff notes that its modeling confirms that it would be less expensive for suppliers to deliver energy to an AEP Ohio zonal price point as compared to the AEP Load Zone. (Staff Ex. 9 at 2-3; Staff Br. at 70-71.) In response, AEP Ohio states that a thorough analysis of the benefits and costs should precede the decision to petition PJM for a change in the delivery point. Accordingly, AEP Ohio commits to conduct the necessary analysis and report back to Staff with the results in a timely manner. (Tr. V at 1319-1322; Co. Br. at 15-16; Co. Reply Br. at 15.) Staff replies that the Commission should direct AEP Ohio to complete its study prior to the independent auction administrator's dissemination of bidder information materials for the first auction in which the new load zone is used as the auction delivery point. Further, Staff recommends that AEP Ohio be required to share the assumptions and results of the study with Staff. (Staff Reply Br. at 48.)

The Commission finds that AEP Ohio's proposal to implement full auction based pricing for its SSO customers for the ESP period beginning on June 1, 2015, and continuing through May 31, 2018, is reasonable and should be approved with modifications. The CBP process, including the products offered and the timing of the auctions, should be designed to minimize uncertainty and potential rate volatility for SSO customers. AEP Ohio's proposed auction schedule, however, places too much emphasis on 12-month products in the later auctions, which may have the adverse effect of higher prices and greater rate volatility. (Staff Ex. 16 at 2-4; OCC Ex. 13 at 49-53.) Accordingly, the Commission finds that AEP Ohio's proposed auction schedule should be modified. Specifically, the first and second auctions should occur sufficiently far in advance of the end of the current ESP term on May 31, 2015, and each offer a mix of 12-month (17 tranches), 24-month (17 tranches), and 36-month (16 tranches) products, with delivery to commence on June 1, 2015. The third and fourth auctions should occur in November 2015 and March 2016, respectively, and each offer a 24-month (17 tranches) product. Finally, the fifth and sixth auctions should occur in November 2016 and March 2017, respectively, and each offer a 12-month (17 tranches) product. Additionally, consistent with Staff's recommendation, AEP Ohio should propose its next SSO sufficiently far in advance of the conclusion of ESP 3, in order to blend the final procurements of ESP 3 with the initial procurements of the next SSO (Staff Ex. 16 at 4). AEP Ohio is, therefore, directed to file its next SSO application, pursuant to R.C. 4928.141, by June 1, 2017. If a subsequent SSO is not authorized by the Commission by April 1, 2018, AEP Ohio shall procure, through the CBP process, 100 tranches of a full requirements product for a term that is not less than quarterly or more than annually to be deliverable on June 1, 2018, until a subsequent SSO is authorized.

The Commission notes that we reserve the right to review and modify any feature of the CBP process, as the Commission deems necessary based upon our continuing oversight of the process, including any reports on the auctions provided to the Commission by the independent auction manager, AEP Ohio, Staff, or any consultant retained by the Commission. Although AEP Ohio's application addresses specific situations in which the Commission may reject the results of an auction, we note that this provision of the CBP proposal does not circumscribe the Commission's authority to oversee the CBP process.

With respect to Staff's recommendation regarding an AEP Ohio settlement zone in PJM, the Commission takes administrative notice of the fact that, on October 1, 2014, American Electric Power (AEP) provided notice[5] to PJM of its intention to change the existing energy settlement area into four separate areas based on operating company, effective June 1, 2015. Given the expected benefits from the implementation of an AEP Ohio settlement zone (Staff Ex. 9 at 3), the new zone should be incorporated into the Company's CBP process as the delivery point for its SSO auctions, beginning on June 1, 2015. Finally, the Commission declines to adopt the recommendations of IGS regarding the implementation of retail auctions or an RPA fee. In the *CRES Market Case*, IGS recommended that the Commission eliminate the SSO or otherwise take immediate steps to transition beyond the current default rate structure. The Commission, however, concluded that the SSO should remain the default service for non-shopping customers at present, in light of the success of the SSO auctions, and the fact that elimination of the SSO could result in customer confusion. *CRES Market Case*, Finding and Order (Mar. 26, 2014) at 19-20. For the same reasons, we again decline to adopt IGS' recommendations.

3. Standard Service Offer Pricing

In the application, AEP Ohio states that the proposed ESP will provide transparency in SSO pricing through implementation of a generation energy (GENE) rider, generation capacity (GENC) rider, and auction cost reconciliation rider (ACRR), while the Company's current base generation charges, fixed cost rider, and auction phase-in rider (APIR) will be eliminated, in addition to the FAC mechanism, following a final true-up of all costs incurred through May 2015. AEP Ohio notes that its proposed generation service riders will give consumers a comparable price to be used when evaluating offers from CRES providers. According to AEP Ohio, the CBP auctions will result in a bundled price for energy and capacity, as well as certain market based transmission services, as discussed further below. AEP Ohio witness Roush explained that, because multiple auctions will be held for each delivery year, a tranche-weighted average auction price will be determined for each delivery year, which will consist of a capacity price and an energy price. Mr. Roush testified that the capacity price will be determined by using the PJM final zonal capacity price for the delivery year, while the energy price will be the remainder after deducting the capacity price from the tranche-weighted average auction price. Mr. Roush further testified that the GENC rider rates, which include a gross-up for taxes, will be determined based upon the contribution of each customer class to the PJM 5 Coincident Peaks (CP), computed as a rate per kilowatt hour (kWh), and updated annually to reflect the PJM final zonal capacity price for the delivery year. The GENE rider rates, according to Mr. Roush, will include a gross-up for taxes, be computed using the seasonal factor set forth in the auction rules and loss factors, and be updated annually to reflect the results of the competitive bid auctions for the delivery year. Mr. Roush testified that any over- or under-recoveries related to the GENE and GENC riders would be reconciled through the

[5] Notice of AEP's Intention to Change Existing Load Zone Energy Settlement Area, http://pjm.com/markets-and-operations/energy/lmp-model-info.aspx.

ACRR. AEP Ohio emphasizes that its proposed pricing methodology is consistent with the manner in which the Commission has approved the conversion of auction prices to customer rates for other Ohio utilities. (Co. Ex. 1 at 7; Co. Ex. 12 at 4-5, Ex. DMR-2; Co. Ex. 13 at 4, 8-9, 11.)

AEP Ohio witness Moore explained that the ACRR will enable the Company to reconcile any over/under recovery based on the amount billed to SSO customers versus the amount paid to auction winners for the procurement of power, as well as to recover all costs associated with the CBP process such as auction manager fees, incremental auction costs, and the costs associated with the contingency plan to procure replacement supply, as necessary. With respect to contingency plan costs in particular, AEP Ohio requests that such costs, if any, be deemed prudent and approved for recovery through retail rates. Ms. Moore testified that the ACRR would be collected on a per kWh basis and updated quarterly. (Co. Ex. 13 at 11, Ex. AEM-4; Co. Ex. 15 at 34.)

With respect to the ACRR, Staff witness Snider recommended that the Commission direct that AEP Ohio be allowed to collect only its prudently incurred CBP costs through the rider. Mr. Snider further recommended that the ACRR be subject to an annual audit by Staff and that AEP Ohio be directed to work with Staff regarding the details of the audit. Finally, Mr. Snider advised that the Commission should direct Staff to ensure that there is no overlap of costs recovered through the ACRR and the existing APIR, which will be replaced by the ACRR. (Staff Ex. 7 at 2-3; Staff Br. at 31-32.) AEP Ohio responds that it does not object to Staff's recommendations (Co. Br. at 19).

Staff witness Turkenton noted that, in Case No. 13-1530-EL-UNC, the Commission approved AEP Ohio's proposed rate mitigation plan for residential customers in the CSP rate zone, which phases in winter tail block capacity rates for a period that ends on May 31, 2015. *In re Comm. Review of Customer Rate Impacts from Ohio Power Company's Transition to Market Based Rates*, Case No. 13-1530-EL-UNC, Finding and Order (Mar. 19, 2014) at 8. Ms. Turkenton further noted that, because capacity costs are expected to decrease beginning on June 1, 2015, the impact from completely phasing in the winter tail block capacity rates on June 1, 2015, would result in moderate increases for residential customers in the CSP rate zone. Accordingly, Staff recommends that AEP Ohio provide a typical bill impact for residential customers in the CSP rate zone within 30 days following the Commission's decision in these proceedings, once the new rates and rider impacts are known, to determine if the complete phase-in of the winter tail block capacity rates is appropriate. (Staff Ex. 15 at 6.) AEP Ohio does not object to this recommendation (Co. Br. at 20).

Regarding the GENC rider, OCC argues that AEP Ohio's proposal to allocate responsibility for capacity costs based on the load factor of each customer class will result in a $30 million annual cost premium for capacity supplied to residential SSO customers.

OCC witness Kahal contends that residential customers pose less migration risk and account for a sizable portion of SSO load, which completely offsets the relatively greater capacity costs incurred by SSO suppliers to provide generation services for the residential class. Mr. Kahal recommends, therefore, that the residential customer class be allocated only an average share of capacity costs or, alternatively, that the CBP auctions be conducted in a manner that procures generation services for the residential class separately from the other classes. (OCC Ex. 13 at 56-59; OCC Br. at 114-117.) AEP Ohio responds that the methodology used by Company witness Roush, including the allocation of capacity costs based on class load factors, has been approved by the Commission for the other Ohio electric distribution utilities. AEP Ohio also asserts that OCC witness Kahal failed to account for governmental aggregation in his assessment of migration risk; failed to conduct an analysis to demonstrate that migration risk would substantially offset the lower capacity factor of the residential class; and did not account for other risks factored into SSO suppliers' bids, such as the weather sensitive nature of residential usage. With respect to OCC's alternative recommendation, AEP Ohio points out that, as Mr. Kahal admits, a separate procurement for the residential class would introduce an undue and unnecessary complexity and cost into the CBP process. AEP Ohio adds that smaller auctions may also result in lower participation and ultimately higher clearing prices. (OCC Ex. 13 at 58; Tr. IX at 2101-2109; Co. Br. at 21-22; Co. Reply Br. at 16.) OCC replies that AEP Ohio has not demonstrated that SSO suppliers will incur greater costs to provide capacity to the residential class. OCC contends, therefore, that AEP Ohio's capacity pricing proposal is discriminatory and contrary to R.C. 4905.33, 4905.35, and 4928.02(A). (OCC Reply Br. at 99-104.)

The Commission finds that AEP Ohio's SSO pricing proposal, including establishment of the GENE and GENC riders and the ACRR, which was generally unopposed, is reasonable and should be approved, subject to Staff's recommendations (Co. Ex. 12 at 4-5, Ex. DMR-2; Co. Ex. 13 at 4, 8-9, 11, Ex. AEM-4; Co. Ex. 15 at 34). Specifically, regarding the ACRR, we note that AEP Ohio is authorized to collect only its prudently incurred CBP-related costs through the rider. The ACRR shall be subject to an annual audit by Staff, which, among other matters, should ensure that there is no overlap of costs recovered through the new ACRR and the current APIR that will be eliminated. AEP Ohio should provide any and all documents or information requested by Staff, and otherwise cooperate with Staff, in conjunction with each annual audit. (Staff Ex. 7 at 2-3.) The Commission notes that this change may result in an increase in rates for residential customers in the CSP zone with high usage in non-peak months. The amount of this increase will be dependent upon the results of the auctions to be held under the ESP, and other provisions of the ESP. We will continue to review the rate impact, including the reasonableness of the impact, on these customers. Accordingly, we reserve our prerogative to phase in any increase we consider necessary to ensure rate stability for these consumers. (Staff Ex. 15 at 6.)

The Commission declines to adopt OCC's recommendations regarding the allocation of capacity costs to the residential customer class. AEP Ohio's proposed allocation, which is based on class load factors, is consistent with cost causation principles. Further, AEP Ohio witness Roush noted that the Company's calculation methodology is consistent with the manner in which auction prices are converted into customer rates for the other Ohio electric distribution utilities (Co. Ex. 12 at 5), and the Commission has previously approved the Company's allocation of capacity costs based on the contribution of each customer class to the PJM 5 CP. *In re Ohio Power Company*, Case No. 13-1530-EL-UNC, Finding and Order (Mar. 19, 2014) at 3, 7-8. OCC witness Kahal admitted that, all other considerations being held equal, the low load factor of the residential class may well merit a pricing premium in comparison to a customer class with a higher load factor. Mr. Kahal nevertheless claimed that the larger load size and lower migration risk of the residential class should also be factored into the determination of capacity rates. (OCC Ex. 13 at 56-57.) Mr. Kahal, however, did not demonstrate that the alleged lower migration risk or the larger size of the residential class would have a material impact on the bids of SSO auction participants, or that these particular factors would substantially offset the increased costs attributable to the low load factor of the residential class. Additionally, Mr. Kahal did not consider other factors in his analysis, such as the weather sensitive nature of residential usage. With respect to OCC's alternative recommendation to conduct a separate procurement for the residential class, the Commission finds that this proposal would introduce an unnecessary layer of complexity in the CBP process, as Mr. Kahal recognizes, and may result in higher costs and lower participation in AEP Ohio's auctions. (OCC Ex. 13 at 58-59.) Accordingly, we find no merit in OCC's contention that AEP Ohio's capacity pricing proposal is discriminatory or otherwise unlawful.

4. Alternative Energy Rider

AEP Ohio proposes to continue the bypassable alternative energy rider (AER), which was approved by the Commission in the Company's prior ESP proceedings. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 18. AEP Ohio explains that the AER enables the Company to recover the renewable energy credit expense associated with acquiring or creating renewable energy. AEP Ohio notes that its proposal to continue the AER is unopposed. (Co. Ex. 1 at 9; Co. Ex. 13 at 3-4; Co. Br. at 69; Co. Reply Br. at 63-64.) The Commission finds that AEP Ohio's proposed extension of the AER is reasonable and should be approved (Co. Ex. 1 at 9; Co. Ex. 13 at 3-4). In the *ESP 2 Case*, the Commission specified that the AER should be subject to an annual audit in conjunction with the audit of AEP Ohio's FAC mechanism. *ESP 2 Case* at 18. Although the FAC mechanism has been replaced with other generation riders, we note that the annual audits of the AER should nevertheless continue in a separate proceeding under the direction of Staff.

5. Variable Price Tariffs

In light of the implementation of full auction based pricing for SSO customers and the continued development of the competitive marketplace, AEP Ohio proposes to eliminate the interruptible power–discretionary rider (IRP-D), supplement no. 18 (Supp. No. 18), schedule standby service (Schedule SBS), and the generation component of the standard time of use (TOU) tariffs not related to the pilot gridSMART project tariffs. AEP Ohio witnesses Spitznogle and Moore testified that CRES providers are better positioned to offer innovative generation service rate offerings, whereas the Company, as a wires business, should no longer provide these generation services. Mr. Spitznogle added that AEP Ohio does not expect any significant customer impact from the elimination of its variable price tariffs, given that there were relatively few customers, ranging from 3 to 915, taking service under any of these tariffs as of August 2013. Regarding the IRP-D, AEP Ohio emphasizes that, because it will procure generation services for SSO customers through an auction process, the Company is not the entity best able to provide an interruptible service product. Similarly, with respect to Supp. No. 18, AEP Ohio states that discounts on demand charges for off-peak usage by schools and churches should no longer be offered by the electric distribution utility and, in any event, a discount on demand is no longer applicable, because SSO rates will be structured as a per kWh charge. Next, AEP Ohio explains that it can no longer administer Schedule SBS, because the Company cannot monitor or provide backup and maintenance service, given that it no longer owns generation assets. Finally, AEP Ohio proposes to eliminate its residential TOU generation rates, in light of the new residential rate design to take effect on January 1, 2015, which the Commission ordered the Company to implement in Case No. 11-351-EL-AIR, et al. *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 11-351-EL-AIR, et al. (*Distribution Rate Case*), Opinion and Order (Dec. 14, 2011) at 10, Entry Nunc Pro Tunc (Dec. 15, 2011) at 2, Entry on Rehearing (Feb. 14, 2012) at 4-9. AEP Ohio explains that this change will flatten the energy rate on residential tariffs, reflecting no benefit of operating during on- or off-peak periods. (Co. Ex. 1 at 9; Co. Ex. 3 at 12-13; Co. Ex. 13 at 9-11; Co. Br. at 70-71.)

RESA, Constellation, and IGS support AEP Ohio's proposal. RESA and IGS assert that the elimination of AEP Ohio's TOU rates would enable CRES providers to provide TOU products in furtherance of the competitive market. Constellation points out that AEP Ohio, as an electric distribution utility, should be providing only basic default service for supply, while CRES providers should be the exclusive suppliers of TOU and other innovative products and services. Constellation adds that the continued reliance on TOU products that are not truly market supplied or market based will prolong the day that such products are developed by CRES providers and that now is the appropriate time to eliminate AEP Ohio's TOU rates. (Constellation Ex. 1 at 11; RESA Br. at 32-33; Constellation Br. at 23; IGS Br. at 21-22; Constellation Reply Br. at 25-26.)

In response to AEP Ohio's request to eliminate the IRP-D, OEG argues that the Company should be required to continue an interruptible program. In light of the proposed PPA rider, OEG points out that, contrary to AEP Ohio's claim, it would not be a wires only company during the ESP term, because the Company would retain its OVEC generation assets, if the rider is approved. OEG adds that Duke and the FirstEnergy operating companies have Commission-approved interruptible programs. Further, OEG contends that there are no realistic market alternatives for customers that currently participate in AEP Ohio's interruptible program. Finally, OEG emphasizes that a number of significant benefits, which were recognized by the Commission in the *ESP 2 Case*, would be lost if the program is terminated. According to OEG, AEP Ohio's interruptible program enhances the reliability of the Company's system, promotes economic development, and contributes to the Company's energy efficiency and peak demand reduction (EE/PDR) requirements under R.C. 4928.66. (OEG Ex. 2 at 7-16, Ex. SJB-4 to SJB-7; Tr. X at 2362-2367, 2383-2385; OEG Br. at 18-25.)

OEG recommends two interruptible rate options for the Commission's consideration. First, OEG proposes that AEP Ohio offer an interruptible program that provides for an interruptible credit equal to 50 percent of the Net Cost of New Entry (Net CONE) ($5.36/kilowatt (kW)-month for 2017/2018), based on Duke's approach and patterned after the PJM Limited Emergency Demand Response program, which limits interruptions to ten times during the months of June through September for participating SSO and shopping customers. As a second option, OEG proposes that AEP Ohio be required to offer an unlimited emergency interruptible program under which a participating customer would continue to receive the existing credit of $8.21/kW-month, with no limitations on the frequency, duration, and timing of emergency interruptions, although the existing notice provisions would continue to apply. According to OEG witness Baron, the potential for unlimited emergency curtailments increases the reliability value of the interruptible load compared to PJM's program, which justifies the larger monthly credit for this option. OEG recommends that AEP Ohio be required to maximize the financial value of the interruptible capacity by bidding it into the appropriate PJM capacity auction and credit that revenue back to consumers through the EE/PDR rider, which would significantly reduce the cost of the program. Further, OEG proposes that AEP Ohio's interruptible program continue to be capped at 525 MW, although, at a minimum, OEG requests that all current IRP-D customers be permitted to participate in one or the other of the two options, if the Commission elects to impose a more restrictive cap. Finally, OEG asserts that, in light of the interruptible program benefits, it would be appropriate for AEP Ohio to recover the costs associated with the interruptible credits through either the EE/PDR rider or the economic development rider (EDR). (OEG Ex. 2 at 16-19; Tr. X at 2346; OEG Br. at 25-26.)

AEP Ohio responds that, in light of changed circumstances, the Company does not object to continuing the IRP-D for existing IRP-D customers and as an option for economic *development purposes, along with the existing $8.21/kW-month credit, and for purposes* of unlimited emergency interruptions only. AEP Ohio emphasizes that its support for a modified IRP-D is contingent upon its ability to recover the costs of any interruptible credits through the EE/PDR rider, as OEG suggests. With respect to OEG's recommended limited emergency interruption program, AEP Ohio states that the program is not appropriate. (Co. Br. at 72-73; Co. Reply Br. at 66-67.) OEG responds that, in light of AEP Ohio's change in position, the Commission should modify the IRP-D to provide for *unlimited emergency interruptions with a credit of $8.21/kW-month available to shopping* and non-shopping customers (OEG Reply Br. at 11-13). EnerNOC believes that there are not enough details in the record regarding OEG's proposed interruptible load program expansion and, therefore, recommends that the Commission open a new docket and direct the parties to develop a reasonable tariff, if the program is approved (EnerNOC Reply Br. at 6-7). OMAEG points out that AEP Ohio has requested recovery of approximately $45 million associated with the IRP-D credit received by three customers from 2012 through 2014. In light of the significant cost, OMAEG recommends that, if the Commission finds that the interruptible load program serves an economic development purpose, the Commission should either continue the existing program or institute a program comparable to Duke's, wherein the credit is equal to 50 percent of the applicable Net CONE rate per MW. OMAEG believes that the costs of the program should be recovered through the EDR rather than the EE/PDR rider. Finally, OMAEG asserts that AEP Ohio should be required to continue to bid the interruptible load in PJM's capacity auctions, with any resulting revenues credited back to customers through the EDR. (Tr. X at 2342-2352; OMAEG Reply Br. at 20-25.) OCC objects to AEP Ohio's late change in position and argues that the Commission should seek ways to protect the customers that fund the IRP-D credit, such as by allowing the credit to continue only until existing IRP-D customers can find a curtailment service provider or bid their interruptible loads into the PJM auctions (OCC Reply Br. at 96-99).

Staff notes that, with respect to Schedule SBS, AEP Ohio proposes to assess generation-related charges for backup power and planned maintenance services under the GENE, GENC, and ACRR based on the actual energy used for those services during a billing period. Staff recommends that Schedule SBS be maintained and modified to reference the applicable generation-related riders, along with the appropriate tariffs for distribution service. Staff asserts that its proposal will make it easier for customers to understand how backup and planned maintenance charges will be calculated and ensure that customers are aware that the services are provided through the SSO. (Staff Ex. 1; Staff Ex. 6 at 2-4; Staff Br. at 68-70.) In its reply brief, Staff points out that AEP Ohio has not clearly indicated whether the Company requests to eliminate standby service or just Schedule SBS. In any event, Staff believes that AEP Ohio has an obligation and should be required, pursuant to R.C. 4928.14 and 4928.141, to continue both standby service and the corresponding tariff. (Staff Reply Br. at 43-47.) For its part, AEP Ohio replies that Staff's recommendation that Schedule SBS be maintained is unnecessarily complex and inappropriate, because the tariff would no longer be used to collect a separate charge for standby service. AEP Ohio adds that it can directly resolve any confusion over the elimination of Schedule SBS with the Company's three standby customers. (Co. Reply Br. at 64-65.)

OCC, ELPC, OEC, and EDF urge the Commission to reject AEP Ohio's proposal to eliminate the generation component of the standard TOU tariffs. OCC points out that CRES providers are not offering TOU products to customers and that the majority of electric utilities in Ohio continue to have tariff based TOU rates, which OCC believes should be retained as the market emerges for these types of product offerings. OCC adds that approximately 915 customers would lose their savings from the TOU rates, if AEP Ohio's proposal is adopted. ELPC argues that AEP Ohio's proposal is contrary to R.C. 4928.02(D); inconsistent with prior Commission directives set forth in the *CRES Market Case* and other proceedings; detrimental to consumers and the environment; and untimely. Because no CRES provider is currently offering TOU rates and the majority of residential consumers continue to receive service under the SSO, ELPC disputes AEP Ohio's claim that CRES providers are better situated to provide TOU rates. OEC and EDF assert that AEP Ohio should provide TOU rates until a reasonable number of CRES providers offer TOU products. (OCC Ex. 11 at 33-34, Ex. JDW-15; ELPC Ex. 1; Tr. I at 78-79; Tr. III at 694-695; OCC Br. at 109-112; ELPC Br. at 4-6; OEC/EDF Br. at 3-6; OCC Reply Br. at 86-88.) In response to such concerns, RESA points out that there is adequate time for CRES providers to make TOU offers before AEP Ohio's proposed elimination of TOU rates would take effect, particularly in light of the small number of affected customers. In any event, RESA believes that the Commission should encourage the competitive market to offer TOU products by approving AEP Ohio's request to terminate its TOU rates. (RESA Br. at 33; RESA Reply Br. at 21.) IGS adds that the Commission should find means to enable CRES providers to offer TOU products, such as ensuring access to the necessary customer data (IGS Reply Br. at 13-14). In its reply brief, AEP Ohio points out that CRES providers are eager to provide TOU products to customers. Regarding the Commission's directives on TOU rates as set forth in the *CRES Market Case*, AEP Ohio notes that this matter should be addressed in the context of the Company's application to eliminate its TOU tariffs associated with the first phase of the gridSMART program, which was filed in Case No. 13-1937-EL-ATA. (Co. Reply Br. at 65-66.)

The Commission finds that AEP Ohio's request to eliminate the IRP-D, Supp. No. 18, Schedule SBS, and the generation component of the standard TOU tariffs not related to the pilot gridSMART project tariffs should be denied. We believe that it is reasonable and appropriate for AEP Ohio to continue the IRP-D, Supp. No. 18, Schedule SBS, and the TOU tariffs at this point in time. Although the Commission fully expects that CRES providers will begin to offer TOU and other innovative and dynamic products as smart grid deployment expands and we strongly encourage their endeavors in this area, the record is clear that such products are not, at present, offered by CRES providers in AEP Ohio's service territory (OCC Ex. 11 at 33-34, Ex. JDW-15; Tr. I at 78-79). As the Commission recently stated in the *CRES Market Case*, time-differentiated rates are a type of generation service that should be offered by generation service providers. We directed the electric distribution utilities to offer time-differentiated rates and to participate in the Market Development Working Group (MDWG) to assist in the development of proper data exchange protocols to improve the ability of CRES providers to offer time-differentiated rates. *CRES Market Case*, Finding and Order (Mar. 26, 2014) at 37-38. Throughout the ESP period, AEP Ohio will remain the SSO provider, regardless of the fact that generation services will be fully procured through the CBP process. Therefore, for the same reasons articulated in the *CRES Market Case* with respect to time-differentiated rates, the Commission finds that AEP Ohio should continue to make its TOU and other variable price tariffs available to customers, while the competitive market sufficiently develops such that a reasonable number of CRES providers, in fact, begin to offer these types of innovative generation services and pricing.

At the same time, we recognize that AEP Ohio's variable price tariffs may require modifications, in light of the implementation of full auction based pricing through several new generation riders. Consequently, Schedule SBS should be modified, as recommended by Staff (Staff Ex. 6 at 3-4), to reference the applicable generation riders and distribution tariffs, such that customers are able to understand how the Company calculates supplemental, backup, and maintenance service charges. With respect to Supp. No. 18 and the residential TOU tariffs, AEP Ohio should propose any rate design changes necessary for schools, churches, and residential customers to retain the current financial benefits associated with using power during off-peak periods. Accordingly, AEP Ohio should file proposed revised tariffs within 60 days of the date of this Opinion and Order.

Finally, the Commission agrees with OEG that the IRP-D offers numerous benefits, including the promotion of economic development and the retention of manufacturing jobs, and furthers state policy, which we recognized in the *ESP 2 Case*. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 26, 66. We find that the IRP-D should be modified to provide for unlimited emergency interruptions and that the $8.21/kW-month credit should be available to new and existing shopping and non-shopping customers. Consistent with its current practice, AEP Ohio should continue to apply for recovery of the costs associated with the IRP-D through the EE/PDR rider, until otherwise ordered by the Commission. AEP Ohio should also bid the additional capacity resources associated with the IRP-D into PJM's base residual auctions held during the ESP term, with any resulting revenues credited back to customers through the EE/PDR rider.

6. Distribution Investment Rider

The DIR was previously approved by the Commission, in the *ESP 2 Case*, to facilitate the timely and efficient replacement of aging infrastructure to improve service reliability. *ESP 2 Case,* Opinion and Order (Aug. 8, 2012) at 46-47. Presently, the DIR is updated quarterly using FERC forms and AEP Ohio's DIR rider rates are automatically approved 60 days after the application is filed, unless the Commission specifically orders otherwise. The Commission reviews the DIR annually for accounting accuracy, prudency, and compliance with the DIR plan developed by AEP Ohio with Staff input.

In this ESP application, under the authority of R.C. 4928.143(B)(2)(h), AEP Ohio requests the continuation of the DIR, with certain modifications and adjustments. AEP Ohio requests that the DIR rate caps be established at $155 million for 2015, $191 million for 2016, $219 million for 2017, and $102 million for January 1 through May 31, 2018, for a total of $667 million. For any year that AEP Ohio's investment results in revenues to be collected that exceed the cap, the excess would be recovered and be subject to the cap applicable in the subsequent period. The same would be true when AEP Ohio's investment results in revenues to be collected that fall below the cap for the period; the cap for the subsequent period would be increased by the amount available from the prior period. AEP Ohio proposes DIR capital projects that primarily fall into eight categories: asset improvement, customer service, forestry, general, other, planning capacity, reliability, and system restoration. AEP Ohio reasons that these types of capital investments are key components in its strategy for maintaining the distribution system and improving reliability. One of the capital investments that AEP Ohio plans to make, if this ESP is approved, is to replace its 800 megahertz radio system at a cost of approximately $23 million. The radio system is used to support field communication, dispatching, remote equipment interrogation, global positioning satellite communications, service restoration, and remote meter reading. (Co. Ex. 1 at 9-10; Co. Ex. 4 at 17-19; Co. Ex. 14 at 5-7.)

However, AEP Ohio requests that the DIR, as currently implemented, be modified in three respects.[6] First, AEP Ohio requests that the DIR mechanism be modified such that the balance of each category of plant incurs an applicable associated carrying charge. Second, AEP Ohio proposes that the DIR be expanded to include general plant. Third, AEP Ohio requests that a gross-up factor be added to riders, including the DIR, to account for the Company's obligation to fund a portion of the budgets of the Commission and OCC. (Co. Ex. 13 at 5-7; Co. Ex. 14 at 1-2.)

Market Strategies International (MSI) conducted telephone surveys for AEP Ohio in 2012 to determine customer reliability expectations. MSI conducted two series of telephone surveys, interviewing a total of 400 residential customers and 400 small commercial customers. According to the survey results, 69.8 percent of residential customers and 75.8 percent of small commercial customers believe that their electric

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6 AEP Ohio also requests that gridSMART Phase 1 capital costs be transferred into the DIR and that issue is addressed in the gridSMART section of this Opinion and Order.

service reliability expectations will stay about the same over the next five years. Significantly fewer customers surveyed, 13.0 percent of residential customers and 14.8 percent of small commercial customers, thought that their service reliability expectations over the next five years would increase somewhat. Some of the customers surveyed thought that their service reliability expectations would increase significantly over the next five years, 5.8 percent of residential customers and 3.0 percent of small commercial customers. On the other hand, the surveys revealed that relatively few customers believe that their service reliability expectations will decrease somewhat, 5.3 percent of residential customers and 2.8 percent of small commercial customers. (Co. Ex. 4 at 5-8, Ex. SJD-1 at 1-2.)

AEP Ohio submits that the DIR advances the state policies expressed in R.C. 4928.02(A), (D), (E), (G), and (M). Further, AEP Ohio encourages the Commission to find that the DIR, as proposed, satisfies the statutory requirements set forth in R.C. 4928.143(B)(2)(h) and to approve the rider. (Co. Br. at 84.)

OHA supports the Commission's approval of the DIR, as proposed by AEP Ohio (OHA Br. at 3). Similarly, Staff generally does not oppose the continuation of the DIR, as the Commission approved the mechanism and the process for review in AEP Ohio's previous ESP proceedings. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 46-47. Staff testified that AEP Ohio's most recent system reliability standards were developed pursuant to Ohio Adm.Code 4901:1-10-10(B)(2), in Case No. 12-1945-EL-ESS, and adopted by the Commission in accordance with a stipulation filed by all of the parties to the proceeding. *In re Ohio Power Company*, Case No. 12-1945-EL-ESS (*Reliability Standards Case)*, Opinion and Order (Mar. 19, 2014) at 6. In the *Reliability Standards Case*, the Commission established a customer average interruption duration index (CAIDI) of 150.0 minutes and a system average interruption frequency index (SAIFI) of 1.20, excluding "major event days," as defined by the Institute of Electrical and Electronics Engineers. The new CAIDI and SAIFI standards were first applicable to AEP Ohio for calendar year 2013. Staff confirmed that, based on AEP Ohio's application filed in Case No. 14-517-EL-ESS, the Company met both its SAIFI and CAIDI performance standards for 2013. For that reason, Staff recommends that the Commission find that AEP Ohio's reliability expectations are aligned with those of its customers. (Staff Ex. 10 at 5-6; Staff Ex. 17 at 2; Staff Br. at 43.)

Staff, however, opposes the substantial increase and modifications that AEP Ohio requests with respect to the DIR. Regarding the request to include general plant, Staff, OCC, and Kroger assert that the request is another example of AEP Ohio's attempt to avoid a distribution rate case. OCC argues that general plant is not, by definition, infrastructure and, therefore, it is not appropriate to include general plant in the DIR. Staff reasons that the recovery of general plant costs via a rider is inconsistent with the intent of the ESP statute and the Commission's directives with respect to the DIR. Noting the

Commission's rationale for approving the DIR as stated in the *ESP 2 Case*, Staff asks the Commission to reaffirm its directive that AEP Ohio's DIR spending focus on those components that will best improve or maintain reliability. General plant, in Staff's and OCC's opinion, does not satisfy the Commission's stated criteria, because the types of general plant expenses that AEP Ohio seeks to include in the DIR do not directly relate to the reliability of the distribution system. Staff maintains that general plant like the radio system and service centers, at best, supports maintaining reliability, but does not directly relate to distribution system reliability. Staff argues that the DIR was never intended to facilitate the recovery of all capital expenditures. General plant, Staff reasons, does not satisfy the Commission's stated objective for the DIR, which is "to encourage the electric utility to proactively and efficiently replace and modernize infrastructure." *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 47. Staff requests that AEP Ohio's proposal to modify the DIR to include general plant be denied. (OCC Ex. 18 at 14; Staff Br. at 43-47; Staff Reply Br. at 34-36; OCC Br. at 85-86; OCC Reply Br. at 59-60; Kroger Reply Br. at 3-4.)

AEP Ohio responds that the general plant investments in question primarily consist of service centers and the radio communications systems that directly support the front-line employees. AEP Ohio witness Dias testified that some of the facilities were built in the World War II era and need work. AEP Ohio notes that the DIR plan will be discussed with Staff, as it has been since implementation, and filed with the Commission. AEP Ohio further notes that Staff witness McCarter indicated that, after a full review, Staff may agree to the inclusion of the radio system. (Tr. II at 344; Tr. IX at 2295; Co. Reply Br. at 73-74.)

AEP Ohio also proposes that the DIR be modified to include a factor to account for the Commission's and OCC's budgets. According to Staff, including a gross-up factor to account for AEP Ohio's share of the Commission's and OCC's budgets is short-sighted and unnecessary. Staff contends that there are only two scenarios where AEP Ohio would owe a significantly larger dollar amount for the assessments in a subsequent year: first, if AEP Ohio's revenues increase disproportionally to the revenues of all of the other regulated public utilities in Ohio; and, second, if there is an increase in either the Commission's or OCC's budget. Staff notes that the Commission's and OCC's budgets have not increased in recent years and are not expected to increase in the foreseeable future. Staff also argues that AEP Ohio did not demonstrate that its revenues would increase so disproportionately as to justify the proposed change in the gross-up factor. (Staff Ex. 17 at 4; Staff Br. at 47-48.)

OCC emphasizes AEP Ohio's failure to provide specific service reliability improvements for each DIR program implemented. OCC and OMAEG argue that AEP Ohio failed to present any analysis to support its claims that service reliability has and will deteriorate without the DIR. For that reason, OCC and OMAEG oppose any increase in the DIR without supporting documentation. (OMAEG Br. at 10; OCC Reply Br. at 56.)

If the Commission approves the continuation of the DIR, Staff makes six recommendations to facilitate the Commission's efficient review of plant recovery costs across the Company's riders. More specifically, Staff recommends that, in all subsequent DIR filings, AEP Ohio include additional detailed account and subaccount information; employ jurisdictional allocations and accrual rates from the *Distribution Rate Case;* provide a full reconciliation between the functional ledger and FERC forms; detail the DIR revenue collected by month; and highlight and quantify any proposed changes to capitalization policy. Staff also recommends that the Commission direct AEP Ohio to file a fully updated depreciation study by November 2016, with a study date of December 31, 2015. (Staff Ex. 17 at 5-7.)

OCC notes that AEP Ohio's enhanced service reliability rider (ESRR) and DIR programs include the widening and clearing of right-of-ways. OCC recommends that the Commission delete $3.9 million from the forestry component of the DIR for each year 2015 through 2018 to avoid any double recovery by AEP Ohio. (Tr. II at 353; OCC Br. at 84-85.) Further, OCC contends that the depreciation reserve used to calculate property taxes should be adjusted to eliminate the cumulative amortization of the excess depreciation reserve and the net plant to which the property tax is applied (OCC Br. at 90). Staff concurs with OCC's recommendation (Staff Reply Br. at 36-37).

OCC believes that the DIR, as well as other riders, should not be allocated based on total base distribution revenues, as AEP Ohio proposes, but rather in proportion to the allocation of net electric plant in service as set forth in the cost-of-service studies filed in the *Distribution Rate Case*. OCC contends that AEP Ohio's allocation does not follow cost causation principles and would result in residential customers being charged approximately $29 million more than their fair share for the DIR, ESRR, and sustained and skilled workforce rider (SSWR). (OCC Ex. 14 at 5-12; OCC Br. at 107-109.)

OEG and IEU-Ohio oppose OCC's reallocation proposal. OEG advocates that the costs underlying the DIR and the other riders are related to the provision of distribution service and it is, therefore, reasonable to allocate the rider costs to rate schedules on the basis of distribution revenues. OEG notes that the Commission adopted the DIR in the *ESP 2 Case* and reasons that it is appropriate for the Commission to follow this methodology for the new and modified riders proposed in these ESP proceedings. OEG also reasons that the approach recommended by OCC would require a fresh review of the cost of service and allocation methodology, which would equate to a "mini rate case" on rider allocation and rate design. OEG offers that such a review is outside of the scope and would unduly complicate the ESP proceedings. OEG and IEU-Ohio submit that the cost-of-service study relied on by OCC is outdated and reliance on the study would be unreasonable. OEG asserts that there is insufficient evidence in these proceedings to change an allocation method and rate design that the Commission has previously vetted and determined to be fair, just, and reasonable. (OEG Br. at 27; IEU-Ohio Reply Br. at 28-30.)

OPAE and APJN challenge the DIR, noting that AEP Ohio is not claiming that reliability will decline if the DIR is not approved in this ESP. Given that the DIR currently constitutes approximately 17.1 percent of the average residential customer's distribution charges, OPAE and APJN reason that this rider makes electric service less affordable for residential customers who are struggling financially. On that basis, OPAE and APJN opine that it is reasonable for the Commission to discontinue the DIR. OPAE and APJN dispute AEP Ohio's contention that the DIR advances the state policy as expressed in R.C. 4928.02(A), which requires the availability to consumers of reliable and reasonably priced retail electric service. OPAE and APJN claim that AEP Ohio failed to present any testimony or discussion on brief indicating how the DIR complies with R.C. 4928.02(L), regarding the protection of at-risk populations. To address this oversight, OPAE and APJN suggest that the Commission require AEP Ohio to continue its annual $1 million funding commitment of the Neighbor-to-Neighbor program. Further, OPAE and APJN ask the Commission to direct AEP Ohio to contribute $1 million annually from shareholders to the Neighbor-to-Neighbor program. Finally, these intervenors ask the Commission to exempt income-eligible customers from riders approved in these ESP proceedings, including the DIR, to mitigate the impact of rate increases on at-risk customers, in support of R.C. 4928.02(L). (OPAE/APJN Reply Br. at 4-9.)

First, the Commission notes that, under R.C. 4928.143(B)(2)(h), an ESP may include provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. In determining whether to approve an ESP that includes a provision for distribution infrastructure modernization, R.C. 4928.143(B)(2)(h) directs the Commission to examine the reliability of the electric distribution utility's distribution system, ensure that the expectations of customers and the electric distribution utility are aligned, and determine that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

The Commission concludes that the record indicates that the vast majority of residential customers, 82.8 percent, and small commercial customers, 90.6 percent, believe their electric service expectations will be about the same, or increase somewhat over the next five years (Co. Ex. 4 at Ex. SJD-1 at 1-2). We note that, in the prior ESP proceedings, when the Commission approved the implementation of the DIR, AEP Ohio's reliability measures were or had been below its reliability standards for 2010 and 2011. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 45. The record in these proceedings indicates that AEP Ohio has met its system reliability standards, CAIDI and SAIFI, for 2013 (Staff Ex. 10 at 5). Further, in the *Reliability Standards Case*, AEP Ohio agreed to file an updated reliability performance standards application by June 30, 2016, to reflect the impact of system design changes, technological advancements, geographical effects of programs like, but not limited to, the DIR and gridSMART programs, and the results of updated and current customer perception surveys. *Reliability Standards Case*, Opinion and Order (Mar. 19, 2014) at 3.

As several of the parties have noted, the Commission approved the current DIR mechanism on the premise offered by AEP Ohio that aging infrastructure was the primary cause of customer outages and reliability issues and the DIR would improve reliability and support the installation of gridSMART technologies. The expanded DIR for which AEP Ohio seeks approval in these ESP proceedings far exceeds the justification offered and accepted by the Commission in approving the original DIR. Furthermore, it appears that AEP Ohio's interpretation of distribution infrastructure exceeds the intent of the statute (Tr. II at 436-438). Accordingly, we must deny AEP Ohio's request to significantly increase the amount to be recovered via the DIR and to incorporate general plant into the DIR mechanism. The record does not support such a significant expansion of the DIR. We find that AEP Ohio's DIR investments, at the level requested in these proceedings, would be better considered and reviewed in the context of a distribution rate case where the costs can be evaluated in the context of the Company's total distribution revenues and expenses, and the Company's opportunity to recover a return on and of its investment can be balanced against customers' right to reasonably priced service. (Staff Ex. 17 at 3.) For these reasons, the Commission denies AEP Ohio's request to increase the DIR to the level proposed in the ESP application and its request to incorporate general plant into the DIR mechanism.

Likewise, we deny AEP Ohio's request to adjust the DIR to account for the budgets of the Commission and OCC. The Commission agrees with the arguments of Staff that it is unlikely that the budgets of either agency will increase significantly over the next few years sufficient to justify revising the DIR (Staff Ex. 17 at 4). For this reason, we find that the requested modification to the DIR is inappropriate and unreasonable. Further, the Commission declines to adopt OCC's recommendation regarding the allocation of the DIR, as it is reasonable and consistent with the *ESP 2 Case* to allocate the rider costs to rate schedules on the basis of distribution revenues. We also decline to adopt OCC's proposal to adjust the forestry component of the DIR, because OCC has not established the occurrence of any double recovery through the DIR and ESRR. We note, however, that the DIR will continue to be subject to an annual audit.

The Commission finds merit in OCC's recommendation to revise the property tax calculation and, therefore, we adopt the adjustment recommended by OCC witness Effron (OCC Ex. 18 at 9-11; Staff Ex. 17 at 4-5). We further modify the DIR to adopt the six recommendations by Staff regarding detailed account information, jurisdictional allocations and accrual rates, reconciliation between functional ledgers and FERC form filings, revenue collected by month in the DIR, highlighting and quantifying DIR capitalization policy, and the filing of an updated depreciation study by November 2016, as outlined in Staff witness McCarter's testimony (Staff Ex. 17 at 5-7).

However, the Commission recognizes that AEP Ohio is now performing at or above its established reliability standards and its reliability expectations appear to be aligned with its customers (Staff Ex. 10 at 5; Co. Ex. 4 at Ex. SJD-1 at 1-2). Therefore, we conclude that it is no longer necessary for AEP Ohio to work with Staff to develop a DIR plan, so long as the Company continues to perform at or above its adopted reliability standards.

To facilitate AEP Ohio's continued proactive investment in its aging distribution infrastructure, we approve the Company's request to continue the DIR at $124 million for 2015, $146.2 million for 2016, $170 million for 2017, and $103 million for January through May 2018, for a total of $543.2 million. The Commission has determined the annual DIR amounts based on the level of growth of three to four percent as permitted for the DIR in the *ESP 2 Case*. We find this to be a reasonable level to allow AEP Ohio to continue to replace aging distribution infrastructure in order to maintain and improve service reliability over the term of this ESP. With the modifications discussed herein, the Commission approves the continuation of the DIR as a component of the ESP.

7. Enhanced Service Reliability Rider

AEP Ohio's ESRR was originally approved by the Commission, under R.C. 4928.143(B)(2)(h), in the *ESP 1 Case*, as the Enhanced Service Reliability Plan – Enhanced Vegetation Initiative. *ESP 1 Case*, Opinion and Order (Mar. 18, 2009) at 34. The ESRR was approved again in the *ESP 2 Case*. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 64-65. As previously approved, AEP Ohio's ESRR is the cost recovery mechanism for implementation of a proactive, cycle-based vegetation management program. Particularly, in the *ESP 2 Case*, the ESRR was focused on AEP Ohio's transition to a four-year proactive cycle rather than primarily reactive vegetation control. Under the program, trees and other vegetation along AEP Ohio's circuits are to be trimmed end-to-end every four years, right-of-ways widened, and danger trees removed, among other things. According to AEP Ohio, the vegetation management program provides storm hardening by reducing the risk of trees contacting power lines during a storm. (Co. Ex. 1 at 9-10; Co. Ex. 4 at 10, 14; Co. Ex. 13 at 3-4; Co. Br. at 84-87.)

In this ESP, AEP Ohio requests the continuation of the ESRR, in order to complete the transition to a cycle-based vegetation management program. AEP Ohio seeks approval to increase operations and maintenance (O&M) and capital costs for the program over the amount currently included in base distribution rates. Beginning in June 2015, AEP Ohio forecasts $1 million per year for 2015 through 2017, and $1.1 million for 2018, in capital costs, as well as $25 million per year for 2015 through 2017, and $26.3 million for 2018, in O&M expense, based on an updated ESRR forecast. AEP Ohio submits that the increase in O&M expense over the approximately $18 million previously included in the ESRR is primarily due to increased fuel and labor costs and the availability of actual historic data used to develop the forecast. Otherwise, AEP Ohio is proposing that the ESRR continue as it is presently approved. AEP Ohio submits that the continuation of the vegetation management program promotes the state policy objectives expressed in R.C. 4928.02(A) and (E). (Co. Ex. 4 at 10, 14, 20; Co. Ex. 13 at 3-4; Tr. I at 80-81; Co. Br. at 84-87.)

Staff opposes the proposed cost increase in O&M expense from $18 million to $25 million. Staff notes that the ESRR was approved to facilitate AEP Ohio's transition to a cycle-based vegetation management program. Staff further notes that, in the *ESP 2 Case*, the Commission approved, at AEP Ohio's request, $18 million in annual O&M expense to enable the Company to recover, through the ESRR, incremental costs above the amount already recovered through base distribution rates. Emphasizing that AEP Ohio expects to have fully transitioned to a four-year maintenance cycle in 2014, Staff submits that catching up on the trimming of the Company's circuits involved higher costs than more routine trimming. Staff challenges the accuracy of the current $25 million annual O&M estimate in comparison to the process AEP Ohio used in the prior ESP. Staff points out that AEP Ohio's current estimate is derived from the Company's average cost per mile for 2009 to 2012, which included the period of time when the vegetation management program was in transition, with a 30 percent reduction based on the experience of the Company's Oklahoma affiliate when it transitioned to a four-year vegetation maintenance program. Staff posits that the prior estimate and methodology used in the *ESP 2 Case* were robust and accurate, incorporating a broad set of factors to determine the costs associated with a cycle-based vegetation maintenance program in Ohio. Staff argues that the $25 million O&M estimate is based on the cost of a special, more expensive catch-up project and then reducing that amount by an inaccurate and inappropriate percentage. Further, Staff asserts that AEP Ohio failed to produce any evidence that tree trimming activities in Oklahoma are comparable to those in Ohio; demonstrate that the former methodology used to estimate vegetation management costs was flawed; or show that the current methodology to estimate vegetation management is more accurate or an improvement. Staff notes that, if AEP Ohio's O&M expense exceeds $18 million, there is a mechanism to ensure the Company recovers the appropriate amount in the annual ESRR reconciliation filing. Staff recommends that the Commission reject the increased ESRR amount and maintain the $18 million O&M estimate already in place. (Staff Ex. 10 at 7-10; Tr. II at 445-446; Staff Br. at 52-55; Staff Reply Br. at 42-43.)

OPAE and APJN object to the continuance of the ESRR, on the basis that AEP Ohio has been approved for sufficient funding to transition to a four-year cycle-based vegetation plan. The intervenors argue that any continued recovery of O&M and capital costs for vegetation management should be reflected in base distribution rates, with any additional collection for vegetation management expense subject to a base distribution rate case, so that AEP Ohio's costs can be reviewed. (OPAE/APJN Br. at 36-37.)

OCC recommends that the ESRR not be allocated based on total base distribution revenues, as AEP Ohio proposes, but that the capital costs be allocated instead in proportion to the allocation of net electric plant in service and the O&M costs be allocated in proportion to the allocation of distribution O&M expenses as set forth in the cost-of-service studies filed in the *Distribution Rate Case*. OCC believes that AEP Ohio's allocation is contrary to cost causation principles and would require residential customers to pay approximately $29 million more than they should for the DIR, ESRR, and SSWR. (OCC Ex. 14 at 5-12; OCC Br. at 107-109.) OEG asserts that the costs underlying the ESRR and the other riders mentioned by OCC are related to the provision of distribution service and it is, therefore, reasonable to allocate the rider costs to rate schedules on the basis of distribution revenues. For the same reasons noted above with respect to the DIR, OEG believes that it is appropriate for the Commission to follow the methodology adopted in the *ESP 2 Case*. (OEG Br. at 27.)

AEP Ohio points out that, while Staff prefers the $18 million O&M estimate for the ESRR, Staff did not perform its own quantification of O&M expense necessary for a four-year trim cycle and, in any event, Staff supports the Company's recovery of prudently incurred costs to maintain the cycle. AEP Ohio retorts that the record evidence supports its $25 million O&M forecast for continuance of the ESRR so that the Company can continue to proactively prevent tree-related outages. (Tr. V at 1349-1350, 1360; Co. Br. at 85-87; Co. Reply Br. at 76.)

The Commission finds that AEP Ohio's request to continue the ESRR is reasonable and should be approved, as proposed by the Company, and as currently allocated between the customer classes and rate schedules. As required pursuant to R.C. 4928.143(B)(2)(h), the Commission has previously considered and discussed the alignment of the expectations of AEP Ohio and its customers with respect to the DIR. The ESRR supports a proactive vegetation program that reduces the impact of weather events and maintains the overall electric system. Continuing the ESRR, including the widening of right-of-ways, the removal of danger trees, and the proactive trimming of vegetation, will prevent and reduce tree-related outages and service interruptions. Regarding AEP Ohio's forecast of O&M expense for the ESRR over the ESP term, the record reflects that the Company's projected increase in O&M expense is derived from an updated estimate based on the actual costs to trim vegetation in Ohio under the current program. AEP Ohio's forecast also incorporates an estimated 30 percent reduction in the cost per mile based on the experience of the Company's affiliate in transitioning from a catch-up period to an ongoing four-year trim cycle. (Co. Ex. 4 at 10, 20; Tr. II at 443-446.) Accordingly, we find that the increased O&M expense, as presented by AEP Ohio, is reasonable and should be approved. The Commission emphasizes, however, that the ESRR is based on AEP Ohio's prudently incurred costs and is subject to the Commission's review and reconciliation on an annual basis.

8. gridSMART Rider

In this ESP, AEP Ohio proposes the continuation of the gridSMART program, including the gridSMART rider initially approved by the Commission in the *ESP 1 Case* and continued in the *ESP 2 Case*. *ESP 1 Case*, Opinion and Order (Mar. 18, 2009) at 37-38, Entry on Rehearing (July 23, 2009) at 18-24; *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 62. However, AEP Ohio proposes modification of the gridSMART rider to transfer the remaining gridSMART Phase 1 costs to the DIR and use the gridSMART rider to track gridSMART Phase 2 costs. AEP Ohio reasons that gridSMART Phase 1 spending concluded at the end of 2013 and the gridSMART Phase 1 assets are not currently in base rates and have been excluded from the DIR. AEP Ohio requests that the DIR be modified to include the existing gridSMART Phase 1 assets. In support of the request, AEP Ohio claims that, beginning in June 2015, the total cost data for gridSMART Phase 1 will be available for reconciliation. With the reconciliation of gridSMART Phase 1, AEP Ohio posits that eliminating the removal of gridSMART Phase 1 net book value from the DIR mechanism will allow the Company to recover its investment on and of gridSMART Phase 1 assets in service. As of the filing of AEP Ohio's direct testimony in these cases, the Company expected to complete the installation of equipment associated with gridSMART Phase 1 and to submit data on gridSMART Phase 1 to the United States Department of Energy (USDOE) by December 31, 2014. AEP Ohio notes that it filed an evaluation of gridSMART Phase 1 with the Commission on or about March 31, 2014. AEP Ohio also notes that the Commission granted the Company authority to initiate the installation of certain gridSMART technologies that have demonstrated success and are cost-effective. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 62-63. AEP Ohio filed its proposed expansion of the gridSMART program, gridSMART Phase 2, in Case No. 13-1939-EL-RDR (*gridSMART 2 Case*), on September 13, 2013. According to AEP Ohio's application in the *gridSMART 2 Case*, the Company plans to invest $465 million in gridSMART Phase 2. (Co. Ex. 1 at 10; Co. Ex. 3 at 4-5; Co. Ex. 4 at 10-11, 13, 15-16, 20; Co. Ex. 13 at 7.)

AEP Ohio reasons that continuation of the gridSMART Phase 2 rider provides for continued deployment of emerging distribution system technologies where they can cost-effectively improve the efficiency and reliability of the distribution system, develop performance standards and targets for service quality for all consumers, and encourage the use of energy efficiency programs and alternative energy resources. AEP Ohio submits that authority for including the gridSMART program in the ESP is set forth in R.C. 4928.143(B)(2)(h). AEP Ohio avers that the continuation of the proposed gridSMART Phase 2 program and rider is consistent with the policies listed in R.C. 4905.31(E) and R.C. 4928.02. (Co. Br. at 87-88.)

OCC argues that customers should not incur gridSMART Phase 2 charges on their bills until there has been a complete review of the gridSMART Phase 1 program and customer representatives and other interested stakeholders are provided an opportunity to raise any issues or concerns. On that basis, OCC requests that AEP Ohio's proposed treatment of gridSMART Phase 1 and gridSMART Phase 2 be rejected. (OCC Br. at 112-113.)

IGS, OEC, and EDF support AEP Ohio's gridSMART rider and the deployment of smart meters throughout the service territory. IGS, OEC, and EDF reason that smart meters are essential for the widespread offering of TOU products to customers. OEC and EDF believe that there is great potential for improved air quality resulting from the deployment of gridSMART technology, due to the reduced number of trucks that must be deployed to read meters and to disconnect and reconnect electric utility service. OEC and EDF also submit that Volt-VAR optimization will facilitate savings through energy efficiency and demand response programs. (OEC/EDF Br. at 7; IGS Reply Br. at 14.)

Further, while OEC and EDF recognize that the details of gridSMART Phase 2 will be determined in the *gridSMART 2 Case*, OEC and EDF aver that certain issues relating to the prudency of gridSMART costs and the associated benefits should be addressed by the Commission as a part of these ESP proceedings. To that end, OEC and EDF recommend that the Commission approve the continuation of the gridSMART program and the introduction of the gridSMART Phase 2 rider subject to nine conditions. (OEC/EDF Ex. 1 at 3-8; Tr. XII at 2784-2785.) OEC and EDF assert that their recommendations are intended to facilitate AEP Ohio's demonstration of the additional benefits of its gridSMART deployment, ease compliance with forthcoming United States Environmental Protection Agency regulations regarding greenhouse gas emissions for existing coal plants under Section 111(d) of the Clean Air Act, and ensure transparency and accountability (OEC/EDF Br. at 7-9; OEC/EDF Reply Br. at 7-8).

Kroger opposes AEP Ohio's request to transfer the remaining gridSMART Phase 1 cost into the DIR. Kroger notes that the Commission previously directed that gridSMART costs be recovered via a separate rider and not be incorporated into the DIR. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 63. Kroger submits that, if gridSMART costs are recovered outside the framework of a distribution rate case, the associated costs should be recovered through a separate rider that properly recovers costs on a per-customer basis. (Kroger Ex. 1 at 11; Kroger Br. at 4, 6.) In reply to Kroger, AEP Ohio states that moving gridSMART Phase 1 costs into the DIR is appropriate in order to dedicate the gridSMART Phase 2 rider to recovery of costs associated with Phase 2 of the program as approved in the *gridSMART 2 Case*. AEP Ohio also posits that the recommendations of OEC and EDF for gridSMART Phase 2 should be addressed in the *gridSMART 2 Case*, not these ESP proceedings. (Co. Reply Br. at 77-78.)

As discussed in the *ESP 1 Case* and the *ESP 2 Case*, the Commission continues to find significant long-term value and benefit for AEP Ohio and its customers with the implementation of advanced metering infrastructure, distribution automation, and other smart grid technologies. In the *ESP 2 Case*, the Commission approved AEP Ohio's request to initiate gridSMART Phase 2, directed that the Company file its proposed gridSMART Phase 2 project with the Commission, and directed that gridSMART Phase 2 costs be recovered through a separate rider as opposed to merging the costs into the gridSMART Phase 1 rider. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 62-63. For that reason, the Commission finds AEP Ohio's request to continue the gridSMART rider, with certain modifications as proposed by the Company, to be reasonable. Further, consistent with our decision in these proceedings to continue the gridSMART Phase 2 rider, we approve AEP Ohio's request to transfer gridSMART Phase 1 capital costs to the DIR mechanism upon the Company's accounting for all USDOE reimbursements due. (Co. Ex. 1 at 10; Co. Ex. 3 at 4-5; Co. Ex. 4 at 10-11, 13, 15-16, 20; Co. Ex. 13 at 7.) Given that, at the conclusion of gridSMART Phase 1, AEP Ohio will have recovered the vast majority of O&M expense, with only capital asset cost remaining to be collected over the useful life of installed gridSMART assets, it is efficient for the associated gridSMART Phase 1 costs to be included in the DIR. We remind AEP Ohio that, consistent with the Commission's directive in the *ESP 2 Case*, within 90 days after the expiration of ESP 2, the Company shall file an application for review and reconciliation of the gridSMART Phase 1 rider. *ESP 2 Case*, Entry on Rehearing (Jan. 30, 2013) at 53. After the Commission has reviewed and reconciled gridSMART Phase 1 costs, AEP Ohio may transfer the approved capital cost balance into the DIR, which will not be subject to the DIR caps, and may also transfer any unrecovered O&M balance into the gridSMART Phase 2 rider.

As with gridSMART Phase 1, the Commission will continue to annually review and approve AEP Ohio's gridSMART Phase 2 program, including the prudency of expenditures and the reconciliation of investments placed in service with revenues collected. We will also evaluate AEP Ohio's gridSMART Phase 2 program and determine the gridSMART rate to be charged customers, as well as consider OEC's and EDF's remaining recommendations, in the *gridSMART 2 Case* currently pending before the Commission.

9. Storm Damage Recovery Rider

AEP Ohio notes that, in the *ESP 2 Case*, the Commission approved the Company's proposed storm damage recovery mechanism for the deferral of incremental O&M expenses that exceed $5 million annually and are related to major events as defined in Ohio Adm.Code Chapter 4901:1-10. Pursuant to R.C. 4928.143(B)(2)(h), AEP Ohio proposes to continue to defer major storm expenses that exceed the $5 million baseline, while also offering a few proposed modifications to the SDRR. Specifically, AEP Ohio seeks approval to file an annual true-up in April of each year, which would be based on the major storm expense incurred in the previous calendar year and include a proposed rate design to collect or refund the regulatory asset or liability recorded at the end of the prior year. AEP Ohio also proposes to establish a carrying charge based on the weighted average cost of capital (WACC) for major storm damage costs exceeding the $5 million baseline, if the costs are deferred and remain unrecovered for longer than 12 months. AEP Ohio witnesses Hawkins and Allen testified that rate recovery that occurs more than a year after an expense is incurred should recognize that the expense has been financed with a combination of both debt and equity and, therefore, a WACC carrying charge should apply until the assets are fully recovered. Ms. Hawkins asserted that the long-term debt rate would not enable AEP Ohio to recover all of its capital costs inclusive of the equity component. Ms. Hawkins further asserted that, if the Commission determines that the long-term debt rate is the appropriate carrying cost rate for the SDRR, that portion of debt should be excluded from the WACC for other assets, in order to ensure that the same debt is not being used to finance multiple assets, which would be inconsistent with how the Company finances its operations. (Co. Ex. 1 at 11; Co. Ex. 4 at 12, 16; Co. Ex. 13 at 4-5; Co. Ex. 17 at 9-12; Co. Ex. 18 at 6; Co. Ex. 33 at 13-14.)

OHA urges the Commission to adopt the proposed SDRR, as a reasonable means to facilitate and improve reliable electric distribution service (OHA Br. at 3). Although Staff also generally supports the continuation of the SDRR, Staff recommends that carrying charges for major storm costs recovered under the rider be calculated using the most recently approved long-term debt rate as opposed to the WACC rate, because there are no capital costs in the SDRR. According to Staff, carrying charges should only accrue until recovery or refund of the difference between AEP Ohio's total major storm costs and the $5 million baseline begins. (Staff Ex. 12 at 3-4; Tr. VII at 1690; Staff Br. at 57; Staff Reply Br. at 37-38.) OCC agrees that, if carrying charges are approved by the Commission, the long-term debt rate should be used. OCC asserts that AEP Ohio's proposal to use the WACC rate to determine the carrying charges associated with various riders is unreasonable; would unnecessarily impose excessive costs on customers; and is inconsistent with the Commission's precedent and sound regulatory policy. (OCC Br. at 143-146; OCC Reply Br. at 112-115.)

Staff also sets forth a number of recommendations regarding the recovery of incremental labor expenses related to major storm restoration work. Specifically, Staff witness Lipthratt testified that the first 40 straight-time labor hours that an employee works in a week are already reflected in AEP Ohio's base rates and should, therefore, not be included in the SDRR. With respect to overtime hours, Mr. Lipthratt testified that, although overtime performed by union employees is considered incremental labor and should be included in the SDRR, management overtime should not be considered incremental labor, because management employees are usually salaried and any such expense would be strictly discretionary. In its brief, Staff also clarifies and recommends that any revenues received by AEP Ohio as a participant in mutual assistance agreements with other utilities should be reviewed to determine whether they should be applied as an offset to the SDRR revenue requirement. Staff notes that, consistent with its position on labor expenses, any revenues received by AEP Ohio for the first 40 hours of straight-time labor related to mutual assistance work may constitute a double recovery, because those hours are already reflected in base rates, and, if so, those revenues should be offset against the SDRR. Staff, therefore, requests that the Commission direct AEP Ohio to maintain a detailed accounting of all expenses incurred and revenues received for providing mutual assistance to other utilities, provide this information annually to Staff, and demonstrate in each SDRR case that the revenues received were incremental and not associated with labor hours already reflected in base rates. (Staff Ex. 12 at 4-7; Staff Br. at 58-62; Staff Reply Br. at 39-41.)

Regarding the rate design of the SDRR, Staff asserts that a fixed charge per customer is appropriate, which would be determined by separating the total amount allowed for recovery between residential and non-residential customers based on the percentage of distribution revenues from the prior calendar year and then dividing the amount in each category by the number of customers, which is consistent with the approach adopted in the *Storm Damage Case*. (Staff Ex. 12 at 7-8; Staff Br. at 62.) According to OCC, AEP Ohio indicated, in a discovery response, that the Company plans to allocate storm damage expenses based on the contribution of each customer class to total base distribution revenues. OCC asserts that AEP Ohio's proposed SDRR allocation method does not follow cost causation principles. OCC, therefore, recommends that storm damage expenses be allocated in proportion to the allocation of distribution O&M expenses contained in the cost-of-service studies from the *Distribution Rate Case*. (OCC Ex. 14 at 6-9; OCC Br. at 107-109; OCC Reply Br. at 84-86.) OPAE and APJN agree with OCC's recommendation (OPAE/APJN Br. at 38-39). OEG, however, argues that storm expenses are distribution-related costs that should, therefore, be allocated using base distribution revenues, which is consistent with the methodology approved in the *ESP 2 Case* for a number of AEP Ohio's riders (OEG Ex. 2 at 6-7; OEG Br. at 27). IEU-Ohio also urges the Commission to reject OCC's position, contending that it is contrary to the concept of rate gradualism and based on an outdated cost-of-service study (IEU-Ohio Reply Br. at 28-30). In response to Staff's and OCC's recommendations, AEP Ohio argues that there is no record evidence to counter the Company's proposal other than Staff's inappropriate attempt to rely on the stipulated allocation methodology used in the *Storm Damage Case* and OCC's preference for a different method based on cost causation principles (Co. Reply Br. at 82).

In response to Staff's other recommendations, AEP Ohio emphasizes that Staff offered no justification for its proposal that carrying charges be calculated using the long-term debt rate. AEP Ohio asserts that Staff's position is without any record support and should, therefore, be disregarded. AEP Ohio reiterates that assigning a long-term debt rate to a regulatory asset fails to recognize that the debt component of the Company's capital structure has already been used to fund other investments and, effectively, uses the same dollar of debt to finance two investments simultaneously. AEP Ohio adds that, once a regulatory asset's recovery has been deferred for longer than a year, it is financed as a long-term asset, with a combination of debt and equity and, therefore, the WACC rate is both appropriate and necessary to enable the Company to recover its costs. Regarding overtime expenses, AEP Ohio points out that Staff witness Lipthratt did not review or consider any of the Company's union contracts, labor policies, or how labor is accounted for in the deferral calculation with respect to the $5 million baseline. AEP Ohio contends that Staff's position is contrary to the establishment of the $5 million baseline in the *ESP 2 Case*, ignores recent Commission precedent in the *Storm Damage Case*, and disregards the realities of major storm restoration work, which involves 16 hour work days, sometimes in extreme conditions, to restore power as quickly and safely as possible. With respect to mutual assistance, AEP Ohio notes that revenues and expenses associated with mutual assistance provided to other utilities are not included in base rates or in the $5 million baseline. AEP Ohio adds that Mr. Lipthratt failed to recognize the benefit received by the Company's customers due to mutual assistance agreements. (Co. Ex. 33 at 10-14, Ex. WAA-R6, Ex. WAA-R7; Tr. VII at 1696, 1699-1702, 1716; Co. Br. at 90-99; Co. Reply Br. at 78-81, 98.)

The Commission finds that AEP Ohio's proposal to continue the SDRR is reasonable and should be approved to the extent addressed herein. Regarding AEP Ohio's recommended modifications, we find that the Company's request to file an annual true-up in April of each year should be adopted. The annual true-up should be based on the major storm expense incurred in the prior calendar year and include a proposed rate design to collect or refund the regulatory asset or liability recorded at the end of the previous year. (Co. Ex. 4 at 12, 16; Co. Ex. 13 at 5; Co. Ex. 18 at 6.) We do not find it necessary to establish a particular rate design in these proceedings. With respect to the carrying cost rate applicable to major storm damage costs recovered through the SDRR, the Commission finds that AEP Ohio's carrying charges should be calculated using the most recently approved cost of long-term debt rate. We agree with Staff that the WACC rate is typically used to determine carrying charges when capital expenditures are involved. *See, e.g., ESP 1 Case*, Opinion and Order (Mar. 18, 2009) at 28; *In re Columbus Southern Power Company*, Case No. 10-164-EL-RDR, Finding and Order (Aug. 11, 2010) at 7, 10; *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 10-155-EL-RDR, Finding and Order (Aug. 25, 2010) at 9-10. Because only O&M expenses are included in the SDRR, the long-term debt rate is more appropriate. Also, once collection of a deferral balance begins, the risk of non-collection is significantly reduced and, as such, it is more appropriate to use the long-term cost of debt rate, which is consistent with sound regulatory practice and longstanding Commission precedent. *See, e.g., In re Columbus Southern Power Company*, Case No. 11-4920-EL-RDR, et al., Finding and Order (Aug. 1, 2012) at 18. AEP Ohio's carrying charges should only accrue on deferred costs that remain unrecovered for a period longer than 12 months and the accrual should cease once recovery of the difference between the Company's total major storm costs and the $5 million baseline begins. (Staff Ex. 12 at 3-4; Tr. VII at 1690.)

Regarding Staff's remaining recommendations, the Commission specified, in the *ESP 2 Case*, that major storm costs eligible for recovery through the SDRR must be incremental, as well as prudently incurred and reasonable. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 68-69. The Commission reiterates that AEP Ohio, in seeking recovery of any major storm expense through the SDRR, must demonstrate that such cost was reasonably and prudently incurred and incremental to any cost recovery through base rates. Consistent with our decision in the *Storm Damage Case*, if AEP Ohio seeks to recover the expense associated with overtime compensation paid to exempt employees during a major storm event, the Company must demonstrate that, under the specific facts and circumstances of the major storm event in question, the overtime compensation was paid in accordance with the Company's non-discretionary major storm restoration overtime policy, and was a reasonable and prudent expense associated with safely and efficiently restoring electric service to customers. *Storm Damage Case*, Opinion and Order (Apr. 2, 2014) at 25-26. Further, regarding mutual assistance revenues, AEP Ohio must show that any such revenues are not a reimbursement of labor hours that are already reflected in base rates. Finally, AEP Ohio should continue to maintain and provide to Staff, on an annual basis, a detailed accounting of all storm expenses, including incidental costs and capital costs, and should also provide a detailed accounting of expenses incurred and revenues received for providing mutual assistance to other utilities. The Commission disagrees with AEP Ohio's contention that Staff's audit of such data constitutes needless review or that it may chill mutual assistance efforts; rather, it will ensure that customers pay only for reasonably and prudently incurred major storm expenses and that there is no double recovery by the Company.

10. Sustained and Skilled Workforce Rider

AEP Ohio proposes the new SSWR to support the Company's comprehensive strategy for long-term improved reliability as permitted under R.C. 4928.143(B)(2)(h). According to AEP Ohio, the SSWR mechanism would recover the incremental O&M labor cost needed to execute infrastructure investments to comply with the Company's long-term reliability strategy. AEP Ohio forecasts the costs to be recovered through the SSWR to be $1.6 million in 2015, $4.9 million in 2016, $7.7 million in 2017, and $8.0 million in 2018. The capital construction costs would continue to be recovered through the DIR mechanism. AEP Ohio proposes to increase the workforce by a total of 150 permanent, full time equivalent (FTE) employees and contractors over the next three years, 50 FTEs each year. AEP Ohio contends that the SSWR would not increase the cost of performing targeted reliability activities, but would serve as a streamlined cost recovery mechanism for prudently incurred costs. (Co. Ex. 1 at 11; Co. Ex. 4 at 22-28; Co. Ex. 13 at 12.)

AEP Ohio projects a shortfall in internal labor resources in both front-line construction and construction support required to execute infrastructure investments.

AEP Ohio contends that it must address the need for additional labor resources necessary to support future work requirements and to achieve an optimal balance of workforce labor resources, including internal company employees and external contract employees. AEP Ohio reasons that, as it reviews the current level of internal labor, additional field employees will be required to execute the infrastructure investment plan. According to AEP Ohio, the approximate number of contract crews and FTEs utilized by the Company has increased from 125 in December 2012 to 496 in November 2013. AEP Ohio submits that contractor firms are sometimes unable to meet the Company's demands for skilled personnel given the transient nature of construction crews. Further, AEP Ohio notes that, in light of the fact that it takes approximately five years to train a new employee from an apprentice-level line, meter, or substation mechanic to the journeyman level, the development cycle requires an appropriate hiring plan to assure a sustainable and skilled labor workforce is available. AEP Ohio submits that, while the Company will continue to utilize contractors as a part of its labor strategy, it is important to augment its labor force because of the transient nature of contract crews. (Co. Ex. 4 at 22-28; Co. Br. at 99-100.)

Staff supports the development and implementation of a comprehensive strategy for long-term reliability. However, Staff and OMAEG oppose the implementation of the SSWR. Staff notes that AEP Ohio has an approved DIR, which is the mechanism to recover labor and other capital costs associated with the replacement of aging infrastructure. For that reason, Staff and OMAEG assert that the proper recovery mechanism for new employee labor is through a distribution rate case, not a rider. Staff reasons that the SSWR is an effort by AEP Ohio to accelerate cost recovery, while avoiding a base rate case and the scrutiny that a base rate case entails. (Staff Ex. 8 at 3-4; Staff Br. at 27-28; OMAEG Br. at 18-19.)

OCC, OPAE, and APJN also oppose the SSWR on the basis that AEP Ohio has failed to meet its burden to demonstrate that the SSWR may be authorized under any provision of R.C. 4928.143(B)(2). OCC insists that this is an attempt by AEP Ohio to recover more costs via a rider than through a distribution rate case. OCC submits that the SSWR does not meet any of the criteria previously used by the Commission for the recovery of costs through a rider. OCC notes that labor costs incurred for new employees are within the control of the utility, are not volatile or subject to unpredictable fluctuations, are not immaterial for a utility the size of AEP Ohio, and are not of the magnitude that should qualify for collection by way of a rider. Further, OCC and Staff argue that AEP Ohio has not established that the number of retiring employees will not offset the number of new employees, the total number of employees will increase actual labor expenses, or that new employees will reduce the need for outside contractors. Finally, OCC notes that AEP Ohio failed to describe any potential offsetting reductions to costs for the new employees reflected in the new SSWR. OCC contends that AEP Ohio has not demonstrated that the Company's financial integrity would be negatively impacted if the costs of new employees had to be recovered by way of a distribution rate case as opposed to through a rider. For these reasons, the intervenors request that the Commission deny the establishment of the SSWR. (OCC Ex. 18 at 20-23; OCC Br. at 101-103; OCC Reply Br. at 63-64; OPAE/APJN Br. at 37; OMAEG Reply Br. at 15-17.)

OCC recommends that, if approved, the SSWR not be allocated based on total base distribution revenues, as AEP Ohio proposes, but in proportion to the allocation of distribution O&M labor expense as set forth in the cost-of-service studies filed in the *Distribution Rate Case*. OCC argues that AEP Ohio's allocation is not consistent with cost causation principles and would cause residential customers to pay approximately $29 million more than is fair for the DIR, ESRR, SDRR, and SSWR. (OCC Ex. 14 at 5-12; OCC Br. at 107-109.) OEG advocates that the costs underlying the DIR, SSWR, SDRR, and ESRR are related to the provision of distribution service and it is, therefore, reasonable to allocate the rider costs to rate schedules based on distribution revenues. For the same reasons mentioned above with respect to the DIR, OEG believes that the Commission should follow the methodology adopted in the *ESP 2 Case*. (OEG Br. at 27.)

AEP Ohio submits that OCC's statutory foundation claim is without merit. As previously noted, AEP Ohio asserts that R.C. 4928.143(B)(2)(h) is the statutory authority for the SSWR. AEP Ohio interprets Staff's and intervenors' positions as supporting the need for additional workforce to assist in the maintenance of the distribution system. AEP Ohio also acknowledges Staff's, OCC's, and other intervenors' preference for the recovery of labor costs by way of a distribution rate case rather than through a rider. AEP Ohio retorts that the General Assembly provided electric utilities the ability to recover costs to ensure safe and efficient operations through an ESP and notes that the option of a base rate case does not eliminate the option of recovering costs needed for operations in an ESP. Furthermore, AEP Ohio acknowledges that employees may retire between the time the rider is implemented and a distribution rate case occurs, but the Company points out that retiring skilled employees will not be replaced by workers related to the SSWR, given the time required for the new employees to train and reach that skill level. However, AEP Ohio offers that, in this ESP, the Company is requesting only 150 FTEs over three years and notes that, as of November 2013, the Company had 496 FTEs and retiring employees were likely skilled labor dedicated to capital projects recovered via the DIR. (Co. Br. at 100; Co. Reply Br. 82-83.)

AEP Ohio further reasons that the intervenors' arguments lose focus of the purpose of the SSWR - to address the projected shortfall of internal construction and construction support labor and the associated costs. AEP Ohio emphasizes that the additional labor is needed to address future work requirements to implement its comprehensive reliability plan and to recast the balance of workforce resources. AEP Ohio notes that the SSWR reflects the Company's prudent planning to avoid being left with an unskilled workforce and unavailable contract services that would be beyond the Company's control. AEP Ohio reiterates that additional Company employees are needed to support the increased level of contractors or to displace or offset the labor supplied by the contractors. AEP Ohio contends that the SSWR would allow the Company to reduce its reliance on contract labor, recognizing that contract labor represents an uncontrollable risk regarding availability and increased costs because of the supply and demand for qualified personnel throughout the country. AEP Ohio implores the Commission to recognize that now is the time to act and commence training and that the SSWR would ensure that the Commission and the Company are currently planning for a sustainable workforce. AEP Ohio also submits that, ultimately, these labor costs will be incorporated into base distribution rates. AEP Ohio encourages the Commission to approve the SSWR, as proposed, to facilitate the immediate implementation of a dedicated and developed training program focused on decreasing contract labor and ensuring the availability of a skilled workforce, as a trained workforce is important to reliable service and safety. (Co. Reply Br. 82-86.)

R.C. 4928.143(B)(2)(h) permits an ESP to include provisions regarding the electric utility's distribution service, including, without limitation, 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 utility. It is important that an electric utility have a long-term reliability strategy, including the adequacy of its workforce. However, for the Commission to approve a proposed provision of an ESP requires more than a mere demonstration that the provision is statutorily permissible. In this instance, AEP Ohio has not demonstrated that the proposed new SSWR, to facilitate the hiring of new skilled construction and construction employees, is necessary in relation to the Company's total workforce. While the Commission recognizes AEP Ohio's proposal is for only about a third of its FTEs as of the filing of this ESP, we nevertheless find that such a significant portion of labor expense is more appropriately reviewed as part of a more comprehensive analysis in the context of a distribution rate case. A comprehensive review of AEP Ohio's overall labor expense in a distribution rate case, rather than approving the SSWR as a provision of the ESP merely to expedite cost recovery, will ensure that the Company is prudent and cost-effective with its labor costs and management. (Co. Ex. 4 at 23, 25, 27-28; Staff Ex. 8 at 4; OCC Ex. 18 at 21-23.) Accordingly, the Commission denies AEP Ohio's request for approval of the SSWR as a component of this ESP.

11. NERC Compliance and Cybersecurity Rider

AEP Ohio proposes the implementation of a new, non-bypassable rider, the North American Electric Reliability Corporation (NERC) compliance and cybersecurity rider (NCCR). The rider would facilitate AEP Ohio's expedited recovery of significant increases in capital and O&M costs for NERC compliance and cybersecurity. As proposed, the rider would be established at zero and AEP Ohio would track associated costs from the date of adoption by the Commission and forward for the remainder of the term of this ESP. NCCR costs would be deferred, including carrying costs, until AEP Ohio files an application and the Commission approves the recovery of NCCR costs. AEP Ohio requests that carrying charges accrue based on the Company's WACC on capital cost components until the costs are fully recovered. All NCCR costs would be subject to the Commission's review for prudency. (Co. Ex. 1 at 11-12; Co. Ex. 2 at 13-18; Co. Ex. 13 at 12; Co. Ex. 17 at 9-13, Ex. RVH-4.)

AEP Ohio reasons that the Company has been required to comply with NERC reliability standards since 2007; however, recent federal and state interests have increased the focus on cybersecurity. NERC reliability standards are implemented and enforced through FERC-approved agreements with regional entities. AEP Ohio is registered with ReliabilityFirst Corporation, the FERC regional operating entity in Ohio. AEP Ohio submits that the dynamic and broad landscape covered by cybersecurity, including the prevention and mitigation of manmade physical and cyber attacks, is continuously evolving and encompasses protection and security of physical distribution and transmission grids, substations, Company offices, communications equipment and systems, and human resources. AEP Ohio offers that cybersecurity includes not only utility-owned systems but aspects of customer and third-party components that interact with the grid, such as advanced meters and devices behind the meter. Citing the National Cybersecurity and Critical Infrastructure Protection Act of 2013, AEP Ohio emphasizes that the Company has faced and complied with ever-increasing new or revised NERC reliability standards and faces increasing compliance requirements in light of recent legislation proposed to strengthen the cybersecurity of the nation's 16 critical infrastructure sectors and the federal government. AEP Ohio argues that approval of the NCCR would permit recovery of the costs of information technology infrastructure, physical security, workforce training, supervisory control and data acquisition systems, smart grid security systems, internal and external audits, external reporting, and recordkeeping that are not recovered through other regulatory mechanisms. AEP Ohio submits that the NCCR supports the state policy articulated in R.C. 4928.02(E). (Co. Ex. 2 at 13-18; Co. Br. at 100-103.)

OCC contends that NERC compliance and cybersecurity costs do not meet the requirements set forth in R.C. 4928.143(B)(2) to be included in an ESP and AEP Ohio has failed to demonstrate that NERC compliance and cybersecurity costs meet any of the nine provisions outlined that may be part of an ESP. Furthermore, OCC agrees with Staff that the NCCR is premature. OCC reasons that AEP Ohio has not provided sufficient specific information for the Commission to determine the need for a separate compliance and cybersecurity rider as opposed to the Company using a distribution rate case for the recovery of such costs. Finally, OCC offers that AEP Ohio has not demonstrated that the scope of NCCR costs is beyond the Company's control. (OCC Br. at 104-107, 119-122.)

Staff argues that there is no reason to believe that AEP Ohio, as a distribution company, will incur costs for compliance with NERC standards, as NERC lacks the authority to establish standards for distribution companies. According to Staff, the FPA grants NERC the authority to establish and enforce reliability standards for the bulk power system including transmission and generation facilities, but specifically excludes facilities used in the local distribution of electric energy. *See* 16 U.S.C. § 824o(a)(1) and (a)(2). Staff reasons that, to the extent that AEP Ohio must comply with NERC requirements, the appropriate mechanism for the recovery of such costs is the TCRR. However, at this point, Staff submits that the types of investments for which AEP Ohio would seek recovery and the magnitude of such investments is unknown. Accordingly, Staff reasons that, until AEP Ohio is able to identify and quantify its cybersecurity and reliability related expenditures, Staff and the other parties to these proceedings are unable to assess the appropriateness and adequacy of those expenditures. Staff, OPAE, APJN, and OCC assert that it is premature to approve recovery of NERC compliance costs, where AEP Ohio has failed to demonstrate that it will be subject to NERC standards, to identify potential investments and costs, and to explain how costs would be allocated between generation, transmission, and distribution functions or why NERC compliance costs cannot be absorbed within the Company's existing budgets. (Staff Ex. 11 at 4-6; Staff Br. at 29-31; OPAE/APJN Br. at 38; OCC Reply Br. at 67-68.)

OMAEG opposes the implementation of the proposed new NCCR as premature. However, OMAEG reasons that, if the Commission elects to approve the NCCR, AEP Ohio should not begin to recover NCCR costs unless or until the Company implements measures to address new NERC compliance and cybersecurity requirements and not while the Company is deliberating to determine the best means of compliance. (OMAEG Br. at 20-21.)

AEP Ohio insists that any attempt to limit NCCR cost recovery to only costs incurred to comply with new NERC compliance and cybersecurity requirements is premature. AEP Ohio argues that costs attributable to new interpretations of existing NERC compliance and cybersecurity requirements should also be recoverable under the rider. AEP Ohio declares that the appropriate time to address the prudency of NERC compliance and cybersecurity costs would be in a future docket where the recovery of such costs has been requested. (Co. Reply Br. at 87.)

AEP Ohio retorts that Staff's opposition to the NCCR, as premature, is somewhat misleading. AEP Ohio notes that Staff witness Pearce admitted on cross-examination that NERC compliance and cybersecurity is very important and Staff is not opposed to the recovery of NERC compliance costs. AEP Ohio further notes that Staff also acknowledged that the Commission has approved placeholder riders set at zero in prior ESPs. (Tr. VI at 1424-1425, 1431.) AEP Ohio reasons that Staff's opposition is not supported by Commission precedent, and points to the Commission's prior approval of a placeholder rider in the *ESP 2 Case* and Staff's endorsement of such riders. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 24-25. Further, AEP Ohio emphasizes that any NERC compliance and cybersecurity costs would be reviewed in a future Commission proceeding, including evaluation of the magnitude and prudency of such costs. AEP Ohio asserts that this process has been followed by the Commission in both of the Company's prior ESP cases and the ESP proceedings of other electric distribution utilities. On that basis, AEP Ohio requests that the Commission approve the NCCR, as proposed. (Co. Br. at 100-103; Co. Reply Br. at 86-87.)

The Commission believes that NERC compliance and cybersecurity matters are of the utmost importance for Ohio's customers and customer information, as well as for the security of the electric grid and electric distribution utility facilities. Just as the Commission has encouraged the implementation and installation of smart grid technologies to allow customers and the electric utility to better manage energy consumption, reduce energy costs, and make energy service more efficient, we must accept that with the introduction of technology comes an increased cybersecurity risk. We recognize that it is important that AEP Ohio take the necessary action to secure the electric grid and react quickly to protect the electric distribution system for the benefit of all consumers and the economic stability of our state. Nonetheless, the Commission finds that AEP Ohio has not sustained its burden of proof and that its request to establish a placeholder rider for NERC compliance and cybersecurity costs is premature at this point in time and should, therefore, be denied. We agree with Staff that it is not evident that AEP Ohio, as an electric distribution company, will incur costs for compliance with NERC standards. Further, as Staff points out, the types of investments for which AEP Ohio would seek recovery and the magnitude of such investments is not presently known and the Company has not demonstrated how any potential costs would be allocated between generation, transmission, and distribution functions. (Staff Ex. 11 at 4-6.) Finally, the Commission notes that, in the event that AEP Ohio incurs NERC compliance or cybersecurity costs during the ESP term, the Company has existing means through which to seek recovery of its costs, such as through a distribution rate case.

12. Pilot Throughput Balancing Adjustment Rider

AEP Ohio proposes to continue, throughout the entire ESP term, the pilot throughput balancing adjustment rider (PTBAR), which is related to a revenue decoupling pilot program applicable to the residential and GS-1 tariff rate schedules and implemented pursuant to the Commission's approval of a stipulation and recommendation in the *Distribution Rate Case*. AEP Ohio notes that, in that case, the Commission extended the PTBAR past its proposed termination at the end of 2014, and directed that the PTBAR continue until otherwise ordered by the Commission. *Distribution Rate Case*, Opinion and Order (Dec. 14, 2011) at 10, Entry on Rehearing (Feb. 14, 2012) at 3-4. According to AEP Ohio, the PTBAR is intended to compensate the Company for the loss of load associated with EE/PDR programs. AEP Ohio notes that no party appears to oppose the Company's proposal to continue the PTBAR. (Co. Ex. 1 at 12; Co. Ex. 3 at 10; Co. Ex. 13 at 4; Tr. I at 230-231.)

NRDC supports the continuation of the PTBAR through the ESP term. According to NRDC, the PTBAR is an effective tool to remove AEP Ohio's throughput incentive and to encourage the Company to assist customers in saving energy through EE/PDR programs. NRDC adds that the PTBAR facilitates AEP Ohio's ongoing efforts to comply with the requirements of R.C. 4928.66. NRDC contends that the PTBAR is working as intended, and that the rider should be extended so that AEP Ohio and interested stakeholders may continue to collect and assess additional performance metrics. (NRDC Br. at 1-4.)

OCC objects to the extension of the PTBAR through these ESP proceedings rather than in the context of an extension of AEP Ohio's EE/PDR plan. OCC points out that the PTBAR was established on a pilot basis in the *Distribution Rate Case* in connection with evaluation of AEP Ohio's EE/PDR plan. Consistent with the Commission's directives in that case regarding measurement of the success of the pilot program, OCC asserts that the Commission should not approve an extension of the PTBAR beyond the period necessary to complete the evaluation. In its reply brief, OCC goes further and argues that the Commission should only consider an extension of the PTBAR in conjunction with the evaluation of the pilot program. (OCC Ex. 11 at 37; OCC Br. at 113-114; OCC Reply Br. at 90-95). AEP Ohio responds that OCC seeks to elevate form over substance and, in any event, the Commission has the discretion to approve the extension of the PTBAR in the present proceedings (Co. Br. at 104; Co. Reply Br. at 88).

We find that the PTBAR should be continued, until otherwise ordered by the Commission. In the *Distribution Rate Case*, we noted that the PTBAR should continue for a sufficient period to enable the Commission to evaluate the revenue decoupling pilot program following its conclusion on January 1, 2015, and to determine whether revenue decoupling should be extended permanently or another mechanism should be implemented. *Distribution Rate Case*, Entry on Rehearing (Feb. 14, 2012) at 3-4. Subsequently, in Case No. 10-3126-EL-UNC, the Commission encouraged AEP Ohio and the other electric utilities to propose a straight fixed variable rate design in their next base rate cases. *In re Aligning Electric Distribution Utility Rate Structure*, Case No. 10-3126-EL-UNC, Finding and Order (Aug. 21, 2013) at 20. Therefore, in accordance with our prior orders, the revenue decoupling pilot program will be evaluated once the program concludes and, at that time, the Commission will determine whether to adopt the program and PTBAR on a permanent basis, or whether a straight fixed variable rate design should be considered as an alternative.

13. Residential Distribution Credit Rider

As a part of this ESP, AEP Ohio proposes continuation of the residential distribution credit rider (RDCR), initially approved by the Commission in the *Distribution Rate Case*, pursuant to a stipulation filed by the parties to the proceedings. *Distribution Rate Case*, Opinion and Order (Dec. 14, 2011) at 5-6, 9, 10. AEP Ohio seeks to extend the RDCR for all residential tariff schedules, as currently implemented, for the term of this ESP from June 1, 2015, to May 31, 2018. (Co. Ex. 1 at 12; Co. Ex. 7 at 4; Co. Ex. 13 at 4; Co. Br. at 104.)

No party directly opposes the continuation of the RDCR. However, OPAE and APJN submit that the RDCR approved by the Commission in the *Distribution Rate Case* included a component to fund a low-income bill payment assistance program, known as the Neighbor-to-Neighbor program. OPAE and APJN note that AEP Ohio states that it will be continuing the RDCR as implemented, but the Company did not explain in its application or any direct testimony that the RDCR would no longer include the funding of the low-income bill payment assistance program in this ESP. (OPAE/APJN Br. at 12-18.) AEP Ohio contends that the RDCR and the bill payment assistance program are separate issues (Tr. III at 696-697).

OPAE and APJN assert that AEP Ohio failed to demonstrate how the proposed ESP advances the state policy to protect at-risk populations as required by R.C. 4928.02(L). OPAE and APJN argue that AEP Ohio is taking a significant step backward by seeking to end its commitment to fund a low-income bill payment assistance program without regard to the effect it will have on vulnerable low-income customers. OPAE and APJN note that the Commission previously ordered AEP Ohio to fund the Partnership with Ohio Initiative at $15 million over the three-year term of the Company's first ESP, with all the funds going to low-income, at-risk customer programs. *ESP 1 Case*, Opinion and Order (Mar. 18, 2009) at 48. Therefore, OPAE and APJN ask the Commission, at a minimum, to order AEP Ohio to continue funding the low-income bill payment assistance program at the current level of $1 million annually and, in addition, direct the Company to add $1 million annually of shareholder funds to increase funding to a total of $2 million annually. Moreover, OPAE and APJN request that the Commission exempt income-eligible customers from riders approved by the Commission in these ESP proceedings to mitigate the bill impact on low-income customers. (OPAE/APJN Br. at 12-18; OPAE/APJN Reply Br. at 7-9.)

The Commission finds the continuation of the RDCR to be reasonable. Additionally, as addressed further below, the Commission concludes that certain intervenors' claims that the RDCR is not a quantifiable benefit of this ESP are without merit. When the Commission adopted the stipulation in the *Distribution Rate Case*, the *ESP 2 Case* was still pending before the Commission. The RDCR was, therefore, approved by the Commission in the *Distribution Rate Case* to prevent a potential double recovery of distribution revenues. *Distribution Rate Case*, Opinion and Order (Dec. 14, 2011) at 5-6, 9, 10. No party has submitted any record evidence that a likelihood of double recovery of distribution investment costs exists in these proceedings. Based on the ESP application and other evidence of record, the Commission approves AEP Ohio's proposal to continue the residential distribution credit of $14.688 million annually for residential customers as a percentage of base distribution charges to continue through May 31, 2018, with one modification (Co. Ex. 1 at 12; Co. Ex. 7 at 4; Co. Ex. 13 at 4).

The Commission finds that the annual $1 million funding of the Neighbor-to-Neighbor program, the other component of the original RDCR mechanism, is an essential element of the credit that furthers the state policy set forth in R.C. 4928.02(L). Further, we agree with OPAE and APJN that nothing in AEP Ohio's application or direct testimony indicates that the funding of the low-income bill payment assistance program was specifically excluded from the Company's request to continue the RDCR, although Company witness Allen testified, on cross-examination, that the Company does not propose to continue the funding (Tr. III at 696-697). Thus, the Commission modifies AEP Ohio's RDCR proposal to continue to include $1 million annually to fund the bill payment assistance program to support at-risk and low-income customers in the Company's service territory.

14. Basic Transmission Cost Rider

Currently, AEP Ohio recovers its PJM-assessed transmission costs from SSO customers through the bypassable TCRR, while CRES providers include their PJM-assessed transmission costs in their rates charged to shopping customers. Under the proposed ESP, AEP Ohio seeks to eliminate the TCRR, following a final true-up filing, and establish a non-bypassable basic transmission cost rider (BTCR) through which the Company would recover non-market based transmission charges from all of its customers, both shopping and non-shopping. Specifically, as proposed, the BTCR would include charges associated with Network Integration Transmission Service; Transmission Enhancement; Transmission Owner Scheduling, System Control, and Dispatch Service; Reactive Supply and Voltage Control from Generation and Other Sources Service; Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service, as well as credits for Firm Point-to-Point Transmission Service and Non-Firm Point-to-Point Transmission Service. AEP Ohio witness Vegas explained that market based transmission charges would be included as part of the auction product offering for SSO customers, while CRES providers would be responsible for paying market based transmission charges for their shopping customers. Mr. Vegas testified that the proposed BTCR would align AEP Ohio's transmission cost recovery mechanism with the other electric distribution utilities in Ohio; enable CRES providers and SSO suppliers to operate and provide product offerings in a similar manner across the state; and ensure that customers only pay the actual costs from PJM through a true-up of the BTCR. AEP Ohio witness Moore testified that the mechanics of the BTCR would operate consistent with the current TCRR and that the BTCR rates would be computed on a consolidated class basis. Finally, AEP Ohio notes that annual filings for the BTCR would comply with the requirements of Ohio Adm.Code Chapter 4901:1-36. (Co. Ex. 1 at 12-13; Co. Ex. 2 at 10-12; Co. Ex. 13 at 4, 7-8, 11, Ex. AEM-3; Co. Ex. 15 at Ex. CL-2, Attach. F.)

RESA, Constellation, and IGS support the proposed BTCR, noting that, currently, it is difficult for CRES providers to predict and manage certain non-market based transmission charges, while AEP Ohio's recommended approach would be competitively neutral, efficient, and likely to result in more competitive prices for consumers (RESA Ex. 1 at 7; Constellation Ex. 1 at 29-30; RESA Br. at 20-21; Constellation Br. at 24; IGS Br. at 19-20). RESA, Constellation, and FES recommend that Generation Deactivation, PJM Invoice Item No. 1930, also be included in the BTCR to ensure consistency among the electric distribution utilities (RESA Ex. 1 at 7-8; Constellation Ex. 1 at 30-31; RESA Ex. 1 at 6-8; FES Ex. 1 at 3-4; Co. Ex. 15 at Ex. CL-2, Attach. F; Tr. I at 167-168; Tr. IV at 1009; RESA Br. at 21-22; Constellation Br. at 26-27; FES Br. at 5-6). AEP Ohio agrees with the recommendation (Co. Br. at 117; Co. Reply Br. at 99).

IEU-Ohio urges the Commission to reject the proposed BTCR. IEU-Ohio points out that, contrary to AEP Ohio's assertion, the BTCR will not result in uniformity of transmission pricing terms across the electric distribution utilities, given that there are distinctions in their respective riders, including the Company's rider, as proposed. Further, IEU-Ohio asserts that the proposed BTCR may disrupt contractual relationships between shopping customers and CRES providers and result in such customers paying twice for non-market based transmission and ancillary services. According to IEU-Ohio, the BTCR would limit customer options, contrary to R.C. 4928.02(B), and is not needed to advance the competitive marketplace. Finally, IEU-Ohio asserts that the BTCR would fail to provide customers with efficient price signals to reduce usage at times of peak demand, in light of AEP Ohio's intention to assign and bill certain non-market based transmission costs in a manner different from PJM. If the BTCR is not rejected, IEU-Ohio recommends that the Commission ensure efficient price signals by directing AEP Ohio to assign Reactive Supply costs to customer classes on a 1 CP basis and to use a 1 CP billing determinant for demand-metered customers. Additionally, to prevent double billing, IEU-Ohio proposes that any shopping customer that can affirmatively demonstrate that its CRES provider has not removed the non-market based transmission services from its bills should be permitted to opt out of the BTCR or receive a credit under the rider, until such time as the customer is no longer paying the CRES provider for the non-market based transmission services. (IEU-Ohio Ex. 1B at 29-33; IEU-Ohio Ex. 10; IGS Ex. 3 at 4; Tr. III at 869; Tr. IV at 1056-1067; Tr. VI at 1390-1392; IEU-Ohio Br. at 37-44; IEU-Ohio Reply Br. at 21-23.) Like IEU-Ohio, OMAEG recommends that the Commission reject the proposed BTCR and require AEP Ohio to maintain the TCRR or, alternatively, direct Staff and the

Company to work with customers and CRES providers to ensure that customers are not charged twice for the same transmission and ancillary services. OMAEG also supports IEU-Ohio's recommendation that the BTCR be bypassable for any shopping customer that can demonstrate that its CRES provider will continue to collect non-market based transmission costs for the remaining term of the contract. (OMAEG Br. at 11-13; OMAEG Reply Br. at 14-15.)

AEP Ohio replies that IEU-Ohio witness Murray conceded that most CRES contracts have a regulatory-out provision; a limited number of customers would be impacted; and the Commission has means to address the concern other than outright rejection of the proposed rider. AEP Ohio and IGS note that CRES providers and the affected customers have been afforded a reasonable amount of time to make contractual adjustments for the transition, given that the BTCR proposal was addressed in the Company's application filed in December 2013 and the rider would not take effect until June 2015. IGS, RESA, and Constellation also note that the Commission has the necessary tools to avoid double billing. RESA and Constellation add that the Commission recently rejected IEU-Ohio's arguments in the *DP&L ESP Case*, in approving a proposal from DP&L comparable to AEP Ohio's proposed BTCR. With respect to IEU-Ohio's recommendations that Reactive Supply costs be assigned to customer classes on a 1 CP basis and that a 1 CP billing determinant be used for demand-metered customers, Constellation points out that IEU-Ohio failed to present sufficient justification for its proposals or to explain their impact. AEP Ohio notes that, as to Reactive Supply costs, the Company's proposal is consistent with the current treatment of such costs under the TCRR, as approved in the *ESP 2 Case*, whereas IEU-Ohio's proposal would have an unknown impact on SSO customer bills. AEP Ohio adds that it cannot bill demand charges on a 1 CP basis, because the Company does not have interval recorders for all customers, while selective billing would have bill impacts that have not been analyzed in these proceedings. (Co. Ex. 13 at Ex. AEM-3; Tr. VI at 1518-1529; Co. Br. at 117-118; RESA Br. at 22-24; Co. Reply Br. at 99-101; IGS Reply Br. at 11-13; RESA Reply Br. at 12-13; Constellation Reply Br. at 17-21.)

Pursuant to R.C. 4928.05(A)(2) and R.C. 4928.143(B)(2)(g), the Commission finds that AEP Ohio's proposal to eliminate the TCRR and implement the BTCR is reasonable and should be approved and modified to include Generation Deactivation charges, as recommended by RESA, Constellation, and FES and agreed to by the Company (Co. Ex. 1 at 12-13; Co. Ex. 2 at 10-12; Co. Ex. 13 at 4, 7-8, 11, Ex. AEM-3; Co. Ex. 15 at Ex. CL-2, Attach. F; RESA Ex. 1 at 7-8; Constellation Ex. 1 at 30-31; RESA Ex. 1 at 6-8; FES Ex. 1 at 3-4; Tr. I at 167-168; Tr. IV at 1009). The proposed BTCR is comparable to the transmission riders approved for the other electric utilities. *DP&L ESP Case*, Opinion and Order (Sept. 4, 2013) at 36; *In re Ohio Edison Co., The Cleveland Elec. Illuminating Co., and The Toledo Edison Co.*, Case No. 12-1230-EL-SSO, Opinion and Order (July 18, 2012) at 11, 58; *In re Duke Energy Ohio, Inc.*, Case No. 11-2641-EL-RDR, et al., Opinion and Order (May 25, 2011) at 7, 17. As the Commission recently found, the bifurcation of the market based and non-market based bill components more accurately reflects how transmission costs are billed to customers. *DP&L ESP Case* at 36. The Commission also stated, with respect to IEU-Ohio's concerns, that it was not persuaded that the bifurcation of the market based and non-market based costs poses a significant risk of double billing. *DP&L ESP Case*, Second Entry on Rehearing (Mar. 19, 2014) at 25. As IEU-Ohio witness Murray admitted, CRES contracts tend to include provisions to address regulatory changes, which is particularly common for commercial and industrial customers (Tr. VI at 1518-1519). In any event, AEP Ohio and CRES providers in the Company's service territory should work together, including Staff in the process if necessary, to ensure that customers do not pay twice for the same transmission-related expenses. If double billing issues nevertheless arise, there are existing means for impacted customers to seek the Commission's assistance, either informally by contacting Staff or through the formal complaint process available under R.C. 4905.26.

Further, we decline to adopt IEU-Ohio's recommendations that AEP Ohio be directed to assign Reactive Supply costs to customer classes on a 1 CP basis and to use a 1 CP billing determinant for demand-metered customers. As AEP Ohio points out, IEU-Ohio's proposals would have an unknown impact on customer bills and, in the absence of any analysis, it is inappropriate to modify the Company's current cost allocation methodology. Finally, consistent with our recent decisions in Case No. 14-1094-EL-RDR, the Commission notes that any remaining over/under recovery balance associated with the TCRR, which will be eliminated effective June 1, 2015, will be addressed in that proceeding. *In re Ohio Company*, Case No. 14-1094-EL-RDR, Finding and Order (Aug. 27, 2014) at 3, Finding and Order (Jan. 28, 2015) at 3.

15. Energy Efficiency and Peak Demand Reduction Rider

AEP Ohio seeks approval to continue its EE/PDR rider. According to AEP Ohio, the EE/PDR rider enables the Company to offer innovative energy efficiency programs for all customer segments and to achieve the established benchmarks for EE/PDR programs. AEP Ohio notes that no party opposes its proposal to continue the EE/PDR rider. (Co. Ex. 1 at 13; Co. Ex. 3 at 6; Co. Ex. 13 at 3; Co. Br. at 133-134; Co. Reply Br. at 109.) The Commission finds, pursuant to R.C. 4928.143(B)(2)(i), that AEP Ohio's request to continue the EE/PDR rider is reasonable and should be approved (Co. Ex. 1 at 13; Co. Ex. 3 at 6; Co. Ex. 13 at 3).

16. Economic Development Rider

AEP Ohio proposes to continue the EDR, as previously approved by the Commission, throughout the new ESP term. AEP Ohio witness Spitznogle testified that the EDR, which enables the Company to recover foregone revenues associated with reasonable arrangements approved by the Commission under R.C. 4905.31, facilitates the state's effectiveness in a regional, national, and global economy by supporting mercantile customers that create and retain Ohio jobs. AEP Ohio notes that no party opposes the continuation of the EDR. (Co. Ex. 1 at 13; Co. Ex. 3 at 9; Co. Ex. 13 at 3; Co. Br. at 134; Co. Reply Br. at 109.)

OEC and EDF argue that the EDR should be modified such that customers with Commission-approved reasonable arrangements are required to engage in all cost-effective energy efficiency programs. OEC and EDF point out that, although such customers enjoy the benefit of subsidized electric rates, they are not currently required to make any commitment regarding the manner in which they use their energy. OEC and EDF witness Roberto recommends, therefore, that, prior to seeking recovery of foregone revenues, AEP Ohio be required to undertake good faith efforts to work with its reasonable arrangement customers to implement cost-effective energy efficiency measures. OEC and EDF assert that Ms. Roberto's recommendation would benefit AEP Ohio and its customers by lowering the Company's cost of complying with the EE/PDR standards. (OEC/EDF Ex. 1 at 9-11; Tr. XII at 2799-2800; OEC/EDF Br. at 9-10.)

AEP Ohio responds that OEC's and EDF's proposal is unworkable, unclear, and incapable of implementation. AEP Ohio points out that Ms. Roberto did not explain why the Company's recovery, through the EDR, of foregone revenues attributable to customers with Commission-approved reasonable arrangements should depend on whether such customers meet OEC's and EDF's energy efficiency goals. AEP Ohio adds that there is no basis for Ms. Roberto's position that customers with reasonable arrangements do not sufficiently know how to make cost-effective investments and that there is no statutory duty to pursue all cost-effective energy efficiency measures. (Co. Br. at 134-136; Co. Reply Br. at 109-110.) Similarly, IEU-Ohio argues that OEC's and EDF's proposal lacks specificity and is unnecessary, in light of existing market incentives, as well as the fact that the Commission already addresses EE/PDR concerns in its orders approving reasonable arrangements (IEU-Ohio Reply Br. at 26-28). OEC and EDF counter that their proposal furthers Ohio's energy policy goals; is intended to lessen the financial impact associated with the subsidies paid by AEP Ohio's customers in support of economic development; and reasonably places responsibility on the Company, as the regulated entity, to ensure that customers with reasonable arrangements successfully implement energy efficiency measures (OEC/EDF Reply Br. at 3-7).

The Commission finds that the EDR should be continued, pursuant to R.C. 4928.143(B)(2)(i), as a means to promote economic development efforts in AEP Ohio's service territory and facilitate the state's effectiveness in the global economy, in accordance with R.C. 4928.02(N) (Co. Ex. 1 at 13; Co. Ex. 3 at 9; Co. Ex. 13 at 3). Additionally, we direct AEP Ohio to continue the Ohio Growth Fund, which creates private sector economic development resources to support and work in conjunction with other resources to attract new investment and improve job growth in Ohio. The Ohio Growth Fund should be funded by shareholders at $2 million per year, or portion thereof, during the term of ESP 3, which is consistent with our decision in the *ESP 2 Case*. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 67. Any funds that are not allocated during a given year shall remain in the fund and carry over to be allocated in subsequent years.

Further, the Commission declines to adopt the recommendations of OEC and EDF. As we have previously stated, each reasonable arrangement application, including consideration of any associated delta revenue recovery, should be evaluated on its own merits, in light of the benefits received by the parties to the arrangement, the electric utility's ratepayers, and the state of Ohio. *In re Ohio Edison Company and V&M Star*, Case No. 09-80-EL-AEC, Opinion and Order (Mar. 4, 2009) at 7. Although the Commission encourages customers receiving electric service pursuant to a reasonable arrangement with AEP Ohio to engage in cost-effective energy efficiency programs, we believe that imposing energy efficiency requirements on either the customer or the Company, as proposed by OEC and EDF, would unnecessarily curtail the benefits of reasonable arrangements afforded under R.C. 4905.31. Apart from energy efficiency considerations, reasonable arrangements may serve numerous other purposes that serve the public interest, such as attracting new businesses and facilitating the expansion of existing businesses in Ohio.

17. Purchase of Receivables Program and Bad Debt Rider

(a) AEP Ohio

AEP Ohio seeks approval to establish a purchase of receivables (POR) program without recourse, in conjunction with a new bad debt rider (BDR). AEP Ohio notes that, in the *ESP 2 Case*, the Commission directed the Company to evaluate a POR program, as a means of supporting retail competition in Ohio. AEP Ohio believes that the combination of the POR program and the BDR would support a competitive marketplace that is attractive to CRES providers, thereby enhancing shopping opportunities for customers, while also providing financial security for the Company. As proposed, the POR program would consist of an agreement between AEP Ohio and each participating CRES provider, under which the Company would purchase and receive title of ownership for receivables billed on behalf of the CRES provider by the Company via consolidated billing. Specifically, AEP Ohio witness Gabbard proposes that CRES providers that elect consolidated billing be required to participate in the POR program, although CRES providers would still be able to choose the dual-billing option, if they prefer, on an account-by-account basis. Further, Mr. Gabbard proposes that shopping customers that are already enrolled in dual billing with a CRES provider, and with receivables in arrears 60 days or more, would not be permitted to enroll in consolidated billing until they are in arrears 30 days or less. Mr. Gabbard also recommends that the initial POR discount rate be set at zero and that only commodity-related charges be included in the POR program.

Regarding POR payment terms, Mr. Gabbard explains that monthly payments for receivables billed and purchased during the prior month would be wired to CRES providers on a date derived by using a revenue lag metric, specifically, AEP Ohio's yearly Day Sales Outstanding value, which would be posted on the support website for CRES providers by January 1 of each year. Finally, AEP Ohio requests a waiver, for receivables purchased under the POR program, of Ohio Adm.Code 4901:1-18-10(D), which prohibits utilities from disconnecting service for failure to pay any non-tariffed service charges, including CRES-related charges. AEP Ohio believes that it must have leverage in the collections process to disconnect service for non-payment. (Co. Ex. 1 at 14; Co. Ex. 2 at 12-13; Co. Ex. 11 at 3, 6-8, 10-13.)

AEP Ohio estimates that implementation of a fully automated POR program would cost approximately $1.5 million, while ongoing incremental O&M support costs for system and program maintenance are forecasted at $207,600 on an annual basis. To recover these costs, AEP Ohio proposes that CRES providers that utilize consolidated billing would be charged an administrative fee each year, with such fees credited to cost of service for customers. AEP Ohio notes that the administrative fee would be designed to recover its initial capital investment over a five-year period as well as ongoing administrative costs, with the fee for each CRES provider based on its current number of enrolled customers or a forecasted number for new market entrants. According to AEP Ohio, the proposed annual per-consolidated bill fee would be $0.77, which the Company derived by dividing the amortized implementation costs over five years and the forecasted yearly administrative costs by the total number of residential and small commercial shopping customers that CRES providers tend to register in consolidated billing. Finally, AEP Ohio projects that it would need approximately 9 to 12 months in order to implement the POR program from the date of approval, with receivables purchased based on the first billing cycle after implementation. In terms of customer impact, AEP Ohio notes that, although the bill format would not change, customers would be able to use the Company's budget billing and average monthly payment plans for both their generation and wires charges; some customers may be required to pay an additional deposit to the Company to cover generation and transmission charges; and, if the requested waiver of Ohio Adm.Code 4901:1-18-10(D) is granted, customers would be subject to disconnection for non-payment of CRES-related charges. (Co. Ex. 11 at 13-17; Tr. III at 784-785.)

Regarding the benefits of the POR program, AEP Ohio explains that all customers would benefit from the likelihood of increased CRES providers and product offerings in the competitive market, while shopping customers, in particular, would benefit from the option to be placed on the Company's budget billing and average monthly payment plans for both wires and commodity charges; the elimination of duplicative credit checks; and dealing with only one entity for late payments and other billing issues. AEP Ohio emphasizes that CRES providers would also benefit from predictable payments for generation services; certainty regarding the amount of incoming receivables; limited need to address billing and payment issues; elimination of the need to perform credit checks, secure collateral, or engage in collections practices for accounts on consolidated billing; and, ultimately, having a more attractive market in which to offer products and services. Finally, AEP Ohio believes that the POR program has the potential to streamline a number of customer service processes for both CRES providers and the Company, such as customer credit and collections calls related to consolidated billing and inquiries regarding past due amounts. (Co. Ex. 11 at 4-6.)

With respect to the BDR, AEP Ohio notes that $12,221,000 in bad debt expense is already included in the Company's base distribution rates. AEP Ohio witnesses Gabbard and Moore testified that the BDR would be designed to recover the forecasted incremental bad debt expense, for each year going forward, that is above the amount already being recovered through base distribution rates, including incremental factoring expense. Mr. Gabbard further testified that this incremental recovery approach would continue until AEP Ohio's next distribution rate case, at which point bad debt expense would be unbundled from the distribution rates and recovered only through the BDR. AEP Ohio proposes that bad debt from both shopping customers and SSO customers be included in the BDR, as well as percentage of income payment plan (PIPP) installment payments not recovered through the universal service fund rider, or from the customer net of any unused low-income credit funds. Mr. Gabbard testified that the BDR would be trued up each year with an application period of January 1 to December 31 and that AEP Ohio's long-term debt rate would be applied to the over/under recovery amount carried forward to the next year. Mr. Gabbard also testified that the BDR would be applied based on the percentage of base distribution revenues and that, for the first year of implementation, the BDR is forecasted to be set at zero percent of base distribution revenues, as the incremental bad debt is forecasted to be zero. AEP Ohio emphasizes that the BDR is preferable to incorporation of the bad debt associated with purchased receivables into the discount rate. Specifically, AEP Ohio points out that its proposed BDR is consistent with the practice of Duke and other utilities with POR programs; would be used to recover bad debt costs associated with both shopping and non-shopping customers through one mechanism that is trued up annually; and would prevent cross-subsidization between shopping and non-shopping customers through the sharing of bad debt costs by all customers. (Co. Ex. 11 at 8-10; Co. Ex. 13 at 11, 12-13.)

Additionally, AEP Ohio seeks to establish for all residential customers, except those enrolled in PIPP plans, a late payment charge of 1.5 percent on the unpaid account balance, including charges related to receivables purchased from CRES providers, existing five days after the due date of the bill. AEP Ohio witness Spitznogle explained that the late payment charge would be assessed once and would become due and payable for that month. Mr. Spitznogle further explained that, if payment is not made by the subsequent month, an additional late payment charge would be applied to the new month's service charges, but would not be applied again to the previous month's unpaid balance. Finally, Mr. Spitznogle noted that any revenues generated from residential late payment charges would be used to offset the bad debt expense that is proposed to be collected through the BDR. AEP Ohio proposes the late payment charge in order to encourage residential customers to pay their bills on time; ensure that late payments from residential customers are treated comparably to late payments from the Company's other customer classes as well as customers of other utilities; and reduce the cost of bad debt paid by all customers. (Co. Ex. 3 at 10-11; Co. Ex. 11 at 9.)

(b) Intervenors and Staff

Although Staff supports the concept of a POR program, Staff opposes AEP Ohio's proposed BDR, late payment charge, and annual administrative fee assessed to CRES providers to pay for POR implementation and administrative costs. In place of the BDR, Staff recommends that AEP Ohio be required to purchase receivables at a discount rate. Staff contends that implementation of a discount rate prior to the BDR would be consistent with the process followed for Duke and the large gas companies, which purchased discounted receivables for years until their uncollectible expense riders were eventually established. Staff also advises that beginning the POR program with a discount rate would enable AEP Ohio to gain experience regarding the potential cost impact of CRES-related uncollectible charges. Staff recommends that AEP Ohio be directed to implement a specific discount rate calculation method that would establish a separate discount rate for each CRES provider, in order to ensure that each CRES provider assumes the appropriate amount of risk of non-collection associated with its customers. Staff further recommends that AEP Ohio establish a POR discount rate cap of 5 percent and implement a partial payment tracking methodology in conjunction with calculation of the discount rate, whereby partial payments would be allocated, after taxes, to generation, transmission, and distribution services based on the percentage that each service represents on the particular bill. Because Staff is opposed to the BDR, Staff states that it cannot support AEP Ohio's requested late payment charge, although Staff notes that it would not oppose a late payment charge proposed by the Company in a distribution rate case. As an alternative to its discount rate proposal, Staff notes that another option would be for AEP Ohio to implement the BDR, with a discount rate, that is limited to CRES receivables and generation-related uncollectable costs. Staff notes that its alternative proposal would avoid the need to rely on the $12.2 million uncollectible expense baseline reflected in base distribution rates, which relates to transmission and distribution. Noting that AEP Ohio has recently experienced uncollectible expenses in excess of the baseline, Staff expresses concern that AEP Ohio's proposal would allow the Company, in effect, to adjust its baseline through the BDR. Staff believes that uncollectible expenses related to distribution and transmission should be adjusted in a distribution rate case. (Staff Ex. 13 at 7-8; Staff Ex. 14 at 4-13; Tr. IV at 1108; Tr. IX at 2171-2172; Staff Br. at 33-36, 38-39; Staff Reply Br. at 27-28.)

With respect to AEP Ohio's recovery of POR program costs, Staff asserts that, with its discount rate proposal in place, recovery of the $207,600 in incremental O&M support costs through an administrative fee to CRES providers would be unnecessary, although Staff agrees with the Company's proposal to assess an annual per-consolidated bill fee for the estimated $1.5 million in implementation costs. Staff believes that such fee should be adjusted annually, when AEP Ohio performs its annual calculation of the discount rate, with the true-up comparing the actual cost of implementation with the cost estimate and also including an adjustment for the most recent consolidated billing customer numbers. Staff does not believe that a hard cap on the cost to implement the POR program is necessary, although Staff recommends that AEP Ohio track its implementation cost. Staff recommends that, if AEP Ohio finds that the implementation cost will exceed the $1.5 million estimate by ten percent, the Company should notify Staff and participating CRES providers, which may then request that an audit be performed at the Commission's discretion, with Staff to file its report within three months of the Commission's approval of the audit request. (Staff Ex. 14 at 13-15; Staff Br. at 37-38.)

Additionally, Staff proposes that the POR program be limited to residential and GS-1 customers that participate in consolidated billing. Noting that AEP Ohio's bad debt expense in 2013 was $22.5 million, which included a $7.2 million charge-off associated with the Ormet Primary Aluminum Corporation, Staff points out that the inclusion of large customers in the POR program may have a severe impact on residential rates. Finally, Staff recommends that, if AEP Ohio's proposed BDR is approved, the Commission should instruct the Company to work with Staff to ensure that strong collection practices are in place, in light of the fact that the rider will collect both CRES- and Company-related uncollectible expenses. Staff emphasizes that AEP Ohio has not provided any criteria or benchmarks that are used by the Company to evaluate collection performance. Staff notes that Duke has criteria that it uses to monitor and evaluate its collection practice. Staff asserts that, like Duke, AEP Ohio should have established benchmarks in place, and provide the benchmarks to Staff, before the BDR is approved. (Staff Ex. 13 at 4-5, 8-9; Staff Ex. 14 at 4; Tr. IV at 1117, 1119; Tr. VIII at 1905, 1911; Staff Br. at 40-43; Staff Reply Br. at 29-31.)

AEP Ohio responds that, in the *CRES Market Case*, Staff emphasized the need for consistent application of policies and practices to encourage the growth of the competitive market and minimize barriers to entry, although the Company believes that Staff's recommendations in the present proceedings are contrary to that goal and fundamentally inconsistent with the current practice in Ohio. AEP Ohio points out that Duke and a number of gas companies have POR programs that are structured similarly to the Company's proposal, with a zero discount rate and recovery of bad debt in a rider. AEP Ohio argues, among other matters, that Staff's assertion that the Company needs time to understand its experience with bad debt is undermined by the fact that the Company will have time to evaluate the relevant data prior to any BDR cost or credit being implemented, because the Company's proposal calls for the establishment of an initial BDR rate of zero. AEP Ohio contends that Staff's recommended POR program will not achieve the same level of intended benefits, as evidenced by the increased competition experienced in Duke's service territory following implementation of a zero discount rate and BDR. With respect to Staff's proposal that a specific discount rate be implemented for each individual CRES provider based on its past experience, AEP Ohio responds that Staff's proposal discriminates against at-risk populations with a higher credit risk and does not support the underlying goal of the POR program. Further, AEP Ohio maintains that, contrary to Staff's position, the Company's collection efforts and history of bad debt management support approval of the proposed BDR. According to AEP Ohio, although Staff opposes the BDR based, in part, on the perceived lack of benchmarks for evaluation of bad debt collection practices, Staff is unaware of any electric distribution utility having such benchmarks. In any event, AEP Ohio argues that the record reflects that the Company manages and takes steps to minimize its bad debt. AEP Ohio concludes that, while Staff agrees that the implementation of a POR program should not harm the utility, Staff's proposal would nevertheless have that effect by capping the level of bad debt recovery and shifting risk to the Company. Finally, AEP Ohio urges the Commission to reject other intervenors' recommended modifications, although the Company states that some of the recommendations would benefit from further discussion in the collaborative environment. (Tr. VIII at 1903-1907, 1911-1912, 1916-1917; Tr. IX at 2131, 2139, 2145, 2163-2164, 2168, 2178-2187; Co. Br. at 125-133; Co. Reply Br. at 105-107.) In its reply brief, Staff responds that, although consistency among utilities is important, POR programs should be evaluated on a case-by-case basis and, in any event, Staff has been consistent in requesting that AEP Ohio develop collections performance benchmarks like Duke, which is the only other electric distribution utility with a POR program combined with a BDR (Staff Reply Br. at 27-31).

OCC argues that AEP Ohio failed to prove any justification for the proposed POR program and BDR, which, according to OCC, would require the Company's customers to subsidize CRES providers' receivables. In support of its argument, OCC emphasizes that neither AEP Ohio nor any CRES provider provided any assurance that implementation of the POR and BDR would bring about additional products or providers in the Company's service territory. Further, OCC asserts that the lack of a POR program is not a barrier to market entry, in light of the significant number of registered CRES providers and current shopping rates, as well as the fact that there is no evidence that the absence of a POR program has inhibited competition. OCC adds that the claimed customer benefits of a POR program cited by AEP Ohio witness Gabbard are non-quantifiable and speculative, while there is no guarantee that CRES providers will flow their cost savings through to customers. With respect to AEP Ohio's proposed late payment charge, OCC argues that the Company failed to demonstrate a need for the charge or consider the impact on affordability of service, and did not provide any supporting documentation in the form of statistics showing the number of customers that make late payments, how late those payments are made, and the impact on the Company's finances. OCC concludes that the proposed POR program, BDR, and late payment charge should be rejected. (OCC Ex. 11 at 21-28; OCC Ex. 13 at 31-42; Tr. III at 830, 836, 839-842, 869; Tr. XI at 2675, 2695, 2709; OCC Br. at 90-101, 150-155; OCC Reply Br. at 71-80, 117-119.) AEP Ohio replies that the evidence of record reflects that a POR program is the appropriate next step to encourage competition in Ohio, consistent with the Commission's findings in the *CRES Market Case* (Co. Reply Br. at 102-103).

Like OCC, OPAE and APJN argue that AEP Ohio's proposed POR program, BDR, and late payment charge should be rejected by the Commission. According to OPAE and APJN, CRES providers should remain responsible for the bad debt of their customers and AEP Ohio should not be permitted to shift the collection risk to all distribution customers, which OPAE and APJN contend is counter to R.C. 4928.02(H). With respect to the late payment charge, OPAE and APJN assert that AEP Ohio failed to perform any study or analysis to demonstrate a need for the proposed charge or to consider its impact on the affordability of electric rates. If the late payment charge is approved, OPAE and APJN recommend that Graduate PIPP customers be exempt in addition to other PIPP customers. Further, OPAE and APJN argue that AEP Ohio should not be permitted to impose additional security deposits under the proposed POR program, given that shopping customers may have already paid a security deposit to their CRES providers or otherwise demonstrated creditworthiness. Next, OPAE and APJN maintain that AEP Ohio's requested waiver of Ohio Adm.Code 4901:1-18-10(D) is an inappropriate attempt to circumvent important consumer protections and should be rejected. OPAE and APJN point out that Ohio Adm.Code 4901:1-10-19(A) also prohibits AEP Ohio from disconnecting service to a residential customer for failure to pay a non-tariffed service, including CRES charges. Finally, OPAE and APJN argue that the POR program would impose significant costs on all distribution customers without any quantifiable benefit. (OPAE/APJN Br. at 18-31; OPAE/APJN Reply Br. at 9-18.) AEP Ohio counters that, among other benefits of the POR program, increased competition and lower prices will serve to protect at-risk populations, while the Company's proposed late payment charge is a common and reasonable type of charge that would be used to offset the BDR and incent timely bill payment (Co. Reply Br. at 104, 107).

IEU-Ohio also contends that the proposed POR program should be rejected. Alternatively, IEU-Ohio recommends that, if the Commission authorizes a POR program, the Commission should reject the BDR and direct that receivables be purchased at a discount. According to IEU-Ohio, AEP Ohio failed to demonstrate a need or customer benefit with respect to the POR program and BDR, particularly for commercial and industrial customers. Specifically, IEU-Ohio asserts that the record does not reflect that a POR program would lower a barrier to entry or that there is currently a shortage of CRES providers or products in AEP Ohio's service territory. Noting that AEP Ohio's proposal is based, in part, on the fact that Duke has a similar POR program and BDR, IEU-Ohio maintains that the Company's position is unwarranted and contrary to the stipulation through which Duke's POR program and BDR were approved. IEU-Ohio notes that AEP Ohio is a signatory party to Duke's stipulation and, as such, is prohibited by its terms from relying on the stipulation in the present proceedings. IEU-Ohio also believes that the BDR will fail to enhance competition; will unreasonably shift the market risk for bad debt to all of AEP Ohio's customers; and will remove the market discipline that encourages CRES providers to evaluate their customers and price their services appropriately. (IEU-Ohio Ex. 2 at 9-14; Co. Ex. 33 at Ex. WAA-R3; Tr. III at 869, 872-876; Tr. VII at 1652-1654; IEU-Ohio Br. at 44-51; IEU-Ohio Reply Br. at 23-26.) In response, AEP Ohio points out that the fact that Duke has a POR program with a BDR, regardless of the stipulation, may be considered by the Commission in these proceedings, contrary to IEU-Ohio's assertion (Co. Reply Br. at 104-105.)

According to FES, the proposed POR program has the potential to act as a barrier to competition and disadvantage responsible CRES providers that have effective collection practices. FES notes that AEP Ohio seeks to tie a CRES provider's use of consolidated billing to the POR program and to raise the discount rate in the future in order to recover costs associated with supplier enhancements unrelated to the POR program. FES contends that CRES providers should not be forced to choose between giving up revenues by participating in the POR program and foregoing the benefits of consolidated billing. FES adds that, under Duke's POR program, CRES providers are free to use consolidated billing apart from the POR program and there is no per-customer fee. FES, therefore, recommends that CRES providers be permitted to use consolidated billing without being required to participate in AEP Ohio's POR program; the proposed per-customer fee be rejected; and the Company be prohibited from recovering non-POR related costs through a non-zero discount rate at any point in the future. (FES Ex. 1 at 4-6; Tr. III at 795-800; FES Br. at 1-5.)

RESA and Constellation assert that AEP Ohio's proposed POR program and BDR should be approved. RESA notes that AEP Ohio's proposal addresses many of the POR-related issues and concerns raised in the *CRES Market Case* and incorporates the best practices from the POR programs in place for Duke and the large gas utilities. RESA witness Bennett testified that the POR program would encourage more CRES providers to enter AEP Ohio's service territory, lower the hurdle for market entry, increase competition, and bring more competitive prices and product offers; simplify billing and the debt and collection process; permit customers to have a single budget plan for energy and wires services; reduce the uncollectible risk for CRES providers; and eliminate customer confusion that results from dual collection efforts and the partial payment priority rules. In response to OCC's and IEU-Ohio's contentions, RESA points out that increases in supplier participation have occurred following implementation of a POR program. RESA believes that residential customers in AEP Ohio's service territory are not taking advantage of lower competitive prices due to the lack of a POR program. With respect to OCC's and IEU-Ohio's opposition to the BDR, RESA asserts that, consistent with AEP Ohio's proposal, all customers by class should contribute on a pro rata basis to cover bad debt, regardless of whether the power was supplied through a CRES provider or the SSO. RESA also argues that Staff's recommendations should be rejected. Specifically, RESA maintains that exclusion of large commercial and industrial customers would be inconsistent with the other POR programs in Ohio and would broadly and inappropriately exclude small GS-2 customers; a zero discount is reasonable at the outset of AEP Ohio's POR program, whereas Staff's proposal for CRES provider-specific discount rates is inconsistent with the existing POR programs, unsubstantiated, time consuming, and unduly burdensome; O&M costs should not be recovered through an adder; and rejection of the BDR is unwarranted, in light of Staff's willingness to accept a BDR that recovers only generation-related bad debt, which is what the Company has proposed. In its reply brief, RESA states that it would not object if mercantile customers are omitted from the POR program and BDR. Finally, as a related matter, RESA recommends that AEP Ohio be required to provide to CRES providers all payment and collection information for the Company-consolidated billing accounts until the POR program is in place and to continue to do so for CRES providers that do not use the program. RESA also notes that certain language in tariff sheets 103-20D and 103-41D grants AEP Ohio sole discretion to terminate certain delinquent customers' CRES contracts and bar such customers from shopping until their arrearages are paid. RESA recommends that the language in question be removed from AEP Ohio's tariffs, as RESA believes that it is unreasonable and anticompetitive. (RESA Ex. 3 at 4-11; Co. Ex. 11 at 4; Tr. III at 829-830; Tr. IX at 2135, 2148, 2169-2172; Tr. XI at 2667, 2681, 2692, 2694-2695, 2709; RESA Br. at 2-19; RESA Reply Br. at 2-12.) With respect to these last two recommendations, AEP Ohio argues that these issues should be considered, if at all, in another proceeding (Co. Br. at 147-148).

Constellation argues that AEP Ohio's proposal is consistent with R.C. 4928.02(C), which requires the Commission to ensure diversity of electricity supplies and suppliers, as well as comparable to similar POR programs that have been successfully implemented by Duke and the large gas utilities. Constellation recommends that the BDR explicitly be made a non-bypassable rider and that AEP Ohio provide a mechanism that shows the various costs included in the BDR. Constellation believes that the proposed BDR is a reasonable approach to fairly socialize the costs of bad debt and ensure that shopping customers do not pay a disproportionate share of bad debt expense. However, if the BDR is rejected in favor of a discount rate, Constellation proposes that the discount rate be based on AEP Ohio's actual historic bad debt experience by customer class, as opposed to Staff's proposal, which Constellation contends is complex and administratively burdensome. Constellation also argues that the Commission should not adopt Staff's proposal to limit the applicability of the POR program to residential and GS-1 customers only, because it has no basis in the record and is inconsistent with Duke's POR program. (Constellation Ex. 1 at 10; Constellation Br. at 20-23; Constellation Reply Br. at 21-24.)

IGS also supports AEP Ohio's proposed POR program and BDR. IGS emphasizes that AEP Ohio currently recovers uncollectible expense associated with SSO generation service from all customers, shopping and non-shopping, through distribution rates. IGS believes that it is more reasonable to recover the uncollectible expense associated with all generation service from all customers equally through the BDR. Additionally, IGS recommends that AEP Ohio be directed to implement supplier consolidated billing, whereby CRES providers would purchase the Company's receivables associated with distribution service and then be responsible for billing and collecting all charges, generation and distribution, from their customers. IGS believes that the flexibility afforded by supplier consolidated billing would enable CRES providers to develop and offer a broader range of products and services. According to IGS, supplier consolidated billing and AEP Ohio's proposed POR program complement each other and could be implemented concurrently. (Co. Ex. 11 at 6-8; IGS Ex. 2 at 22-24; IGS Br. at 18-19, 20-21; IGS Reply Br. at 17-18.)

Direct Energy also asserts that AEP Ohio should be directed to take steps to implement supplier consolidated billing, which Direct Energy contends would enable CRES providers to offer new and better products on a single bill. Specifically, Direct Energy recommends that, within 30 days of the Commission's decision in these proceedings, AEP Ohio be required to convene a working group for the purpose of creating a structure and process for supplier consolidated billing. Direct Energy further recommends that, within one year of the Commission's decision, AEP Ohio be required to file proposed tariffs in a new proceeding to address the timing for programming and the costs associated with supplier consolidated billing. With respect to the POR program, Direct Energy argues that the program, as proposed by AEP Ohio, would eliminate the current option for shopping customers to be billed by the Company for additional products and services outside of their ordinary commodity service. Direct Energy points out that AEP Ohio would expect CRES providers to bill and collect for these types of products and services, which would eliminate the benefits of a single bill. Direct Energy, therefore, recommends that AEP Ohio be required to program its billing system to allow for continued billing and collection for non-POR items, even if a CRES provider chooses to participate in the POR program. Alternatively, Direct Energy recommends that AEP Ohio be directed to allow CRES providers to continue to participate in utility consolidated billing, even if they elect not to participate in the POR program. Finally, Direct Energy contends that approval of the POR program should not relieve AEP Ohio of its obligation to provide payment information to CRES providers, consistent with the Commission's directives in the *CRES Market Case*. (Direct Energy Ex. 1 at 6-8; Tr. III at 787-789; Direct Energy Br. at 5-11.)

AEP Ohio opposes the supplier consolidated billing proposals of IGS and Direct Energy. According to AEP Ohio, an ESP proceeding is not the appropriate forum in which to consider intervenors' new and experimental ideas. AEP Ohio argues that, if the

Commission finds that the proposals warrant any consideration, they should be deferred to another proceeding. AEP Ohio further argues that Direct Energy's request that the Company continue to allow non-commodity items on the bill, including termination fees, should be rejected, because such items are not related to the provision of electric service or regulated by the Commission. AEP Ohio does not oppose Direct Energy's request to continue to receive customer payment information to the extent that it involves accounts with past due amounts and only for the period prior to implementation of the POR program. (Co. Br. at 147-148; Co. Reply Br. at 107-109.) Direct Energy responds that it agrees with AEP Ohio that these proceedings are not the proper venue for addressing the details of supplier consolidated billing, which is why Direct Energy merely proposes that the Company be directed to convene a stakeholder group and to file proposed tariffs within a year (Direct Energy Reply Br. at 2-3).

(c) Conclusion

The Commission notes that we have previously addressed the issue of implementation of a POR program in AEP Ohio's service territory. In the *ESP 2 Case*, several CRES providers and RESA advocated for implementation of a POR program, which, at the time, AEP Ohio neither supported nor opposed. The Commission, however, declined to adopt the recommendation and instead directed interested stakeholders to further discuss the merits of a POR program in conjunction with the five-year rule review of Ohio Adm.Code Chapter 4901:1-10, in Case No. 12-2050-EL-ORD. *ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 41-42. Subsequently, in the *CRES Market Case*, the Commission declined to adopt Staff's recommendation that the electric distribution utilities be required to file an application to implement a POR program within one year, although the Commission encouraged the utilities to include, in their next SSO or distribution rate case, a proposal to implement a POR program or equivalent. *CRES Market Case*, Finding and Order (Mar. 26, 2014) at 21.

The Commission continues to encourage the electric distribution utilities to consider and propose a POR program for implementation in their respective service territories. However, we also agree that each such proposal should be evaluated on its own merits, on a case-by-case basis, as Staff contends in the present proceedings. Consistent with this approach, and upon careful consideration of AEP Ohio's proposal, the Commission finds that a POR program should be approved for the Company, with the implementation details to be determined in a subsequent proceeding. Specifically, as discussed further below, we authorize AEP Ohio to establish a POR program that complies with the following requirements: (1) receivables must be purchased at a single discount rate that applies to all CRES providers; (2) only commodity-related charges may be included in the POR program; (3) participation in the POR program by CRES providers that elect consolidated billing must not be mandatory; and (4) a detailed implementation plan should be discussed within the MDWG, with a proposal subsequently filed for the

Commission's consideration. Additionally, AEP Ohio is authorized to establish a generation-related BDR set initially at zero.

We find that a POR program will provide significant customer benefits, including the likelihood of increased numbers of active CRES providers and product offerings in AEP Ohio's service territory, which, as the record reflects, occurred following the implementation of a POR program in Duke's service territory (Co. Ex. 11 at 4-6; RESA Ex. 3 at 8; Tr. III at 824-825). The Commission notes that the MDWG will provide an existing forum for discussion regarding the implementation of AEP Ohio's POR program, and interested stakeholders should address matters such as the POR program rules, calculation of the discount rate, implementation and maintenance costs, collection rates and procedures, and the timing and other mechanics of the process by which the Company will purchase receivables from CRES providers. We direct Staff to report on the progress of such discussions. The specific discount rate to be initially established, as well as the detailed implementation plan for the POR program, should be proposed for the Commission's consideration by AEP Ohio, Staff, and any other interested stakeholders through a filing made in a new docket by August 31, 2015. The Commission also notes that the recommendations regarding supplier consolidated billing offered by Direct Energy and IGS and RESA's objections to the switching provisions in tariff sheets 103-20D and 103-41D should be further discussed within the MDWG.

The Commission finds that, with the implementation of a discount rate, AEP Ohio's request for approval of the BDR should be approved, with modifications. We note that, as proposed by AEP Ohio, the BDR would flow the bad debt of both shopping and non-shopping customers, whether generation- or distribution-related, through a single rider, which may cause the type of subsidy that the Commission must avoid under R.C. 4928.02(H). Although AEP Ohio emphasizes that its BDR was modeled after Duke's approach in many respects, the proposed rider is inconsistent with Duke's practice of maintaining separate uncollectible expense riders for generation- and distribution-related bad debt. *See, e.g., In re Duke Energy Ohio, Inc.*, Case No. 14-953-EL-UEX, Finding and Order (Sept. 25, 2014); *In re Duke Energy Ohio, Inc.*, Case No. 14-955-EL-UEX, Finding and Order (Sept. 25, 2014). As Staff points out, AEP Ohio's proposal would effectively enable the Company to adjust, through the BDR, the $12.2 million in bad debt expense that is already reflected in its base distribution rates. We agree with Staff that, if this baseline is to be adjusted, it should be done in the context of a distribution rate case and not in these proceedings. Consequently, consistent with Staff's alternative recommendation, the BDR should be limited to CRES receivables and generation-related uncollectible expenses above the amount already being recovered through base distribution rates. As the implementation details of the POR program will be resolved in another docket, the BDR should initially be established as a placeholder rider set at zero. Further, we believe that the merits of a late payment charge for residential customers would be more appropriately addressed in a distribution rate case and, accordingly, do not approve the proposed charge at this time.

The Commission also finds it necessary to address AEP Ohio's request for a waiver of Ohio Adm.Code 4901:1-18-10(D), which provides that a utility company shall not disconnect service due to failure to pay CRES-related charges. Additionally, as OPAE and APJN point out, Ohio Adm.Code 4901:1-10-19(A) similarly provides that no electric utility may disconnect service to a residential customer for failure to pay CRES-related charges. More importantly, we note that R.C. 4928.10(D)(3) requires the Commission to adopt rules regarding a number of specific consumer protections, including, with respect to disconnection and service termination, a prohibition against blocking, or authorizing the blocking of, customer access to a non-competitive retail electric service when a customer is delinquent in payments to the electric utility or electric services company for a competitive retail electric service. No party has persuaded the Commission that we can waive Ohio Adm.Code 4901:1-18-10(D) in light of this statutory provision. We, therefore, find that AEP Ohio's request for a waiver of Ohio Adm.Code 4901:1-18-10(D) should be rejected, as it is counter to the statute's prohibition on disconnection for non-payment of CRES-related charges. The Commission cannot grant a rule waiver that is inconsistent with the statute.

Finally, in accordance with the Commission's directive in the *CRES Market Case*, AEP Ohio should continue to make available to CRES providers the data necessary to assist them in collection efforts, including the total customer payment amount, the amount billed by the CRES provider, the amount of the payment allocated to the CRES provider, the date on which the payment was applied, and a payment plan flag. *CRES Market Case*, Finding and Order (Mar. 26, 2014) at 21-22.

18. Continuation or Elimination of Other Riders

In addition to the riders specifically addressed above, AEP Ohio requests authority to continue or eliminate other existing riders. Specifically, AEP Ohio witness Moore testified that the pool termination rider and generation resource rider would be eliminated, while the deferred asset phase-in rider, universal service fund rider, kWh tax rider, phase-in recovery rider, and transmission under recovery rider would continue in their current form. (Co. Ex. 1 at 14; Co. Ex. 13 at 4, Ex. AEM-1; Co. Br. at 137; Co. Reply Br. at 110.) The Commission finds that AEP Ohio's request is reasonable and should be approved (Co. Ex. 1 at 14; Co. Ex. 13 at 4, Ex. AEM-1).

19. Capital Structure and Cost of Capital

AEP Ohio proposes to use the expected capital structure and cost of capital for the wires business that will exist as of May 31, 2015, following completion of the Company's transfer of its generation assets. Specifically, AEP Ohio witness Hawkins testified that the targeted capital structure is 52.5 percent long-term debt and 47.5 percent equity, which is a change from the current capital structure of approximately 43 percent debt and 57 percent equity. Ms. Hawkins recommended a pre-tax weighted cost of capital of 10.86 percent, after-tax weighted cost of capital of 8.23 percent, and an embedded cost for long-term debt of 6.05 percent. AEP Ohio witness Avera recommended an ROE of 10.65 percent, in order to enable the Company to maintain its financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital. (Co. Ex. 17 at 4-9; Co. Ex. 19 at 5-9; Co. Br. at 106-110.)

OCC urges the Commission to adopt an ROE of 9.00 percent for AEP Ohio. OCC points out that AEP Ohio, as a wires only business, has a lower risk than an integrated generation, transmission, and distribution owner. OCC also asserts that its recommendation is reasonable, given the lower risk inherent in the electric industry and AEP Ohio's continued reliance on numerous riders, as well as the relatively slow growth in the economy. Further, OCC argues that AEP Ohio witness Avera's analysis is flawed in numerous respects and, therefore, the Company's requested ROE is overstated and unreasonable. (OCC Ex. 12; OCC Ex. 12A; OCC Br. at 134-142; OCC Reply Br at 107-112.) AEP Ohio replies that OCC recommends an inordinately low ROE and that Dr. Avera thoroughly explained and supported his methodology. AEP Ohio adds that Dr. Avera's analysis implicitly accounts for all risk affecting factors. (Co. Br. at 111-113; Co. Reply Br. at 89-97.)

Like OCC, Walmart also contends that AEP Ohio's proposed ROE is unreasonable, because it fails to reflect a reduction in regulatory lag attributable to the DIR and other riders, and is inflated in comparison to the average ROE of 9.57 percent for other distribution only utilities since 2012. In addition to supporting OCC's recommended ROE of 9.00 percent, Walmart requests that the Commission approve an ROE of no higher than 9.57 percent. (Walmart Ex. 1 at 7-10, Ex. SWC-2; Tr. II at 313-314; Tr. V at 1299; Walmart Br. at 3-5.) AEP Ohio responds that riders, such as the DIR, are commonplace and do not distinguish the Company's risk level and, in any event, the impact on the risk due to the DIR is already factored into Company witness Avera's analysis. Addressing Walmart's argument regarding the average ROE for other distribution only entities, AEP Ohio points out that the most relevant historical ROE is the one authorized for the Company by the Commission. AEP Ohio notes that Dr. Avera's ROE recommendation of 10.65 percent is squarely within the range recently established for the Company by the Commission, namely above the 10.20 percent ROE approved in the *Distribution Rate Case* and below the 11.15 percent ROE approved in Case No. 10-2929-EL-UNC with respect to capacity charges. AEP Ohio adds that Dr. Avera's recommendation is further supported by the fact that the ROE established in these proceedings will be used for rates that do not go into effect until June 2015, when interest rates and costs of equity are likely to be higher. (Co. Br. at 110-111; Co. Reply Br. at 89.)

Upon review of the parties' positions, the Commission finds that the record reflects a range in ROE recommendations, beginning with a low of 9.00 percent, put forth by OCC and supported by Walmart, increasing to Walmart's upper bound recommendation of 9.57 percent, and, finally, ending at the Company's requested ROE of 10.65 percent. We agree with Walmart and OCC that AEP Ohio's requested ROE is too high, as gauged by comparison with the average reported ROE for comparable utilities since 2012 (Walmart Ex. 1 at 9-10). Further, AEP Ohio's requested ROE does not adequately account for the Company's reduced exposure to risk from regulatory lag in light of the DIR and numerous other riders (Walmart Ex. 1 at 8; OCC Ex. 12 at 54-55; OCC Ex. 12A). On the other hand, we find that OCC's and Walmart's ROE recommendations are not sufficient to enable AEP Ohio to maintain its financial integrity and protect its ability to attract capital.

In the *Distribution Rate Case*, the Commission adopted a joint stipulation and recommendation submitted by the parties, which included approval of an ROE of 10.00 percent for CSP and 10.30 percent for OP, or an ROE of 10.20 percent for the merged corporate entity. *Distribution Rate Case*, Opinion and Order (Dec. 14, 2011) at 12, 14. Following our review of the record in the present ESP proceedings, we find that it is appropriate to maintain the ROE of 10.20 percent authorized for AEP Ohio in the *Distribution Rate Case*. The Commission recognizes that the ROE was adopted pursuant to the stipulation in the *Distribution Rate Case*, which was intended by the parties to have no precedential effect. The Commission has stated, however, that, while parties may agree not to be bound by the provisions contained within a stipulation, such limitations do not extend to the Commission. *See, e.g., ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 10. We, therefore, find that an ROE of 10.20 percent is appropriate, just, reasonable, and supported by the record, as it falls within AEP Ohio witness Avera's recommended range of 9.50 percent to 11.00 percent (Co. Ex. 19 at 7, Ex. WEA-2), as well as within the range of recommendations put forth by OCC, Walmart, and the Company.

20. Accounting Authority

AEP Ohio requests authority to record regulatory liabilities and regulatory assets and, thus, to perform regulatory deferral over/under recovery true-up accounting for a number of riders, as well as continued deferral accounting authority for the SDRR and additional deferral authority related to the proposed NCCR. (Co. Ex. 1 at 15; Co. Ex. 18 at 3-6.) The Commission finds that AEP Ohio's request for accounting authority is reasonable and should be approved (Co. Ex. 1 at 15; Co. Ex. 18 at 3-6), except with respect to the NCCR, consistent with our rejection of the proposed rider.

21. Early Termination

In its application, AEP Ohio states that it reserves the right to terminate the proposed ESP one year early (i.e., by June 1, 2017), based upon a substantive change in

Ohio law (including rules or orders of the Commission) affecting SSO obligations or rate plan options under R.C. Chapter 4928; or a substantive change in federal law (including FERC rules or orders) or PJM tariffs or rules with respect to capacity, energy, or transmission regulation or pricing that has an impact on SSO obligations or rate plan options. AEP Ohio further states that it may exercise its early termination right, at its sole option and discretion, by giving written notice to the Commission no later than October 1, 2016. Finally, AEP Ohio states that, if the Company elects to exercise its right to early termination, it will propose a new SSO rate plan to encompass the period from June 1, 2017, through May 31, 2018, which may also encompass a longer time period consistent with applicable law. According to AEP Ohio, the early termination provision is reasonable, prudent, and necessary to protect the interests of the Company and its customers, in light of the rapidly changing legal and regulatory environment and the attendant supply risks. (Co. Ex. 1 at 15; Co. Ex. 2 at 8; Tr. I at 65-67; Co. Br. at 137-139.)

Staff, OCC, OMAEG, Constellation, Direct Energy, and RESA oppose AEP Ohio's reservation of right to terminate the ESP at the end of the second year. These parties raise a number of reasons for their opposition, arguing that AEP Ohio's reservation of right lacks statutory or other legal authority; interferes with the MRO/ESP analysis; grants the Company nearly unfettered discretion; lacks objective criteria for determining when the right may be properly exercised; creates substantial uncertainty, risk, and higher costs in the market for customers, SSO suppliers, and CRES providers; harms competition; and proposes a timeframe that would allow little time for a new ESP to be approved. OCC adds that, if the Commission nevertheless approves the early termination provision, it should not apply to the PPA rider. (Staff Ex. 16 at 2-4; OCC Ex. 15A at 44; Constellation Ex. 1 at 24-27; RESA Ex. 3 at 11-12; Tr. I at 67-68; Staff Br. at 67-68; OCC Br. at 154-157; OMAEG Br. at 3-6; Constellation Br. at 25-26; Direct Energy Br. at 12; RESA Br. at 34-36; OCC Reply Br. at 40-42; OMAEG Reply Br. at 18-20; Constellation Reply Br. at 24-25; RESA Reply Br. at 22.)

AEP Ohio responds that intervenors' concerns are misplaced, because the Commission and customers would receive advance notice if the Company exercises its early termination right, and a new SSO would have to be approved by the Commission before ESP 3 would end. AEP Ohio points out that its advance notice should eliminate any uncertainty for customers and CRES providers. AEP Ohio also argues that nothing in R.C. 4928.143 or any other statutory provision prohibits the Commission from approving the Company's reservation of an early termination right. Further, AEP Ohio contends that the length of the ESP term has no bearing on the Commission's MRO/ESP analysis. Finally, AEP Ohio notes that it is not opposed to extending the PPA rider past the ESP term, to the extent that the Commission is committed, at the outset, to the Company's proposed hedging arrangement. (Co. Ex. 1 at 15; Co. Ex. 2 at 8; Tr. I at 65-66, 68, 133; Co. Reply Br. at 110-114.)

To the extent that AEP Ohio seeks the Commission's approval of its reservation of right to terminate the ESP after a two-year period, we find that the Company's request should be denied. AEP Ohio offers no statutory or other legal citation in support of its request. Further, as proposed, AEP Ohio's early termination provision is neither reasonable nor prudent. As noted by Staff and numerous intervenors, AEP Ohio's proposal would afford the Company considerable discretion to end the ESP after two years. In fact, among other circumstances, the ESP would be subject to early termination due to any Commission order that affects the ESP, including any of its riders, or the Company's SSO obligations under R.C. Chapter 4928. The Commission also believes that the proposed early termination provision would generate a significant measure of uncertainty and risk in the market and, potentially, higher costs for customers. (Staff Ex. 16 at 4; Constellation Ex. 1 at 24-27; RESA Ex. 3 at 11-12; Tr. I at 67-68.) Finally, the Commission notes that, if AEP Ohio finds it necessary to take steps to protect the interests of the Company or its customers, in light of regulatory or other changes in the law, the Company has other existing means by which to seek relief.

22. Other Issues

(a) Demand Response

In its brief, AEP Ohio notes that the recent polar vortex affirms that demand response programs play an important role, even when sponsored by a wires only company. AEP Ohio also points out that a federal appeals court ruling called into question FERC's approval of PJM's demand response programs and emphasized the states' role in overseeing demand response programs for retail customers. OEG recommends that the Commission ensure that state-established demand response programs for shopping and non-shopping customers remain available, even if PJM is required to change its tariffs as a result of federal proceedings. OEG adds that demand response programs provide both reliability and efficiency benefits. (Co. Br. at 72-73; OEG Reply Br. at 12.)

The Commission notes that the United States Court of Appeals for the District of Columbia Circuit has vacated FERC Order 745, which established a means for regional transmission organizations to compensate demand response resources in wholesale electricity markets. *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014). Specifically, the court determined that demand response is solely a retail matter subject exclusively to state jurisdiction. The United States Solicitor General, on behalf of FERC, filed a petition for a writ of certiorari at the United States Supreme Court on January 15, 2015.

The Commission agrees with AEP Ohio and OEG that demand response plays an important role in ensuring reliability, while also encouraging state economic development.

We find that, because of the possibility that federal proceedings may significantly alter the jurisdiction of demand response, a new placeholder pilot demand response rider should be established. The Commission emphasizes that this is merely a placeholder rider and that no cost allocation or recovery shall occur at this time. Within 30 days of a final order from the United States Supreme Court or an order denying petitions for certiorari, AEP Ohio or the Commission may open a new docket to revisit any provisions in these proceedings that relate to demand response and load management mechanisms within the Company's service territory.

(b) Retail Stability Rider

In the ESP application, AEP Ohio states that it plans to continue the RSR through the term of the proposed ESP, consistent with the Commission's decision in the *ESP 2 Case*. AEP Ohio explains that the sole purpose of the RSR during the ESP term will be to collect the Company's previously authorized capacity charge deferrals, including carrying charges, for three years or until fully recovered. AEP Ohio notes that it intends to file a separate application to continue the RSR, although the rider has been incorporated into the Company's projected rate impacts submitted as part of these proceedings. (Co. Ex. 1 at 3, 14; Co. Ex. 7 at 11-12; Co. Ex. 13 at 4; Co. Br. at 137.)

The Commission notes that, in Case No. 14-1186-EL-RDR, AEP Ohio filed an application on July 8, 2014, to continue the RSR until the deferrals and carrying charges are fully recovered. Accordingly, continuation of the RSR will be addressed in that case.

(c) Significantly Excessive Earnings Test

AEP Ohio requests that the Commission confirm the methodology by which it intends to implement the SEET for the duration of the ESP, in order to maintain a level of consistency to enable investors and utility managers to make the significant investments in utility infrastructure that are necessary to meet customers' needs and expectations. AEP Ohio witness Allen testified that, while none of the SEET threshold values for 2009, 2010, 2011, or 2012 can possibly include the ROE for comparable companies for the term of the proposed ESP, they individually and collectively support the proposition that an earned ROE below 15 percent cannot be the result of significantly excessive earnings. Mr. Allen further testified that, although AEP Ohio does not believe that a SEET threshold should be set prospectively for the ESP period, if the Commission elects to establish such a threshold in these proceedings, the Company believes that a threshold of 15 percent would be reasonable under the terms of the proposed ESP, as well as consistent with other SEET thresholds established by the Commission in prior proceedings. (Co. Ex. 7 at 5-8; Co. Br. at 146-147.)

OCC points out that the business and financial risk faced by AEP Ohio has declined, in light of the fact that the Company is now a wires only business and continues to rely on riders to collect revenues. OCC also notes that AEP Ohio's current SEET threshold is 12 percent, which was established in the *ESP 2 Case*, at which time the Company still owned numerous generation assets. Further, OCC argues that AEP Ohio has not demonstrated that it is reasonable or in the public interest to increase the SEET threshold from 12 percent to 15 percent. OCC, therefore, recommends that the SEET threshold remain at 12 percent or be lowered, given AEP Ohio's lower risk exposure. Alternatively, OCC recommends that the Commission determine the SEET threshold within the context of each annual proceeding, as it has done in the past. (OCC Ex. 12 at 54-55; OCC Ex. 12A; OCC Br. at 147-149; OCC Reply Br. at 116-117.) AEP Ohio replies that a SEET threshold of 15 percent is reasonable and appropriate based upon the methodology previously used by the Commission, while OCC's proposal lacks any connection to either historical or future earnings. AEP Ohio adds that the 12 percent SEET threshold established in the *ESP 2 Case* is inadequate in numerous respects and, in any event, the Commission should not prospectively establish a SEET threshold. (Co. Ex. 7 at 5-7; Co. Reply Br. at 130-132.)

The Commission finds that, since we have not authorized or renewed a service stability rider, it is not necessary to establish a SEET threshold in these ESP proceedings. Accordingly, AEP Ohio's SEET threshold for each year of the ESP will be determined within the context of each annual SEET case.

(d) Market Energy Program

RESA proposes that the Commission adopt a market energy program (MEP), which would be modeled after a similar concept implemented in Pennsylvania. RESA contends that the proposed MEP would be a direct and easy way in which to introduce shopping to eligible customers by means of a straightforward competitive offer that would be approved by the Commission. Specifically, RESA proposes that AEP Ohio's non-shopping residential and small commercial customers, when calling the Company's call center for any reason other than termination or emergency, would be offered a three percent discount off the applicable price to compare at the time of enrollment for a six-month period, with no termination fee. If a customer elects to participate in the MEP, RESA explains that the customer would be immediately enrolled with a specific CRES provider, if desired, or otherwise assigned sequentially to a CRES provider from a list of participating providers. With respect to costs, RESA recommends that AEP Ohio, following consultation with interested CRES providers, submit a start-up and maintenance plan with estimated costs for the Commission's review and approval of a per-enrolled customer charge to be paid by participating CRES providers at a level that will recoup the start-up costs, over a three-year period, as well as ongoing maintenance costs. RESA also proposes that the MEP be evaluated through quarterly reports and an annual meeting among interested stakeholders. (RESA Ex. 2 at 4-8; Tr. VIII at 1945, 1949-1951; RESA Br. at 24-27; RESA Reply Br. at 13-14.)

IGS recommends that RESA's proposed MEP be approved, in order to encourage customers to engage in the competitive retail electric market (IGS Br. at 22; IGS Reply Br. at 15-16). Staff states that it is not opposed to RESA's MEP proposal, but makes a number of recommendations. If the Commission approves the MEP, Staff recommends that the Commission direct that Staff has final authority regarding how the program will be implemented; the customer enrollment processing and notification rules contained in Ohio Adm.Code Chapters 4901:1-10 and 4901:1-21 apply to the program; and AEP Ohio must track certain customer enrollment data and report the data to Staff upon request. (Staff Br. at 73-74.)

AEP Ohio opposes the proposed MEP. AEP Ohio argues that the MEP proposal has not been adequately developed and would benefit from discussion and further refinement in a collaborative environment. According to AEP Ohio, the Commission's sole focus in these proceedings should be on the proposed ESP, while the MEP, if considered at all, should be the subject of review in another proceeding. (Co. Br. at 147-148; Co. Reply Br. at 132-133.) OCC, OPAE, and APJN also oppose the MEP proposal put forth by RESA. OCC emphasizes that RESA provided very few details regarding its proposal; failed to support the basic terms that were proposed, particularly the three percent discount; and failed to explain key differences between its proposal and the similar program implemented in Pennsylvania. OCC believes that the MEP would result in customer confusion and higher costs. OPAE and APJN point out that many important details of the MEP have not been worked out and that the program is an attempt to undermine the SSO. OPAE and APJN add that the MEP would result in a subsidy of a CRES product through distribution rates and is, therefore, contrary to R.C. 4928.02(H). (OCC Br. at 125-131; OPAE/APJN Br. at 48-51; OCC Reply Br. at 82-84; OPAE/APJN Reply Br. at 26-27.)

The Commission declines to adopt the proposed MEP. RESA's proposal is outside the scope of these ESP proceedings and, as several intervenors note, many of the key elements of the MEP have not been adequately developed. In the *CRES Market Case*, the Commission established the MDWG to be facilitated by Staff as a forum for the electric distribution utilities, CRES providers, and other interested stakeholders to address issues related to the development of the competitive market. *CRES Market Case*, Finding and Order (Mar. 26, 2014) at 23. The Commission, therefore, notes that interested stakeholders and Staff may work through the MDWG to evaluate the proposed MEP. If, upon further evaluation by the MDWG, Staff concludes that the proposed MEP or a comparable program should be considered by the Commission for implementation in the state of Ohio, Staff should file a detailed proposal in a new case with an EL-EDI designation.

(e) Immediate Enrollment and Accelerated Switching

IGS witness White testified that customers are currently required to enroll in SSO generation service upon enrolling in AEP Ohio's distribution service and must wait a minimum period of time before they can enroll with a CRES provider. Mr. White further testified that this requirement is a barrier to competition. IGS, therefore, proposes that customers be permitted to enroll with a CRES provider immediately upon enrolling in AEP Ohio's distribution service. Additionally, IGS recommends that AEP Ohio be directed to implement accelerated switching for customers with smart meters, such that customers are permitted to switch from one generation service to another in a period of five days or less. (IGS Ex. 2 at 24-25; IGS Reply Br. at 16-17.)

RESA supports IGS' immediate enrollment proposal, as another means to develop the competitive market in AEP Ohio's service territory. RESA asserts that IGS' recommendation will not conflict with the efforts of the MDWG to develop an operational plan for a statewide instant connect process, as directed by the Commission in the *CRES Market Case*. (RESA Br. at 33-34.) AEP Ohio, however, opposes both of IGS' proposals and urges the Commission to consider the issues raised by IGS, if at all, in another proceeding (Co. Br. at 147-148).

The Commission finds that IGS' proposals should not be adopted at this time, as they are outside the scope of these ESP proceedings and would be more appropriately addressed through the MDWG.

(f) Affordability of Retail Electric Service

OCC, OPAE, and APJN argue that AEP Ohio failed to propose an ESP that will result in reasonably priced retail electric service and that will protect at-risk populations, as required by R.C. 4928.02(A) and (L), respectively. OCC, OPAE, and APJN point out that AEP Ohio did not evaluate or even address the impact of its proposed ESP on rate affordability. Relying on current rate information, OCC witness Williams testified that approximately 21.8 percent of AEP Ohio's customers are significantly and negatively impacted by the Company's current rates, with approximately 7.6 percent of customers disconnected for non-payment in 2013. OCC, therefore, recommends that the Commission reject the proposed POR program, BDR, and late payment charge; discontinue the DIR and ESRR; and reject the proposed elimination of the TOU tariffs. Raising similar concerns, OPAE and APJN recommend that AEP Ohio be required to continue the annual $1 million funding commitment for the low-income bill payment assistance program known as the Neighbor-to-Neighbor program, which is currently part of the residential distribution credit approved in the *Distribution Rate Case*. OPAE and APJN further recommend that AEP Ohio be required to add $1 million annually from shareholder funds to increase the Company's funding commitment, as a means to ensure that there is adequate funding to meet the current need. Additionally, OPAE and APJN assert that the Commission should consider exempting income-eligible customers from any of the approved riders in order to mitigate the bill impact. (OCC Ex. 11 at 4-20; Tr. III at 696-697; OCC Br. at 31-37; OPAE/APJN Br. at 5-18; OPAE/APJN Reply Br. at 5-9.) AEP Ohio responds that the proposed POR program, distribution-related riders, PPA rider, and extension of the residential distribution credit will benefit and protect at-risk populations (Co. Reply Br. at 104).

Walmart contends that AEP Ohio's rates are inordinately complex, noting that the Company has more than 20 riders, some of which are adjusted on a quarterly basis, and, therefore, it is difficult for commercial customers to evaluate their rates and determine the complete billing impact. Walmart encourages the Commission to find ways in which to simplify AEP Ohio's rate structure and recommends that the Company be directed to file a rate case with new rates to be effective on or before May 31, 2018. (Walmart Ex. 1 at 4-6; Tr. II at 424-425; Walmart Br. at 2.)

The Commission finds that the concerns raised by OCC, OPAE, and APJN have been thoroughly addressed above through our modifications to AEP Ohio's proposed ESP, including, but not limited to, limitations imposed on the DIR and continuation of the Company's variable price tariffs and the funding commitment for the Neighbor-to-Neighbor program. The Commission finds that, with these modifications, AEP Ohio's ESP will provide reasonably priced retail electric service for consumers, including at-risk populations, consistent with the state policy enumerated in R.C. 4928.02. Regarding Walmart's recommendation, although the Commission declines to direct AEP Ohio to file a distribution rate case application by a specific date, we encourage Staff and intervenors to recommend, in the Company's next rate case, ways in which the Company's rate structure may be simplified.

III. IS THE PROPOSED ESP MORE FAVORABLE IN THE AGGREGATE AS COMPARED TO THE RESULTS THAT WOULD OTHERWISE APPLY UNDER R.C. 4928.142?

Addressing the statutory test set forth in R.C. 4928.143(C)(1), AEP Ohio asserts that its proposed ESP is more favorable in the aggregate than would be expected under an MRO. AEP Ohio points out that, under either an ESP or MRO, the Company would acquire all generation services for SSO customers from the market and, accordingly, there would be no quantifiable difference in the commodity prices. However, AEP Ohio notes that its proposed extension of the RDCR through May 31, 2018, provides an annual benefit of $14,688,000, or $44,064,000 over the three-year term of the ESP, which would not exist under an MRO. AEP Ohio adds that it estimates that the PPA rider would provide an $8.4 million credit over the ESP term, while the DIR and ESRR would offer a streamlined approach to recovering many of the costs associated with investment in distribution infrastructure without the time and expense of a distribution rate case. Further, AEP Ohio emphasizes that there are numerous non-quantifiable benefits of the ESP compared to an MRO, including the Company's accelerated move to fully market based rates by June 1, 2015, the increased rate stability of the proposed PPA rider, and the benefits associated with the proposed POR program. AEP Ohio concludes that the combination of these numerous quantifiable and non-quantifiable benefits demonstrates that the Company's proposed ESP is more favorable in the aggregate than the results that would be expected under an MRO. (Co. Ex. 2 at 9; Co. Ex. 7 at 3-5; Co. Ex. 33 at 10; Tr. XIII at 3251-3252; Co. Br. at 139-143.)

Staff witness Turkenton testified that the ESP, as modified by Staff's recommendations, is more favorable in the aggregate than an MRO. Initially, Ms. Turkenton explained that there would be no difference in AEP Ohio's fully market based generation rates under an MRO compared to the ESP. According to Ms. Turkenton, there are a number of benefits under the ESP. Specifically, Ms. Turkenton testified that AEP Ohio's base distribution rates would remain frozen through May 31, 2018, and the DIR and ESRR would enable the Company to make necessary distribution system investments, while avoiding the time and expense of a distribution rate case. Ms. Turkenton also cited the $44,064,000 associated with the RDCR; the accelerated implementation of fully market based generation rates; and the possibility of increased CRES providers, products, and payment options and elimination of customer confusion under the POR program. Finally, Ms. Turkenton testified that, because Staff recommends that certain proposed riders be rejected, including the PPA rider, SSWR, NCCR, and BDR, the potential costs of these riders were not considered in her MRO/ESP analysis. (Staff Ex. 15 at 2-5; Tr. IX at 2202, 2211, 2225; Staff Reply Br. at 49-50.)

OCC, IEU-Ohio, and OMAEG argue that AEP Ohio failed to demonstrate that the proposed ESP is more favorable in the aggregate than an MRO. OMAEG notes that the $44,064,000 residential distribution credit is only available to the residential customer class and would be reduced to $29,376,000, if AEP Ohio exercises its reserved right to terminate the ESP after two years. OCC believes that the residential distribution credit is not a quantifiable benefit, because the credit may be needed to correct excess revenue collections under the proposed expansion of the DIR. OCC, IEU-Ohio, and OMAEG further note that AEP Ohio failed to quantify the effects of several riders, including the BDR, NCCR, PPA rider, DIR, ESRR, and SSWR. According to OCC, over the three-year term of the ESP, customers are projected to pay $116 million for the PPA rider and $240 million for the DIR, ESRR, and SSWR combined, which OCC asserts should be accounted for in the MRO/ESP analysis. Similarly, IEU-Ohio argues that the known cost of the PPA rider is somewhere in the range of $82 million to $116 million over the ESP term and, accordingly, the proposed ESP is $38 million to $72 million worse than an MRO, after accounting for the RDCR. OCC and OMAEG add that, contrary to Staff's interpretation, AEP Ohio did not commit to refrain from filing a distribution rate case during the term of the ESP. According to

OMAEG, AEP Ohio also did not account for costs associated with accelerating the recovery period of capacity deferrals collected through the RSR from 36 months to 32 months, as proposed by the Company in Case No. 14-1186-EL-RDR. With respect to AEP Ohio's claimed non-quantifiable benefits, IEU-Ohio and OCC argue that the Commission may not lawfully weigh such benefits against the quantifiable costs of the proposed ESP, because the Commission must apply an objective standard to the MRO/ESP analysis, in accordance with R.C. 4903.09. Further, OCC, IEU-Ohio, and OMAEG contend that, even if non-quantifiable benefits are considered, the PPA rider and POR program would impose costs on customers without any commensurate benefit, while also harming customer choice. OCC maintains that there is no evidence in the record that the POR program would drive market development or that the PPA rider would provide rate stability. Further, OCC, IEU-Ohio, and OMAEG assert that AEP Ohio's commitment to implement fully market based rates cannot be claimed as a non-quantifiable benefit, because it was already factored into the statutory test in the *ESP 2 Case*. IEU-Ohio adds that there is no benefit in AEP Ohio's agreement to implement a CBP process to fulfill its obligation to provide market based default service under the statutory scheme of R.C. Chapter 4928. With respect to Staff's position regarding the non-quantifiable benefits of the DIR and ESRR, IEU-Ohio responds that the same benefits can be realized under an MRO and, in any event, AEP Ohio failed to provide evidence showing that distribution investment will improve customer satisfaction or service quality. (OCC Ex. 13 at 15-30; IEU-Ohio Ex. 1B at 18-27, Ex. KMM-5; Tr. II at 603, 606, 611-613; OCC Br. at 6-26; IEU-Ohio Br. at 51-67; OMAEG Br. at 21-26; OCC Reply Br. at 42-50; IEU-Ohio Reply Br. at 30-38; OMAEG Reply Br. at 25-29.)

AEP Ohio responds that the intervenors' concerns are without merit. With respect to the residential distribution credit, AEP Ohio emphasizes that the credit is set to expire as of May 31, 2015, and there is no requirement that the Company provide the credit after that date, either as part of an ESP or as part of a future distribution rate case. AEP Ohio points out that OCC witness Kahal conceded that residential customers' rates would increase by $14,688,000 per year beginning on June 1, 2015, in the absence of the Company's proposal to extend the credit. In terms of the capacity deferrals, AEP Ohio responds that recovery of the deferrals through the RSR is not a provision of ESP 3, because recovery was authorized by the Commission in the *ESP 2 Case*, and, therefore, it is not appropriate to consider the deferrals in the MRO/ESP analysis. Regarding the $240 million cost of the DIR, ESRR, and SSWR combined, AEP Ohio contends that the revenue requirements associated with the recovery of incremental distribution investments are considered to be the same whether recovered through a provision included in an ESP or through a distribution rate case conducted in conjunction with an MRO and, therefore, such investments are not considered in the quantitative MRO/ESP analysis. Addressing the PPA rider, AEP Ohio maintains that OCC and IEU-Ohio fail to recognize the rate stability and hedging benefits of the rider and, in any event, the Company projects an $8.4 million credit over the ESP term. In terms of the POR program, AEP Ohio responds that the program would provide substantial qualitative benefits, which would not otherwise be available under an MRO. Finally, with respect to the transition to fully market based rates, AEP Ohio argues that the proposed ESP continues to facilitate the Company's accelerated transition to competition and should be recognized as a qualitative benefit, since that progress would be much more uncertain under an MRO. In making its arguments regarding the various qualitative benefits of the proposed ESP, AEP Ohio points out that R.C. 4928.143(C)(1) does not preclude the Commission from considering the significant non-quantifiable benefits of an ESP, which, according to the Company, is consistent with the Commission's own interpretation of the statutory test in prior cases. (Co. Ex. 33 at 10; Tr. IX at 2129-2130; Tr. XIII at 3251-3252; Co. Br. at 143-146; Co. Reply Br. at 114-130.)

Pursuant to R.C. 4928.143(C)(1), the Commission must determine whether the proposed ESP, as modified, 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 R.C. 4928.142. The Supreme Court of Ohio has determined that R.C. 4928.143(C)(1) does not bind the Commission to a strict price comparison, but rather instructs the Commission to consider pricing as well as all other terms and conditions. *In re Columbus S. Power Co.*, 128 Ohio St.3d 402, 2011-Ohio-958, 945 N.E.2d 501. Therefore, we must ensure that the modified ESP as a total package is considered, including both a quantitative and qualitative analysis. Upon consideration of the modified ESP, in its entirety, we find that the ESP is, in fact, more favorable in the aggregate than the expected results under R.C. 4928.142.

Initially, the Commission finds that the modified ESP is more favorable quantitatively than an MRO. Under the ESP, the rates to be charged customers will be established through a fully auction based process and, therefore, will be equivalent to the results that would be obtained under R.C. 4928.142. However, as part of its proposed ESP, AEP Ohio has made a commitment to continue, throughout the ESP term, the RDCR, which would otherwise expire as of May 31, 2015, and which would not be available under an MRO. The record reflects that the residential distribution credit will provide a quantifiable benefit in the amount of $44,064,000 over the three-year term of the ESP. Further, in light of our rejection of AEP Ohio's proposed NCCR and SSWR, and the fact that the PPA rider and BDR have been set at zero, it is not necessary to attempt to quantify the impact of any of these riders in the MRO/ESP analysis. Finally, regarding the DIR, ESRR, and other approved distribution-related riders, we agree with AEP Ohio that the revenue requirements associated with the recovery of incremental distribution investments should be considered to be the same whether recovered through the ESP or through a distribution rate case conducted in conjunction with an MRO. Accordingly, we do not consider such investments in our quantitative MRO/ESP analysis. We further agree with AEP Ohio that it is not necessary to consider the Company's recovery of the capacity deferrals through the RSR, which were authorized by the Commission in the *ESP 2 Case* and are, therefore, not a provision of ESP 3. In sum, the Commission finds that, quantitatively, the modified ESP is better in the aggregate than an MRO by $44,064,000. (Co. Ex. 7 at 4; Staff Ex. 15 at 3-5.)

The evidence in the record reflects that there are additional benefits that make the ESP, as modified by the Commission, more favorable in the aggregate than the expected results under R.C. 4928.142. The Commission notes that many of the provisions of the modified ESP advance the state policy enumerated in R.C. 4928.02, as discussed above. The modified ESP also continues to enable AEP Ohio to move more quickly to market rate pricing than would be expected under an MRO. In fact, under ESP 3, AEP Ohio will implement fully market based prices beginning on June 1, 2015. The Commission continues to believe that the more rapid implementation of market based rates possible under an ESP is a qualitative benefit that is consistent with R.C. 4928.02. (Co. Ex. 7 at 4-5; Staff Ex. 15 at 4.) Additionally, although AEP Ohio has not committed to refrain from filing a distribution rate case application during the ESP period, the Commission's approval of the continuation of the DIR, ESRR, and other distribution-related riders should enable the Company to hold base distribution rates constant over the ESP period, while making significant investments in distribution infrastructure and improving service reliability (Co. Ex. 7 at 4; Tr. II at 611-613).

IV. CONCLUSION

Upon consideration of the ESP application filed by AEP Ohio, the Commission finds that the ESP, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, as modified by this Opinion and Order, is more favorable in the aggregate as compared to the expected results that would otherwise apply under R.C. 4928.142. Therefore, the Commission finds that the proposed ESP should be approved, with the modifications set forth in this Opinion and Order. As modified herein, the ESP provides rate stability for customers and revenue certainty for AEP Ohio. To the extent that intervenors have proposed modifications to AEP Ohio's ESP that have not been addressed by this Opinion and Order, the Commission concludes that the requests for such modifications should be denied.

AEP Ohio is directed to file revised tariffs consistent with this Opinion and Order, to be effective with the first billing cycle in June 2015.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) AEP Ohio is a public utility as defined in R.C. 4905.02 and an electric utility as defined in R.C. 4928.01(A)(11), and, as such, is subject to the jurisdiction of this Commission.

(2) On December 20, 2013, AEP Ohio filed an application for an SSO pursuant to R.C. 4928.141. The application is for an ESP in accordance with R.C. 4928.143.

(3) On January 8, 2014, a technical conference was held regarding AEP Ohio's ESP application.

(4) Notice was published and local public hearings were held in Columbus, Lima, Canton, and Marietta, at which a total of 11 witnesses offered testimony.

(5) The following parties were granted intervention in these proceedings: IEU-Ohio, OCC, OEG, Dominion, Duke, OHA, DERS, DECAM, IGS, OMAEG, FES, OPAE, Kroger, DP&L, EDF, OEC, Direct Energy, APJN, RESA, Constellation, ELPC, Walmart, NRDC, Border Energy, EnerNOC, Paulding II, and EPO. Border Energy filed a notice of withdrawal from these proceedings on October 3, 2014.

(6) A procedural conference regarding the ESP application was held on May 27, 2014.

(7) The evidentiary hearing on the ESP application commenced on June 3, 2014, and concluded on June 30, 2014.

(8) Briefs and reply briefs were filed on July 23, 2014, and August 15, 2014, respectively.

(9) An oral argument was held before the Commission on December 17, 2014.

(10) The proposed ESP, as modified pursuant to this Opinion and Order, 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 R.C. 4928.142.

ORDER:

It is, therefore,

ORDERED, That the motions for protective order filed by AEP Ohio, OCC, and IEU-Ohio be granted for 24 months from the date of this Opinion and Order. It is, further, ORDERED, That AEP Ohio shall file proposed final tariffs consistent with this Opinion and Order, subject to review and approval by the Commission. It is, further,

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

THE PUBLIC UTILITIES COMMISSION OF OHIO

Thomas W. Johnson, Chairman

Steven D. Lesser

Lynn Slaby

M. Beth Trombold

Asim Z. Haque

SJP/GNS/sc

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Secretary

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company to Initiate Phase 2 of its gridSMART Project and to Establish the gridSMART Phase 2 Rider	)))))	**Case No. 13-1939-EL-RDR**

APPLICATION

1. Ohio Power Company[1] ("AEP Ohio" or the "Company") is an electric light company as that term is defined in §§4905.03 and 4928.01 (A) (7), Ohio Rev. Code. and, as such, is subject to the jurisdiction of the Public Utilities Commission of Ohio ("Commission").

2. In AEP Ohio's first electric security plan proceeding, the Company proposed and was granted approval for gridSMART Phase 1, a smart grid deployment project within AEP Ohio's service territory. In its order in that proceeding, the Commission authorized AEP Ohio to establish the gridSMART Rider, subject to annual true-up and reconciliation. *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, *et al.*, Opinion and Order, at 37-38 (March 18, 2009) ("ESP I Order"). In the ESP I Order, the Commission noted the benefits of the gridSMART project:

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[1] By Order issued on March 7, 2012 in Case No. 10-2376-EL-UNC, the merger of Columbus Southern Power Company with and into Ohio Power Company was approved effective December 31, 2011. Accordingly, references herein to Ohio Power Company or AEP Ohio, the surviving entity after the merger, include the predecessor interests of Columbus Southern Power Company.

> [I]t is important that steps be taken by the electric utilities to explore and implement technologies...that will potentially provide long-term benefits to customers and the electric utility. GridSMART Phase 1 will provide CSP with beneficial information as to implementation, equipment preferences, customer expectations, and customer education requirements.... More reliable service is clearly beneficial to CSP's customers. The Commission strongly supports the implementation of AMI and DA, with HAN, as we believe these advanced technologies are the foundation for AEP-Ohio providing its customers the ability to better manage their energy usage and reduce their energy costs.

Id. at 34-35.

3. In its order in AEP Ohio's second electric security plan proceeding, the Commission reaffirmed its conviction as to the benefits of the gridSMART project and directed the Company to continue gridSMART Phase 1 and to initiate Phase 2 of the gridSMART project. *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 No. 11-346-EL-SSO, *et al.*, Opinion and Order, at 62-63 (August 8, 2012) ("ESP II Order") ("The Company shall file its proposed expansion of the gridSMART project, gridSMART Phase 2, as part of a new gridSMART application. . . .").

4. Through this application, AEP Ohio presents its proposed expansion of the gridSMART project – gridSMART Phase 2 – and seeks to establish the gridSMART Phase 2 Rider as the mechanism for recovering any gridSMART project investment beyond Phase 1, as contemplated by the Commission in the ESP II Order.

5. Phase 2 will build upon AEP Ohio's successful gridSMART Phase 1 experience. Phase 2 will be comprised of Advanced Metering Infrastructure ("AMI") for

approximately 894,000 customers across urban and suburban areas of the Company's service territory; Distribution Automation Circuit Reconfiguration ("DACR") for approximately 250 priority circuits; and Volt/VAR Optimization ("VVO") for approximately 80 circuits. Attachment A provides additional detail on the equipment and technology proposed as part of Phase 2 and discusses the demonstrated success, cost-effectiveness, feasibility, and customer acceptance of the proposed technology.

6. AEP Ohio proposes that the gridSMART Phase 2 Rider become effective on January 1, 2014 and operate similarly to the Company's current gridSMART Rider. On an annual basis, the Company would make a filing with the Commission to true-up and reconcile the actual costs of investments placed in-service and the revenues collected under the rider during the prior period. A projection of the revenue requirement for the gridSMART Phase 2 project over the next five years is set forth in Attachment B.

7. In its order in the Company's most recent gridSMART Rider proceeding, the Commission authorized the Company to recover, with certain adjustments, the loss associated with the disposition of electro-mechanical meters replaced as a result of AMI equipment installation. *In the Matter of the Application of Ohio Power Company to Update Its gridSMART Rider*, Case No. 12-509-EL-RDR, Finding and Order, at 3-6 (October 3, 2012). The Company has included as a program expense in the gridSMART Phase 2 Rider the net book value of the electro-mechanical meters to be replaced as a part of the gridSMART Phase 2 project. The Company proposes to expense the loss as it occurs and to recover the loss over five years.

8. In its order in AEP Ohio's 2010 long-term forecast proceeding, the Commission noted that the Company remains obligated to invest $20 million in a project

benefitting the Company's ratepayers. *In the Matter of the Long-Term Forecast Report of Ohio Power Company and Related Matters*, Case No. 10-501-EL-FOR, *et al.*, Opinion and Order, at 27-28 (January 9, 2013). AEP Ohio proposes to satisfy this outstanding obligation by investing $20 million in VVO technology as part of the gridSMART Phase 2 project. The Company is willing to expand the investment in VVO technologies to up to $40 million if appropriate for energy efficiency benchmark compliance. VVO technology provides a direct benefit to AEP Ohio's customers: it enables a reduction of the average voltage that each customer on a circuit receives, thereby reducing customers' annual energy consumption. Although the Commission has indicated that investment in Volt/VAR technologies should be included only within the Company's distribution investment rider ("DIR"), the Commission has also recognized that such technology "enhances or is necessary for grid smart technology to operate properly and efficiently." ESP II Order at 62. Because VVO technology plays an important, if not essential, role in the Company's gridSMART program, it is logical and appropriate to recover VVO investment through the gridSMART Phase 2 Rider.

9. Attachment C provides additional detail on the expected benefits of the gridSMART Phase 2 project and discusses how AEP Ohio proposes to verify those benefits.

10. As reflected in Attachment A, the Company proposes an average monthly rate cap for rate impact purposes during the first five years of the gridSMART Phase 2 Rider. Any costs incurred above the amount associated with a given year's cap would still be available for recovery in a subsequent period.

11. Because the authority to make this filing results from the Commission's ESP II Order, and because the application and attachments include sufficient detail on the equipment and technology proposed as part of the gridSMART Phase 2 project and discuss the demonstrated success, cost-effectiveness, feasibility, and customer acceptance of the proposed technology, AEP Ohio does not believe a hearing in this matter is required or needed. Instead, the Company requests the Commission establish an opportunity for the filing of comments and reply comments similar to the method currently in place for the Company's gridSMART Rider.

12. The proposed expansion of the gridSMART project will build upon AEP Ohio's successful gridSMART Phase 1 experience and deliver the benefits of the gridSMART project to a broader and more diverse customer base. The proposals in this application are just and reasonable and were contemplated by the Commission as part of the Company's ESP. Therefore, AEP Ohio respectfully requests that the Commission approve this application for the initiation of Phase 2 of the gridSMART project and the establishment of the gridSMART Phase 2 Rider, effective January 1, 2014.

Respectfully submitted,

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gridSMART® Phase 2 Business Case

Introduction

American Electric Power ("AEP") has been actively engaged in planning, deploying, and evaluating smart grid technologies and programs across the 11-state AEP System since 2007. AEP's gridSMART® initiative integrates a suite of advanced grid technologies into the existing electric network that can improve service quality and reliability, lower energy consumption, and save money. The new technologies can help AEP improve efficiencies, identify and respond to outages more quickly, and better monitor and control the operation of the distribution grid.

AEP Ohio's ("Ohio Power Company" or the "Company") gridSMART® Phase 1 project was designed to evaluate a broad scope of potential smart grid technologies on a smaller scale in order to guide subsequent deployment plans. AEP Ohio has not only gained valuable experience in the performance of these technologies, but also in the operation of communication interfaces and how to optimize the processes to deliver on the benefits envisioned. This experience prepares AEP Ohio for a more efficient and effective implementation as it deploys select technology and process improvements to the broader scale and more diverse customer base proposed in Phase 2.

The following benefits have been achieved as a result of AEP Ohio's Phase 1 in the deployment area:

1. Improved safety for AEP Ohio employees
2. Operational efficiencies through real-time information and remote operations
3. Fewer number of customer outage events
4. Reduced number of customers experiencing sustained (>5 minutes) outages
5. Faster restoration times for sustained outages (>5 minutes)
6. Demand reduction through new tariff offerings and the education of customers regarding energy costs and use of technology
7. Improved energy efficiency and demand reduction with Volt/VAR Optimization ("VVO")
8. Improved customer satisfaction
9. Improved access to meter reading data

As we reflect on the successes of our gridSMART Demonstration Project, we have analyzed what others in our industry have already achieved with their Smart Grid deployments, recognizing that many others are extending these Smart Grid benefits to their customers at a much faster pace and have dramatically increased customer satisfaction. In numerous cases, large Electric Utility companies have deployed Smart Grid modernizations to their entire customer base. AEP Ohio believes that a gridSMART expansion enables a fundamental change in the way we operate, serving as the necessary foundation upon which we will provide more reliable service and greater efficiency opportunities for our customers in the future. Going forward, it is the intent of AEP Ohio to continue to extend elements of the gridSMART® program throughout the AEP Ohio service territory, starting with the proposed Phase 2 project as further defined through this submittal.

gridSMART® Phase 2 will build upon AEP Ohio's successful gridSMART® Phase 1 experience. The project will be comprised of Advanced Metering Infrastructure ("AMI") for approximately 894,000 customers across urban and suburban areas; Distribution Automation Circuit Reconfiguration ("DACR") for approximately 250 priority circuits; and Volt/VAR Optimization ("VVO") for approximately 80 circuits. AEP Ohio is targeting a deployment timeline of approximately four years for all three technologies as proposed. In addition to extending the benefits of AMI, DACR, and VVO achieved in Phase 1 to a larger base of customers, it is envisioned that Phase 2 also will provide the following benefits:

1. Support for a more robust customer choice market by enabling customer access to information, improved data for market settlement, and potential for time-differentiated rate design offerings.
2. Reduced uncollectible revenue, theft and consumption on inactive meters through automated remote disconnect and continuous usage data availability.
3. Enhanced customer service and satisfaction (e.g., through faster, remote service connection).
4. Better information to customers concerning their electricity usage, enabling them to conserve energy, save money, and help to protect the environment.

gridSMART® Phase 2 is built upon proven technologies and solutions that have been implemented in gridSMART® Phase 1 and broadly deployed in the market. This document describes the benefits, costs, and rate impacts for gridSMART® Phase 2 as well as examples of benefits achieved by other utilities who have deployed AMI, VVO, and Distribution Automation ("DA") reliability solutions similar to DACR, plus examples of customer acceptance of utility smart grid programs.

AEP Ohio gridSMART® Roadmap

As technology advances, the electric utility industry has the opportunity to enhance the way it does business to provide both customer and utility benefits. AEP Ohio's gridSMART® strategy takes advantage of these technology advancements. It is the Company's vision that these technology improvements will yield customer satisfaction layered upon a foundation of utility efficiencies.

The Company has approximately 1,533,000 meters installed throughout its service territory. Of this total, AEP Ohio has converted approximately 132,000 meters to AMI. The converted meters are providing the expected benefits. The current AMI technology is proven for urban deployment areas, typically with meters in relatively close proximity to one another.

This proposal for Phase 2 includes the next step for AMI deployment. In Phase 2, the Company expects to convert an additional 894,000 meters to AMI bringing the total to just over one million AMI meters. AEP Ohio has 200,000 customers with automated meter reading, not associated with this proposal, and an additional 302,000 customers for which an advanced metering plan is still under review. The Company will continue to carefully evaluate meter and networking technologies to determine how best to serve these customers in the most cost-effective manner possible while delivering maximum benefits. If the AMI technology continues to advance and a rural AMI solution becomes more cost effective, the Company may reevaluate the plan regarding rural meter technology. Overall, the Company envisions all meters to be replaced with an advanced meter technology over the next 4-6 years.

Of the approximate 1,600 total distribution circuits within AEP Ohio, the Company has deployed DACR on 70 circuits in Phase 1. These circuits are providing the expected benefits. When a fault occurs, DACR automatically reconfigures the associated circuits to restore power to customers in non-faulted zones on a circuit. Circuits that have a physical connection to other circuit(s) or are adjacent to other circuits are candidates for deployment where reliability could be enhanced through the installation of the DACR technology. Each DACR installation provides added reliability and operational enhancements. Currently, the Company has targeted approximately 450 circuits with these physical characteristics that should yield solid reliability benefits through the deployment of DACR. Phase 2 proposes installing this technology on approximately 250 distribution circuits that result in the greatest reliability or operational benefits. The remaining circuits could be proposed to be deployed under a gridSMART® Phase 3 at a later date or under the Distribution Investment Rider, if approved by the Commission.

The Company has also deployed VVO on 17 distribution feeders at five substation feeders as part of Phase 1. The formal evaluation of these circuits indicated the technology provided the expected results. The VVO technology the Company intends to deploy takes advantage of Conservation Voltage Reduction ("CVR") in addition to Volt-Amp Reactive ("VAR") or reactive power optimization. This combination improves the overall efficiency of the circuit as the majority of the electrical loads on a distribution system will consume less energy as the voltage is reduced. Currently, the Company has targeted approximately 80 circuits for VVO deployment as part of Phase 2. The targeted circuits are expected to yield significant benefits. Additional circuits that are considered good candidates for VVO could then be proposed for deployment under a Phase 3 plan at a later date or under the Distribution Investment Rider, if approved by the Commission or under the Energy Efficiency ("EE") program if needed to meet required objectives.

Benefits

DACR Benefits

Reliability

AEP Ohio's gridSMART® Phase 2 DACR is designed to improve outage identification and restoration times, and to enhance storm hardening with enhanced visibility in the areas where the systems are deployed.

In Phase 1, through the deployment of DACR on 70 circuits, AEP Ohio was able to reduce Customer Minutes of Interruption ("CMI") by 1,861,441 minutes, improving reliability for 22,427 customers in 2012. While weather conditions are the primary driver for changes in SAIFI and CAIDI, AEP Ohio can attribute some improvements of these indices from the DACR deployment. In 2012, all customers on the 70 DACR circuits experienced a SAIFI of 1.228 as compared to 1.429 without DACR deployed on the same 70 circuits – an improvement of 14.1 percent. Similarly, all customers on the 70 DACR circuits experienced a SAIDI of 161.5 as compared to 178.3 without DACR deployed on the same 70 circuits – an improvement of 9.4 percent. Importantly, these results were realized prior to more recent efforts to optimize the system with initial 2013 results significantly more favorable than those experienced in 2012.

Phase 2 will deploy DACR technology on approximately 250 circuits that have the characteristics of being best positioned to yield reliability improvements. This deployment is targeted to reduce CMI by up to 30 percent over the 3-year average for the deployed circuits, which is approximately the midpoint of the achieved CMI reductions reported by the US Department of Energy ("DOE") in December 2012 for utilities that had prior experience with automated feeder switching. This could yield more than 21 million CMI per year on circuits serving more than 330,000 customers in the project areas.

In addition to the reliability benefits described above, the systems also enable crew labor savings, up to 2 hours per event, and in some instances avoid service calls entirely. Both of these situations provide opportunities for AEP Ohio to perform additional proactive work on circuits in need of service, further enhancing reliability.

Economic Output

Improved system reliability has significant impact on economic output too. Based on the "Cost of Power Interruptions to Electricity Consumers in the United States, Ernest Orlando Lawrence Berkeley National Laboratory" (2006), AEP Ohio estimates that DACR could reduce societal costs by approximately $71 million per year through the reduction of outages experienced by customers.

AMI Benefits

AMI Financial Benefits

gridSMART® Phase 1 has demonstrated several operational benefits. For instance, by installing AMI meters, AEP Ohio was able to eliminate 100 percent of the meter reading routes (187 routes) in the area where AMI was deployed. AMI also enabled AEP Ohio to reduce costs associated with meter operations activities. For example, through the use of remote service switch capabilities that enable secure connection and disconnection of electric service to customer premises from the utility back office, AEP Ohio was able to reduce field visits associated with standard move in/move out orders. The combined meter reading and meter operations savings totaled approximately $860,000 ($6.50 per meter per year).

For Phase 2, the per-meter savings are projected to be higher because meters are less geographically concentrated in Phase 2 than in Phase 1, and Phase 2 projections include labor inflation. These efficiencies are projected to ramp to approximately $6-$7 million in annual utility benefits.

Category	Phase 1 result	Phase 2 projection
AMI Meters	132,000	894,000
Meter Reading and Meter Operations Savings (annual)	$860,000 ($6.50/meter)	$6,000,000-$7,000,000 ($6.71-7.83/meter)

Credit, collections and revenue enhancements through earlier theft detection, lower consumption on inactive meters and greater billing accuracy are projected to lead to an additional $8-$10 million in annual utility benefits. Of that benefit, $1.5-$2 million annually is operational savings from use of the remote service switch specifically for credit disconnects. It is important to note that the benefits associated with automated credit disconnects require a PUCO waiver for the current process that requires on-site customer interaction. The PUCO would need to consider whether and how the rules would be adjusted to allow for credit disconnects, considering all stakeholder options.

AMI Additional Benefits

AMI offers a host of important benefits that have not been monetarily quantified in the business case, such as:

1. Improved data for billing
2. Better customer service and satisfaction
3. Reduced outages
4. Improved crew and meter reader safety
5. Reduced environmental impact

With automated meter reads, AMI nearly eliminates estimated bills, leading to greater billing accuracy. AMI has been proven to yield a typical monthly read rate of 99.9 percent as compared to the AEP Ohio average of 96.9 percent across its entire system. With automated meter reads and a higher read rate, AMI helps to nearly eliminate estimated monthly consumer electricity usage, leading to greater billing accuracy and improved customer satisfaction.

AMI leads to better service and customer satisfaction. For instance, when a customer wishes to terminate service, the AMI meter can be read remotely and a final bill sent without delays caused by manual reads. Similarly, AMI meters equipped with a remote service switch enable power to be turned on or off remotely. As a result, a customer moving in can have service turned on in minutes, rather than waiting days.

AMI also provides the customer with the ability to view their energy consumption on a more granular level; typically multiple data points per day will be provided. This data can be useful for a customer providing better understanding of their consumption behavior. The availability of this data can also enable customers to participate in programs such as enhanced demand response ("DR") or time-differentiated pricing tariffs that might be offered by DR or CRES providers. AEP Ohio envisions that DR or CRES providers will take the lead role in these enhanced customer program offerings. As the auction market develops, AEP Ohio will evaluate filing for a supplemental simple time-differential Standard Service Offering (SSO) rate option. Such programs are designed to reduce peak demand, thereby allowing customers to benefit through savings. Additionally, Home Area Network ("HAN") devices can be used by the customer to better utilize the data and pricing signals to control their consumption activity. The proposed AEP Ohio gridSMART® Phase 2 will deploy AMI meters with communication modules to enable in-home communication from the meter. AEP Ohio views its role as a provider of the metering infrastructure that enables the offering of these programs by market participants.

Customer programs like the gridSMART® Phase 1 SMART Shift, two-tier time-of-day tariff could provide significant net benefit to customers. If DR or CRES providers offered similar programs to Phase 2 AMI customers, the estimated net customer benefits, assuming 5 percent penetration and 10 percent peak load reduction across all AEP Ohio customers, could be approximately $4 to $6 million in annual customer savings.

In addition to the benefits previously described, AMI provides billing and call center efficiencies that will enable staff to address more inquiries and to do so faster. Customers should experience fewer billing issues from continual meter reads and the elimination of estimated meter reads through AMI, and call center representatives will have real-time access to meter data which will help them discuss actual usage information with customers. When a customer calls about power loss, the real-time access also will enable call center representatives to determine whether the power loss is due to an outage or to an issue on the customer side of the meter, such as a blown house breaker fuse.

From a reliability perspective, when an AMI meter detects a loss of voltage, a message is sent indicating the customer has lost power. Messages that successfully reach AEP Ohio's internal systems can be used in conjunction with customer telephone calls to predict the extent of the outage. Also, meters can be queried (pinged/polled) to get an indication of whether a customer has power. This indication can be useful to troubleshoot customer issues and to verify restoration following an outage.

From a safety perspective, because crews can remotely determine whether a meter has power, crew exposure and safety is improved. Also, due to AMI, fewer meter readers will be required in the field, which will reduce physical meter reading efforts and, thus, will reduce safety issues. AEP Ohio estimates that incidents and severity days associated with meter reading will be reduced by 72 percent relative to the past two years' performance.

With remote capabilities, the number of miles driven by metering and service personnel will be reduced by an estimated 440,380 miles annually. In addition, there are some environmental benefits associated with reduced vehicle emissions as a result of reduced vehicle miles traveled with 186,556 metric tons of CO_2 avoided annually. These estimates are based on reductions experienced during AEP Ohio's gridSMART® Phase 1.

The above benefits from customer programs, billing and call center efficiencies, reduced personal injuries, and other operational savings together could represent an estimated $39 million in incremental net present value.

VVO Benefits

Efficiency Benefits

AEP Ohio's gridSMART® Phase 2 VVO is designed to realize a reduction in energy consumption where deployed, and a reduction in peak demand on circuits where VVO is deployed.

Voltage standards exist in the electric utility industry, such as ANSI C84.1, that mandate an acceptable voltage range at the secondary of the distribution transformer. VVO enables a reduction of the average voltage that each customer on the circuit receives, thereby reducing the annual energy consumption of the feeder while maintaining the quality of service to the end-use customer. Based on results obtained through field demonstrations, AEP Ohio estimates that a 3 percent reduction in energy consumption and a 2 to 3 percent reduction in peak demand can be obtained on those circuits on which the technology is deployed.

Other Benefits

Along with the expected efficiency benefits, the technology associated with VVO also provides VAR support, offsetting the need for Generation and Transmission resources to provide VARs. VVO also promotes a "self-healing" grid by maintaining acceptable voltages after a "self-healing" event has occurred. The technology required for VVO will also augment other technologies to improve visibility into system performance and circuit automation.

Costs

DACR Costs

DACR costs are primarily capital costs from equipment and installation, and an O&M component associated with operating and maintaining this equipment. As for DACR, AEP Ohio requested its existing vendors to provide an estimate of updated costs to help in evaluating the cost effectiveness of potential future deployments. The costs included in this business case are current and will be updated annually as actuals are incurred For Phase 2, AEP Ohio is estimating $427,000 in total capital cost per deployed DACR circuit through the life of the technology. This cost represents an increase of approximately $37,500 per circuit relative to Phase 1, due to adding functionality in order to improve load transferability. Operating and Maintenance expense is estimated at 3% of the total capital investment through the life of the technology.

AMI Costs

To generate an accurate estimate of AMI costs, AEP Ohio asked its existing vendors of key system elements to provide an estimate of updated costs to help in initially evaluating the cost effectiveness of potential future deployments. The costs included in this business case are current and will be updated annually as actuals are incurred.

AMI costs will be driven largely by capital expenditures for meters, meter communications equipment, and labor for meter installation. Ongoing operating costs, primarily consists of incremental back office staff to operate the systems. In direct dollar terms, the Phase 1 average cost per meter installed (a combined average for single phase and poly-phase including all related project expenses including associated communication infrastructure) for AMI was $210. For Phase 2, AEP Ohio is estimating $180 per installed meter, a reduction of approximately 17 percent.

In addition, the existing meters to be replaced will have a net book value ("NBV") of approximately $72 million. As part of this filing, AEP Ohio seeks to recover the NBV costs, as they are incurred, as a Phase 2 program expense over the term of the rider.

VVO Costs

VVO costs are primarily capital costs from equipment and installation, and an O&M component associated with operating and maintaining this equipment. For Phase 2, AEP Ohio is estimating approximately $250,000 in total capital cost per deployed VVO circuit through the life of the technology. Operating and Maintenance expense is estimated at 3% of the total capital investment through the life of the technology.

Along with the capital and O&M cost associated with the VVO technology deployment, this type of energy efficiency technology also provides significant customer energy and bill savings benefits. Even though the technology is installed on the distribution system, VVO is an energy efficiency program that directly reduces demand and energy for AEP Ohio customers. Like more traditional energy efficiency programs, VVO should qualify for recovery of all distribution lost revenues and shared savings, and the VVO energy efficiency savings should count towards AEP Ohio's energy efficiency targets. AEP Ohio anticipates the approval for recovery in AEP Ohio's 2015-2017 Energy Efficiency filing. The lost distribution revenue should be recovered for all customer rate classes not currently covered in the pilot decoupling adjustment mechanism and shared savings should be approved in the same manner as other measurable programs in the current and future approved energy efficiency plans.

In Case No. 10-501-EL-FOR, the Commission denied the Company's request to determine there is a need for the Turning Point Solar Project. As part of that order, the Commission reiterated that the Company had committed to spend $20 million on that investment and ordered AEP Ohio to do so by the end of 2013. The Commission directed that the benefits of the $20 million investment flow through to the Company's rate payers. The Company is proposing to invest $20 million in VVO which if approved for this investment, will allow the Company to optimize approximately 80 circuits. AEP Ohio is currently evaluating it future needs associated with meeting its Energy Efficiency (EE) legislative mandates and may request up to another 80 VVO circuits as a separate filing if needed to meet these EE targets.

In Case No. 11-346-EL-SSO, the Commission determined that VVO was not necessarily a part of gridSMART® as it could be installed without the presence of gridSMART® technologies but recognized that it enhances or is necessary for gridSMART® technology to operate properly and efficiently (Case No. 11-346-EL-RDR Opinion and Order at 62). The Company proposes to install $20 million of VVO as part of the gridSMART® Phase 2 rider filing. VVO benefits the customers by reducing usage up to 3 percent as determined through the gridSMART® Phase 1 pilot. This benefit will be realized by customers by reducing usage and as such reducing the charges to be realized in the future.

Rate Impacts

The table below reflects the first five years of customer impact assuming the same mechanics of the Phase 1 rider with the exception of changing the recovery of investments from an "as spent" to an "in service" basis as the Commission directed in its August 8, 2012 Opinion and Order in Case No. 11-346-EL-SSO (page 63). The table also reflects, fully loaded costs, and 7-year depreciation for AMI and 30-year depreciation for DACR and VVO.

Average Monthly Rate Impact $		
	Residential	Non-Residential
Year 1	0.42	1.74
Year 2	1.75	7.19
Year 3	2.34	9.64
Year 4	2.75	11.31
Year 5	2.90	11.93
Average	2.03	8.36
Average monthly bill in 2012	127.93	Varies
Average Increase	1.6%	Varies

Based on the average AEP Ohio Residential monthly customer bills for 2012, the average monthly bill increases represent 1.6 percent. Due to such wide varieties in usage and operational characteristics, the non-residential impact will vary for each customer class. Based on the cash flows of the proposed project plan and associated capital deployment, the average monthly Residential rate impacts will not exceed $1.00 in year 1, $2.25 in year 2, $2.75 in year 3, $3.00 in year 4 and $3.25 in year 5. The average monthly non-Residential rate impacts will not exceed $3.50 in year 1, $9.00 in year 2, $10.75 in year 3, $11.50 in year 4 and $13.25 in year 5.

Benefit/Cost Analysis

As described above, Phase 2 involves a variety of benefits and costs. Those have been evaluated over a 15-year period, and the delta between benefits and costs reflects the customer impact. Each metric is shown below with two different views: the Cash View (or nominal view) and the Net Present Value ("NPV") View.

For the comprehensive benefits and costs for the three technologies, the Cash View shows a net of $860 million benefit and benefit-cost ratio of 2.8. The NPV shows a net of $346 million benefit and a benefit-cost ratio of 2.0.

	CASH VIEW		NET PRESENT VALUE VIEW**	
15 Year Benefits	O&M:	$193 million	O&M:	$100 million
	Capital:	$ 1 million	Capital:	$ 1 million
	Energy / Capacity:	$115 million	Energy / Capacity:	$ 59 million
	Reliability:*	$1.016 billion	Reliability:*	$519 million
	TOTAL:	$1.325 billion	**TOTAL:**	$679 million
15 Year Costs	O&M;	$136 million	O&M:	$ 77 million
	Capital:	$329 million	Capital:	$256 million
	TOTAL:	$465 million	**TOTAL:**	$333 million
15 Year Customer Impact	Net Cash Flows:	$860 million	Net Cash Flows:	$346 million
	Benefit/Cost Ratio:	2.8	Benefit / Cost Ratio:	2.0

* Based on the "Cost of Power Interruptions to Electricity Consumers in the United States, Ernest Orlando Lawrence Berkeley National Laboratory" (2006)

* * The Cash View reflects the nominal estimated expenditures and benefits related to the Phase II implementation. The Net Present Value (NPV) is calculated using an After Tax Weighted Average Cost of Capital (WACC) of 7.69%.

Proven Solutions and Technologies

gridSMART® Phase 2 represents a fundamental change in the way AEP Ohio operates and enables new technologies, and is based on proven solutions that have been deployed across the United States.

For example, the Edison Foundation estimates that 36 million Smart Meters already had been installed by May 2012, and several utilities have already completed large-scale AMI deployments such as Florida Power & Light, CenterPoint, Sacramento Municipal Utility District, and Southern Company. AEP's subsidiary AEP Texas is also deploying 1 million AMI meters, with 80 percent currently installed. Many of these and other utilities are achieving tangible benefits. The December 2012 U.S. DOE SGIG Program AMI report ("Operations and Maintenance Savings From Advanced Metering Infrastructure – Initial Results") shows reductions in meter operations costs of 13 to 77 percent and reductions in miles driven, fuel consumed and CO_2 emission of 12 to 59 percent.

AMI has also enabled numerous dynamic pricing programs. For example, Oklahoma Gas & Electric ("OGE") has enrolled approximately 76,000 customers in its AMI-based demand response program, which resulted in a 67 megawatt reduction in peak demand in 2012 and an average $191 savings in energy costs per participating customer.

Reliability applications like DACR are widely deployed and generating benefits as well. For example, the U.S. DOE reported in December, 2012, that approximately 30 utilities that had deployed automated feeder switching. Among the approximately 300 feeders where operators had previous experience with automated feeder switching, CMI was reduced 11 to 56 percent.

VVO is a proven commercial technology with multiple suppliers providing solutions to accomplish similar goals. AEP Ohio proposes to implement a technology similar to the Phase 1 deployment. VVO technology is being deployed at three AEP Ohio affiliates in Indiana, Oklahoma, and Kentucky.

The above examples highlight how technologies like those in the gridSMART® initiative have been broadly proven in the field, reducing the technology risks associated with AEP Ohio achieving its target benefits.

Customer Acceptance

The gridSMART® technologies not only are proven to be technically a success, but also widely accepted by customers. Customers who participated in gridSMART® Phase 1 and participated in AMI-enabled consumer programs rated their overall satisfaction with AEP Ohio seven percent higher than did AEP Ohio customers overall.

A public outreach and education plan will play a key role in the successful implementation of Phase 2. Similar to the successful strategy used in Phase 1, a multipronged communications approach will engage key community thought leaders, customers and other targeted audiences by providing timely and thorough information regarding the overall project, timeline, rollout and benefits of the technologies. An outreach plan that clearly communicates transparency with communities and customers will be developed and used to ensure acceptance, which ultimately will lead to higher customer satisfaction.

Other utilities across the US have reported strong acceptance of Smart Grid technology, such as:

- Sacramento Municipal Utility District ("SMUD") has deployed approximately 600,000 AMI meters and has reported high customer satisfaction. As SMUD reported, "Customer satisfaction drove the project. Throughout, SMUD maintained customer satisfaction levels in the mid-90th percentile. Ongoing surveys measure customer satisfaction with the meters, the installation process and the associated communications. The complaint rate was only 0.09 percent."
- OGE has deployed approximately 780,000 AMI meters and has enrolled over 76,000 participants to its AMI-based dynamic pricing demand response program called SmartHours. 94 percent of customers said they were likely to recommend the program to friends and family.
- Memphis Light Gas and Water ("MLGW") conducted a survey after its AMI pilot with "95 percent saying they would recommend the smart meter experience to a friend."

At a macro level, JD Power and Associates reported higher customer satisfaction with AMI. They found that customer satisfaction among customers with smart meters "averages 667 (on a 1,000-point scale), 43 points higher than among customers whose homes are not equipped with smart meters."

Another successful key to achieving customer acceptance is offering an alternative to the limited number of customers who have concerns with AMI meters. AEP Ohio supports providing the customer an opportunity to "opt-out" of receiving an AMI meter and retaining a standard meter. If a customer opts-out they would incur all expenses associated with manual meter reading so that these costs are not paid for by other customers. AEP Ohio appreciates the PUCO initiative for "opt-out" rulemaking and the Company has provided comments on the initial version of the rule. AEP Ohio will comply the future PUCO ruling related with AMI meter opt-outs.

Security and Privacy

Through the gridSMART Demonstration Project, AEP Ohio implemented innovative advancements in the cyber security arena including an enhanced state of the art Cyber Security Operations Center (CSOC) in partnership with the U.S. Department of Energy and vendors. Providing advanced security checks and balances, this CSOC monitors and identifies vulnerabilities 24/7 to ensure grid security.

Customers can be assured that the safety and security of their information is protected by extensive and dedicated resources. Recognized as an innovator with its industry threat sharing integration functionality, this CSOC continuously gathers and shares threat information with peer utilities and government agencies.

Privacy issues have garnered customer attention, though the Company notes that the issue of customer privacy is not a new concept introduced by the deployment of the smart grid. The Company is supportive of the PUCO's continued efforts to ensure the protection of customer information and commented on consumer privacy in Case No. 11-277-GE-UNC.

The electric utility industry in Ohio has traditionally collected, used, and protected significant amounts of sensitive customer information. For example:

- The nature of information necessary to conduct utility business includes personally identifiable information (PII) such as social security numbers and related credit information.
- Utilities have routinely collected interval metering information for decades for larger commercial and industrial customers as part of administering and billing tariffs that rely on such information and for operating its business.
- Interval metering data on select residential and smaller commercial and industrial customers has been collected and utilized for decades in order to develop and monitor customer load profiles necessary for system resource planning and the proper allocation of costs. This data is not substantially different than that which is collected by newer smart meters.

Therefore the collection, use, and protection of proprietary and confidential data have occurred in some form almost since AEP Ohio's inception. The Company has always fulfilled the obligation to maintain the confidentiality of this information, as well as the trust of their customers, without notable exception.

The current legislative and regulatory rules provides for protection of customer data privacy, regardless of how that information is gathered by the utility. AEP Ohio treats customer consumption data collected through the smart grid with the same high level of protection required by these legislative and regulatory expectations.

The proposed Phase 2 deployment will continue these efforts and strive to improve security and privacy customer protection. We will utilize dedicated security and privacy experts to review the technology and equipment to ensure strict standards are met. We will place emphasis on building security and privacy into the deployment as well as creating a system to evaluate that these standards remain as the technologies go into service.

Conclusion

AEP Ohio's gridSMART® Phase 2 project, based on proven and accepted technology solutions, will extend the benefits demonstrated in Phase 1 and deliver additional benefits to a broader set of customers. Through Phase 2 AMI, the Company expects to drive significant financial benefits through AMI and enable a variety of additional benefits that positively impact customer service such as customer satisfaction; meter field personnel safety; regional economic output and reduced environmental impacts. It also will help enable DR and CRES providers to offer valuable customer programs. Phase 2 DACR is expected to improve CMI where the system is deployed, which will help avoid millions of dollars of potential lost economic productivity annually. Phase 2 VVO is expected to generate significant efficiencies that translate to customer savings. Overall, the rate impact on customers is expected to be low, just 1.6 percent on average.

Attachment B
YEAR 1

gridSMART Phase 2

CSP - gridSMART Incremental Investment	Estimated gridSMART Spending	Annual Carrying Charge		gridSMART Revenue Requirement	
O&M (AMI, VVO, DACR)	$ 6,648,975			$ 6,648,975	
Capital - 7 Year Life- AMI		$ 3,033,097		$ 3,033,097	(a)
Capital - 30 Year Life - VVO		$ 172,960		$ 172,960	(b)
Capital - 30 Year Life - DACR		$ 558,729		$ 558,729	(b)
		Total		$ 10,240,801	
		Tax Gross Up Rate		100.859%	
		Revenue Requirement		$ 10,328,781	
		Loss on Removal of meters		$ -	
		Total Revenue Requirement		$ 10,328,781.1	
Residential Base Distribution	$ 406,542,657.87	Residential Revenue Requirement		$ 6,448,907	
Non-Res Base Distribution	$ 244,589,408.48	Non-Res Revenue Requirement		$ 3,879,874	
		Residential Customers	1,273,961	5.06	
		Non-Residential Customers	186,129	20.85	
		Residential Customers	Monthly Rate	$ 0.42	
		Non-Residential Customers	Monthly Rate	$ 1.74	

(a) AMI Assets (account 370.16) are Capitalized on Purchase and have 7 year life.
(b) VVO & DA Assets (account 362-station equipment) are capitalized after 6 months and have 30 year life.

Notes:
ROR from Renee Hawkins Rate of Return Summary Modified ESP Case 11-346-EL-SSO

Attachment B
YEAR 2

gridSMART Phase 2

CSP - gridSMART Incremental Investment	Estimated gridSMART Spending		Annual Carrying Charge	gridSMART Revenue Requirement
O&M (AMI, VVO, DACR)	$ 7,496,589			$ 7,496,589
Capital - 7 Year Life- AMI			$ 13,684,537	$ 13,684,537
Capital - 30 Year Life - VVO			$ 1,722,817	$ 1,722,817
Capital - 30 Year Life - DACR			$ 5,085,669	$ 5,085,669
		Total		$ 27,989,612
		Tax Gross Up Rate		100.859%
		Revenue Requirement		$ 28,230,074
		Loss on Removal of meters		$ 14,539,444
		Total Revenue Requirement		$ 42,769,518.4
Residential Base Distribution	$ 406,542,657.87	Residential Revenue Requirement		$ 26,703,697
Non-Res Base Distribution	$ 244,589,408.48	Non-Res Revenue Requirement		$ 16,065,821
		Residential Customers	1,273,961	20.96
		Non-Residential Customers	186,129	86.32
		Residential Customers	Monthly Rate	$ 1.75
		Non-Residential Customers	Monthly Rate	$ 7.19

(a) AMI Assets (account 370.16) are Capitalized on Purchase and have 7 year life.
(b) VVO & DA Assets (account 362-station equipment) are capitalized after 6 months and have 30 year life.

Notes:
ROR from Renee Hawkins Rate of Return Summary Modified ESP Case 11-346-EL-SSO

gridSMART Phase 2

CSP - gridSMART Incremental Investment	Estimated gridSMART Spending	Annual Carrying Charge		gridSMART Revenue Requirement
O&M (AMI, VVO, DACR)	$ 8,610,621			$ 8,610,621
Capital - 7 Year Life- AMI		$ 20,050,781		$ 20,050,781
Capital - 30 Year Life - VVO		$ 3,488,464		$ 3,488,464
Capital - 30 Year Life - DACR		$ 10,250,285		$ 10,250,285
		Total		$ 42,400,151
		Tax Gross Up Rate		100.859%
		Revenue Requirement		$ 42,764,417
		Loss on Removal of meters		$ 14,539,444
		Total Revenue Requirement		$ 57,303,860.9
Residential Base Distribution	$ 406,542,657.87	Residential Revenue Requirement		$ 35,778,401
Non-Res Base Distribution	$ 244,589,408.48	Non-Res Revenue Requirement		$ 21,525,460
		Residential Customers	1,273,961	28.08
		Non-Residential Customers	186,129	115.65
		Residential Customers	Monthly Rate	$ 2.34
		Non-Residential Customers	Monthly Rate	$ 9.64

(a) AMI Assets (account 370.16) are Capitalized on Purchase and have 7 year life.
(b) VVO & DA Assets (account 362-station equipment) are capitalized after 6 months and have 30 year life.

Notes:
ROR from Renee Hawkins Rate of Return Summary Modified ESP Case 11-346-EL-SSO

Attachment B
YEAR 4

gridSMART Phase 2

CSP - gridSMART Incremental Investment	Estimated gridSMART Spending		Annual Carrying Charge		gridSMART Revenue Requirement
O&M (AMI, VVO, DACR)	$ 9,605,920				$ 9,605,920
Capital - 7 Year Life- AMI			$ 22,264,705		$ 22,264,705
Capital - 30 Year Life - VVO			$ 5,127,073		$ 5,127,073
Capital - 30 Year Life - DACR			$ 15,267,102		$ 15,267,102
		Total			$ 52,264,799
		Tax Gross Up Rate			100.859%
		Revenue Requirement			$ 52,713,813
		Loss on Removal of meters			$ 14,539,444
		Total Revenue Requirement			$ 67,253,257.2
Residential Base Distribution	$ 406,542,657.87	Residential Revenue Requirement			$ 41,990,434
Non-Res Base Distribution	$ 244,589,408.48	Non-Res Revenue Requirement			$ 25,262,823
		Residential Customers		1,273,961	32.96
		Non-Residential Customers		186,129	135.73
		Residential Customers		Monthly Rate	$ 2.75
		Non-Residential Customers		Monthly Rate	$ 11.31

(a) AMI Assets (account 370.16) are Capitalized on Purchase and have 7 year life.
(b) VVO & DA Assets (account 362-station equipment) are capitalized after 6 months and have 30 year life.

Notes:
ROR from Renee Hawkins Rate of Return Summary Modified ESP Case 11-346-EL-SSO

gridSMART Phase 2

CSP - gridSMART Incremental Investment	Estimated gridSMART Spending	Annual Carrying Charge		gridSMART Revenue Requirement
O&M	$ 8,092,872			$ 8,092,872
Capital - 7 Year Life		$ 24,707,401		$ 24,707,401
Capital - 30 Year Life - VVO		$ 5,430,612		$ 5,430,612
Capital - 30 Year Life - DACR		$ 17,693,769		$ 17,693,769
		Total Revenue Requirement		$ 55,924,654
		Tax Gross Up Rate		100.859%
		Revenue Requirement		$ 56,405,110
		Loss on Removal of meters		$ 14,539,444
		Total Revenue Requirement		$ 70,944,554.0
Residential Base Distribution	$ 406,542,657.87	Residential Revenue Requirement		$ 44,295,142
Non-Res Base Distribution	$ 244,589,408.48	Non-Res Revenue Requirement		$ 26,649,412
		Residential Customers	1,273,961	34.77
		Non-Residential Customers	186,129	143.18
		Residential Customers	Monthly Rate	$ 2.90
		Non-Residential Customers	Monthly Rate	$ 11.93

(a) AMI Assets (account 370.16) are Capitalized on Purchase and have 7 year life.
(b) VVO & DA Assets (account 362-station equipment) are capitalized after 6 months and have 30 year life.

Notes:
ROR from Renee Hawkins Rate of Return Summary Modified ESP Case 11-346-EL-SSO

Benefit	Estimate Savings (15 year cash view total in millions)	Verification Approach	Mechanism for the customers to obtain the benefit
Benefits included in the Benefit / Cost Analysis			
Meter Reading and Meter Operational Labor Savings	$ 83	Compare Annual Meter Reading and Meter Operational Budgets to the Pre-deployment Budget	Customers will see this benefit by AEP Ohio having lower ongoing costs which yield lower customer rates as an outcome of filing future Distribution rate cases
Credit and Collections Operational Labor Savings	$ 21	Compare Annual Credit and Collections Operational Budgets to the Pre-deployment Budget	Customers will see this benefit by AEP Ohio having lower ongoing costs which yield lower customer credit disconnect and reconnect fees as an outcome of filing future Distribution rate cases
Reduction in Uncollectible Revenue Through Use of Remote Disconnect - Estimate Based on Industry Analysis and Internal Uncollectible Revenue.	$ 49	Compare Annual Uncollectible Revenue Write-off to the Pre-deployment data; performance is prone to other economic factors that will not allow for pure measure	Company Savings - Flow back to customers through a future Uncollectible Revenue Rider that the company plans to file separate from this gridSMART Phase 2 filing
Reduction in Theft (Estimate Based on Industry Benchmarking)	$ 35	Compare Annual Theft of Energy revenue savings, though some savings will be unidentifiable	Increase Company Revenue (Wires Only) Flow Through to Customers
Reduction in Consumption on Inactive Meters - Estimate Based on Industry Benchmarking	$ 6	No Verification method possible	Increase Company Revenue (Wires Only) Flow Through to Customers
Customer Savings associated with VVO benefits	$ 115	Compare annual voltage reduction by circuit to pre-deployment data	Customer Benefit
Distribution Automation Circuit Reconfiguration Outage Reduction	$ 1,016	Compare annual Customer Minutes of Interruption for DACR circuits to pre-deployment data; performance is prone to weather impacts that will not allow for pure measure	Customer Benefit
TOTAL	$ 1,325		
Other Benefits			
Customer savings associated with participating in TOU programs	$ 63	Compare updated pricing to projected participation rate expectations.	Customer Benefit
Billing Labor Benefits (soft saving benefits from industry saving models -- allows staff to reallocate to higher priority tasks)	$ 2	Compare number of annual No-Bill workflows created for AMI customer and compare to the predeployment quantity.	Customers will see this benefit by AEP Ohio having lower ongoing costs which yield lower customer rates as an outcome of filing future Distribution rate cases
Call Center Labor Benefits (soft saving benefits from industry saving models -- allows staff to reallocate to higher priority tasks)	$ 1	No Verification method possible	Customers will see this benefit by AEP Ohio having lower ongoing costs which yield lower customer rates as an outcome of filing future Distribution rate cases
Long-Term Capacity Planning Labor / Non-Labor Capital Savings Due to Superior AMI Data Quality (soft saving benefits from industry saving models -- allows staff to reallocate to higher priority tasks)	$ 10	Shift of resources to other required work - no verification	Customers will see this benefit by AEP Ohio having lower ongoing costs which yield lower customer rates as an outcome of filing future Distribution rate cases
Short-Term Capacity Planning Labor / Non-Labor Capital Savings Due to Superior AMI Data Quality (soft saving benefits from industry saving models -- allows staff to reallocate to higher priority tasks)	$ 1	Shift of resources to other required work - no verification	Customers will see this benefit by AEP Ohio having lower ongoing costs which yield lower customer rates as an outcome of filing future Distribution rate cases
Capacity Planning Labor / Non-Labor O&M Savings Due to Superior AMI Data Quality (soft saving benefits from industry saving models -- allows staff to reallocate to higher priority tasks)	$0.2	Shift of resources to other required work - no verification	Customers will see this benefit by AEP Ohio having lower ongoing costs which yield lower customer rates as an outcome of filing future Distribution rate cases
Injury Reduction - Reduction in liability / lost work days	$ 1	Compare OSHA recordable and severity rates to pre-deployment data	Customers will see this benefit by AEP Ohio having lower ongoing costs which yield lower customer rates as an outcome of filing future Distribution rate cases
TOTAL	$ 77		

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in

Case No(s). 13-1939-EL-RDR

Summary: Application of Ohio Power Company to Initiate Phase 2 of its gridSMART Project and to Establish the gridSMART Phase 2 Rider electronically filed by Mr. Yazen Alami on behalf of Ohio Power Company

KWalton

May 28, 2015 Case 14-192 AEP SmartGrid.pdf
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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company to Update its gridSMART Rider.	)))	Case No. 14-192-EL-RDR

ENTRY

The Commission finds:

(1) Ohio Power Company (AEP Ohio) is an electric distribution utility as defined by R.C. 4928.01(A)(6) and a public utility as defined in R.C. 4905.02, and, as such, is subject to the jurisdiction of this Commission.

(2) R.C. 4928.141 provides that an electric distribution utility shall provide consumers within its certified territory a standard service offer (SSO) of all competitive retail electric services necessary to maintain essential electric services to customers, including firm supply of electric generation services. The SSO may be either a market rate offer in accordance with R.C. 4928.142 or an electric security plan (ESP) in accordance with R.C. 4928.143.

(3) By Opinion and Order issued August 8, 2012, the Commission approved, with modifications, AEP Ohio's application for an ESP commencing June 1, 2012, and continuing through May 31, 2015, pursuant to R.C. 4928.143. *In re AEP Ohio,* Case Nos. 11-346-EL-SSO et al., Opinion and Order (August 8, 2012) (*ESP 2 Case*). As part of the *ESP 2 Case,* the Commission approved, among other things, the continuation and expansion of the Company's gridSMART program for the recovery of costs associated with the installation of smart grid technologies and equipment, including automated meter infrastructure and distribution automation. Pursuant to the *ESP 2 Case,* the gridSMART rider is subject to annual reconciliation, prudency review, and true-up. *ESP 2 Case* at 61-63.

(4) On February 3, 2014, AEP Ohio filed the instant application for the annual review of its gridSMART rider mechanisms. In this application, AEP-Ohio presents actual gridSMART project spending and revenue recovery during 2013, as well as projected costs, and revenue requirements for 2014.

(5) In this case, by Finding and Order issued March 18, 2015, the Commission directed AEP Ohio to reduce the proposed gridSMART rider rates for adjustments to its operations and maintenance expense associated with the community energy storage (CES) units and non-incremental labor, and to reduce the revenue requirement to reflect a reduction in capital. *In re AEP Ohio*, Case No. 14-192-EL-RDR, Finding and Order (Mar. 18, 2015) at 6-7.

(6) On March 25, 2015, AEP Ohio filed its proposed tariffs to comply with the Commission's March 18, 2015 Finding and Order.

(7) On April 16, 2015, Staff filed a letter indicating that Staff had reviewed the Company's proposed gridSMART rider tariffs. Staff found AEP Ohio's gridSMART tariffs to be in compliance with the Commission's Order in this case. Accordingly, the Commission finds the gridSMART tariffs filed by AEP Ohio should be approved to be effective with the next billing cycle, reflecting a tariff rate of $1.01 per bill for residential customers and a rate of $4.22 per bill for non-residential customers. The new gridSMART rider rates reflect an increase of $.50 per bill for residential customers and an increase of $2.12 per bill for non-residential customers over currently effective gridSMART rider rates. *In re AEP Ohio*, Case No. 13-345-EL-RDR, Finding and Order (Feb. 19, 2014).

It is, therefore,

ORDERED, That the proposed gridSMART compliance rates and tariffs filed by AEP Ohio on March 25, 2015, be approved to the extent set forth in this Entry. It is, further,

ORDERED, That the effective date of the new tariffs shall be a date not earlier than the date upon which the final tariff pages are filed with the Commission. It is, further, ORDERED, That a copy of this Entry be served upon all persons of record in this case.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Andre T. Porter, Chairman

Lynn Slaby

M. Beth Trombold

Asim Z. Haque

Thomas W. Johnson

GNS/dah

Entered in the Journal MAY 28 2015

Barcy F. McNeal
Secretary

KWalton

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

CONSIDERATION OF THE IMPLEMENTATION OF SMART GRID AND SMART METER TECHNOLOGIES	)))	CASE NO. 2012-00428

INDEX

Page No.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

CONSIDERATION OF THE IMPLEMENTATION OF SMART GRID AND SMART METER TECHNOLOGIES	)))	CASE NO. 2012-00428

ORDER

BACKGROUND

By Order dated October 1, 2012, the Commission initiated this administrative proceeding to consider the implementation of Smart Grid and Smart Meter technologies, and time-of-use, or dynamic, pricing ("Opening Order"). The Opening Order provided that this administrative proceeding would also include a determination as to whether the Smart Grid Investment Standard and the Smart Grid Information Standard as set forth in the Energy Independence and Security Act of 2007 ("EISA 2007") should be adopted.[1] In particular, the purpose of the instant administrative matter would address all aspects of a Smart Grid system from hardware and software issues to reliability improvement, cost recovery issues, and dynamic pricing. All of Kentucky's jurisdictional electric

[1] The EISA 2007 Smart Grid Investment Standard and the Smart Grid Information Standard were part of standards considered by the Commission in Case No. 2008-00408, *Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007* (Ky. PSC Oct. 6, 2011). The Commission, however, ultimately deferred consideration of these two standards until the completion of this administrative proceeding.

utilities[2] and the five largest jurisdictional gas utilities[3] ("Gas LDCs") were made parties to this proceeding.

The Opening Order also incorporated into the record of this matter certain documents which had been filed in Administrative Case No. 2008-00408 and a report, along with supporting documents, developed by the Kentucky Smart Grid Roadmap Initiative.[4] The Opening Order also established a procedural schedule for the processing of this administrative proceeding. The procedural schedule provided deadlines for, among other things, the filing of individual or joint testimony, two rounds of discovery, and two informal conferences.

The following parties petitioned for and were granted intervention in this proceeding: the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); and the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG").

Joint testimonies were filed by Big Rivers and its three distribution cooperative members; EKPC and its 16 distribution cooperative members; LG&E and KU; and

[2] The jurisdictional electric utilities are Big Rivers Corporation ("Big Rivers"), Big Sandy Rural Electric Cooperative Corporation, Blue Grass Energy Cooperative Corporation, Clark Energy Cooperative, Inc., Cumberland Valley Electric, Inc., Duke Energy Kentucky, Inc. ("Duke Kentucky"), East Kentucky Power Cooperative, Inc. ("EKPC"), Farmers Rural Electric Cooperative Corporation, Fleming-Mason Energy Cooperative, Inc., Grayson Rural Electric Cooperative Corporation, Inter-County Energy Cooperative Corporation, Jackson Energy Cooperative, Jackson Purchase Energy Corporation, Kenergy Corp., Kentucky Power Company ("Kentucky Power"), Kentucky Utilities Company ("KU"), Licking Valley Rural Electric Cooperative Corporation, Louisville Gas and Electric Company ("LG&E"), Meade County Rural Electric Cooperative Corporation, Nolin Rural Electric Cooperative Corporation, Owen Electric Cooperative, Salt River Electric Cooperative Corporation, Shelby Energy Cooperative, Inc., South Kentucky Rural Electric Cooperative Corporation, and Taylor Rural Electric Cooperative Corporation.

[3] The Gas LDCs are Atmos Energy Corporation ("Atmos"), Columbia Gas of Kentucky, Inc. ("Columbia"), Delta Natural Gas Company ("Delta"), Duke Kentucky, and LG&E.

[4] *See* Opening Order, Appendix A.

Atmos, Columbia, and Delta. Individual testimonies were filed by Duke Kentucky, Kentucky Power, and CAC.

An informal conference was conducted on April 19, 2013, to discuss the need for, and feasibility of, uniform standards for Smart Grid Investment and Smart Grid Information; to identify the process for determining reasonable standards and programs for the implementation of Smart Grid Investment, Smart Grid Information, reliability improvements, and dynamic pricing; and to assess the willingness of all parties to work in a collaborative manner to identify such reasonable standards and programs. Discussions at the April 19, 2013 informal conference resulted in an agreement among the parties to engage in a collaborative effort to address the issues raised in this administrative proceeding. On May 20, 2013, the parties to this proceeding, with the exception of KIUC, submitted Joint Comments setting forth a recommendation of the topics the collaborative would address, a proposed schedule going forward, and the manner in which the intervening parties and Commission Staff would participate in the collaborative process. The Joint Comments also recommended that the Commission not require adoption of the Smart Grid Investment Standard and the Smart Grid Information Standard.

On July 17, 2013, the Commission issued an Order in this proceeding requiring the parties to collaboratively address the following topics: 1) EISA 2007 Smart Grid Information and Smart Grid Investment Standards; 2) customer privacy; 3) opt-out provisions; 4) cybersecurity; 5) customer education; 6) dynamic pricing; 7) advanced metering infrastructure ("AMI") and automated meter reading ("AMR") deployment; 8) cost recovery for smart technology deployments; and 9) participation by natural gas companies in the electric Smart Grid. In addition, the Commission found that those topics should include issues relating to the recovery of costs of obsolete equipment.

The parties, with the exception of KIUC, implemented the collaborative process by holding monthly meetings to discuss each of the nine topics. The meetings began in August 2013 and concluded in June 2014. The collaborative effort culminated with the filing of a report on June 30, 2014, of the jurisdictional electric utilities and the Gas LDCs (collectively "Joint Utilities") addressing in detail and containing findings and recommendations on each of the nine issues referenced above. The report also contained comments from the AG and the CAC.

Finding that additional discovery was needed to further develop the record on the complex issues addressed by the June 30, 2014 report ("Report"), the Commission established a supplemental procedural schedule that provided for two rounds of discovery and set a hearing date. On November 25, 2014, after additional discovery was conducted, the Commission issued an Order finding that the record has been sufficiently developed for the Commission to render a decision based on the evidentiary record without the need for a formal hearing. The November 25, 2014 Order then established a deadline for the parties to this proceeding to, either individually or jointly, notify the Commission in writing whether the formal hearing should be held as scheduled or whether the matter could be submitted to the Commission for a determination based on the evidentiary record. In the event the parties recommended that no formal hearing be held, the November 25, 2014 Order established a deadline allowing the parties an opportunity to submit a brief, either individually or jointly. The November 25, 2014 Order also scheduled two dates for a meeting in which the

Commission would take public comments. The first public meeting was conducted on December 16, 2014, and the second on December 17, 2014.

On December 3, 2014, the parties to this matter submitted a joint statement stating their belief that a formal hearing for this matter was not necessary and that the case could be submitted to the Commission for a decision based upon the existing evidentiary record.

On February 27, 2015, the Joint Utilities filed a brief unanimously recommending that the EISA 2007 Smart Grid Investment and Smart Grid Information Standards should not be adopted by the Commission. The Joint Utilities assert that adopting the former standard would require them to make uneconomical investments, and adopting the latter standard would be largely redundant, while potentially stifling useful innovation in smart-technology proposals. The brief further summarized the Joint Utilities' positions on the nine issues that were addressed in their Report.

DISCUSSION

EISA 2007 Smart Grid Information Standard

The Joint Utilities state in the Report that they continue to believe that "[e]ach utility's unique circumstances and the pace of technological change make it unnecessary, and likely counterproductive, to impose uniform, one-size-fits-all standards, such as the EISA 2007 Smart Grid Information and Investment Standards."[5] The Joint Utilities state that the better approach is to use the Commission's existing authority to ensure the prudence of utility operations and investments.[6]

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[5] Report at 6.

[6] *Id.*

The EISA 2007 Smart Grid Information Standard for electric utilities requires that electric suppliers provide to purchasers of electricity direct access to time-based wholesale and retail price information, purchaser usage information, updates of price and usage information, day-ahead projections, and information concerning sources of generation, including associated greenhouse gas emissions.

This standard also requires electric utilities to provide consumers access to their customer-specific information at any time through the Internet and by other means elected by the utility, with other interested persons able to access only non-customer specific information.[7]

The Joint Utilities unanimously recommend that the Commission not adopt the EISA 2007 Smart Grid Information Standard. They state that adoption of the standard would require utilities to make uneconomical investments to provide customers direct access to a wide array of information, including price and usage information, without considering the costs or benefits of the provision of the information.[8]

Kentucky is not a restructured state in which customers may select an electricity supplier other than their incumbent utility, nor may customers utilize the services of aggregators.[9] The Joint Utilities point out that time-based or time-of-use ("TOU") pricing programs are currently voluntary and are not widely available to all customers.[10]

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[7] Opening Order at 4–5.

[8] Report at 77.

[9] Aggregators are entities that bring together, and negotiate on behalf of, large groups of consumers for reduced rates for goods or services or improved terms and/or conditions of service, especially in the energy sector

[10] Report at 78.

With regard to customer-specific information and privacy issues, the Joint Utilities state that they each have an internal customer privacy policy or practice currently in effect,[11] and that there does not appear to be a need to adopt this standard or develop a similar standard at this time.

As previously stated, the Joint Utilities recommend that the Commission continue to use its existing review processes and authority to ensure that utilities are providing customers with the information they need in economical ways. They believe that this will allow the Commission to continue to have oversight over the information provided to customers, yet still recognize each utility's individual characteristics, including the utility's unique costs and benefits of providing various information in certain ways to each utility's customers.[12] The Joint Utilities identified a list of terms and substantive items which they believe the Commission may consider useful when reviewing Smart Grid or customer privacy proposals.[13]

The AG states that he does not oppose the "economical use of smart technologies,"[14] but agrees with the Joint Utilities that the Commission should not adopt the EISA 2007 Smart Grid Information Standard.[15] The CAC provided no comments regarding the Smart Grid Information Standard.[16]

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[11] *Id.* at 11.

[12] *Id.* at 78.

[13] *Id.* at 1.

[14] *Id.* at 80.

[15] *Id.*

[16] *Id.*

The Commission will not require adoption of the EISA 2007 Smart Grid Information Standard or a similar standard. We will, however, require the utilities to provide certain basic information to their customers. Customers should be able to access their own information at any time through the internet or by other cost-effective means of communication selected by the utility. At a minimum, customers should be able to access historical information regarding their electricity or natural gas usage, expressed in each utility's respective billing units, as well as the customers' current applicable tariff rate. Additionally, the utilities should endeavor to provide customers this information in as close to real time as practical.

In addition, the Commission accepts the Joint Utilities proposal to adopt the "voluntary-checklist approach"[17] set forth in the Customer Privacy section of the Report. The Commission's decision is discussed in further detail in the Customer Privacy section later in this Order.

EISA 2007 Smart Grid Investment Standard

The EISA 2007 Smart Grid Investment Standard for electric utilities provides that each state consider requiring electric utilities to demonstrate that certain factors with regard to investing in a Smart Grid system were considered before the utilities invested in non-advanced grid technologies.

The standard also requires each state to consider rate recovery of Smart Grid capital expenditures, operating expenses, and other costs related to the deployment of Smart Grid technology, including a reasonable return on the capital expenditures, as

[17] *Id.* at 15.

well as recovery of the remaining book value of obsolete equipment replaced with Smart Grid deployment.[18]

As previously stated, the Joint Utilities do not support the adoption of the EISA Smart Grid Investment Standard, but rather believe that the Commission should exercise its existing authority to review Smart Grid investments.[19]

Based on the testimony and the responses to data requests in this case, most electric utilities have migrated to AMR or AMI meters and functionality, or are in the process of doing so.

Additionally, the electric utilities' systems include Smart Grid technologies such as Distribution Automation ("DA") features, volt/volt-ampere-reactive ("volt/var") programs and Supervisory Control and Data Acquisition ("SCADA") systems.

As the Joint Utilities note, they have all deployed smart technologies, but in different ways and degrees.[20] The record reflects that the Joint Utilities have adequately demonstrated that system investments are tied to issues relating to cost and how to incorporate components that are compatible with the current distribution system. They have also demonstrated that they are attempting to improve system reliability as they make investment decisions.

Although not stated directly in the Report, the Joint Utilities imply that adoption of the EISA 2007 Smart Grid Investment Standard would require them to seek a certificate of public convenience and necessity ("CPCN") for Smart Grid investments. In the

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[18] Opening Order at 4.

[19] Report at 6.

[20] *Id.* at 77.

discussion in the Cost Recovery section of the Report, the Joint Utilities argue that, while CPCN proceedings may be needed for some smart technology deployment, CPCN authorization is not necessary for all smart technology investment.[21]

The AG concurs with the Joint Utilities that the Commission should not adopt the EISA 2007 Smart Grid Investment Standard. CAC provided no comments with regard to the adoption of this standard.

The Commission believes that the record in this case demonstrates that the deployment of Smart Grid technology, whether in the form of smart meters or DA, varies from utility to utility, as are the reasons for the investment decisions that are made. Some of the investments in existing Smart Grid technology were made after the utilities had obtained a CPCN, and some were not. The Commission has not found any of the investments to be unreasonable.

While the Commission supports the intent of the EISA 2007 Smart Grid Investment Standard, we will not require its adoption. The Commission does not find it practical for each jurisdictional utility to be required to obtain a CPCN for every Smart Grid or meter investment decision. The Commission does find that each of the Joint Utilities should develop internal procedures and policies regarding Smart Grid investments. Such procedures and policies should include a description of their systems, their planning goals, and explanations of how such investments will be considered. This will be discussed in more detail in the discussion of Distribution Smart Grid Components.

[21] *Id.* at 76.

In support of our decision, the Commission notes the steps the distribution cooperatives take in developing their Construction Work Plans ("CWPs"). The CWPs set forth straightforward design criteria and explain the basis for each project included therein.

With regard to CPCNs, the Commission finds it appropriate for jurisdictional electric utilities to obtain CPCNs for major AMR or AMI meter investments and distribution grid investments for DA, SCADA or volt/var resources. In the past, when addressing requests for CPCNs for AMR and AMI meters, the Commission has noted its concern regarding a number of meter related issues such as cost, compatibility with current system equipment and software, and unplanned obsolescence.

Customer Privacy

In the Executive Summary of the Report ("Executive Summary"), the Joint Utilities take the position that it is not necessary for the Commission to mandate a new customer privacy standard that includes the customer data provisions of the EISA 2007 Smart-Grid Information Standard.[22]

In their Report, the Joint Utilities propose a list of terms and substantive items for utilities to consider when reviewing customer privacy policies and practices.[23] The Joint Utilities state that the Commission may find this information "useful when addressing smart-grid or other customer-privacy-related utility proposals."[24] According to the Joint Utilities, this voluntary checklist approach will ensure that utilities have the flexibility they

[22] *Id.* at 1 and 9–16.

[23] *Id.*

[24] *Id.* at 1–2 and 9.

need to continue to provide safe, reliable, and economical service while protecting their customers' privacy.[25] As previously stated, the Joint Utilities noted in their Report that each member of the Joint Utilities has a voluntary customer privacy policy or practice in force.[26] In their brief, the Joint Utilities state that federal and state legal protections are already in place concerning customer information and that government and industry groups are working to develop even more robust voluntary standards for utilities.[27] In addition, the Joint Utilities state that Kentucky's utilities have gone beyond the legal requirements to ensure that only appropriate use is made of customer information.[28] The Joint Utilities, therefore, assert that a new mandatory customer privacy standard, including the requirements set forth by the EISA 2007 Smart Grid Information Standard, is unnecessary.[29]

The AG recommends that the Commission adopt a statewide mandated customer privacy standard. The AG further recommends that the standard provide for significant civil penalties for non-compliance and include a universal opt-in policy that would prevent a utility from disclosing consumer information unless the customer elects to allow such disclosure.[30]

CAC states that it supports utilities' efforts to maintain customer privacy. However, CAC believes that aggregated customer information is often helpful to it in its

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[25] *Id.* at 15.

[26] *Id.* at 11.

[27] Brief of the Joint Utilities (filed Feb. 27, 2015) at 6.

[28] *Id.*

[29] *Id.*

[30] Report at 2 and 15.

effort to provide assistance to low-income customers in paying their bills and in its mission as an advocate for low-income customers. CAC believes that information should be readily available to it for these purposes and in regulatory proceedings. Also, since utilities benefit from its low-income assistance, CAC recommends that the utilities absorb the costs of providing this information.[31]

The Commission agrees that each utility should have a customer privacy policy and will accept the proposal set forth in the Report. Although the Commission will not mandate the adoption of a particular standard, the Commission finds that each utility should formalize its customer privacy policy and include it as part of its internal procedures. Each utility should incorporate appropriate items from Section VI and Section VII of the Customer Privacy section of the Report.[32] The Commission also finds that each utility's customer privacy policy (or a descriptive summary of that policy) should be available on the utility's website. Through independent research of the websites of the jurisdictional electric utilities, the Commission notes that each investor-owned utility ("IOU") has an established privacy policy accessible via its website, but only a few of the cooperatives have a privacy policy available on their websites.

Also, aggregated customer information should be available to CAC to assist it in its effort to provide assistance to low-income customers in paying their bills and in its mission as an advocate for low-income customers. That information, however, should be provided only at the request of CAC after it provides a reasonable basis for requesting the information.

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[31] *Id.* at 2.

[32] *Id.* at 11–14.

The Commission finds the AG's recommendation to adopt a statewide privacy standard that provides for civil penalties and requires opt-in to be inappropriate. If necessary, utility customers may seek civil penalties through individual court actions. Further, the Commission believes that the utilities' existing customer privacy policies should be sufficient to address any issues regarding the use of their individual information, and that aggregate information provided to entities such as CAC will be to the benefit, rather than the detriment, of utility customers.

Opt-Out

In the Executive Summary, the Joint Utilities state that requiring utilities to offer opt-out from smart meters "has potentially significant cost and operational impacts for utilities and customers"[33] and that such requirements are generally not beneficial.[34] They further note that allowing a customer to opt out of using a smart meter will inhibit the customer's ability to participate in and obtain timely information about usage.[35] The Joint Utilities recommend that the Commission evaluate the issue of opting out on a case-by-case basis.[36]

The Joint Utilities state that the two primary objections some customers raise about smart meters are that smart meters will adversely affect their health and that smart meters invade their privacy.[37] In the Report, the Joint Utilities provide a brief

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[33] *Id.* at 2.

[34] *Id.*

[35] *Id.* at 26.

[36] *Id.* at 2.

[37] *Id.* at 17.

rebuttal to each concern.[38] In addition, the Commission notes that the AG states that very few independent scientific results have been produced demonstrating that smart meters are either unsafe or dangerous to human health.[39]

To support their argument regarding the potential negative effects of allowing customers to opt out of smart meters, the Joint Utilities cite some of the potential costs and operational impacts in the Report.[40]

In addition to the information provided in the Report, the Commission notes the issues identified in Farmers RECC's response to a Staff data request regarding the impact of opt-outs from AMI deployment:

- Metering: A utility would be required to purchase special meters that would not have the current AMI capability.

- Billing: A utility would be required to establish special meter reading routes and cycles to accommodate opt-out customers. Additional administrative time and other costs would be incurred to manage the billing for these customers.

- Manual meter reading: A utility would incur additional costs to dispatch meter readers to travel to, and read the meter of, each opt-out customer.

- Outage notification: Information on whether opt-out customers were being affected by service outages would also be limited to either the customer notifying the utility or through a personal visit.

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[38] *Id.* at 17–18.

[39] *Id.* at 27.

[40] *Id.* at 20–23.

- Voltage/Current system modeling: Opt-out customers would be more difficult to include in these types of studies due to the lack of data.

- System reliability/Blinks: Opt-out customers would no longer be a part of this trouble-shooting capability, as no data could be supplied from their meters.[41]

The Joint Utilities state that they did not address AMR metering in the Report.[42] AMR meters only allow for one-way communication, and the Joint Utilities have defined the term "smart meter" as a meter that allows two-way communication. Therefore, AMR meters would not fall within their definition of a "smart meter." However, the Joint Utilities contend that no opt-out should be allowed for AMR meters and state that a number of utilities have already deployed AMR systems.[43]

The Joint Utilities oppose opt-outs of any kind for digital meters with no communications capabilities because such meters function in a manner essentially identical to older electromechanical meters. They do not believe electromechanical meters are being manufactured domestically today.[44] Therefore, they state that any opt-out from a non-communicating digital meter is impracticable at best.[45]

The AG recommends that both technical and informational opt-out should be available to customers, where infrastructure allows.[46]

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[41] Farmer's response to Commission Staff's Request for Information (Ky. PSC Sept. 18, 2014), Item 10.

[42] Report at 17.

[43] *Id.*

[44] *Id.* at 18.

[45] *Id.*

[46] *Id.* at 27–28.

CAC recommends that if a utility offers opt-out alternatives, customers should not be penalized for choosing to opt out.[47] In addition, CAC believes that the ability of utilities with smart meter deployments to instantaneously remotely disconnect customers could potentially have negative consequences for low-income customers which should be mitigated.[48]

Due to the potential negative impact on the operational benefits of a Smart Grid, the Commission does not support meter opt-outs, whether they be from digital, AMR or AMI meters. However, almost all of the public comments submitted in this proceeding address concerns with smart meters from either a health or privacy perspective. Therefore, the Commission accepts the Joint Utilities' recommendation to consider opt-out on a case-by-case basis (or more precisely, on a utility-by-utility basis). Each utility will be able to determine the need for an opt-out provision and petition the Commission for consideration. The Commission believes that each utility can best determine the need for an opt-out provision and whether that the proposed opt-out provision will apply to digital, AMR, or AMI meters will be at the utility's discretion.

The Commission finds that any opt-out provision should require those customers that opt out to bear the cost related to that decision — through a one-time fee and/or a monthly charge, as appropriate.

Customer Education

The Joint Utilities believe that customer education will increase the success of smart meter deployment. They recommend that each utility deploying smart meters consider using some of the customer-education topics that are addressed in the

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[47] *Id.* at 2 and 28.

[48] *Id.* at 28.

Report.[49] However, most utilities have already migrated to AMR or AMI meters, so initial education efforts for smart meter deployment have, for the most part, already been made.

The Joint Utilities state that customer education on the benefits of smart technology is critical to gaining customer acceptance and use of Smart Grid technology.[50] In addition, they state that customer education tends to increase the benefits from Smart Grid investment, consistent with the Smart Grid Investment Standard's consideration of cost effectiveness.[51]

The Joint Utilities cite the customer education efforts undertaken by Duke Energy, American Electric Power ("AEP") (the parent company of Kentucky Power), and Owen Electric.[52] In addition, the Joint Utilities cite various topics and communication channels that the utilities may utilize for customer-education purposes.[53]

In his testimony, the AG acknowledges the need for customer education but does not include any additional comments in the Report. CAC recommends that customer education should be mandatory as smart meters are deployed.[54]

It is evident from the testimony, responses to data requests, and the Report that utilities are already engaging in customer education concerning safety and some Smart Grid efforts. However, the Commission is uncertain as to the structure of each utility's

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[49] *Id.* at 3.

[50] *Id.* at 29.

[51] *Id.* at 35.

[52] *Id.* at 29–31.

[53] *Id.* at 31–35.

[54] *Id.* at 36.

customer-education policy or practice. The Commission, therefore, has determined that each utility should formalize its customer-education policy or practice with regard to Smart Grid and smart meters as part of its internal procedures manual.

At a minimum, the policy should address the appropriate education activities for deployment of smart meters and other Smart Grid components (including DA, volt/var and SCADA). The requirement will allow each utility to develop educational materials that apply to its own system.

Dynamic Pricing[55]

In the Report's Executive Summary, the Joint Utilities state that their collective experience is that residential dynamic pricing programs have had low participation and have sometimes resulted in energy-consumption increases.[56] The Joint Utilities contend that they should not be required to create and offer dynamic rate offerings, but should be allowed to do so voluntarily, subject to Commission approval.[57]

As defined in the Report, dynamic pricing refers to pricing that varies according to the time at which the energy is consumed, is normally tied to energy prices in the wholesale market or to system peaks, and is delivered to customers through time-based rates or tariffs.[58] The Report describes several forms of dynamic pricing, including time-

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[55] In the Opening Order establishing this case, dynamic pricing was defined to include time-of-use pricing, critical peak pricing, real-time pricing, and credits for consumers with large loads that enter into pre-established peak load reduction agreements that reduce a utility's planned load capacity obligations. *See* further definition in the Appendix to this Order.

[56] Report at 3.

[57] *Id.*

[58] *Id.* at 37.

of-use ("TOU") or time-of-day ("TOD") pricing, both variable and fixed critical-peak pricing ("CPP"), peak-time rebate ("PTR") and real-time pricing ("RTP").[59] [60]

Although there has not been significant customer participation, several utilities continue to offer some form of dynamic pricing options, such as on peak/off peak TOD rates. The Joint Utilities provide a discussion of the experiences of Duke Energy, the parent company of Duke Kentucky, in North Carolina, South Carolina, and Ohio, and the experiences of Kentucky Power, KU/LG&E, Owen Electric and Jackson Energy.[61] In addition, the Report lists the residential dynamic pricing programs available in Kentucky[62] and those offered by AEP and Duke Energy in other jurisdictions.[63]

The Report also includes a discussion of issues that need to be addressed when considering dynamic pricing. The rate and tariff issues include: opt-in/opt-out, rate structure, contract terms, waiting periods to switch rates, complexity, criteria for participation and hold-harmless trial periods.[64] Also discussed in the Report are technology considerations that the customer and utility must address, customer education and marketing. Other considerations, including cost, equity, and economic justification, are also discussed.[65]

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[59] *Id.* at 37–38.

[60] Some utilities, such as AEP, do not consider TOD rates to be dynamic pricing.

[61] Report at 38–41.

[62] *Id.*, Appendix B at 85–86.

[63] *Id.*, Appendix C at 87.

[64] Report at 41–42.

[65] *Id.* at 42–43.

Noting that the results of dynamic pricing are mixed at best, the AG states that the Commission should not require mandatory residential TOU rates and that such rates should be no more than an option for residential ratepayers.[66] In the Report, the AG also adopted all of the positions set forth by CAC.[67]

According to CAC, the potential impact on low-income customers is a concern because these customers typically do not fully understand the complexities of dynamic pricing or they lack the technology to fully take advantage of such rates. As a result, participation in dynamic-pricing programs could inadvertently result in higher bills. CAC therefore recommends that dynamic pricing should not be required for residential customers and that efforts should be undertaken to prevent any inadvertent increases in bills for low-income customers who may choose to take advantage of voluntary pricing options. CAC also states that the rates of customers not participating in dynamic pricing should not be negatively impacted by dynamic pricing offerings.[68]

The Commission is on record as noting its consistent support of dynamic pricing. At one point in Administrative Case 2008-00408, the Commission stated its hope to ultimately develop some dynamic pricing options for utility customers. In its Opening Order initiating this case, the Commission likewise stated its intent to consider issues relating to dynamic pricing. However, the Joint Utilities argue that utilities should not have an obligation to create dynamic rate offerings, but should have the option to do so

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[66] *Id.* at 3 and 44.

[67] *Id.*

[68] *Id.* at 3–4 and 45. As noted earlier, a definition of each form of dynamic pricing can be found in the Appendix to this Order.

subject to Commission approval. The AG and CAC support this position. All parties agree that customer participation in dynamic pricing should be voluntary.

The Commission believes that a strong economic argument cannot currently be made for mandatory dynamic pricing tariffs in Kentucky, and there is uncertainty what impact dynamic pricing tariffs may have on energy consumed or on utility revenues. However, the Commission notes that its general intent is to incentivize consumers to decrease usage, move usage to off-peak hours, and/or reduce energy bills, all of which will likely reduce a utility's revenues.

The Commission, therefore, will not require that a broad array of dynamic pricing proposals be developed. The Commission strongly encourages the jurisdictional electric utilities to develop some pilot programs for consideration. It seems appropriate, at a minimum, that the jurisdictional electric utilities could develop and offer "on-peak/off-peak" TOD tariffs (including seasonal TOD tariffs). In fact, TOU and TOD rates are currently offered by some of Kentucky's jurisdictional electric utilities, as reflected in Appendix B of the Report.

The Commission finds that any dynamic pricing offering should be voluntary for customer participation, and efforts should be made to mitigate negative impacts on low-income customers through customer education or any other reasonable and cost-effective method.

<u>Distribution Smart Grid Components</u>

The Joint Utilities state that distribution Smart Grid components can provide benefits to customers and add value to utilities' distribution systems.[69] However, they

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[69] *Id.* at 4.

cite a number of items which can impact customers that utilities should consider before investing in Smart Grid systems.[70] These items include technological obsolescence, prepaid metering, and remote connection and disconnection of utility service.[71] The Joint Utilities contend that adding more regulation such as that represented by the EISA 2007 Smart Grid Investment Standard is unnecessary.[72] They claim that the Commission already has the authority through review of base rates, CPCN authority, and other mechanisms to ensure that utilities make prudent investments.[73]

As technologies have demonstrated value or have been determined to be advisable, the Joint Utilities have deployed smart technologies in their distribution systems.[74] Currently, all of the Joint Utilities have deployed some form of Smart Grid technology.[75]

A summary example of some Smart Grid deployment discussed in the report includes:

- Kentucky Power has deployed AMR, DA — Circuit Reconfiguration, Volt/VAR Optimization, and SCADA.[76]

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[70] *Id.*

[71] *Id.*

[72] *Id.* at 4 and 56.

[73] *Id.*

[74] *Id.* at 46.

[75] *Id.* at 47.

[76] *Id.* at 47–48.

- Duke Kentucky has installed four self-healing systems as part of its normal reliability improvement process.[77]

- LG&E and KU have deployed four SCADA systems (KU, LG&E electric, LG&E gas, and downtown Louisville), and have installed about 90,000 AMR meters (electric and gas) across their service territories. LG&E is currently deploying approximately 1,500 AMI meters and related infrastructure in its downtown Louisville network as part of a project to gather enhanced engineering information for network planning.[78]

- Jackson Purchase Energy Corporation has illustrated the value of Smart Grid deployments in its system with DA and Voltage Conservation.

- Other smart technology components that are utilized include:
    - Switches and valves (Duke Kentucky);
    - Voltage stabilization (Kentucky Power);
    - Meters (Duke Kentucky); and
    - Communications and SCADA (LG&E/KU).[79]

- 15 distribution cooperatives offer prepaid metering as a voluntary option to their consumers.[80]

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[77] *Id.* at 48.

[78] *Id.*

[79] *Id.* at 52–53.

[80] *Id.* at 48–49.

The AG did not comment on Smart Grid components. CAC states that it is open to "fair and limited"[81] prepaid metering, but notes its concerns with prepaid metering and remote disconnection.[82]

As the Commission stated earlier, its findings and the requirements set forth in this section are coupled with the decision regarding the EISA 2007 Smart Grid Investment Standard. The Commission will require that each of the jurisdictional electric utilities develop internal procedures regarding Smart Grid investments that include a description of their systems, their planning goals, and an explanation of how such investments will be considered a Smart Grid plan.

Requiring each utility to develop a Smart Grid plan should not be burdensome. As noted earlier, the steps the distribution cooperatives take in developing their CWPs set forth straightforward design criteria and explain the basis for each project included in the CWP. The Commission will not apply the formal CPCN process to each utility investment decision, but needs to ensure that the jurisdictional electric utilities define and develop a strategy that can guide their investment decisions. Until recently, the distribution cooperatives were required to submit their CWPs for Commission review and receive a CPCN before starting construction. The IOUs have not been subjected to that requirement. As such, they have invested in AMR and AMI meters, DA, SCADA and other Smart Grid deployment without prior Commission oversight. With the deployment of smart technology that may directly impact the service provided to

[81] *Id.* at 57.

[82] *Id.*

customers becoming more prevalent, the Commission believes that a requirement to develop internal procedures regarding Smart Grid investment is reasonable.

Cybersecurity

In the Executive Summary of the Report, the Joint Utilities state that all stakeholders' interests are aligned and that utilities should take reasonable measures to prevent cyber-attacks. However, they state that existing mandatory and voluntary cybersecurity standards, frameworks, and guidelines are sufficient, and that adding regulations or rules serves to weaken utilities' ability to thwart cyber-attacks. They state that the focus should be on the ability to evolve with emerging threats and not on compliance with cybersecurity standards. They believe an effective cybersecurity process is one that is continuously evolving based on emerging threat intelligence. As a result, they assert that additional requirements at the state level are not necessary or advisable.[83]

As the Joint Utilities note, some members are subject to mandatory cybersecurity standards to protect the Bulk Electric System.

These include the Critical Infrastructure ("CIP") Standards developed by the North American Electric Reliability Corporation ("NERC"), approved by the Federal Energy Regulatory Commission ("FERC"), and administered and enforced by NERC and its regional entities, including the SERC Reliability Corporation ("SERC").[84] [85]

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[83] *Id.* at 4.

[84] *Id.* at 59.

[85] SERC has jurisdiction over all of Kentucky except the easternmost portion, which is under the jurisdiction of the Reliability First Corporation.

The Joint Utilities cite and discuss the eight CIP standards that apply to cybersecurity,[86] as well as the voluntary cybersecurity guidelines developed by the National Institute of Standards and Technology.[87]

The Joint Utilities also provide a discussion of the tools that comprise the "Guide to Developing a Cyber Security and Risk Mitigation Plan," developed by the National Rural Electric Cooperatives Association and the Cooperative Research Network ("CRN"). The purpose of the CRN guide is to enable cooperatives to strengthen their security posture and allow for continuous improvement.[88]

Finally, the Joint Utilities cite the "Cyber Security Risk Assessment and Risk Mitigation Plan Review for the Kentucky Public Service Commission" ("Guernsey Report") that shows that oversight activities are being conducted for utilities not subject to mandatory requirements.[89]

The Guernsey Report offered a focused assessment and general guidance on areas of utility operations that may be susceptible to cyber threats for Kentucky's smaller electric cooperatives and other similarly situated entities. Although participation in the Guernsey cybersecurity assessment was voluntary and limited to only six electric cooperatives, the intent was to develop a document that could be a starting point for further evaluation and improvement of utility operations. Twenty one topical areas were identified in the Guernsey Report for the purpose of evaluating the general effectiveness of utility operations and identifying opportunities for improvement in mitigating cyber

[86] Report at 59–60.

[87] *Id.* at 60–61.

[88] *Id.* at 61.

[89] *Id.* at 62.

risks. Since release of the Guernsey Report, the Kentucky Association of Electric Cooperatives has spearheaded a workgroup to further develop operating procedures and work practices to address cybersecurity threats for its membership.

The Joint Utilities state that none of its group takes cybersecurity lightly.[90] However, they argue that more requirements may be counterproductive because cyber-attacks are constantly evolving and a focus on compliance could create a false sense of security.[91]

The AG recommends that the Commission require compliance with the mandatory and voluntary standards, guidelines and resources cited in the Report.[92] The AG also recommends that the Joint Utilities use the best foreseeable measures possible to secure their cybersecurity.[93] To support its position, the AG cites comments from several cybersecurity experts and from a Chairman's forum on cybersecurity hosted by the Commission.[94] CAC states that utilities should work diligently to take reasonable measures to prevent and defeat cyber-attacks.[95]

The Commission agrees with the Joint Utilities that a mature, effective cybersecurity process is one that is continuously evolving to address new cyber threats. However, the Commission believes that each utility should have some form of cybersecurity plan in place beyond the FERC or NERC mandatory standards.

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[90] *Id.* at 63.

[91] *Id.* at 62.

[92] *Id.* at 5 and 64.

[93] *Id.*

[94] *Id.* at 63–64.

[95] *Id.* at 5 and 64.

Therefore, the Commission will require that the Joint Utilities develop internal procedures addressing cybersecurity.

Having met with representatives of each of Kentucky's major jurisdictional electric, gas, and water utilities to discuss cybersecurity, the Commission is generally aware of the effort the Joint Utilities have taken (and are taking) to address cyber threats.[96] Each utility particularly cited the confidential and sensitive nature of their plans to address cyber issues. Given the sensitivity of cybersecurity concerns, the utilities should be allowed to keep their procedures confidential.

The Commission, therefore, will not require each utility's actual internal procedure be filed; rather each utility will be required to certify the development of cybersecurity procedures. The utilities will then be required to make a presentation describing their procedures to the Commission (and the AG, should he wish to attend). In addition, the Joint Utilities will be required to continue to make cybersecurity presentations every two years to the Commission through the Track Meeting process.

All utilities are advised to develop, maintain and enforce a management approved written cybersecurity policy that addresses known and reasonably foreseeable cybersecurity risks. The policy and any subsequent procedures developed should incorporate essential elements of each utility's system that may be susceptible to cyber threats in conjunction with plans for hazard mitigation, emergency response and recovery and other relevant continuity of service arrangements.

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[96] The AG was invited and participated in person or by phone in each meeting.

Cost Recovery

The Joint Utilities state that since each utility is deploying smart technology "under different circumstances, in different ways, at different paces, and to different extents,"[97] there cannot be one specific approach to addressing cost recovery.[98] The Joint Utilities believe that all the utilities should be able to propose, and the Commission should consider, any form of cost recovery including traditional base rates, existing cost recovery mechanisms (e.g., demand-side management riders), and new riders or surcharge mechanisms.[99] They also believe that utilities proposing smart technology deployments that necessitate retiring existing utility assets with unrecovered book life should take the cost of those retirements into account in their cost-benefit analyses and be able to recover that cost if the deployment is prudent.[100] Finally, the Joint Utilities state that additional proceedings or criteria for Smart Grid deployments are unnecessary because existing cost recovery and other review proceedings and mechanisms are sufficient.[101]

In the Report, the Joint Utilities state that there must be reasonable assurance of cost recovery of prudent investments and of the remaining book costs of replaced equipment for utilities to invest in Smart Grid technologies to improve the service and information their customers receive.[102] They state that there is nothing novel about this

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[97] Report at 5.

[98] *Id.*

[99] *Id.* at 5 and 70.

[100] *Id.*

[101] *Id.*

[102] *Id.* at 70.

concept, whether for smart technologies or other utility investments.[103] The Joint Utilities cite the manner in which they have been allowed to recover smart technology costs in Kentucky and other jurisdictions in which they operate.[104] In particular, they discuss the cost recovery authorized for Taylor County RECC, Shelby Energy, and South Kentucky RECC for major meter change outs.[105]

The AG does not oppose the economical and cost-effective investment in smart technologies, but reserves judgement on his ultimate position based on a case-by-case review of cost recovery requests as they occur. CAC provided no comments on this topic.[106]

The Commission is sensitive to the Joint Utilities' concern regarding the cost recovery of reasonable smart technology investment and recovery of the remaining cost of replaced facilities and equipment. The Commission currently has the authority to reasonably address smart technology investment issues, and we conclude that the requirement to develop internal procedures regarding Smart Grid investment will assist both the utilities and the Commission in addressing cost-recovery concerns. To the extent that investments are in accordance with a Commission-approved internal Smart Grid investment policy, there should be a strong presumption that the investment was reasonable. Therefore, except for the development of an internal Smart Grid investment policy, the Commission will not impose any additional review of such

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[103] *Id.*

[104] *Id.* at 70–74.

[105] *Id.* at 71–73.

[106] *Id.* at 5 and 76.

investments. Smart Grid investments will therefore be treated like any other investment or expense.

How Natural Gas Companies Might Participate in Electric Smart Grid

The Joint Utilities state that Kentucky's Gas LDCs have pioneered deployment of automated and smart technologies because they have deployed SCADA in their distribution systems and AMR in meter reading for many years.[107] They assert that the Gas LDCs have already achieved associated efficiencies and that they have less to gain from smart technology deployment than the electric utilities.[108]

Neither the AG nor CAC provided any comments with regard to this issue in the Report.

The Commission recognizes that Smart Grid and smart meter issues are predominantly confined to the electric industry. We also agree that operational savings from further Smart Grid investment is not likely to be achieved by the Gas LDCs. The Commission further notes that, with one exception, the Gas LDCs do not offer TOU or dynamic pricing structures.[109]

The Commission will require the Gas LDCs to comply with the customer privacy, consumer education, and cybersecurity internal procedures requirements contained herein. The broad issues in these three areas apply to both electric and gas utilities.

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[107] *Id.* at 6 and 64.

[108] *Id.*

[109] LG&E's TS-2 transportation service reduces the transportation rate to commercial and industrial customers by $.50 per Mcf during the months of April through October.

SUMMARY OF FINDINGS

1. Neither the EISA 2007 Smart Grid Information Standard nor the Smart Grid Investment Standard should be adopted.

2. The Joint Utilities should provide customers access to historical information regarding their energy use and tariff rate and should endeavor to provide this information to customers in as close to real-time as practical. Furthermore, the Joint Utilities should provide aggregated information to CAC upon its reasonable request.

3. The Joint Utilities should develop internal procedures governing customer privacy, customer education, and cybersecurity as set forth in this Order.

4. Within 60 days of the date of this Order, the Joint Utilities should file with the Commission their internal procedures governing customer privacy and customer education.

5. Within 60 days of the date of this Order, the Joint Utilities should certify to the Commission that they have developed internal cybersecurity procedures.

6. Dynamic pricing requirements should not be mandated, but the jurisdictional electric utilities should strongly consider the development of voluntary pilot programs and tariffs.

7. Provisions allowing customers to opt out of smart meter deployments should be considered as they are proposed by individual utilities.

8. The jurisdictional electric utilities should be required to develop internal procedures regarding Smart Grid investments to include but not be limited to a

description of their systems, their planning goals, and explanations of how such investments will be considered.

9. The jurisdictional electric utilities should identify Smart Grid investments in each rate case.

10. Utility investments in Smart Grid and unrecovered book value of replaced equipment should be treated like any other investment or expense, and afforded full rate recovery following a request for recovery, discovery, and Commission approval, if reasonable.

IT IS HEREBY ORDERED that:

1. Neither the EISA Smart Grid Information Standard nor the EISA 2007 Smart Grid Investment Standard shall be adopted.

2. The Joint Utilities shall develop policies and procedures that provide customers access to historical information regarding their energy use and tariff rate and shall endeavor to provide this information to customers in as close to real-time as practical. Furthermore, the Joint Utilities shall provide aggregated information to CAC upon its reasonable request.

3. The Joint Utilities shall develop internal policies and procedures governing customer privacy, customer education, and cybersecurity as set forth in this Order.

4. Within 60 days of the date of this Order, the Joint Utilities shall file with the Commission their internal procedures governing customer privacy and customer education.

5. Within 60 days of the date of this Order, the Joint Utilities shall certify to the Commission that they have developed internal cybersecurity procedures.

6. The jurisdictional electric utilities shall not be required to develop Dynamic Pricing programs and tariffs, but they are encouraged to do so.

7. Customer participation in any Dynamic Pricing program or tariff shall be voluntary.

8. Provisions allowing customers to opt out of smart meter deployments shall be considered as they are proposed by individual utilities.

9. The jurisdictional electric utilities shall be required to develop internal policies and procedures regarding Smart Grid investments as described in this Order.

10. Within 60 days of the date of this Order, the jurisdictional electric utilities shall file with the Commission their internal procedures regarding Smart Grid investments.

11. The jurisdictional electric utilities shall identify Smart Grid investments in each rate case.

12. Utility investments in Smart Grid and unrecovered book value of replaced equipment shall be treated like any other investment or expense, and afforded full rate recovery following a request for recovery, discovery, and Commission approval, if reasonable.

13. Any documents filed in the future pursuant to ordering paragraphs 4, 5, and 10 herein shall reference this case number and shall be retained in the utility's general correspondence file.

14. The Executive Director is delegated authority to grant reasonable extensions of time for the filing of any documents required by this Order upon the showing of good cause for such extension.

15. This case is hereby closed and removed from the Commission's docket.

By the Commission

ENTERED

APR 13 2016

KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Aaron D. Greenwell

Acting Executive Director

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2012-00428 DATED APR 13 2016

Dynamic Pricing defined:[110]

Dynamic pricing refers to pricing that varies according to the time at which the energy is consumed. It is normally tied directly or indirectly to prices in the wholesale market or to system conditions (peaks) and normally is delivered to a customer via time-based rates or tariffs. There are several different kinds of dynamic pricing.

A. Time-of-Use ("TOU") or Time-of-Day ("TOD") — TOU or TOD rates typically divide a day into two or three groups of hours that have different rates associated with them. For example, a utility might divide the day into peak, intermediate, and off-peak rates, with different hours assigned to each rate, e.g., late evening through early morning would typically be off-peak hours. Each day may have one or two peak periods and may have as many as three intermediate periods. The hours assigned to each pricing period may change seasonally, as well; for example, a summer-peaking utility may have summer TOU periods and different non-summer TOU periods. The rates associated with each period might also change seasonally.

TOU or TOD rates may vary by season, but typically the design is predictable and easy for the customer to understand. Because these rates do not reflect varying cost conditions, they are ordinarily characterized as having little dynamism.

B. Critical-Peak Pricing ("CPP") — There are two types of CPP rates: variable and fixed. Fixed CPP rates are identical to TOU rates with the added feature that during certain days of the year, which are prescribed by tariff, there are a relatively small number of critical-peak hours that have a markedly higher rate than the standard TOU peak rate. Like TOU rates, fixed CPP rates do not reflect varying cost conditions, making them equally lacking in dynamism as TOU rates. Variable CPP rates, however, add an element of dynamism that TOU and fixed CPP rates do not have because the critical-peak periods are not established by tariff; rather, the implementing utility typically may call a critical peak no more than a certain number of times for certain maximum durations during a year, and may do so on an established amount of notice to customers, usually anywhere from half an hour to several hours.

C. Peak-Time Rebate ("PTR") — PTR rates usually involve establishing a baseline amount of usage for a customer or group of customers and then rewarding those customers with rebates for using less than the baseline amount of energy during peak periods. As with CPP rates, the peaks can be established by tariff or can be called by the utility upon established notice to customers.

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[110] Report at 37–38.

D. Real-Time Pricing ("RTP") — RTP rates are the most dynamic of the dynamic-pricing options. Under RTP, customers pay rates linked to the hourly market price for electricity. Customers typically receive hourly prices on a day-ahead or hour-ahead basis.

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Legal Department

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

March 25, 2015

Barcy F. McNeal
Docketing Division Chief
Public Utilities Commission of Ohio
180 East Broad Street
Columbus Ohio 43215-3793

Re: *In the Matter of the Application of Ohio Power Company to Update its gridSMART Rider*, Case No. 14-192-EL-RDR; *Ohio Power Company*, Case No. 89-6007-EL-TRF

Steven T. Nourse
Senior Counsel –
Regulatory Services
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Dear Ms. McNeal:

Enclosed are Ohio Power Company's compliance tariffs, which are being filed in accordance with the Commission's Finding and Order dated March 18, 2015 in Case No. 14-192-EL-RDR.

The Companies will update their tariffs previously filed electronically with the Commission's Docketing Division. Thank you for your attention to this matter.

Regards,

/s/Steven T. Nourse

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cc: Parties of Record

COMPLIANCE
Attachment 1

2014 Ohio Power Company gridSMART Rider True-Up
Case No. 14-0192-EL-RDR

Line No.	2013 Over/(Under) Recovery	2013 Actual Spending	2013 Actual Carrying Charge	2013 Actual Revenue Requirement
1	O&M	$ 2,276,840		$ 2,276,840
2	Capital - 5 Year Life	$ 2,857,383	$ 6,056,646	$ 6,056,646
3	Capital - 7 Year Life	$ 3,261,405	$ 3,782,144	$ 3,782,144
4	Capital - 10 Year Life	$ (684,215)	$ 170,962.52	$ 170,963
5	Capital - 15 Year Life	$ (598,501)	$ (209,766)	$ (209,766)
6	Capital - 30 Year Life	$ 97,619	$ 2,070,545	$ 2,070,545
7	Capital - 35 Year Life	$ 910	$ 66,957	$ 66,957
8	Capital - 40 Year Life	$ 187,690	$ 230,109	$ 230,109
9	Total Capital	$ 5,122,290	$ 12,167,597	$ 12,167,597
10	Total		2013 Actual Revenue Requirement	$ 14,444,437
11			2013 gridSMART Rider Collections	$ 2,468,188
12			2013 Over/(under) Recovery	$ (11,976,249)

Line No.	AEP Ohio- gridSMART 2014 Incremental Investment	2014 Estimated gridSMART Spending (a)			Carrying Charge Rate	2014 gridSMART Revenue Requirement	
13	O&M	2,211,483				$ 2,211,483	
14	Capital - 5 Year Life	-			31.29%	$ -	
15	Capital - 7 Year Life	-			26.54%	$ -	
16	Capital - 10 Year Life	-			21.07%	$ -	
17	Capital - 15 Year Life	-			18.14%	$ -	
18	Capital - 30 Year Life	-			14.95%	$ -	
19	Capital - 35 Year Life	-			14.51%	$ -	
20	Capital - 40 Year Life	-			14.19%	$ -	
21	Total Capital	-		2014 Revenue Requirement		$ 2,211,483	(a)
22				Credit RR Captial Carrying Charge Adj		$ (7,324,644)	(b)
23				O&M Reclass		$ 10,130,608	(c)
24				Capital Carrying Costs		$ 9,878,514	(d)
25				Over/(Under) Recovery to Date		$ 1,983,728	(e)
26				Over/(Under) Recovery (From Above)		$ (11,976,249)	
27				Total 2013 Revenue Requirement		$ 24,888,482	
			December 31, 2013 Base Distribution Rev				
28		Residential	$ 392,896,753	Residential Revenue Requirement		$ 15,405,767	
29		Non-Residential	$ 241,841,069	Non-Res Revenue Requirement		$ 9,482,715	
30				Residential Customers @12/31/213	1,273,602	12.10	
31				Non-Residential Customers @12/31/213	187,382	50.61	
32				Residential Customers	Monthly Rate	$ 1.01	
33				Non-Residential Customers	Monthly Rate	$ 4.22	

(a) Estimated 2014 gridSMART O&M spending (Capital Spending ended at 12/31/2013)
(b) Captial Projects Reclassed to O&M. Carrying Charges credited from inception
(c) Capital Projects Reclassed to O&M
(d) Annual carrying charge rate times actual capital spending as of 12/31/2013 (Includes Reduced Carrying Charges for Captial Reclassed to O&M)
(e) gridSMART Over Recovery to date $1,983,728 (Actual 2009 over recovery of $7,936,573, plus 2010 under Recovery of $1,734,209, plus 2011 over recovery of $1,076,281 plus 2012 under recovery $5,294,916)

P.U.C.O. NO. 20

gridSMART RIDER

Effective ~~April 17, 2014~~__________, all customer bills subject to the provisions of this Rider, including any bills rendered under special contract, shall be adjusted by the monthly gridSMART charge. This Rider shall be adjusted periodically to recover amounts authorized by the Commission.

Residential Customers	$ ~~0.51~~1.01/month
Non-Residential Customers	$ ~~2.10~~4.22/month

OHIO POWER COMPANY

COMPLIANCE
~~3rd~~ 4th Revised Sheet No. 484-1D
Cancels ~~2nd~~ 3rd Revised Sheet No. 484-1D

P.U.C.O. NO. 20

OAD – gridSMART RIDER
(Open Access Distribution – gridSMART Rider)

Effective ~~April 17, 2014~~__________ all customer bills subject to the provisions of this Rider, including any bills rendered under special contract, shall be adjusted by the monthly gridSMART charge. This Rider shall be adjusted periodically to recover amounts authorized by the Commission.

Residential Customers	$ ~~0.51~~1.01/month
Non-Residential Customers	$ ~~2.10~~4.22/month

Filed pursuant to Order dated ~~February 19,2014~~March 18, 2015 in Case No. ~~13-0345-EL-RDR~~14-192-EL-RDR

Issued: ~~April 15, 2014~~__________ Effective: ~~April 17, 2014~~__________

Issued by
Pablo Vegas, President
AEP Ohio

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KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 96

Responding Witness: William S. Seelye

Q.1-96. With regard to Schedule M-2.3 pages 3-15, please explain how the total Base Demand charge revenue requirement for Rates TOD-Secondary, TOD-Primary and RTS were each determined.

A.1-96. The Base Demand Charge revenue requirement corresponds to the transmission and distribution demand-related costs from the cost of service. Specifically, Base Demand Charge revenue requirements include the fixed demand cost portions of depreciation expenses, operation and maintenance expenses, return on investment, income taxes less miscellaneous revenues.

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IMPLAN Multipliers for Kentucky, 2015 Data			
	Employment Multiplier		
NAICS Industry, 2-digit level	Unweighted	Weighted	Percent of Jobs in KY
Utilities	3.911	3.069	0.37%
Information	3.047	2.892	1.24%
Real estate & rental	2.777	1.702	3.08%
Manufacturing	**2.604**	**2.636**	**10.15%**
Finance & Insurance	2.369	2.383	4.36%
Transportation & warehousing	2.279	1.925	5.07%
Management of companies	2.271	2.271	0.88%
Wholesale trade	2.194	2.194	3.29%
Mining	1.962	1.968	0.96%
Prof, tech & sci services	1.831	1.909	5.28%
Government & non-NAICS	1.814	1.445	13.95%
Construction	1.789	1.809	5.32%
Administrative & waste services	1.555	1.356	6.46%
Ag, forestry, fishing, hunting	1.542	1.434	3.69%
Health & social services	1.535	1.636	10.65%
Other services	1.506	1.411	4.99%
Arts, entertainment, & rec	1.454	1.385	1.52%
Retail trade	1.406	1.390	9.89%
Educational services	1.340	1.354	1.25%
Accommodations & food services	1.310	1.267	7.61%

Note: Weighted multiplier column uses the number of jobs in each individual industry within each two-digit industrial sector to weight the employment multipliers.

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evaluated in the Mid CO_2 price scenarios before the capacity was needed to maintain the target reserve margin.[16]

Capacity factors for existing coal units were averaged over the three gas price scenarios in each load-CO_2 price scenario. If an existing coal unit's capacity factor was consistently less than 10 percent in a given load-CO_2 price scenario, the unit was assumed to be retired in the year when its capacity factor consistently dropped below 10 percent.

8.(5)(d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;

The reliable supply of electricity is vital to Kentucky's economy and public safety. As electricity has become a more integral part of daily routines, customers have grown to expect it to be available at all times and in all weather conditions. The Companies carry generating reserves in excess of their expected peak demand in an effort to meet the needs of their customers and the communities they serve. However, customers also demand that energy is affordable, thus the Companies must balance the costs of generating capacity with the reliability benefits provided by that capacity.

The Companies' reserve margin analysis was prepared to determine the Companies' optimal reserve margin range. At higher reserve margin levels, the Companies' cost of carrying additional generating capacity is greater, but the risk and associated costs of shedding firm load due to generation shortages are lower. In addition, at higher reserve margins, the Companies' reliance on neighboring markets and the need to dispatch higher cost generating resources is reduced. At lower reserve margin levels, costs may be lower but the risk of load shedding is increased.

[16] 2x1 NGCC and wind units were the most economical options in a CO_2-constrained world.

In the analysis, the cost of the Companies' generating portfolio was evaluated at different reserve margin levels by adding or subtracting simple-cycle combustion turbine ("SCCT") capacity. "Scarcity cost" is defined as the sum of unserved energy costs, the cost of purchased power greater than the marginal cost of a SCCT, and the cost of dispatching other generating resources more expensive than a SCCT. As SCCT capacity is added, scarcity costs will decrease.

The Strategic Energy Risk Valuation Model ("SERVM") from Astrape Consulting was used to estimate scarcity costs as well as the number of loss-of-load events per year over a range of reserve margin levels. Scarcity costs and the likelihood of loss-of-load events are impacted by the uncertainty in weather, unit availability, economic load growth, the ability to import power from neighboring regions, and other factors. To properly capture the cost of high-impact, low-probability events, SERVM evaluates thousands of scenarios that encompass a wide range of the input variables.

The analysis determined the Companies' economic reserve margin range as well as the reserve margin needed to meet physical reliability standards. To determine the economic reserve margin range, scarcity costs and the cost of carrying SCCT capacity were estimated over a range of reserve margin levels. The economic reserve margin is the reserve margin where the sum of these costs is minimized.

In North America, the most commonly used physical reliability guideline is the "1-in-10 loss-of-load event" ("1-in-10 LOLE") guideline. Systems that adhere to this guideline are designed to experience one loss-of-load event in ten years. The reserve margin that meets the 1-in-10 LOLE guideline does not necessarily coincide with the economically optimal reserve margin.

In the reserve margin analysis, the planning reserve margin range was determined by considering the economic reserve margin range as well as the reserve margin needed to meet physical reliability guidelines. The Companies' reserve margin analysis is titled *2014 Reserve Margin Study* and is contained in Volume III, Technical Appendix.

8.(5)(e) Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;

The Companies will continue to develop the least cost strategy for meeting future load requirements by analyzing the economics of various configurations of combined-cycle units and renewable generation, monitoring the development of environmental regulations, evaluating the potential for retiring existing units, and reviewing purchased power as an option to delay generation construction. In addition, the Companies will continue to develop ways to incorporate uncertainty into their analyses.

8.(5)(f) Actions to be undertaken during the 15 years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment; and

The Acid Deposition Control Program was established under Title IV of the CAAA and applies to the acid deposition that occurs when SO_2 and nitrogen oxides NO_X are transformed into sulfates and nitrates and combine with water in the atmosphere to return to the earth in rain, fog or snow. Title IV's purpose is to reduce the adverse effects of acid deposition through a permanent reduction in SO_2 emissions and NO_X emissions from the 1980 levels in the 48 contiguous states. With the CAIR implementation in 2009 for NO_X and 2010 for SO_2, the further reductions in SO_2 and NO_X aided in reducing ozone and fine particulate ("$PM_{2.5}$") in the affected regions of the country (including Kentucky). However, with the future implementation of new NAAQS for NO_X, $PM_{2.5}$, Ozone, and SO_2, future promulgation or replacement of CSAPR