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Columbus Southern Power

Ohio Power Company

List of exhibits being filed:

AEP Exs. 120 and 122

FES Ex. 119

NFIB Ex. 105

OCC Ex. 109

IEU Ex. 120

Reporter's Signature: Maria DiPaolo Jones

Date Submitted:

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

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

- - -

PROCEEDINGS

before Ms. Greta See and Mr. Jonathan Tauber, Attorney Examiners, and Commissioner Andre Porter, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 8:30 a.m. on Friday, May 25, 2012.

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VOLUME VII

- - -

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AE p 120

Footnote

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company.	)	Case No. 02-2779-EL-ATA
In the Matter of the Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code.	)	Case No. 02-2879-EL-AAM
Ohio Consumers' Counsel, Industrial Energy Users-Ohio and American Municipal Power-Ohio, Inc., v. The Dayton Power and Light Company.	)	Case No. 02-2364-EL-CSS
In the Matter of the Application of The Dayton Power and Light Company for Authority to Revise Tariff Sheet in DP&L P.U.C.O. No. 17.	)	Case No. 02-570-EL-ATA

OPINION AND ORDER

The Commission, coming now to consider the stipulation, testimony, and other evidence presented in these proceedings, hereby issues its opinion and order.

APPEARANCES:

Faruki Ireland & Cox P.L.L., by Mr. Charles J. Faruki, Mr. Paul L. Horstman, and Mr. Jeffrey S. Sharkey, 500 Courthouse Plaza, S.W., 10 North Ludlow Street, Dayton, Ohio 45402-1818, and Mr. Athan A. Vinolus, Associate Counsel of The Dayton Power & Light Company, 1065 Woodman Drive, Dayton, Ohio 45432, on behalf of The Dayton Power and Light Company (DP&L).

Jim Petro, Attorney General of the State of Ohio, Duane W. Luckey, Section Chief, by Mr. William L. Wright, Mr. Thomas G. Lindgren, and Mr. Thomas McNamee, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of the staff of the Public Utilities Commission of Ohio.

Robert S. Tongren, Ohio Consumers' Counsel, by Mr. Jeffrey L. Small, Ms. Ann M. Hotz, Mr. Larry S. Sauer, and Mr. John R. Smart, Assistant Consumers' Counsels, Office of Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215, on behalf of residential utility consumers of DP&L.

Ellis Jacobs, 333 West First Street, Suite 500, Dayton, Ohio 45402, on behalf of Community Action Partnership of the Greater Dayton Area, f/k/a Supporting Council of Preventative Effort.

Bell, Royer & Sanders Co., LPA, by Ms. Judith B. Sanders, 33 South Grant Avenue Columbus, Ohio 43215-3927, on behalf of The Ohio Manufacturers' Association.

Vorys, Sater, Seymour & Pease LLP, by Mr. M. Howard Petricoff and Mr. W. Jonathan Airey, 52 East Gay Street, PO Box 1008, Columbus, Ohio 43215, on behalf of Constellation NewEnergy, Inc.

Vorys, Sater, Seymour & Pease LLP, by Mr. Steven M. Howard, 52 East Gay Street, PO Box 1008, Columbus, Ohio 43215, on behalf of Strategic Energy, LLC.

McNees, Wallace & Nurick, by Mr. Samuel C. Randazzo, Ms. Lisa M. Gatchell, Ms. Gretchen J. Hummel and Mr. Michael R. Rankin, 21 East State Street, 17th Floor, Columbus, Ohio 43215, on behalf of Industrial Energy Users-Ohio.

David C. Rinebolt, Executive Director and Counsel, 337 South Main Street, 4th Floor, Suite 5, Findlay, Ohio 45840, on behalf of Ohio Partners for Affordable Energy.

Craig I. Smith, 2824 Coventry Road, Cleveland, Ohio 44120, on behalf of Cargill, Inc.

Hahn Loeser & Parks LLP, by Ms. Janine L. Migden, 21 East State Street, Columbus, Ohio 43215, on behalf of Energy America, LLC.

Gary A. Jeffries, Senior Counsel, 1201 Pitt Street, Pittsburgh, Pennsylvania, 15221, on behalf of Dominion Retail, Inc.

Evelyn R. Robinson, Green Mountain Energy Company, 5450 Frantz Road, Suite 240, Dublin, Ohio 43016, and Bruce J. Weston, 169 W. Hubbard Avenue, Columbus, Oho 43215, on behalf of Green Mountain Energy Company.

Vorys, Sater, Seymour & Pease LLP, by Mr. Gregory D. Russell, 52 East Gay Street, PO Box 1008, Columbus, Ohio 43215, and Mr. Ivan Henderson, WPS Energy Services, Inc., Bank One Center, 600 Superior – Suite 1300, Cleveland, Ohio 44114, on behalf of WPS Energy Corporation.

I. HISTORY OF THE PROCEEDINGS

On June 22, 1999, the Ohio General Assembly passed legislation[1] requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (SB 3). Pursuant to SB 3, on August 31, 2000, the Commission issued an opinion and order (ETP opinion) approving and modifying a stipulation and recommendation with regard to the electric transition plan (ETP) of DP&L.[2] In its ETP opinion, the Commission, among other things, allowed DP&L a market

1 Amended Substitute Senate Bill No. 3 of the 123rd General Assembly.

2 *In the Matter of the Application of the Dayton Power and Light Company for Approval of its Transition Plan Pursuant to Section 4928.31, Revised Code and for the Opportunity to Receive Transition Revenues as Authorized Under Sections 4928.31 to 4928.40, Revised Code,* Case No. 99-1687-EL-ETP, Opinion and Order, .

development period (MDP) of three years, ending December 31, 2003, and calculated the regulatory transition charges (RTC) and customer transition charges (CTC) on the basis of that three-year MDP. In the ETP opinion, the Commission also required DP&L to take a variety of listed actions related to transmission issues, including transferring control of its transmission facilities to a regional transmission organization (RTO) approved by the Federal Energy Regulatory Commission (FERC) and becoming a transmission-owner member of an RTO by no later than January 1, 2001. During that MDP, the Commission anticipated that competition would develop, to the level described by the General Assembly in SB 3. The parties to this proceeding do not dispute that such competition has not developed.[3] It is also clear that a variety of events have occurred which have served as obstacles to DP&L's compliance with its transmission-related obligations under the ETP opinion.[4]

As a result of the failure of competition to develop according to expectations, on October 28, 2002, DP&L filed an application to extend its MDP through December 31, 2005, the latest date allowed for termination of the MDP under Section 4928.40(A) (MDP case).[5] On November 1, 2002, DP&L also filed an application for accounting authority to defer costs associated with the implementation of the revised Electric Service and Safety Standards adopted by the Commission on September 29, 2002 (accounting case).[6] Motions to intervene in the MDP case and the accounting case were received from the Ohio Consumers' Counsel (OCC), Ohio Partners for Affordable Energy (OPAE), Honda of America Mfg., Inc. (Honda), The Supporting Council of Preventive Effort (now known as Community Action Partnership of the Greater Dayton Area) (CAP), Industrial Energy Users-Ohio (IEU-Ohio), Strategic Energy, LLC (Strategic), The Kroger Co. (Kroger), Energy America, LLC (Energy America), Constellation NewEnergy, Inc. (Constellation); The Ohio Manufacturers' Association (OMA); AMPO, Inc. (AMPO); and Cargill, Inc. (Cargill). Comments were also received from the Ohio Hospital Association. On April 1, 2003, the Commission issued an entry setting April 16, 2003, as the final date on which motions to intervene in these cases would be received, setting a schedule for other aspects of the cases, and granting all intervention motions filed to date.[7] Additional motions for intervention were subsequently received from the National Energy Marketers Association (NEMA) and Dominion Retail, Inc (Dominion). Such intervention was granted to Dominion at the hearing on May 15, 2003.

The staff of the Commission filed a report and recommendations in the MDP and accounting cases on March 31, 2003. Responses to that report and objections to DP&L's application in the MDP case were received from DP&L, Strategic, Constellation, CAP, Cargill, OPAE, ACC, IEU-Ohio, and NEMA.

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3 See, for example, The Dayton Power and Light Company's Comments on Staff Recommendations, Filed April 16, 2003, at 2; Testimony of Ms. Seger-Lawson, Tr. II at 50; The Dayton Power and Light Company's Reply Hearing Brief at 1; Post-Hearing Merit Brief of the Ohio Consumers' Counsel, at 1-3; Initial Brief of Strategic Energy, LLC, Dominion Retail, Inc. and Constellation NewEnergy, Inc., at 2; and Reply Brief Submitted on Behalf of the Staff of the Public Utilities Commission of Ohio at 5.

4 See, for example, Pre-Filed Testimony of Mr. Hertzel Shamash, Company Exhibit 2.

5 *In the Matter of the Continuation of the Rate Freeze and Extension of the Market Development Period for the Dayton Power and Light Company*, Case No. 02-2779-EL-ATA.

6 *In the Matter of the Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code*, Case No. 02-2879-EL-AAM.

7 AMPO, Honda, Kroger, and Cargill subsequently withdrew from these proceedings.

On September 12, 2002, OCC, IEU-Ohio and American Municipal Power-Ohio, Inc., brought an action against DP&L, alleging that DP&L violated the terms of the stipulation adopted in the ETP opinion by failing to be a part of an operating, FERC-approved RTO on the anticipated schedule (RTO case).[8] CAP intervened in this proceeding. Following discovery, on February 20, 2003, the Commission issued an entry staying all further actions in the RTO case and denying DP&L's motion to dismiss the complaint. On March 21, 2003, DP&L filed an application for rehearing, which was denied by the Commission on April 17, 2003.

On March 1, 2002, DP&L filed an application to modify its current company tariffs to allow it to withdraw some services that are being offered and to modify some others, including the interest rate paid on customer deposits (deposits case).[9] Following an October 31, 2002, Commission finding and order authorizing DP&L to modify its tariffs as requested, an application for rehearing was filed by OCC on November 27, 2002, and granted on December 19, 2002, for the purpose of allowing the Commission additional time to consider the issues raised on rehearing.

On April 25, 2003, OCC and IEU-Ohio filed a motion to consolidate the MDP case, the accounting case, the RTO case, and the deposits case, to lift the stay on the RTO case, and to clarify the issues to be considered. As requested, on May 6, 2003, the Commission did consolidate the four cases, lift the stay and clarify issues to be considered.

The hearing on the consolidated cases commenced on May 15, 2003, with the hearing of public testimony. Mr. Harvey Tuck, a customer of DP&L for 50 years and a stockholder in DP&L for 27 years, testified as to his opinion of electric deregulation. He stated that he believes deregulation will cause a risk of substantial price escalation and blackouts, in exchange for only a modest cost savings.

The hearing continued on May 29, 2003, at which time DP&L presented a stipulation which was reached among some of the parties in the proceeding. Testimony by DP&L's witnesses was received. The hearing was then adjourned to allow for further discovery related to the stipulation.

On June 9, 2003, Green Mountain Energy Company (Green Mountain) moved to intervene in the MDP case, the accounting case and the RTO case (Green Mountain's motion to intervene). Memoranda in opposition to this intervention were filed by DP&L and OCC (DP&L's memorandum contra intervention and OCC's memorandum contra intervention, respectively). On June 12, 2003, WPS Energy Services, Inc., filed a motion to intervene in all four consolidated cases (WPS's motion to intervene). On June 16, 2003, OCC filed a letter requesting that this motion be denied (OCC's letter contra intervention).

On June 16, 2003, Strategic, Constellation, and Dominion filed a motion to compel discovery (CRES motion to compel), relating to certain deposition questions about the existence of agreements, other than the proposed stipulation, between DP&L and any of the parties to that stipulation.

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8 *Ohio Consumers' Counsel, Industrial Energy Users-Ohio and American Municipal Power-Ohio, Inc. v. The Dayton Power and Light Company*, Case No. 02-2364-EL-CSS.

9 *In the Matter of the Application of The Dayton Power and Light company for Authority to revise Tariff Sheet in DP&L P.U.C.O. No. 17*, Case No. 02-570-EL-ATA.

On June 17, 2003, the hearing continued. Interventions by Green Mountain and WPS were denied. However, Green Mountain and WPS were permitted to file amicus curiae briefs. The motion to compel discovery was likewise denied. The remainder of the testimony was received and the hearing was adjourned and submitted on the record, subject to the filing of briefs.

On June 20, 2003, Green Mountain filed an interlocutory appeal to the denial of its intervention (Green Mountain's intervention appeal). Memoranda contra the interlocutory appeal were filed by DP&L (DP&L's memorandum contra intervention appeal), OCC (OCC's memorandum contra intervention appeal), and IEU-Ohio (IEU-Ohio's memorandum contra intervention appeal).

On June 23, 2003, Strategic Energy, Constellation New Energy and Dominion Retail filed an application for review and approval of their interlocutory appeal of the attorney examiners' denial of their motion to compel discovery related to side agreements (CRES discovery appeal). Memoranda contra their interlocutory appeal were filed by DP&L and IEU-Ohio (DP&L's memorandum contra discovery appeal and IEU-Ohio's memorandum contra discovery appeal, respectively). Strategic Energy, Constellation NewEnergy and Dominion retail filed for leave to file a reply to the memoranda contra their appeal (CRES discovery appeal reply). A memorandum contra the filing of such a reply was filed by DP&L, and a letter expressing its opinion that such a reply should not be received was filed by OCC.

An initial hearing brief was filed by DP&L on May 29, 2003, at the second day of the hearing (DP&L's initial brief). Post hearing briefs were filed on July 3, 2003, by DP&L (DP&L's brief), OCC (OCC's brief), CAP (CAP's brief), OMA (OMA's brief), IEU-Ohio (IEU-Ohio's brief), and the staff of the Commission (staff's brief), and by Strategic, Dominion and Constellation, filing as a group (CRES group's brief). A letter stating its concurrence with the CRES group's brief was filed by Energy America. Amicus curiae briefs were filed by Green Mountain (Green Mountain's brief) and WPS (WPS's brief).

Reply briefs were timely filed on July 15, 2003, by DP&L (DP&L's reply), OCC (OCC's reply), IEU-Ohio (IEU-Ohio's reply), OMA (OMA's reply), and the staff of the Commission (staff's reply), and by Constellation, Dominion, Strategic, WPS, and Energy America, filing as a group (CRES group's reply). An amicus curius reply brief was timely filed by Green Mountain. Additionally, a reply brief was filed late by OPAE and CAP.

Letters expressing support for the proposed stipulation were filed by Ohio Home Builders Association, Inc.; The Timken Company; Appleton Papers Inc.; and Marathon Ashland Petroleum LLC. OMA also filed a letter expressing its concern regarding its not having been included in settlement negotiations.

II. INTERLOCUTORY APPEALS

A. Intervention

Ohio law provides that a motion to intervene will not be considered timely if it is filed later than either five days before the scheduled date of the hearing on the matter or the specific deadline established for intervention in the particular matter.[10] In the MDP case and the accounting case, the Commission issued an entry specifically setting the deadline for intervention at April 16, 2003.[11] Thus, intervention was required by that specific date. In the RTO case and the deposits case, no specific deadline was set. Intervention was therefore required in those cases by no later than five days before the scheduled commencement of the hearing. As the hearing was scheduled to begin on May 15, 2003, timely motions for intervention in the RTO case and the deposits case would have been required by May 12, 2003.[12]

As noted above, Green Mountain and WPS filed their motions for intervention on June 9, 2003, and June 12, 2003, respectively, both well after the deadlines in the various cases.[13]

In Green Mountain's motion to intervene, in addition to discussing the merits of its intervention,[14] Green Mountain briefly argues that its motion should be considered timely, as it was filed more than five days prior to the date of the third day of the hearing.[15] It also contends that, if late, its intervention should still be allowed on the basis of "good cause shown," as required by Section 4903.221, Revised Code, or "extraordinary circumstances," as required by Rule 4901-1-11(F), O.A.C. Green Mountain's argument was that it could not have known, prior to the filing of the proposed stipulation in these cases on May 28, 2003, that it was going to need to intervene. Green Mountain stated that it believes that the proposed stipulation will, if approved, perpetuate the lack of competition in the DP&L area and that, therefore, its presentation to the Commission gave Green Mountain impetus to file for intervention. (Green Mountain's motion to intervene.)

DP&L counters that the intervention was not filed on a timely basis and that the subject matters covered by the proposed stipulation were requested by DP&L long before the stipulation was filed, thus countering Green Mountain's argument that it could not have known it would want to intervene until the filing of that stipulation. DP&L reviews each issue raised in Green Mountain's motion to intervene, arguing that, with regard to each subject, the issue was raised in the cases prior to the filing of the stipulation. These issues include the level of shopping credits, the extension of the MDP, the calculation of switching percentages as including certain switching to an affiliate of DP&L, and the deferral of costs in the accounting case and the resolution of transmission issues in the RTO case. DP&L also argues that intervention by Green Mountain would delay the resolution of these cases, as its motion to intervene only includes a statement that it would "pursue reasonable efforts to work cooperatively with other CRES providers in the cases, to maximize case efficiency where practical." Finally, DP&L states that it believes Green Mountain's interests to be already represented adequately by the other CRES providers in the cases. (DP&L's memorandum contra intervention.)

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10 Section 4903.221, Revised Code; Rule 4901-1-11(E), Ohio Administrative Code (O.A.C).

11 Commission Entry, dated April 1, 2003.

12 As May 10th was a Saturday, intervention would have been required by the end of business on the following Monday.

13 Green Mountain sought intervention in all cases other than the deposits case. WPS sought intervention only in the MDP case.

14 The Commission does not disagree that Green Mountain has adequately shown its right to intervene, from a substantive standpoint. It is only the timing of the motion that is at issue.

15 The hearing was held on three days: May 15, May 29, and June 17, 2003.

OCC also opposed Green Mountain's motion to intervene. OCC insists that the motion was not filed on a timely basis and that Green Mountain's interests were already represented by other CRES providers. It notes that the filing of a stipulation in these cases was always a "distinct possibility." (OCC's memorandum contra intervention at 4.)

WPS also moved for intervention beyond the established deadline. However, it does not argue that its intervention should be considered timely. Rather, WPS complains that the stipulation would remove DP&L from the rules being developed for standard offer and bid out procedures, following the MDP. It points out that DP&L did not seek relief regarding post-market development activities prior to May 28, 2003, with the filing of the stipulation. Thus, WPS could not know that its interests were in jeopardy until that date. WPS only requests intervention with regard to "post-market development issues which were not a part of the original application." (WPS's motion to intervene at 3-4.)[16]

OCC opposed WPS's motion to intervene on the same grounds as it opposed the intervention of Green Mountain. It notes that the Commission's entry consolidating these four cases also made it clear that broad issues were potentially being resolved in these cases. (OCC's letter contra intervention; Commission entry, May 6, 2003.)

At the third day of the hearing, immediately following the filing of these motions to intervene, the parties orally argued their positions on this issue. Green Mountain emphasizes that it believes that the stipulation proposed in these cases "is dramatically different than what had previously been filed in this case." (Tr. III at 8.) The major changes mentioned in this oral argument by Green Mountain are, first, the possibility of an increase in rates of up to eleven percent under certain future circumstances, after approval by the Commission and, second, the extension of the impact of these cases to 2008 rather than 2005. (Tr. III at 8-9.) Counsel for WPS argues that the issues in the stipulation go beyond the relief sought in DP&L's original application in the MDP case and are contrary to statute. (Tr. III at 10.) Both Green Mountain and WPS believe that their interests are not represented by other CRES providers, as they are all competitors by their very nature (Tr. III at 18-19).

Counsel for DP&L points out that Green Mountain's interests are already represented and contends that Green Mountain's presence in these cases will delay the process (Tr. III at 11-12). DP&L also argues that Green Mountain's late filing of its motion to intervene should not be excused, as a broad stipulation should have been anticipated. "It is hardly unusual when a case before this Commission ends up with a stipulation that deals with matters that weren't covered in the applicant's initial filing. . . . In the give-and-take of bargaining, something ends up in the Stipulation and recommendation that you can't find in the initial filing." (Tr. III at 13-14.) As to WPS's intervention, DP&L notes that its interests are already vigorously represented (Tr. III at 14-15).

IEU-Ohio points out that the possible eleven percent increase would be submitted to the Commission for approval and that, if it were then interested, Green Mountain could submit comments in that proceeding. It also comments that it is the customers who

[16] The Commission does not disagree that WPS has adequately shown its right to intervene, from a substantive standpoint. It is only the timing of the motion that is at issue.

would be paying that increased fee who are truly interested in its existence, not the CRES providers. (Tr. III at 15-16.)

OCC also argues that the breadth of the stipulation is not a surprise which should allow late intervention (Tr. III at 17-18).

Following denial of their motions to intervene ((Tr. III at 19),[17] Green Mountain filed an interlocutory appeal of that denial. In Green Mountain's intervention appeal it first notes that Rule 4901-1-15(A)(2), O.A.C., allows the immediate appeal of an attorney examiner's denial of a motion to intervene. Thus, its appeal is properly before the Commission. Its argument on the merits is based on all of its previously argued positions, with additional discussion of the standard for granting a late-filed motion, undue delay which might be caused by its presence, and the representation of its interests by other CRES providers. Green Mountain also noted that the publication date of the Commission's legal notice regarding these cases was after the intervention deadline established for the MDP case and the accounting case. Finally, it submits that there was never any public notice given of various matters covered by the stipulation, including, the fact "that these consolidated cases would become the forum for resolving post-MDP issues." (Green Mountain's intervention appeal at 9.)

DP&L opposed this appeal. It argues that the stipulation does not implement an increase in rates since "the increase, if any, will occur only at some future date upon the filing of an application . . .." (DP&L's memorandum contra intervention appeal at 3.) It also contends, among other things, that Green Mountain's interests are adequately represented by other intervenors. (DP&L's memorandum contra intervention appeal at 4-5.)

OCC's opposition to this appeal begins with the argument that Green Mountain failed, in OCC's opinion, to explain why it could not have intervened earlier. OCC believes that Green Mountain's interests were represented and that resolution of these cases by means of a stipulation should not have been unanticipated. It points out that Green Mountain "does not argue that it did not receive notice of these proceedings, but that it did not receive 'notice that these consolidated cases would become the forum for resolving post-MDP issues.'" (OCC's memorandum contra intervention appeal at 4.)

IEU-Ohio notes that Green Mountain's motion to intervene did not rely on the rate increase claim or the deficient notice claim in order to justify its late filing. It argues that existing issues in the cases gave rise to the possibility that post-MDP issues would be covered. (IEU-Ohio's memorandum contra intervention appeal at 1-3.)

As argued by Green Mountain, the Commission can overlook the relevant deadlines if good cause is shown. Section 4903.221(A), Revised Code. Rule 4901-1-11(F), O.A.C., further states that motions to intervene which are filed late will be granted only in "extraordinary circumstances." The Commission does not believe that it should have been a surprise to anyone that these cases might be resolved by the proposal of a stipulation, as this is a common outcome in complicated cases before this Commission. Such

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[17] The attorney examiner denied the motions but specifically allowed Green Mountain and WPS to file amicus curiae briefs, so as to make their comments known to the Commission. It should also be noted that, while the transcript only records that the attorney examiner said that "briefs" could be filed, his actual bench ruling specified that such briefs would be "amicus briefs." (Tr. III at 19.)

stipulations often encompass a variety of issues, as they are, by their very nature, compromises by all of the parties involved. The mere fact that a stipulation may resolve matters differently than initially proposed by any party to the proceeding does not afford a party seeking intervention an automatic right to be granted intervention beyond the established deadline. Each case must be looked at on its own merit to determine if extraordinary circumstances exist.

The Commission is, however, unable to overlook one issue that was raised in Green Mountain's intervention appeal. The Commission recently initiated a rule making proceeding in order to develop rules concerning standard service offers and the conduct of competitive bidding for electric distribution utilities (EDU). *In the Matter of the Commission's Promulgation of Rules for the Conduct of a Competitive Bidding Process for Electric Distribution Utilities Pursuant to Section 4928.14, Revised Code,* Case No. 01-2164-EL-ORD (Bidding Rules Case). The rules proposed by the Commission's staff include a provision that would, if adopted, require that "[c]oncurrent with the filing of an application [for standard service offer and competitive bidding processes] and the filing of any waiver requests, the EDU shall provide notice of proposed filings to each party in its ETP case and all competitive retail electric service providers." Bidding Rules Case, Entry (February 20, 2003), Proposed Rule 4901:1-35-04(A). The Commission has, thus, informed the CRES providers that it may determine that it is important for EDUs to notify CRES providers of post-MDP procedures that they will follow. The stipulation proposed in this case clearly covers such matters and neither the public notice given in these cases nor any of the prior filings in the cases presented the possibility that such matters would be resolved in this proceeding. Therefore, the Commission finds that Green Mountain has shown good cause why it should be allowed to intervene after the relevant deadlines.

Both Green Mountain and WPS stated at the hearing their intent not to present witnesses in this proceeding (Tr. III at 7, 8). Green Mountain, in its interlocutory appeal, is not requesting that the Commission reopen the hearing, but only that it be granted party status for the opportunity to brief the issues as a party and to have the right to file further pleadings. Accordingly, the Commission is granting Green Mountain intervention, as conditionally requested, for any proceedings which arise in these cases from this point forward. However, it should be understood that their intervention is being allowed, not because the issues in the proceeding have been expanded, but because they did not receive notice that the establishment of a standard service offer after the end of the MDP would be a part of the proceeding.

Although WPS did not file an interlocutory appeal of the denial of intervention, the Commission will grant its intervention on the same grounds and the same terms as it does with regard to Green Mountain.

B. Discovery

In the event that a person is called to appear at a deposition and refuses to answer a question propounded according to applicable rules, the deposing party may file a motion asking for an order compelling the deponent to answer the question asked. Rule 4901-1-23(A)(3), O.A.C. Where, as in this case, the attorney examiner refuses to issue such an order, the moving party may only take an interlocutory appeal from that ruling if the appeal is certified to the commission on the basis that it presents a new or novel question of interpretation, law, or policy, or is taken from a ruling which represents a departure from past precedent, and immediate determination is needed in order to prevent undue prejudice or expense. Rule 4901-1-15(B), O.A.C.

Strategic, Constellation, and Dominion filed the CRES motion to compel, asking that the attorney examiner direct DP&L "witness Dona R. Seger-Lawson to answer certain questions which were posed at her deposition relating to any side agreements between the signatory parties that are not reflected in the May 28, 2003 Stipulation and Recommendation." (CRES motion to compel at 1.) They point to language in the proposed stipulation which states that the stipulation contains the entire agreement among the parties. Their questions of Ms. Seger-Lawson, and the concomitant request for the production of any related documents, were directed at determining whether the stipulation's provision is accurate. They claim that without knowing the terms of the entire agreement package among the parties the Commission cannot determine whether the "settlement, as a package, benefits ratepayers and the public interest" or whether it "violates any important regulatory principle or practice." (CRES motion to compel at 6 (emphasis omitted).) Strategic, Constellation, and Dominion argue that they are not seeking to determine the motives and consideration for the agreement but, rather, the exact terms of the settlement package. (CRES motion to compel at 7.) They compare the present situation with that which faced the Commission in *Time Warner AxS v. Pub. Util. Comm.*, 75 Ohio St.3d 229, 661 N.E.2d 1097 (1996), in which case the Ohio Supreme Court stated in a footnote that it had "grave concerns regarding the commission's adoption of a partial stipulation which arose from the exclusionary settlement meetings." *Time Warner*, 75 Ohio St. 3d at 233, footnote 2 (Time Warner footnote). The movants also point to Commission precedent in which discovery of side agreements was upheld. (CRES motion to compel at 10.)

DP&L initially objected to the request for production of written agreements between DP&L or its affiliates with any of the signatory parties to the stipulation, on the basis that the requested materials relate to settlement and are therefore not relevant or discoverable, citing *In the matter of The Cincinnati Gas & Electric Company for Approval of its Electric Transition Plan*, Case No. 99-1658-EL-ETP, Opinion and Order (August 31, 2000) (CG&E opinion).

At the start of the third day of the hearing on this matter, following the filing of the CRES motion to compel, the parties orally argued their positions. Counsel for Strategic emphasized the argument that the Commission will evaluate the stipulation on the basis of its standard, three-part test, requiring it to consider the stipulation as an entire package. In their view, the discovery which the movants seek to compel would help to determine what constitutes that package. He distinguished the CG&E opinion from the present case on the basis that AK Steel, in the CG&E case, was always present at the negotiating table. He also compared the present situation with that in *In the Matter of the Joint Application of SBC Communications, Inc., SBC Delaware Inc., Ameritech Corporation, and Ameritech Ohio for Consent and Approval of a Change of Control*, Case No. 98-1082-TP-AMT (Ameritech case), in which the attorney examiner allowed questioning which related to the existence of side agreements, where the party asking the questions was not a signatory party to the stipulation. (Tr. III at 20-22.)

Counsel for DP&L countered by noting that the court in the Time Warner footnote specifically said that "there is no requirement that all parties be at the table all the time." (Tr. III at 23.) He also insisted that all "Time Warner objections" had been resolved at the second day of the hearing on this matter, by agreement among the parties. Finally, he maintained that the CG&E opinion is binding precedent, noting that AK Steel in that case made precisely the same argument that the movants are making in this case as to the stipulation not being the entire agreement among the parties. He insisted that the question is whether the information sought to be discovered is or is not relevant. (Tr. III at 23-26.)

Counsel for IEU-Ohio stressed that the moving parties were not actively excluded from negotiation of the stipulation (Tr. III at 27).

The attorney examiner denied the motion to compel discovery, stating that the ruling was "based on the commission's precedent in the matter in the CG&E case," not passing upon whether all the parties should have been present at settlement discussions (Tr. III at 28-29).

Following denial of their motion, Strategic, Constellation, and Dominion filed an application requesting certification and approval of their interlocutory appeal of that denial. They argue that the attorney examiner's ruling departs from the Commission's policy favoring unanimous settlements, prevents the Commission from being in a position to approve or disapprove the stipulation as a package, and is in conflict with rulings in similar situations in other proceedings. They stress that, in their opinion, the CRES providers and OMA were intentionally excluded from settlement negotiations, supporting their conclusion that the CG&E case is inapplicable. They believe that, in the CG&E case, the motion to compel discovery was rejected because the Commission would not inquire into parties' motives for agreeing to stipulations. Here, they insist that they are not looking for motives but, rather, for an understanding of what actually comprises the complete settlement package. (CRES discovery appeal.)

DP&L opposed the CRES discovery appeal. It insists that the criteria for certification of an interlocutory appeal have not been met. Rule 4901-1-15(B), O.A.C. It also suggests that the application is now moot, as DP&L has provided to the movants the only document which it believes is responsive to the movants' document request. Additionally, DP&L suggests that since the only responsive document has, according to DP&L, been provided, further testimony from Ms. Seger-Lawson on this subject is now moot or pointless. Finally, DP&L argues that there is no Commission policy requiring unanimous settlements, the CRES providers were not excluded from settlement discussions, and the attorney examiner's ruling was consistent with Commission precedent. (DP&L's memorandum contra discovery appeal.)

IEU-Ohio also opposed the CRES discovery appeal. It contends that the attorney examiner ruling is directly in keeping with Commission precedent and that the CRES providers' absence was due to their own silence. (IEU-Ohio's memorandum contra discovery appeal.)

Contrary to ordinary practice, the CRES providers filed a motion for leave to file a reply to both DP&L's memorandum contra discovery appeal and IEU-Ohio's memorandum contra discovery appeal.[18] The movants point out that the motion to

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[18] Although interlocutory appeals are normally supported only by an initial brief, and although the filing of the reply was opposed by both DP&L and IEU-Ohio, because new issues were suggested by

compel discovery was not limited to a document request, and the document request portion of the motion was not limited to the production of "sidebar" agreements. They also again stress that, in their opinion, they were excluded from settlement negotiations. (CRES discovery appeal reply.)

Inasmuch as the CRES discovery appeal has not been addressed prior to the issuance of this opinion and order, the Commission will address it at this time. The Commission will affirm the ruling of the attorney examiner. Initially, the Commission would note that the production of one responsive document has not mooted the appeal, as the appeal was clearly directed at testimony as well as document production. In addition, while it would have been preferable if all parties had been present at settlement negotiations, unanimous settlement is not required by Commission policy or precedent, or by the Ohio Supreme Court's statement in the Time Warner footnote.

The scope of allowed discovery in proceedings before the Commission is limited to "any matter, not privileged, which is relevant to the subject matter of the proceeding." Rule 4901-1-16(B), O.A.C. Therefore, in determining whether or not to grant a motion to compel discovery, the Commission, or the attorney examiner, must determine that the information sought to be discovered is neither privileged nor irrelevant.

Settlement communications have recently been determined by the Circuit Court of Appeal for the 6th Circuit to be privileged. In *The Goodyear Tire & Rubber Company v. Chiles Power Supply, Inc.*, 332 F.3d 976 (6th Cir. 2003), the court determined that the policy goal of encouraging settlement, as well as the traditional treatment of settlement discussions in this country, lead to the conclusion that a settlement privilege should exist. Pursuant to this determination, the Commission finds that the information sought to be discovered by the CRES discovery appeal, being information related to the negotiation of the proposed stipulation in this matter, is privileged and therefore not discoverable.

In addition, even if it were not privileged, the information sought would not be relevant to the determination of this matter. It appears to the Commission that the result of the proposed discovery would be to determine the motivations of the various parties to enter into the stipulation. As stated by the Commission in the CG&E opinion, "[t]he motives of the parties in agreeing or not agreeing to sign the stipulation will not affect the Commission's determination of the reasonableness of the stipulation . . .." (CG&E opinion at 58.) To the extent that the movants' assertion is correct that they are merely attempting to determine the nature of the entire package that is being presented to the Commission for approval, the Commission would note that no agreement among the signatory parties to the stipulation can change the terms of the stipulation. Either the terms of the stipulation are, on their face, beneficial to the ratepayers and the public or they are not. Even if there were side agreements among the signatory parties, those agreements would not change the public benefit or detriment of the stipulation. The Commission will evaluate the terms of the stipulation as they appear on its face. Therefore, the discovery sought in the CRES discovery appeal is not relevant to the subject matter of these proceedings.

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the opponents to the motion in their memoranda contra, the CRES providers' motion for leave to file a reply is hereby granted.

III. SUMMARY OF THE STIPULATION

The proposed stipulation was signed by DP&L, OCC, staff of the Commission, IEU-Ohio, OPAE and CAP (collectively, signatory parties) and was intended to resolve all of the outstanding issues in the four consolidated cases. In the stipulation, the signatory parties agree that DP&L's MDP will be extended through December 31, 2005. Under the stipulation, the RTC and CTC riders are to be terminated and the corresponding rates which were previously set forth in those riders are to be added to the electric generation service rates. (Joint Exhibit 1, at 6.)

Shopping credits are detailed in an attachment to the stipulation without any explanation of how they were calculated. (Joint Exhibit 1, at 6.) Testimony at the hearing, however, made it clear that residential shopping credits are left unchanged from current residential shopping credits and that nonresidential shopping credits are set at current levels plus fifty percent of the current CTC rider for 2004 and seventy-five percent of the current CTC rider for 2005. (Tr. III at 56-58.)

The stipulation also sets up a series of steps for the establishment of a voluntary enrollment procedure (VEP) in the event that load-switching does not reach the twenty percent level by any of several dates. The procedure includes the creation of a committee to oversee a customer education effort to encourage shopping. (Joint Exhibit 1, at 8-10.)

After the MDP terminates on December 31, 2005, the stipulation would set up a rate stabilization period (RSP). During the RSP, several additional provisions would take effect. First, DP&L agrees to provide a "market-based standard service offer" (SSO) to its customers during the RSP. The SSO will be the generation rates currently charged customers subject to the following provisions. Residential customers will continue to receive the five percent reduction to the unbundled generation component for retail electric generation service plus an additional 2.5 percent reduction. Second, DP&L may adjust transmission charges to incorporate certain applicable, FERC-approved transmission rates. Third, DP&L's distribution rates will remain frozen at current levels, subject to adjustments that may be permitted in the ETP opinion. Fourth, subject to a possible rider (discussed in the following sentence), customers obtaining generation from a provider other than DP&L would pay DP&L only for transmission and distribution, together with associated riders. Fifth, all customers, regardless of the source of their generation service, may be charged a surcharge (RSS) of up to eleven percent of the tariffed generation charges as of January 1, 2004. The RSS will only be assessed following Commission approval and will be designed to allow DP&L to recover costs associated with fuel price increases or actions taken in compliance with environmental and tax laws, regulations or court or administrative orders, and costs associated with physical security and cybersecurity relating to the generation of electricity from plants owned by DP&L and its affiliates, which costs are imposed by final rule, regulation or administrative or court order. Sixth, the SSO will be subject to review by the Commission and, if the Commission determines that "readily available pricing information is not adequate or sufficiently reliable to conduct the examination, then the Commission may order a competitive bidding process to be used. The Commission may also terminate all provisions of the stipulation and order DP&L to proceed according to post-MDP rules established by the Commission. (Joint Exhibit 1, at 11-15.)

The proposed stipulation would require DP&L, among other things, to turn over control of as many transmission functions as reasonably possible to Pennsylvania-New

Jersey-Maryland Interconnection, LLC (PJM), to forego seeking any rate of return incentives for RTO membership or participation through December 31, 2005, and to participate and support the establishment and implementation of certain methods for the management of price volatility risks related to congestion. (Joint Exhibit 1, at 7-8.)

Finally, the proposed stipulation handles a few simpler matters. It would require DP&L to retain its current line extension policies and tariffs, through December 31, 2008, subject to changes approved by the Commission and previously communicated to the signatory parties. (Joint Exhibit 1, at 10.) It would also require OCC and IEU-Ohio to withdraw from the RTO case, would require OCC to withdraw its application for rehearing in the deposits case (thereby allowing the Commission's approval of the application to stand), and would require DP&L to withdraw its application in the accounting case, subject to a future such filing after the effective date of electric service and safety standards rules. (Joint Exhibit 1, at 10-11.)

IV. CRITERIA FOR EVALUATING STIPULATIONS

Rule 4901-1-30, Ohio Administrative Code, authorizes parties to Commission proceedings to enter into stipulations. Although not binding on the Commission, the terms of such agreements are accorded substantial weight. *See, Consumers Counsel v. Pub. Util. Comm.*, 64 Ohio St.3d 123, 125 (1992), *citing Akron v. Pub. Util. Comm.*, 55 Ohio St.2d 155 (1978). This concept is particularly valid where the stipulation is supported or unopposed by the vast majority of parties in the proceeding in which it is offered.

The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. *See, e.g., Ohio-American Water Co.*, Case No. 99-1038-WW-AIR (June 29, 2000); *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR (April 14, 1994); *Western Reserve Telephone Co.*, Case No. 93-230-TP-ALT (March 30, 1994); *Ohio Edison Co.*, Case No. 91-698-EL-FOR et al. (December 30, 1993); *Cleveland Electric Illum. Co.*, Case No. 88-170-EL-AIR (January 30, 1989); *Restatement of Accounts and Records (Zimmer Plant)*, Case No. 84-1187-EL-UNC (November 26, 1985). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

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

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

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

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

In determining whether to approve the stipulation proposed in this matter, the Commission will follow this analysis.

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

Several of the parties to these proceedings have argued that the stipulation is not the product of serious bargaining among capable, knowledgeable parties, as they believe that a number of the entities which should have been included in that bargaining were intentionally excluded from participation. Strategic, Dominion, and Constellation, for example, assert that neither any marketer nor OMA was at the negotiating table (CRES group's brief at 21). They rely on the ETP opinion, in which the Commission found that this test was met since "[m]ultiple bargaining sessions, open to all parties, took place before commencement of the hearings." ETP opinion at 36. (CRES group's brief at 22; CRES group's reply brief at 6.) These CRES providers also point to the Time Warner footnote as evidence that the Ohio Supreme Court also wants to see inclusion of all customer classes in settlement negotiations. Finally, they contend that serious bargaining did not even take place among the signatory parties, as two of those six parties were absent from two of the negotiating sessions (CRES groups' reply brief at 6). Because, in their belief, an entire customer class was excluded from the sessions, and the negotiations did not even always include all of the signatory parties, they do not find this test to have been satisfied. (CRES group's brief at 22-23; Tr. III at 63-75, 77-75.)

OMA also discussed its exclusion from the settlement discussions. It contends that, although Ms. Seger-Lawson testified that the stipulation resulted from a great deal of negotiation, "in actuality the negotiations were initiated by a conference call . . . on May 20 . . . and produced a written and signed stipulation by May 28, 2003." (OMA's brief at 8.) In addition, OMA asserts that "parties who had expressed a continued interest in settling the case were intentionally left out of these discussions." (OMA's brief at 8.) Finally, OMA submits that the parties who were involved in the negotiation were heavily weighted in favor of residential consumers, excluding medium and small manufacturing customers and commercial customers entirely and only representing large industrial customers through one negotiating entity. (OMA's brief at 8; Tr. III at 101-108.)

Green Mountain argues that this test should require that negotiating sessions be open to all parties, following appropriate notice, regardless of whether all parties actually sign the resulting stipulation. It contends that the Commission's ETP opinion incorporated such a standard by stating that the test was met by there having been "[m]ultiple bargaining sessions, open to all parties." ETP opinion at 36. It also relies on the Time Warner footnote to show that entire customer classes should not be excluded from negotiations. Here, Green Mountain maintains that the CRES providers and OMA were excluded, contrary to expectations of the Commission and the Ohio Supreme Court. Thus, it maintains that this test is not met. (Green Mountain's brief at 8-9; Green Mountain's reply brief at 12.)

DP&L, OCC, CAP, IEU-Ohio, and staff of the Commission, on the other hand, unanimously urge the Commission to find that the stipulation is the product of serious bargaining among capable, knowledgeable parties. DP&L, initially, asserts that the stipulation meets the test since it was "a product of months of negotiations," the parties and their counsel have substantial experience before the Commission, the negotiations were both lengthy and filled with compromises on all sides (DP&L's initial brief at 6; DP&L's reply brief at 4). DP&L insists that the nonsignatory parties were not excluded from the negotiations but, rather, appeared to be uninterested in settlement (DP&L's brief at 11-13). As to the Time Warner footnote, DP&L reasons that it is inapplicable for a number of reasons, including that the nonsignatory parties declined to participate in earlier negotiations, that filings with the Commission referenced settlement discussions, that every customer class was represented at negotiations, and that including nonsignatory parties would have been futile (DP&L's reply brief at 4-8).

The briefs filed by OCC also reflect its belief that this test is met. Reciting its view of the history of negotiations (OCC brief at 9-10), OCC posits that settlement negotiations began in December 2002 (OCC brief at 11). OCC maintains that the absence of the CRES providers and OMA from negotiations is not relevant to the question of whether the stipulation results from serious bargaining among capable, knowledgeable parties. "Surely the commission cannot conclude from the absence of the Marketers and the OMA as signatory parties that the Stipulation did not result from serious bargain regarding disputes between the parties that have been discussed extensively in numerous pleadings in these cases." (OCC reply brief at 5.) As to the Time Warner footnote, OCC disputes its application here, as it points out that the court in that case specifically stated that it would not require that all parties be involved in settlement negotiations (OCC brief at 19).

The brief filed by CAP, like that of OCC, states that negotiations began in December 2002 and that all parties are experienced and represented by counsel (CAP's brief at 3).

IEU-Ohio discusses the alleged exclusion of CRES marketers and OMA at some length (IEU-Ohio's reply brief at 4-8),[19] noting that the exclusion of OMA from a distribution list for a proposed settlement was inadvertent (IEU-Ohio's reply brief at 6).

Staff of the Commission initially notes that, in its opinion, no class of customers was excluded from negotiations and all customer classes will receive benefits from the approval of the stipulation (staff's brief at 3; staff's reply brief at 16). Additionally, staff argues that the CRES providers do not represent any customer class but, rather, represent their own business and financial interests (staff's reply brief at 16). Staff also stated that it does not believe that any party was actively excluded (staff's reply brief at 17, 18). "The apparent inflexibility or unwillingness to compromise on certain central issues demonstrated by those who oppose the Stipulation suggests that their participation in the latter stages of settlement negotiations would have been counterproductive to reaching a balanced settlement package." (Staff's reply brief at 17.) Staff believes that the nonsignatory parties dropped out of negotiations by their own choice (staff's reply brief at 17).

It is unfortunate that the negotiations for the settlement of these proceedings did not include all parties at all times. As the Ohio Supreme Court stated in the Time Warner footnote, while it is not critical that all parties be involved, it is certainly preferable. However, the Commission would note that it is not any one party's responsibility to see to it

[19] Counsel for OMA sought to refute certain portions of this discussion through a letter filed with the Commission on July 22, 2003.

that everyone is included. Where one or more parties take no actions to discuss settlement or to determine what discussions may be ongoing among other parties, that party cannot be held entirely blameless. Communication, on which such settlement must be based, requires the cooperation of all parties. It is, however, incumbent upon those who are approached regarding settlement to respond accurately and to ensure that the party who has inquired about settlement status is kept aware of ongoing conversations.

In the present situation, however, the lack of involvement of certain parties, for whatever reason and due to whichever parties' actions or inactions, does not change the fact that the stipulation resulted from serious bargaining among capable, knowledgeable parties. That standard does not require one hundred percent cooperation or participation. All parties who attended the status conference at Commission offices did have an opportunity to discuss issues with other parties. Thus, the Commission does find that the stipulation meets the first requirement of the three-pronged test.

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

Several signatories to the proposed stipulation spelled out the benefits that they believe would accrue to the ratepayers and the public upon the approval of the stipulation by the Commission. There appears to be relative unanimity among the signatories to the stipulation that those benefits, in their opinions, include: (1) extending the MDP through December 31, 2005, thus extending the freeze on rates through 2005; (2) creating a subsequent period during which rates are generally frozen; (3) continuing the existing 5 percent residential discount and agreeing to an additional 2.5 percent residential discount during the RSP; (4) increasing the shopping credits for commercial and industrial customers; (5) providing for the transfer of certain transmission system operations to an RTO and strengthening DP&L's commitment to satisfy RTO obligations; (6) enhancing the VEP, in order to provide CRES suppliers an additional opportunity to offer services to customers; (7) resolving the accounting case, the RTO case and the deposits case, as well as the MDP case; (8) limiting rate increases during the RSP to actual increases in certain cost items, not to exceed 11 percent of DP&L's January 1, 2004, tariffed generation rate; (9) allowing the Commission to void the RSP if generation rates during the RSP do not reasonably reflect market-based rates (DP&L Ex. 1A, at 4). (See, also, DP&L's brief at 5; OCC's brief at 13, CAP's brief at 3-4, IEU-Ohio's brief at 5-6, 9-10; staff's brief at 6-8; DP&L's reply brief at 8-9).

Certain of the parties also noted that, among other things, (1) the shopping credits in the stipulation are higher than those that were proposed by DP&L in its original application in the MDP case (Tr. III at 40-41; OCC's brief at 13; IEU-Ohio's brief at 10); (2) the stipulation requires DP&L to support the establishment and implementation of "follow the load" approach to allocation of financial transmission rights (OCC's brief at 13); (3) line extension policies will not be changed prior to the end of 2008 (OCC's brief at 13; IEU-Ohio's brief at 5, 10); (4) DP&L will be required to provide standard service offer rates after the MDP on the basis of existing prices (OCC's brief at 13); (5) DP&L will be prohibited from challenging the Commission's jurisdiction to enforce compliance with the stipulation (IEU-Ohio's brief at 10); (6) DP&L will be required to avoid transmission rate increases related to certain incentives which may be available from FERC (IEU-Ohio's brief at 10); (7) the availability of a fund to offset pancaked transmission charges will be continued (IEU-Ohio's brief at 10; staff's brief at 8); and (8) current distribution and transmission prices will be continued through the extended MDP (IEU-Ohio's brief at 10).

The CRES providers disagree with the contention that the second criterion of the test for evaluating stipulations is met. They contend that the criterion requires that the stipulation benefit both the ratepayers and the public interest, not just one or the other. They argue that, while it may benefit ratepayers, it does not benefit the public interest. The most critical problem, in their opinion, is that the RSP proposal, together with the RSS, will make it impossible for the Commission's post-MDP rules to have a uniform, statewide application. Additionally, they dispute the public benefits of the portion of the stipulation dealing with transmission issues, as (1) compliance with the identified FERC order is already required, (2) there was no evidence that DP&L was going to seek a rate return incentive for RTO membership, (3) any rate increase from joining an RTO would be offset by costs savings, (4) there was no evidence that ancillary service charges would not already be included in the rate cap, (5) there is no evidence that DP&L's support would cause the "follow the load" approach to FTR allocation to be adopted, and (6) there is no evidence that DP&L's recognition that compliance with transmission requirements is critical is going to benefit anyone. (CRES group's brief at 30-33.)

The CRES providers also dispute the benefits claimed by the signatory parties to the stipulation in that (1) while rates would remain frozen for an additional two years, continued transition fee payment by customers will discourage shopping; (2) the transmission-related pledges by DP&L are not necessarily causing it to do anything that it would not have done without the stipulation, (3) the VEP would not be implement until January 2004 even though, under the ETP opinion, it should already be implemented now, and (4) although the line extension section of the stipulation purports to require DP&L to maintain its current policies, it can actually modify those policies with advance notice to signatory parties and approval from the Commission. (CRES group's reply brief at 7.)

OMA also disputes the benefit of the stipulation. It points out that, while Ms. Seger-Lawson testified that the stipulation would substantially increase the shopping credits for commercial and industrial classes, she actually admitted on cross-examination that the proposed shopping credits in the stipulation were less than had been recommended by Commission staff. In addition, OMA asserts that, although Ms. Seger-Lawson testified that the stipulation would provide price stability and frozen rates, the stipulation actually contains a rate increase for all customers, subject to Commission approval. (OMA brief at 7, 8.) Finally, referring to the testimony of Messrs. Frank Lacey, who testified on behalf of Dominion and Strategic, and Phillip M. Brock, who testified on behalf of Constellation, OMA submits that the shopping credits proposed under the stipulation will not promote shopping in the commercial and primary classes of customers (OMA brief at 8).

Green Mountain believes that the stipulation will reduce the possibility of competition in Ohio, thus not benefiting the public (Green Mountain's reply at 1, 12). In addition, it notes, among other things, that the stipulation does not necessarily result in lower prices for ratepayers. Rather, it freezes rates, thus protecting ratepayers against possible rate increases. Even Ms. Seger-Lawson admitted that market-based rates might be higher or lower than those in the stipulation. (Green Mountain's brief at 11-12.)

WPS disputes even that the stipulation is a benefit to the ratepayers in its protection against price volatility, noting that customers of a CRES supplier could sign a long-term contract for service at a fixed price (WPS brief at 4-5). It also reasons that it is not in the public interest to require continued payment of transition costs after December 31, 2003, when those stranded cost payments are currently scheduled to terminate (WPS brief at 6).

The Commission finds that the stipulation, as modified in this opinion and order, does benefit the ratepayers and the public in a number of ways. The most immediate benefit is the extension of the MDP for an additional two years. Under the terms of the ETP opinion, the MDP was scheduled to terminate at the end of 2003. If an electric market had developed as anticipated, this termination date would have allowed the customers of DP&L to obtain the advantages of competition as early as January 2004. However, there is currently no effective electric competition in the DP&L market. Therefore, having frozen rates terminate at the end of 2003 could result in DP&L having an unregulated monopoly in the area. This result is untenable. Therefore, it is beneficial to the public and to the ratepayers for the MDP to be extended, while competitors have an additional two years to enter the market.

Another clear benefit is the existence of the RSP. During this three-year period, the stipulation would have the effect of capping the price of generation. The price can go no higher under any circumstances than the legacy rates as of January 1, 2004, plus eleven percent. On the other hand, if market prices fall during the RSP, the Commission can terminate the RSP and allow rates to be set by the prescribed competitive methods. Thus, the stipulation would act as a hedge against substantial price increases for three years.

C. Does the settlement package violate any important regulatory principle or practice?

The proponents of the stipulation submit that the stipulation satisfies policy goals of SB 3 and does not violate the requirements relating to termination of an MDP, the offering of a market-based rate or competitive bidding following the MDP (DP&L's initial brief at 7-8; OCC's brief at 17-18; CAP's brief at 4; IEU-Ohio's brief at 8; and staff's brief at 9-10). The nonsignatory parties disagree. The elements of that disagreement will be discussed individually.

1. Level of Shopping Credits/Recovery of Transition Costs

Section 4928.39, Revised Code, allows for the recovery by an electric utility of certain costs which are directly allocable to generation activities and are unrecoverable in a competitive electric market. The burden is specifically placed on the electric utility to demonstrate such costs. The Commission is also given the authority to impose rules on their collection.

> Upon the filing of an application by an electric utility . . . for the opportunity to receive transition revenues . . ., the public utilities commission, . . . shall determine the total allowable amount of the transition costs of the utility to be received as transition revenues under those sections. Such amount shall be the just and reasonable transition costs of the utility, which costs the commission finds meet all of the following criteria:
>
> (A) The costs were prudently incurred.

> (B) The costs are legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state.
> (C) The costs are unrecoverable in a competitive market.
> (D) The utility would otherwise be entitled an opportunity to recover the costs.
>
> . . .
>
> Further, the commission's order under this section shall separately identify regulatory assets of the utility that are a part of the total allowable amount of transition costs determined under this section and separately identify that portion of a transition charge determined under section 4928.40 of the Revised Code that is allocable to those assets, which portion of a transition charge shall be subject to adjustment only prospectively and after December 31, 2003, unless the commission authorizes an adjustment prospectively with an earlier date for any customer class based upon an earlier termination of the utility's market development period pursuant to division (B)(2) of section 4928.40 of the Revised Code.
>
> The electric utility shall have the burden of demonstrating allowable transition costs as authorized under this section. The commission may impose reasonable commitments upon the utility's collection of the transition revenues to ensure that those revenues are used to eliminate the allowable transition costs of the utility during the market development period and are not available for use by the utility to achieve an undue competitive advantage, or to impose an undue disadvantage, in the provision by the utility of regulated or unregulated products or services.

Section 4928.39, Revised Code. Thus, the law prohibits the Commission from allowing the recovery of transition costs except upon the filing of an application for such recovery, proof of the costs' existence, and the compliance with any specific commitments imposed on the utility.

Chapter 4928, Revised Code, also allows the Commission to consider, in determining the expiration date for the recovery of transition costs and the transition charge for each class of customers, the "shopping incentives necessary to induce, at the minimum, a twenty per cent load switching rate by customer class halfway through the utility's market development period but not later than December 31, 2003." Section 4928.40(A), Revised Code. Similarly, the code provides that "transition charges shall be structured to provide shopping incentives to customers sufficient to encourage the development of effective competition in the supply of retail electric generation service." Section 4928.37(A)(1)(b), Revised Code.

In the ETP opinion, the Commission specifically addressed transition costs of DP&L. After reviewing the legal requirements and the positions of the parties in that case, the Commission determined that the stipulation in that case (ETP stipulation) specified that maximum allowable amount to be recovered in transition costs during the MDP (ETP opinion at 30) and that the amount of the transition costs set in the ETP stipulation was reasonable (ETP opinion at 29).

The ETP stipulation placed strict limits upon the recovery of transition costs, including regulatory transition charges (RTC) and customer transition costs (CTC). The ETP stipulation set forth the following:

> The Stipulating Parties agree that the period for recovery for CTC and RTC will end on December 31, 2003. Except as otherwise provided in Sections IV [relating to the base rate] and VIII(C) [relating to the temporary increase in the shopping credit if the designated shopping percentage was not reached by November 30, 2002] of this Stipulation, there will be no further netting or adjustments of any kind to any rate, CTC rate, RTC rate, or shopping credit through December 31, 2003, including, but not limited to, adjustments for the sale, lease, or transfer of any assets by DP&L or any of its affiliates.
>
> Ohio Revised Code §4928.40(B)(2) provides that the MDP shall not end earlier than December 15, 2005, unless, upon application by the electric utility, the Commission authorizes an earlier termination date for one or more customer classes based upon a finding that there is a 20 percent switching rate of load by the customer class or that effective competition exists in the utility's certified territory. By this Stipulation, DP&L, supported by the other signatory parties, applies to the Commission for authorization of an MDP termination date of December 31, 2003, based upon DP&L's agreement to forego the recovery of transition costs beyond that date (see Ohio Revised Code §4928.38) and the measures to accelerate switching provided in Section XVII of this Stipulation.

(ETP stipulation at VII.) As a result of this section, the amounts to be paid by ratepayers were calculated so as to recover the total amount of transition revenues by the end of 2003. DP&L specifically agreed not to attempt to recover any transition costs beyond that date.

In the ETP stipulation, the parties agreed on a methodology for calculating rates in the unbundling of services (ETP stipulation at II). Rates are calculated so that transition costs are paid by all ratepayers, regardless of whether or not they shop for electric generation services. The calculation begins with the total unbundled rate. From this amount, the parties subtract the costs of transmission and distribution, as well as certain ancillary services and riders, to reach a total generation rate.[20] The total generation rate less the transition costs results in a shopping credit.[21] Customers are required to pay DP&L the total bundled rate or, if they choose an alternate generation supplier, the total bundled rate less the shopping credit. Hence, all ratepayers contribute to the recovery of the transition costs.

The proposed stipulation in the present case is that residential shopping credits will remain as currently calculated; that is, at an amount equal to the total generation rate less RTC costs. The nonresidential shopping credits would rise somewhat starting in 2004, and

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20 This result was discounted by 5 percent for residential customers.

21 The ETP stipulation also provided that, if the specified 20 percent level of shopping was not reached for the residential class by November 30, 2002 (which, in fact was not reached), then the CTC rate would be added to the shopping credit beginning on January 1, 2003. Thus residential customers who shop after the beginning of 2003 only pay toward the recovery of RTC costs.

more in 2005. Specifically, in 2004 nonresidential customers would be allowed shopping credits equal to total generation costs less an amount equivalent to the RTC and fifty percent of CTC, and in 2005, total generation costs less RTC and twenty-five percent of CTC. (Joint Exhibit 1, at Attachment A; Tr. III at 56-58.)[22]

The CRES providers argue that the provisions of the proposed stipulation result in the continued payment of transition costs by shopping customers. They use schools as an example:

> [A]ny customer who shops pays a rate calculated by taking all of the Company's charges, including generation, as if they bought tariff service. Then a generation credit is applied to basically offset the fact that the customer is supply *[sic]* its own generation. When all of the expenses are calculated and then the shopping credit is subtracted, there is a "residual" which is the payment to DP&L. For schools, this residual would be the difference between $.05401 per Kwh minus the 2004 proposed shopping credit of $.04227, or a little over a penny per kilowatt hour. This penny plus per Kwh that the schools would pay to DP&L was not designed to offset the costs of the schools coming back for service but was rather "just a factor of the Stipulation."
>
> After paying for unbundled distribution fees, unbundled transmission fees, ancillary fees, and all the riders involved in the provision of electric service, a school would still be paying a portion for DP&L generation even though the generation was being supplied by others and such portion is represented by the difference between "Big G" and the shopping credit. By proposing a shopping credit which is less than Big G, DP&L is in effect collecting additional transition revenues.

(CRES group's brief at 11-12 (citations to transcript omitted).) They argue that "the establishment of a shopping credit at any level less than Big G for 2004 and 2005 is unlawful unless and until DP&L makes a showing that it has either additional stranded costs or regulatory assets . . .." (CRES group's reply brief at 9.) The CRES group points out that DP&L made no attempt to prove that it has incurred, or will incur, additional transition costs which should be collected from shopping customers. Therefore, under the terms of Section 4928.39, Revised Code, the Commission should not, in the CRES providers' opinion, allow the collection of additional transition revenues. (CRES group's brief at 13.)

OMA, in its brief, notes that the level of shopping credits proposed in the stipulation is actually lower than that suggested by staff of the Commission (OMA's brief at 7). It also suggests that the proposed shopping credits will not produce shopping during the extended MDP, thereby violating important principles set forth in SB 3 (OMA's brief at 8-9).

Green Mountain also disagrees with the level of the shopping credits, stating that Ms. Seger-Lawson "does not even make a colorable claim that the shopping credits . . . would produce 20 percent shopping credits. Nor could she since DP&L did not conduct one single study on the relationship between the proposed shopping credits and the

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[22] Although the Commission uses the terms RTC and CTC to explain the shopping credits for years 2004 and 2005, we recognize that there is no actual RTC or CTC cost recovery during 2004 and 2005.

shopping levels." It continues by referring to testimony by Mr. Phillip M. Brock in which he gave examples of savings for sample customers if the shopping credit were set at the full amount of generation costs. (Green Mountain's brief at 22-23.)

Like the CRES group, WPS reviews the history of the current shopping credit as it arose under Chapter 4928, Revised Code, pointing out that the Commission's authorization for the recovery of transition costs requires such recovery to terminate on December 31, 2003 (WPS's brief at 1-3). WPS's description of the current situation very clearly states its position:

> DP&L, for almost three years, has been protected from competing with other CRES providers at market prices. If a customer were to leave DP&L and get its power from another CRES provider, that customer would have to make a subsidy payment to DP&L of the customer transition charges. Thus, DP&L was assured that for three years it would collect more than the market value for its power either through sale of power at prices above market rates, or by the collection of transition costs from customers that shopped.
>
> As clearly listed in Appendix A, the transition cost payments to DP&L for the three year period were substantial.... If [a small residential customer] chose to buy power from [WPS], the customer would also have to pay DP&L a transition fee of ... some 29% of the total cost of power. Thus, in order for that small residential user to just break even, or in the parlance of the bill message which the Commission has ordered to be on each statement – exceed the "price to match" – the residential customer would have to find a CRES provider willing to sell power for ... 30% less than Big G. As a consequence, not a single kWh has been sold to a residential customer by a nonaffiliated CRES provider on the DP&L system to date.

(WPS's brief at 3-4.) WPS contends that the shopping credits proposed in the stipulation would continue the payment of transition costs beyond the Commission's deadline. It avers that the signatory parties' reasoning would argue that this is beneficial because the customer is protected from price volatility. WPS points out that protection from price volatility could be obtained by customers by "simply signing a one- or two-year contract with a CRES provider at a fixed price" or by deciding not to shop. (WPS's brief at 4-5.) Finally, WPS asserts that, if DP&L wishes to receive more transition revenues, it "must bear the burden of proving that additional transition costs or regulatory assets have occurred since the [ETP opinion] and that its meets the criteria for payment established in Section 4928.39, Revised Code. Since DP&L has presented no evidence in this proceeding of the need for more transition revenues . . ., transition revenue collection must end on December 31, 2003." (WPS's brief at 6.)

Several parties also approve of the shopping credits in the stipulation. DP&L, following its review of the positions taken on shopping credits by various of the parties at various times during the course of these proceedings, states that it believes that the "negotiated shopping credits . . . constitute a compromise between those competing positions." (DP&L's brief at 3.) It points out that the residential shopping credits have recently been increased, pursuant to the terms of the ETP stipulation, and that competition appears to be starting. Based on testimony concerning offers made by marketers in other territories, DP&L believes that marketers will be able to compete effectively with residential shopping credits at their current levels. DP&L also states that nonresidential shopping credits are set to phase in under the proposed stipulation, an approach deemed reasonable by Dr. Stephen S. George, a witness on behalf of DP&L, and Mr. Brock. Finally, DP&L contends that the direct testimony filed by Ms. Seger-Lawson and Dr. George demonstrate the reasonableness of the nonresidential shopping credits proposed in the stipulation and that the level of proposed incentives will promote effective competition (DP&L's brief at 3-7; DP&L's reply brief at 16-21.)

As to the argument that the stipulation would allow the continued recovery of transition costs, DP&L argues that the stipulation's express termination of transition cost recovery riders eliminates this possibility. "Because the riders are eliminated and added to the electric generation service rates, DP&L, effective January 1, 2003, will no longer be recovering any transition revenues." DP&L's reply brief at 12.

IEU-Ohio asserts that the shopping credits in the stipulation should be adopted, as they "are higher than the currently effective shopping credits in DP&L's tariff and are not subject to downward adjustment by the Commission should shopping exceed the twenty percent (20%) statutory threshold." (IEU-Ohio's brief at 12.) It also discusses the fact that the termination of transition cost recovery has no effect on the "residually determined price for unbundled standard generation service." (IEU-Ohio's reply brief at 14.)

The staff cites the testimony of Dr. George, in which he stated that "artificially high shopping credits, although they can induce customer switching and retailer market entry in the short term, do not lead to sustainable competition and, in any event, produce a result that is not well grounded economically." Staff notes that the marketers made no showing that the level of shopping credits proposed in the stipulation would fail to encourage shopping. An incremental increase in shopping credits is, in staff's view, appropriate. (Staff's reply brief at 6-10.)

Section 4928.37, Revised Code, provides that the Commission shall structure rates, during the market development period, "to provide shopping incentives to customers sufficient to encourage the development of effective competition in the supply of retail electric generation service." The statute does not otherwise specify the level at which any incentives are to be set. As the Commission endeavors to set shopping credits that will encourage competition, as required by the statute, several factors should be noted. First, the residential customers' shopping credits were raised, under the terms of the stipulation adopted pursuant to the ETP opinion, as of January 1, 2003. Second, the stipulation proposed in the present case would increase the non-residential shopping credit, first, as of January 1, 2004, and, again, as of January 1, 2005. Finally, the shopping credits proposed in the stipulation were agreed to by several parties, including residential consumer representatives and industry representatives. The Commission therefore finds that the residential shopping credits proposed in the stipulation are reasonable and are likely sufficient to encourage the development of effective competition in the supply of retail electric generation service.

Section 4928.02(C), Revised Code, states that it is the public policy of this state to "[e]nsure diversity of electricity supplies and suppliers." This diversity must be encouraged, not only with regard to residential customers, but also in the commercial and industrial marketplace. The proposed stipulation would, in 2004, provide only a small increase in nonresidential shopping credits over those which have applied to date during the MDP. An additional increase in the nonresidential shopping credits would be delayed until 2005, thus delaying the impact of that additional increase and delaying the resultant encouragement of diversity and competition in the electric marketplace. This yearly change in shopping credits not only adds an element of inconsistency that, in itself, may hinder the development of the market, but also may make it more difficult for electric marketers to enter into long-term contracts with potential customers. The Commission believes that, rather than the proposed yearly increase in the nonresidential shopping credits, an immediate, more substantial increase is more likely to ensure diversity of electricity supplies and suppliers. Therefore, the Commission will modify the stipulation such that the nonresidential shopping credits in 2004 and 2005 will equal total generation costs less an amount equivalent to the RTC and twenty-five percent of CTC, as was proposed for 2005 only.[23]

2. Rate Stabilization Period – Standard Service Offer and Competitive Bidding

The provisions added to Ohio law by SB 3 require that, after the end of the MDP, an electric utility will provide a "market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers," as well as the option to purchase competitive retail electric service the price of which is determined through a competitive bidding process." Section 4928.14, Revised Code. The competitive bidding process (CBP) may also be replaced with other means to accomplish generally the same option for customers. Section 4928.14(B), Revised Code. The Commission is in the process of adopting rules concerning these matters, pursuant to which the Commission's staff has recommended that the market-based standard service offer (MBSSO) should be a "market-based, variable rate" and the CBP should result in a "market-based, fixed rate." Bidding Rules Case, Entry (February 20, 2003).

The proposed stipulation provides that the three-year period immediately following the end of the MDP will be a rate stabilization period (RSP), during which several provisions will apply. The first such provision is that DP&L agrees to provide a MBSSO to its customers. Specifically, during the RSP the customers will receive generation service at rates that are set forth in the stipulation, based upon the negotiation among the various parties to the stipulation. These rates will be the generation rates currently charged customers, except as otherwise provided for in the stipulation, and are subject to periodic review by the Commission to determine, among other things, whether "they reasonably reflect prices that would otherwise be established for comparable service as between willing buyers and sellers operating in an efficient marketplace." To conduct such a review, the Commission may use then existing information or, if necessary, may direct "DP&L to implement a competitive bidding process that will reveal such pricing information as the Commission may deem useful to test such standard offer prices against the market." The Commission may then terminate all provisions applicable to the RSP, if it deems that such termination would be appropriate. (Joint Exhibit 1, at 14-15.)

The stipulation also provides that, if the specified twenty percent shopping level has not been attained by certain specified dates, then the parties will engage in a voluntary en-

[23] Although the Commission uses the terms RTC and CTC to explain the shopping credits for years 2004 and 2005, we recognize that there is no actual RTC or CTC cost recovery during 2004 and 2005.

rollment process (VEP) designed to encourage shopping. The VEP would, basically, provide customers an opportunity to choose any certified generation supplier. (Joint Exhibit 1, at 8-10.)

The signatory parties propose that the negotiated rates in the stipulation, as reviewed periodically by the Commission to ensure that they are comparable to market rates, would serve as DP&L's MBSSO during the RSP. (DP&L's brief at 7; DP&L's reply brief at 21-25; IEU-Ohio's reply brief at 21; staff's reply brief at 12.) Staff explains the provision as follows:

> Importantly, the settlement agreement fulfills the requirement of Section 4928.14(A) that DP&L offer its customers a "market-based rate" once the MDP expires. The RSP provisions satisfy that requirement for each of the following reasons: (1) the generation rates established in the Stipulation for the [RSP] were the product of serious bargaining by knowledgeable buyers and sellers, thus ensuring that they are market-based; (2) the provisions of [the stipulation] provide for changes to rates during the RSP to reflect changes to limited, enumerated DP&L costs, and only upon approval by the Commission, thus ensuring that the rates charged during the RSP will track market conditions; and (3) [the stipulation] provides for continuing Commission review of the rates charged during the RSP, and if market rates do not reasonably reflect the rates charged during the RSP, then for good cause shown, the Commission may terminate the RSP after which DP&L will charge a market-based rate pursuant to Section 4928.14(A).

(Staff's brief at 9-10.)

The signatory parties also argue that the VEP will qualify to provide consumers with generally the same option as competitive bidding (DP&L's brief at 8-9; staff's brief at 10; DP&L's reply brief at 25-27; OCC's reply brief at 11; IEU-Ohio's reply brief at 20-22; staff's reply brief at 12).

The CRES providers contest these claims. They submit that the rates which would be established as the MBSSO "are the rates established in their last rate case." They disagree with the contention that negotiations which included buyers and sellers must have resulted in "market based" rates. They dispute the argument that buyers and sellers were present, since they say that only one seller was present and no buyer was present. They argue that the purpose of the negotiation was not to determine market rates and no effort was made to do so. (CRES group's brief at 23-24; CRES group's reply brief at 12.) Green Mountain also protests the use of negotiated rates as the MBSSO (Green Mountain's brief at 11), as does WPS (WPS's brief at 10-13). The nonsignatory parties also dispute the use of the VEP as an alternative to the CBP (CRES group's brief at 24-26; OMA's brief at 9; WPS's brief at 15; CRES group's reply brief at 13; Green Mountain's reply brief at 7-10).

The Commission finds that the procedure set forth in the proposed stipulation does provide consumers with market-based rates. Initially, the rates were set by negotiations among two suppliers[24] and organizations representing various categories of consumers. The stipulation's standard service offer can also be considered market based inasmuch as it

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[24] Not only was DP&L present, but IEU-Ohio is also a certified CRES supplier.

includes provisions that provide for changes to the MBSSO to reflect changes in certain costs. More importantly, however, adequate safeguards are in place to allow the Commission to monitor the prices and confirm that, over time, those prices remain market-based and that consumers have adequate options for choosing among generation suppliers. The stipulation does not violate the requirements of Section 4928.14, Revised Code. Section 4928.14, Revised Code, provides the Commission with flexibility in approving processes for determining market-based rates for the standard service offer. We believe that, for DP&L, the methodology for establishing an MBSSO set forth in the stipulation is reasonable, subject to our findings below. We also find that by renewing efforts to implement the VEP program and establishing the MBSSO with price monitoring, the stipulation provides a reasonable alternative to a more traditional CBP, provides for a reasonable means of customer participation, and fulfills the requirements of Section 4928.14 (B), Revised Code.

3. Rate Stabilization Period – Rate Stabilization Surcharge

The stipulation would provide that, during the RSP, DP&L's rates will be charged as set forth in the stipulation, provided that the rates can be increased to recover verified increases in

> production costs per kWh directly related to the generation of electricity from plants owned by DP&L and its affiliates resulting from *fuel price increases*, or actions taken in *compliance with environmental and tax laws*, regulations or court or administrative orders; and . . . costs per kWh directly related to *physical security and cyber-security* costs associated with the generation of electricity from plants owned by DP&L and its affiliates imposed by final rule, regulation or administrative or court order.

(Joint Exhibit 1, at 13 (emphasis added).) These increased costs are imposed in the form of a rider (RSS) on all customers, whether they purchase their generation from DP&L or from any other supplier. DP&L argues that the RSS is a mechanism for recovery of provider-of-last-resort (POLR) costs (DP&L's brief at 9-11).

The CRES suppliers complain that the RSS violates state law in that it increases the rates charged by DP&L without complying with the Commission's practices for applying for such increases (CRES group's brief at 26-28) and it discriminates against the CRES marketers by giving a fuel cost advantage to DP&L (CRES group's brief at 28-30). They also dispute the identification of the RSS as a means to recovery POLR costs, since they argue that fuel, environmental compliance, taxes, and security are not POLR type items (CRES group's reply brief at 15). OMA agrees (OMA's reply brief at 6).

Green Mountain also contends, among other things, that the RSS would extend an undue advantage to DP&L, in violation of Section 4928.17(A)(3), Revised Code, regarding the development of a corporate separation plan. It would also, in Green Mountain's opinion, double charge shopping customers for the covered items, since they would also have to pay for those items from their generation provider. Green Mountain agrees with the CRES group that the RSS amounts to an improperly filed application for an increase in rates. (Green Mountain's brief at 12-16.) Finally, it contends that the RSS does not recover POLR costs (Green Mountain's reply brief at 10-11).

After considering the arguments raised by the parties, we find that the provisions of the stipulation regarding the establishment of the RSS are not unreasonable if certain modifications are made. In this proceeding, the Commission is being asked to approve a procedure for the possibility of a surcharge on all customer bills starting no earlier than 2006. Pursuant to the stipulation, the RSS is capped at 11 percent of DP&L's generation rate effective January 1, 2004. The stipulation states that the RSS will allow DP&L the opportunity to recover certain verifiable increases in costs over a base period of twelve months ending May 31, 2003. DP&L argues that the RSS, with respect to those customers who do not take generation service from DP&L, is to compensate DP&L for the risks and costs that DP&L will incur as a POLR.

The Commission believes that an RSS is reasonable and legally sustainable as part of a proposed methodology for developing an MBSSO for customers who subscribe to that service. As to the issue of whether the RSS should apply to all customers, whether or not they purchase their generation from DP&L, the Commission would note, initially, that representatives of all customer groups agreed, in the stipulation, with charging the RSS to all customers. In addition, the Commission finds that it is reasonable for DP&L to argue that it will incur costs in its position as the provider of last resort, which costs would not be recoverable other than through the RSS. While the Commission is not finding that the costs specified in the stipulation as the basis for the RSS are POLR costs, the Commission does find that the existence of POLR costs makes it reasonable to apply the RSS to all customers.

In addition, the Commission is concerned about the potential negative impact an additional two and one-half percent discount to residential customers could have on the development of a competitive retail electric market. Residential customers have already received, pursuant to the terms of the ETP stipulation, a five percent discount on the rate competitors must beat. Further reductions could make it more difficult for competitors to enter the market and, consequently, harm residential customers in the long term if a competitive market fails to develop. Inasmuch as the Commission cannot determine at this time how competition will develop through the course of the MDP, the Commission will modify the stipulation to provide that, at the end of the MDP, we will again look at the state of the retail electric market. If, at that time, competition in the DP&L service territory has not developed sufficiently, the Commission finds that an additional two and one-half percent residential discount would be appropriate, and we will allow the stipulated residential discount to take effect.

D. Summary

Based on our three-prong standard of review, we find that the first criterion, that the process involved serious bargaining by knowledgeable, capable parties, is met. Multiple bargaining sessions took place before commencement of the hearings. The parties to these negotiations have been involved in many cases before the Commission, including a number of prior cases involving rate issues.

The stipulation, as modified by this Opinion and Order, also meets the second criterion. The stipulated resolution of these cases is for many reasons advantageous and promotes the public interest. The stipulation, as modified, establishes a framework for the extension of DP&L's MDP in a way that the Commission believes will likely encourage competition and will protect consumers. The stipulation also removes significant uncertainty as to the future prices of electricity generation. Adoption of the stipulation also resolves several ongoing legal matters before the Commission, and evidence that the public interest is served by the stipulation is found in the support offered by representatives of residential, commercial, and industrial customers, including OCC and the Commission's staff.

Finally, the stipulation as modified to require the shopping credit to equal Big G and the RSS to apply to only customers who subscribe to the MBSSO does not violate any important regulatory principle or practice. Indeed, the agreement balances the interests of a broad range of parties that represent a diverse spectrum of views. As indicated in the description of the stipulation provided above, the stipulation as modified provides substantial benefits to all customer classes and stakeholders, and is consistent with the policies of the state.

Although the Commission is approving the stipulation with certain modifications, we support the efforts of the stipulating parties to establish a plan for the continuation of the market development period for an additional two years as well as plan for a rate stabilization period and an MBSSO which will provide additional time for competitive electric markets to grow. We encourage other electric utilities to consider such options if competitive electric markets have not fully developed in the service territory by the end of their MDPs.

V. FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) On March 1, 2002, DP&L filed its application in the deposits case.

(2) September 12, 2002, the complainants in the RTO case filed their complaint.

(3) October 28, 2002, DP&L filed its application in the MDP case.

(4) On November 21, 2002, DP&L filed its application in the accounting case.

(5) On May 28, 2003, a stipulation and recommendation was filed on behalf of DP&L, OPAE, OCC, IEU-Ohio, CAP and staff of the Commission.

(6) On June 9, 2003, and June 12, 2003, Green Mountain and WPS, respectively, filed motions for intervention in certain of the consolidated cases. These motions were denied.

(7) On June 16, 2003, Strategic, Constellation and Dominion filed a motion to compel discovery. This motion was denied.

(8) The hearing was held on May 15, May 29, and June 17, 2003.

(9) On June 20, 2003, Green Mountain filed an interlocutory appeal of the denial of its intervention. The stipulation proposed in this case clearly covers such matters and neither the public notice given in these cases nor the any of the prior filings in the cases presented

the possibility that such matters would be resolved in this proceeding. Therefore, Green Mountain has shown good cause why it should be allowed to intervene after the relevant deadlines.

(10) The Commission is granting Green Mountain intervention, as conditionally requested, for any proceedings which arise in these cases from this point forward. Although WPS did not file an interlocutory appeal of the denial of intervention, the Commission will grant its intervention on the same grounds and the same terms as it does with regard to Green Mountain.

(11) On June 23, 2003, Strategic, Constellation and Dominion filed an application for review and approval of interlocutory appeal related to the denial of their motion to compel discovery.

(12) The matters sought to be discovered by Strategic, Constellation and Dominion are both privileged and irrelevant. The Commission will evaluate the terms of the stipulation as they appear on its face. Therefore, the discovery sought in the CRES discovery appeal is not relevant to the subject matter of these proceedings.

(13) The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

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

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

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

(14) While the Commission is not condoning the process used to reach the proposed stipulation in this matter, it does find that the stipulation meets the first requirement of the three-pronged test.

(15) The stipulation, as modified by this Opinion and Order, also meets the second criterion. The stipulated resolution of these cases is for many reasons advantageous and promotes the public interest.

(16) The stipulation, as modified (a) to provide that, at the end of the MDP, the Commission will consider whether to allow the proposed additional two and one-half percent residential discount and will allow such discount if it determines that sufficient

> competition has not developed, and (b) to increase the nonresidential shopping credit in 2004 to the same level as proposed for 2005, does not violate any important regulatory principle or practice. Indeed, the agreement balances the interests of a broad range of parties that represent a diverse spectrum of views.

It is, therefore,

ORDERED, That the denial of the motion to intervene by Green Mountain be reversed; and the intervention of Green Mountain in the MDP case, the accounting case and RTO case, and the intervention of WPS in the MDP case, be granted, on the terms set forth herein. It is, further,

ORDERED, That the denial of the motion to compel discovery, filed by Strategic, Constellation and Dominion, be affirmed. It is, further,

ORDERED, That the stipulation filed on May 28, 2003, is approved, to the extent and subject to the modifications and conditions set forth above. It is, further,

ORDERED, That DP&L file tariffs for Commission approval that reflect the terms of the stipulation as modified by this opinion and order within 75 days. It is, further,

ORDERED, That a copy of this opinion and order be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

JWK/RRG;geb

Entered in the Journal

SEP 2 2003

Reneè J. Jenkins
Secretary

Footnote

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of First-Energy Corp. on behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of Tariff Adjustments.	)	Case No. 03-1461-EL-UNC

ENTRY

The Commission finds:

(1) On July 1, 2003, FirstEnergy Corp. (FirstEnergy), on behalf of The Cleveland Electric Illuminating Company, The Toledo Edison Company, and Ohio Edison Company, filed an application to revise, for the years 2004 and 2005, its shopping credits established in each of the utilities' electric transition plans (ETP). The application was submitted pursuant to the Stipulation and Recommendation (Stipulation) and the Supplemental Settlement Materials (Supplemental Settlement) filed in Case No. 99-1212-EL-ETP, which were approved by the Commission on July 19, 2000. The level of the shopping credits set out in the tariffs consists of a market support pricing component and an incentive component. The Stipulation specifies that the shopping incentive percentage for the classes of customers will not be increased from the previous year if more than 20 percent shopping levels have been attained. FirstEnergy states that more than 20 percent shopping levels have been attained for all residential, commercial and industrial classes for the measuring period in accordance with the provisions specified in the Stipulation and the Supplemental Settlement.

(2) The current shopping credits were approved by Entry dated March 25, 2003, in Case No. 02-2877-EL-UNC (02-2877). FirstEnergy, in this application, seeks to reduce the shopping credit incentive for each rate class for each of the three operating companies. This application seeks to reduce the shopping credit levels beginning with the bills reflecting usage in 2004, and continuing through 2005 or the end of the market development period. The Stipulation provides that the incentive may be reduced in subsequent years as deemed appropriate by the Commission, to minimize specified

deferrals. The company identified two objectives in determining the amount of the adjustment; the first being to have a shopping incentive level that maintains shopping levels of at least 20 percent and the second being to minimize the regulatory asset deferral to levels contemplated in the ETP. FirstEnergy avers that the initial level of shopping credits was meant to "jump-start" the market and that current shopping percentages demonstrate that the initial level of incentive is no longer needed. FirstEnergy contends that there is a sufficient margin between the shopping credit and the expected cost of power to provide significant price reductions to customers, and cost recovery and an opportunity to earn reasonable profits for suppliers. FirstEnergy asserts that reduction of the shopping credit will serve to eliminate an extension of the regulatory transition charges (RTC) recovery period, effectively reducing by more than two hundred million dollars the forecasted deferral balance, while maintaining shopping levels of over 20 percent.

(3) Motions for intervention and memoranda in support were filed by Office of Consumers' Counsel (OCC); cities of Maumee, Northwood, Oregon, Perrysburg, Sylvania, Toledo, Village of Holland and Unincorporated Townships of Lucas County (NOAC); The Kroger Company (Kroger); Dominion Retail Inc. (Dominion); Green Mountain Energy Company, MidAmerican Energy Company, Strategic Energy LLC, WPS Energy Services, Inc., Constellation NewEnergy, Inc., Sempra Energy Solutions, (Marketers); Northeast Ohio Public Energy Council (NOPEC); American Greetings Corporation (American Greetings); Ohio Energy Group (OEG); city of Cleveland (Cleveland); Ohio Manufacturers' Association (OMA); and National Energy Marketers Association (NEM). FirstEnergy filed a memorandum contra NEM's motion to intervene and NEM filed a response.

(4) There were also numerous letters filed, supporting certain parties' intervention motions and opposing the application, from various cities, villages, a township, individual consumers and elected officials.

(5) A technical conference was held on August 8, 2003, and comments delineating specific objections to the application were filed by August 22, 2003.

(6) On July 30, 2003, Gary A. Jeffries filed a Motion for Admission Pro Hac Vice of Todd S. Stewart, for the representation of Dominion in this proceeding and on August 7, 2003, Stephen Howard filed a Motion for Admission Pro Hac Vice of Craig G. Goodman for the representation of NEM. On August 25, 2003, a Motion for Leave Instanter to file comments one business day out of time was filed by Green Mountain Energy Company. The motions Pro Hac Vice and for Leave Instanter to file comments late are well made and should be granted.

(7) The sixteen filings for intervention were consistent in their stated purpose of opposing the application. The comments in opposition to the adjustment of the incentive focused on the potential for diminished competition in Ohio. NOPEC asserts that the market has not matured to the point of permitting deviation from the Stipulation. Kroger contends that lowering the credits mid-course would undermine confidence in Ohio's ability to manage the transition to competition. WPS maintains that the Stipulation was a balanced bargain between the parties and that FirstEnergy receives seven billion dollars in generation and regulatory asset charges in exchange for sufficient shopping credits to develop a retail generation market. NOAC claims that approval of the application could destroy governmental aggregation and that residential shopping in Toledo Edison Company's territory could fall below 20 percent. The Marketers allege that granting the application would impair the viability of contracts that they have reached with customers on the system. American Greetings submits that an elasticity study is needed on the relationship between the level of the shopping credit and switching. OCC, and many other commenters, state that there are factual issues as to shopping levels, marketer margin and costs that would necessitate a hearing before the application could be considered.

(8) Although we agree with FirstEnergy that in accordance with the Stipulation we should monitor and consider adjustments to the shopping credit in order to maintain a balance between

encouraging shopping and limiting the RTC recovery period, the market development has not matured to the point of deviating from the calculations in the Stipulation. There is the real possibility that the adjustment could cause certain customer classes to fall back below 20 percent or that the market would not remain viable or attractive to suppliers. The FirstEnergy service territory still is not seeing the entry of new suppliers into the marketplace that would evidence a mature or robust competitive market. We note that, based upon FirstEnergy's forecast of shoppingprovided as part of its application, the extension of the RTC recovery period that may result from the failure to grant the application is twelve weeks for Ohio Edison, seven weeks for CEI and six weeks for Toledo Edison. The extension of the RTC recovery period was anticipated by and may be handled through the mechanism of the Stipulation. Therefore, given the uncertainty a midcourse adjustment might have on market development at this time, and given the relative short increase in the RTC collection period occasioned by maintaining the levels dictated by the Stipulation, the application to modify the shopping credits should be denied.

(9) The application filed by FirstEnergy and the comments submitted to the Commission identify the difficulty in striking a balance between encouraging shopping and limiting the RTC recovery period. The Commission previously stated that "...we should monitor and consider adjustments to the shopping credit in order to maintain ... [this]...balance..." (02-2877 at 2). The Commission also recently encouraged utilities to consider rate stabilization plans to provide additional certainty for ratepayers and market participants, while at the same time encouraging competitive markets to further develop. *In Re Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company,* Case No. 02-2779-EL-ATA at 29 (Opinion and Order, September 2, 2003). The instant order decides the matter of shopping credits for the year 2004 only. The Commission believes that the matter of shopping credits for 2005 may best be considered in the context of what would best promote orderly and progressive market development in the post market development period. We encourage FirstEnergy to consider and develop plans for 2005 and beyond, which balance three

objectives: rate certainty, financial stability for the electric distribution utilities and further competitive market development. We further encourage FirstEnergy to file its plan before December 31, 2003, in a separate docket.

(10) Upon consideration, we find that it is not necessary to grant intervention in order to consider the comments in our determination in this application. Furthermore, we do not believe a hearing is necessary for conducting an evaluation of the application.

(11) FirstEnergy should submit its tariffs that reflect the shopping credit values for 2004 in accordance with the Stipulation within 14 days of this entry for Commission approval. The filing should comport with the table attached to this entry. The shopping credits in the Stipulation are average shopping credits, which are applied to specific customers using the rate designs included in the applicable rate schedules. The table attached to this entry shows the derivation of the average shopping credit increases that result from applying the appropriate parameters from the Stipulation. In order to apply these average increases, we direct FirstEnergy in its compliance filing, to adjust each rate block contained within the existing tariffs from their current levels by the appropriate percentage from column (e) of the table.

It is, therefore,

ORDERED, That FirstEnergy's application of July 1, 2003 to revise its shopping credits is denied. It is, further

ORDERED, That the motions to intervene as listed in paragraph 3 are denied. It is, further,

ORDERED, That the motions Pro Hac Vice and for Leave Instanter to file comments late are well made and are granted. It is, further,

ORDERED, That FirstEnergy submit its tariffs that reflect the shopping credit values for 2004 in accordance with the Stipulation and paragraph 11 of this entry within 14 days of this entry for Commission approval. It is, further, ORDERED, That the FirstEnergy is authorized to file in final form, four complete printed copies of the tariff consistent with the findings of this entry, and to cancel and withdraw the superseded tariffs. One copy shall be filed with its TRF dockets, and the remaining two copies shall be designated for distribution to the Commission staff. It is, further,

ORDERED, That the effective date of the new tariffs shall be January 1, 2004. However, this shall be interpreted as being applicable to a customer's usage after the customer's first scheduled meter read date in 2004. It is, further,

ORDERED, That FirstEnergy shall make all approved tariffs available on their official company websites and shall provide all approved tariffs electronically to the Commission's docketing division. It is, further,

ORDERED, That nothing in this entry shall be binding upon this Commission in any future proceeding or investigation involving the justness or reasonableness of any rate, charge, rule or regulation. It is, further, ORDERED, That a copy of this Entry be served on all interested persons of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

SDL;geb

Entered in the Journal

SEP 2 3 2003

Reneé J. Jenkins
Secretary

03-1461-EL-UNC
Table Attachment

Table 1

	(A) 2003 CURRENT SHOPPING CREDIT	(B) 2004 MARKET SUPPORT PRICE	(C) APP. INCENT.	(D) STEP 2004 SHOPPING CREDIT	(E) % INCR.
OE					
RES.	48.17	35.66	45%	51.71	7.35%
COM.	42.58	34.98	30%	45.47	6.79%
IND.	31.89	30.04	15%	34.55	8.34%
CEI					
RES.	48.87	36.18	45%	52.46	7.35%
COM.	42.58	34.98	30%	45.47	6.79%
IND.	31.89	30.04	15%	34.55	8.34%
TE					
RES.	46.37	34.33	45%	49.78	7.35%
COM.	42.58	34.98	30%	45.47	6.79%
IND.	31.89	30.04	15%	34.55	8.34%

Footnote

3&4

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post-Market Development Period Rate Stabilization Plan.	))))	Case No. 04-169-EL-UNC

OPINION AND ORDER

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OPINION AND ORDER

The Commission, having considered the evidence, the arguments of the parties, and the applicable law, hereby issues its opinion and order in this proceeding.

APPEARANCES

Marvin I. Resnik and Sandra K. Williams, 1 Riverside Plaza, Columbus, Ohio 43215-2373, and Daniel Conway, Porter, Wright, Morris & Arthur, 41 South High Street, Columbus, Ohio 43215, on behalf of Columbus Power Company and Ohio Power Company.

Jim Petro, Attorney General of the state of Ohio, Duane W. Luckey, Senior Deputy Attorney General, by William Wright, Steven Nourse, and Thomas McNamee, Assistant Attorneys General, 180 East Broad Street, 9th Floor, Columbus, Ohio 43215, on behalf of the staff of the Public Utilities Commission of Ohio.

Michael R. Smalz, Ohio State Legal Services Association, 555 Buttles Avenue, Columbus, Ohio 43215, and Joseph V. Maskovyak, Legal Aid Society of Columbus, 40 West Gay Street, Columbus, Ohio 43215, on behalf of Appalachian People's Action Coalition.

Robert P. Mone, Scott A. Campbell, and Kurt P. Helfrich, Thompson Hine LLP, 10 West Broad Street, Suite 700, Columbus, Ohio 43215-3435, on behalf of Buckeye Power Inc. and Ohio Rural Electric Cooperatives Inc.

Joseph Condo, Calpine Corporation, 250 Parkway Drive, Suite 380, Lincolnshire, Illinois 60069, on behalf of Calpine Corporation.

Stephen J. Smith, Gregory J. Dunn, and Christopher L. Miller, Schottenstein, Zox & Dunn, 41 South High Street, Columbus, Ohio 43215, on behalf of City of Dublin.

Jeanine Amid, City Attorney, and Tom Lindsey, First Assistant City Attorney, 3600 Tremont Road, Upper Arlington, Ohio 43221, on behalf of City of Upper Arlington.

M. Howard Petricoff, W. Jonathan Airey, and Jeffrey Becker, Vorys, Sater, Seymour and Pease LLP, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, on behalf of Constellation NewEnergy Inc., MidAmerican Energy Company, Strategic Energy LLC, and WPS Energy Services Inc.

M. Howard Petricoff, Vorys, Sater, Seymour and Pease LLP, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, and Michael D. Smith, Constellation Power Source Inc., 111 Marketplace, Suite 500, Baltimore, Maryland 21202, on behalf of Constellation Power Source Inc.

Evelyn R. Robinson, Green Mountain Energy Company, 5450 Frantz Road, Suite 240, Dublin, Ohio 43016 and Bruce J. Weston, 169 Hubbard Avenue, Columbus, Ohio 43215-1439, on behalf of Green Mountain Energy Company.

Samuel C. Randazzo, Lisa Gatchell McAlister, and Daniel J. Neilsen, McNees Wallace & Nurick LLC, 21 East State Street, 17th Floor, Columbus, Ohio 43215-4228, on behalf of Industrial Energy Users-Ohio.

Michael L. Kurtz, Boehm, Kurtz & Lowry, 36 East Seventh Street, Suite 2110, Cincinnati, Ohio 45202, on behalf of The Kroger Company.

Ellis Jacobs, Advocates for Basic Legal Equality Inc., 333 West First Street, Suite 500B, Dayton, Ohio 45402, on behalf of Lima/Allen Council on Community Affairs and WSOS Community Action.

Craig G. Goodman and Stacey L. Rantala, National Energy Marketers Association, 3333 K Street NW, Suite 110, Washington, DC 20007, on behalf of National Energy Marketers Association.

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, and Colleen L. Mooney, Kimberly J. Bojko, Eric B. Stephens, and Larry Sauer, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215-3485, on behalf of the residential customers of Columbus Power Company and Ohio Power Company.

David F. Boehm and Michael L. Kurtz, Boehm, Kurtz, & Lowry, 36 East Seventh Street, Suite 2110, Cincinnati, Ohio 45202, on behalf of Ohio Energy Group.

Richard L. Sites, 155 East Broad Street, 15th Floor, Columbus, Ohio 43215-3620, on behalf of Ohio Hospital Association.

Sally W. Bloomfield and Thomas J. O'Brien, Bricker & Eckler LLP, 100 South Third Street, Columbus, Ohio 43215-4291, on behalf of Ohio Manufacturers' Association.

David C. Rinebolt, Ohio Partners for Affordable Energy, 337 South Main Street, 4th Floor, Suite 5, P.O. Box 1793, Findlay, Ohio 45839-1793, on behalf of Ohio Partners for Affordable Energy.

Craig A. Glazer and Janine Durand, PJM Interconnection L.L.C., 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403-2497, on behalf of PJM Interconnection L.L.C.

Shawn P. Leyden, 80 Park Plaza, 19th Floor, Newark, New Jersey 07102, on behalf of PSEG Energy Resources and Trade LLC.

Peter J.P. Brickfield and Emily W. Streett, Brickfield, Burchette, Ritts & Stone PC, 1025 Thomas Jefferson Street NW, 8th Floor – West, Washington, DC 20007, on behalf of Wheeling-Pittsburgh Steel Corporation.

OPINION

I. Background

In June 1999, the Ohio General Assembly passed legislation (Amended Substitute Senate Bill No. 3 of the 123rd General Assembly, referred to as SB3) requiring the restructuring of the Ohio electric utility industry and providing for competition for the generation component of electric service. That legislation was signed by the governor in July 1999. Pursuant to SB3, the Commission received and reviewed proposed plans by Columbus Southern Power Company and Ohio Power Company (collectively AEP) to transition from the then-existing regulatory framework to the restructured SB3 framework. *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 (September 28, 2000) and Entry on Rehearing (November 21, 2000).

Ohio electric choice (a short-hand term for the competitive electric generation component in Ohio) began on January 1, 2001. Under Section 4928.40, Revised Code, a period of time was established to allow a competitive electric market to develop for the generation component of electric service (market development period, MDP). The default expiration date of the MDPs was December 31, 2005, unless otherwise determined by the Commission in conformance with certain statutory criteria. Since electric choice began, three competitive retail electric service providers have been certified to serve customers in AEP's service territories, with only one actually serving customers (nonresidential) (Tr. I, 34, 127). There has been at most 3.4 percent shopping in Columbus Southern's service territory and zero percent shopping in Ohio Power's territory (Tr. II, 175; OCC Ex. 8; GMEC Ex. 5, at first set discovery requests 25 and 26 and third set discovery requests 1 and 2). AEP's MDP is currently scheduled to expire on December 31, 2005.

In September 2003, the Commission (while addressing a proposed stipulated plan for the competitive market in The Dayton Power and Light Company service territory) encouraged all other electric distribution utilities (EDUs) in the state to consider continuation of their MDPs, a plan for rate stabilization, and/or a market-based standard service offer as a means for allowing time for their competitive electric markets to grow. *In the Matter of the Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company*, Case No. 02-2779-EL-ATA, Opinion and Order at 29 (September 2, 2003). Then later that month, the Commission elaborated further that such proposals should balance three objectives: rate certainty, financial stability for the EDU, and further competitive market development. *In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of Tariff Adjustments*, Case No. 03-1461-EL-UNC, Entry at 4-5 (September 23, 2003).

On February 9, 2004, AEP filed an application with the Commission for approval of a rate stabilization plan (RSP) to follow its competitive electric MDP. AEP proposes a plan to substitute for a post-MDP, market-based standard service offer and to eliminate a competitive bidding process from 2006 through 2008.

Twenty-five entities filed motions to intervene in this proceeding. Those requests were all granted and the intervenors are:

Appalachian People's Action Coalition (APAC)[1]	Buckeye Power Inc.
Calpine Corporation	City of Dublin
City of Upper Arlington	Constellation NewEnergy Inc.[2]
Constellation Power Source Inc.	Green Mountain Energy Company (Green Mountain or GMEC)
Industrial Energy Users-Ohio (IEU-Ohio)	The Kroger Company
Lima/Allen Council on Community Affairs	MidAmerican Energy Company
National Energy Marketers Association (NEMA)	Ohio Consumers' Counsel (OCC)
Ohio Energy Group (OEG)[3]	Ohio Hospital Association
Ohio Manufacturers' Association	Ohio Partners for Affordable Energy (OPAE)
Ohio Rural Electric Cooperatives Inc.	PJM Interconnection L.L.C. (PJM)
PSEG Energy Resources and Trade LLC (PSEG)	Strategic Energy LLC
Wheeling-Pittsburgh Steel Corporation	WPS Energy Services Inc.
WSOS Community Action	

By entry dated March 11, 2004, the Commission established a procedural schedule for this proceeding. A technical conference was held on March 24, 2004. Objections to the application were filed on April 8, 2004. By entry dated April 27, 2004, the examiner slightly modified that procedural schedule, changing deadlines for prefiling expert testimony, discovery cut-off, the local hearing dates (to be held in Canton and Columbus), and the evidentiary hearing date. In May 2004, the parties prefiled their expert testimony under the revised schedule.

Pursuant to the revised schedule, the local, public hearing in Canton, Ohio, was conducted on May 19, 2004. However, the examiner discovered after that hearing that the Commission had not properly sent any of the publication notices to the newspapers in AEP's service territory. Therefore, the examiner scheduled another local hearing in Canton, Ohio, for July 7, 2004, and rescheduled the local hearing in Columbus for July 1, 2004.

On May 24, 2004, OCC filed a motion to dismiss the application on various legal grounds. On May 25, 2004, AEP filed a motion to extend the time to respond to OCC's motion. IEU-Ohio supported an extension of the time to respond to OCC's motion. By

1 Appalachian People's Action Coalition, Lima/Allen Council on Community Affairs, Ohio Partners for Affordable Energy, and WSOS Community Action are collectively referenced in this decision as the low-income advocates or LIA.

2 Constellation NewEnergy Inc., MidAmerican Energy Company, Strategic Energy LLC, and WPS Energy Services Inc. are collectively referenced in this decision as the Ohio Marketers Group or OMG.

3 OEG is composed of AK Steel Corporation, BP Products North America Inc., The Procter and Gamble Co., Ford Motor Company, and International Steel Group Inc.

entry dated June 1, 2004, the examiner granted the request to defer a ruling on OCC's motion to dismiss, stating that all parties shall have the opportunity to argue the legality of AEP's proposal in post-hearing briefs.

The evidentiary hearing began on June 8, 2004, and continued to June 14, 2004. AEP presented the testimony of five witnesses. The staff and OCC each presented the testimony of two witnesses. APAC, Lima/Allen Council on Community Affairs, and WSOS Community Action jointly sponsored the testimony of one witness and OEG presented the testimony of one witness. At the July 1 and 7, 2004 local hearings, three people provided testimony in opposition to AEP's proposed RSP. The parties filed post-hearing briefs on July 13 and 30, 2004.

II. The Law

Section 4928.14, Revised Code, states in pertinent part:

(A) After its market development period, an electric distribution utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified service territory, a market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service....

(B) After that market development period, each electric distribution utility also shall offer customers within its certified territory an option to purchase competitive retail electric service the price of which is determined through a competitive bidding process....At the election of the electric distribution utility, and approval of the commission, the competitive bidding option under this division may be used as the market-based standard offer required in division (A) of this section. The commission may determine at any time that a competitive bidding process is not required, if other means to accomplish generally the same option for customers is readily available in the market and a reasonable means for customer participation is developed.

Also relevant, the Commission approved a request filed by AEP to temporarily waive the need for it to propose a market-based standard service offer and/or competitive bidding process (CBP). *In the Matter of the Request for a Temporary Waiver by Columbus Southern Power Company and Ohio Power Company from the Requirements of Chapter 4901:1-35, Ohio Administrative Code,* Case No. 04-888-EL-UNC, Entry (June 23, 2004). The Commission agreed that AEP need not make such proposal(s) until 30 days after the final order is issued in this proceeding.

III. Certain Elements of the Approved Electric Transition Plan

In moving to electric choice in Ohio, the Commission had to address a number of financial and regulatory concerns so that each of the electric utilities could transition into utilities providing monopoly distribution service, while competing to provide the generation component. In the course of making that transition, the bundled rates and services of the electric utilities had to be separated, or unbundled, into generation, distribution and transmission components in the electric transition plan (ETP) proceedings.

Most of the parties to the AEP ETP proceedings agreed upon a resolution of the issues. The Commission reviewed that proposed resolution and approved it, with some minor modifications and with a reservation of a ruling upon the independent transmission plan. For purposes of better understanding the proposed RSP, several relevant components of the ETP are:

(1) All distribution rates effective December 31, 2005 will be frozen through 2007 for Ohio Power and 2008 for Columbus Southern. However, during that period, distribution rates can adjust to reflect costs of complying with certain changes (e.g., environmental, tax and regulatory changes) and for relief from storm damage or emergencies.

(2) Columbus Southern and Ohio Power agreed to absorb the first $20 million of actual consumer education, customer choice implementation and transition plan filing costs, but the remainder of such were permitted to be deferred, plus a carrying charge, as regulatory assets for recovery in future distribution rates (via a rider).

(3) Regulatory asset recovery was approved for the companies' MDP and for the subsequent three years for Columbus Southern and the subsequent two years for Ohio Power. Recorded regulatory assets at the beginning of the MDP, which exceeded specific regulatory asset dollar amounts in the stipulation, were amortized during the MDP and recovered through existing frozen and unbundled rates.

(4) Columbus Southern made available to the first 25 percent of the switching residential customers a shopping incentive. Any unused portion of that incentive as of December 31, 2005, will be credited to Columbus Southern's regulatory transition cost recovery.

(5) AEP reduced by five percent its generation component (including the regulatory transition costs). AEP agreed to not seek to reduce that five percent reduction for residential customers during the MDP. The first 20 percent of Ohio Power residential customer load as of December 31, 2005, that switches will not be charged the regulatory transition charge in 2006 and 2007.

(6) AEP shall transfer, by no later than December 15, 2001, operational control of its transmission facilities to a Federal Energy Regulatory Commission (FERC) approved regional transmission organization (RTO). AEP established a fund (up to $10 million) for costs associated with transmission charges imposed by PJM and/or the Midwest

Independent System Operator (MISO) on generation originating in the service territories of PJM or MISO as such costs may be incurred.

IV. Elements of the Proposed Rate Stabilization Plan

AEP proposes a plan from 2006 through 2008 to substitute for a post-MDP market-based standard service offer and to eliminate a competitive bidding process (Tr. I, 27). The RSP states that all provisions of the approved ETP that are not changed by the RSP will not be changed. The RSP proposal can be quickly summarized as follows:

(1) Keeps distribution rates in effect on December 31, 2005, frozen through 2008, except for changes allowed by 12 categories.

(2) Continues to defer pre-2006 consumer education, customer choice implementation and transition plan filing expenses beyond $20 million. Defer post-2005 consumer education, customer choice implementation and transition plan filing expenses and all RSP filing costs. All will be recovered as distribution regulatory assets, along with carrying charges, after the RSP.

(3) Allows deferral and recovery in RSP distribution rates of: (a) RTO administrative charges from the date of integration in PJM through 2005, along with a carrying cost; (b) full carrying charges for construction expenses in Accounts 101 (electric plant in service) and 106 (completed construction not classified) from 2002 through 2005; and (c) 2004 and 2005 equity carrying charges for expenditures from 2002 through 2005 in Account 107 (construction work in progress).

(4) Increases generation rates for all customer classes by three percent for Columbus Southern and seven percent for Ohio Power each year of the plan. Also, generation rates can be adjusted in the event that any of five situations arise, but the sum of the generation increases shall not be greater than seven percent for Columbus Southern and 11 percent for Ohio Power in any one of the years. As an alternative to the increases for residential customers, AEP offers that the Commission can terminate the five percent residential generation rate discount on June 30, 2004 (which will, instead, increase generation rates for residential customers by 1.6 percent for Columbus Southern and 5.7 percent for Ohio Power each year of the plan). These generation rate increases are avoidable for customers who choose another competitive generation supplier.

(5) Allows adjustments of transmission components for changes in costs directly or indirectly imposed on the companies during the RSP.

(6) Recovers amortized generation-related transition regulatory assets under the ETP rates.

(7) Makes the Columbus Southern 2.5 mills per kilowatt-hour (kWh) shopping incentive available during the RSP to the first 25 percent of the Columbus Southern residential load. Any unused portion will not be credited to the regulatory asset charge, but will become income to Columbus Southern. Still for 2006 and 2007, the first 20 percent of Ohio Power residential load that switches will not be charged the regulatory asset charge.

(8) Includes other terms addressing post-RSP Commission action, functional separation, an allowance for AEP to participate in the CBPs of other companies, and minimum stay requirements for all categories of customers.

AEP provided estimated revenue amounts expected from the fixed generation rate increases and the new deferrals to be recovered during the RSP (AEP Ex. 3, at 10):

Company	2006	2007	2008	Total
Columbus Southern	$48 million	$74 million	$100 million	$222 million
Ohio Power	$112 million	176 million	$247 million	$535 million

If the potential four percent generation increase were also added to the calculation, AEP acknowledges that the total estimated revenue amount combined for both companies becomes $1.17 billion (Tr. II, 78).

V. OCC's Motion to Dismiss

As noted earlier, OCC filed, on May 24, 2004, a motion to dismiss the application in this proceeding on two grounds, namely that the application will violate several statutes and it illegally proposes to repudiate the ETP stipulation. In the context of describing the various components of the RSP, we will also explain and address the legal and policy arguments raised by the parties, including the specific arguments made by OCC.

VI. Positions of the Intervening Parties and Commission Discussion

Of the parties who have expressed a position in this proceeding, nearly all agree that a competitive market has not adequately developed in AEP's service territories (AEP Ex. 1, at 4; AEP Ex. 2, at 24; Tr. I, 201; Staff Ex. 2, at 3; Tr. IV, 151; OEG Ex. 2, at 5; Tr. III, 208; GMEC Initial Br. 2, 5; IEU-Ohio Initial Br. 8-10; LIA Reply Br. 2, 9). Moreover, many also believe that some action needs to be taken by the Commission to avoid a "flash-cut" in 2006 to a freely competitive electric generation market (OEG Ex. 2, at 5; Tr. III, 208; 7/7/04 Tr. 6-7, 9; IEU-Ohio Reply Br. 7). Some of these parties openly fear that, without some Commission action, generation rates will escalate and fluctuate dramatically, which could hurt consumers, hurt the development of a competitive market, and harm the market participants (AEP Ex. 1, at 4; Staff Ex. 2, at 7; Staff Initial Br. 1, 12). The disagreement here is over the specific approach that the Commission should take to spur competition in AEP's service territories, while balancing the interests of the different market participants. As already noted, the Commission has determined that the objectives of an RSP are to develop a plan providing for: rate certainty, financial stability for the EDU, and further competitive market development.

A. Market-Based Standard Service Offer and Competitive Bidding Process

AEP has not conducted any studies or surveyed the market to determine the impact of its RSP upon shopping or participation by competitive suppliers (Tr. II, 177; GMEC Ex. 2). However, AEP believes that the proposed rate increases will create some opportunity for increased shopping (Tr. II, 178). Staff also agreed (Tr. IV, 23, 243-244). Moreover in AEP's view, its RSP will cover AEP's need to spend approximately $1.3 billion on environmental controls after 2005 and address AEP's environmental expenditures of roughly $1.0 billion between 2002 and 2004 (AEP Ex. 3, at 8, 11; Tr. I, 234-235). Additionally, AEP states that the RSP addresses transmission expenses, customer switching and future uncertainty (AEP Initial Br. 11). It is for those reasons that AEP believes its RSP is a reasonable proposal and good substitute for a market-based standard service offer and CBP.

AEP's RSP contains no CBP; instead, AEP seeks to substitute its RSP for a CBP. AEP takes the position that a CBP is not practical and not worth the effort (Tr. I, 96-97, 104-105). As noted earlier, the Commission has waived, temporarily, the current requirement for the filing of a CBP while the proposed RSP is under consideration. AEP believes that its proposed increased generation rates are reasonable substitutes for market-based rates. In AEP's view, if the market exceeds those rates, customers will benefit by having a fixed rate and, if the market rates fall below the increase levels, customers can avoid them by switching to another supplier (AEP Initial Br. 23, 65-66). Staff concurs that the generation rates constitute a reasonable proxy of market-based rates because of prices in the current wholesale market, prices in AEP's area, and shopping levels (Tr. IV, 20-21, 26-27, 244; Staff Initial Br. 4, 6). Moreover, staff believes that a next step (RSP) that provides generation rate stability and gradual, predictable increases is the best approach (Staff Reply Br. 3).

OEG and IEU-Ohio agree with the Commission's stated objectives and the concept of an RSP. However, neither agrees with AEP's RSP. Instead, they each advocate that their own proposed rate plan be adopted by the Commission (OEG Ex. 2, at 7-9; OEG Initial Br. 15-18; IEU-Ohio Initial Br. 6, 14, 37-40). OEG's rate plan basically provides: (a) no new transmission and distribution deferrals beyond that authorized in the ETP decision; (b) no transmission and distribution increases except for costs to comply with environmental (distribution-related), tax and regulatory laws or regulations, relief from storm damage expenses, or an emergency; (c) transmission and distribution rate increases after 2005 only upon a fully evaluated rate case; and (d) fixed generation rate increases after 2005 through a monthly rider designed to recover incremental environmental and governmentally mandated costs that have passed an earnings test (OEG Ex. 2, at 7-9; OEG Initial Br. 15-18). OEG's plan also addresses allowed components of rate base, components of operating expenses and rate of return (OEG Initial Br. 23-26).[4] OEG considers its plan to appropriately balance several things: (a) new environmental and

[4] Green Mountain disagrees with OEG's proposed RSP because the increases are cost-based, not market-based (GMEC Reply Br. 6).

generation-related costs are balanced with timely recovery, while the rates increase to reasonable levels based upon earned returns; (b) allows gradual and steady monthly rate increases when needed for financial stability; (c) ensures market development through moderate generation rate increases; and (d) ensures that earned returns do not increase through piecemeal, single-issue, distribution rate increases (*Id.* at 18; OEG Reply Br. 23-24).

IEU-Ohio recommends various modifications to AEP's RSP that focus upon the price certainty and financial stability objectives identified by the Commission (IEU-Ohio Initial Br. 38-40). In particular, IEU-Ohio recommends that: (a) AEP establish its standard service offer prices as the current generation charge[5] of each rate schedule; (b) AEP continue to collect transition costs; and (c) AEP be permitted to seek adjustment of the current generation charges (either as confiscatory or as requiring increases due to increased jurisdictional costs from fuel prices, environmental actions, tax laws, or judicial/administrative orders).[6] In the alternative, IEU-Ohio urges the Commission to consider extending and lowering the current fixed rates, as was found to be acceptable in Virginia (IEU-Ohio Reply Br. 11). AEP responds to both OEG's and IEU-Ohio's proposed plans, stating among other things that those parties simply want to keep AEP's low rates for another period of time and their plans do not take into account all three Commission goals (AEP Reply Br. 14, 25-26).

OCC argues that AEP's proposed RSP does not meet the requirements of Sections 4928.02 or 4928.14, Revised Code, because the RSP is not a market-based standard service offer and/or a CBP (OCC Motion to Dismiss 3-4, 11; OCC Initial Br. 35-36; OCC Reply Br. 22). Thus, in OCC's view, the Commission has no authority to approve the RSP. Similarly, OCC argues that the generation rate component of the RSP is improper because it contains no CBP, as required by Section 4928.14(B), Revised Code (OCC Initial Br. 35). Also, OCC contends that, since the RSP addresses service during the MDP that conflicts with the approved ETP, it violates Section 4928.33(C), Revised Code (OCC Motion to Dismiss 12). OMG, NEMA, PSEG, Green Mountain, and LIA concur with these criticisms (OMG/NEMA Initial Br. 2-6, 15; OMG/NEMA Reply Br. 3-5; PSEG Br. 3-4, 8-9; GMEC Initial Br. 6; GMEC Reply Br. 4; LIA Initial Br. 9-11). In their view, the RSP cannot be an acceptable substitute because it is not based on market prices. OCC, OMG and NEMA acknowledge that the RSP was proposed as an alternative to the market-based standard service offer, but argue that, legally, an alternative cannot be substituted because the statute does not allow for such (OCC Initial Br. 38; OMG/NEMA Initial Br. 5-6; OMG/NEMA Reply Br. 4-5). LIA and Green Mountain state that, instead of illegally seeking RSP proposals, the Commission should have followed the path set forth in Section 4928.06, Revised Code, and provided an evaluation to the legislature (LIA Initial Br. 12-14; LIA Reply Br. 8; GMEC Reply Br. 6). OCC recommends that a CBP be filed as soon as

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5 In IEU-Ohio's proposal, it references the "little g" instead of current generation charges. When AEP's rates were unbundled prior to the start of electric choice, the amounts that were categorized as generation-related (or the "big G") were the amounts not distribution-related, transmission-related, other unbundled amounts, and tax valuation adjustments. Section 4928.34(A)(4). Revised Code. For AEP, the "little g" is the difference between the "big G" and the amounts allotted for the regulatory transition charge. The "little g" is what is reflected in AEP's charges as the current generation charges.

6 Green Mountain also disagrees with IEU-Ohio's proposed RSP because the MDP rates are not market-based rates (GMEC Reply Br. 5).

possible and recommends a particular format (OCC Ex. 10, at 10, Attach. A; OCC Reply Br. 24-25).

PSEG and OEG argue that the Commission's goals for a RSP are not fulfilled by AEP's proposal. Specifically, PSEG states that rate certainty is not assured because of the many exceptions that are contained in the RSP for possible future events (PSEG Br. 6). OEG states that rate stability is not included in the RSP because the $1.17 billion potential increase cannot constitute stability (OEG Initial Br. 5). Next, they both contend that the RSP really just provides financial stability to AEP and PSEG believes it will benefit AEP's competitive activities, rather than financial stability of its regulated functions (PSEG Br. 7; OEG Initial Br. 5). Moreover, PSEG claims that the RSP will do nothing to foster development of the competitive electric market (PSGE Br. 8). OCC quantifies the impact on the residential class for some of the costs over the three years as $266 million if the additional generation increase is not included and $410 million if it is included (OCC Ex. 5, at 3-4, Schedule FRP-1). OCC recommends that the entire RSP be rejected (OCC Initial Br. 64)

If the RSP is not rejected for failure to use market-based rates, OMG, NEMA and PSEG recommend that the Commission require a competitive bid to test the market (as it did with the FirstEnergy EDUs) and establish a basis for that market's prices (OMG/NEMA Reply Br. 6-8, 11; PSEG Br. 9).[7] Moreover, OMG and NEMA point out that, pursuant to Section 4928.14(B), Revised Code, AEP must either provide for a competitively bid generation service or demonstrate that such would be duplicative to available services. They argue that AEP cannot make such a demonstration and, therefore, a CBP must be scheduled like the Commission has done with other EDUs (OMG/NEMA Reply Br. 8-9). If the Commission decides to require a CBP, Green Mountain advocates a retail CBP (bidding for customers) as done in Pennsylvania, instead of a wholesale CBP (bidding to provide generation) (GMEC Reply Br. 10-12). IEU-Ohio took the opposite position, stating that providing customers with a CBP in the current state of the market would elevate form over substance (IEU-Ohio Initial Br. 40). Instead, IEU-Ohio believes the Commission should ask the legislature to delay the CBP option until the Commission concludes that the market is sufficiently mature to warrant the time and resources needed for CBPs (*Id.*).

Commission Discussion

At the outset, we will note that AEP proposed an RSP because we requested it. All parties to this proceeding are aware of the direction that this Commission has taken and the concerns it has with the post-MDP competitive electric environment. In fact, many of

7 The Commission ordered a CBP for the FirstEnergy EDUs in *In the Matter of the Applications of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges Including Regulatory Transition Charges Following the Market Development Period,* Case No. 03-2144-EL-ATA (June 9, 2004). On December 8, 2004, the CBP took place (an auction). The Commission concluded, on December 9, 2004, that the CBP auction price should be rejected because the previously approved RSP price is more favorable for consumers than the clearing price of the auction, which represented the best available market-based price to cover FirstEnergy's retail load. *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Competitive Bid Process to Bid Out Their Retail Electric Load,* Case No. 04-1371-EL-ATA, Finding and Order.

the parties in this proceeding have participated in several other proceedings involving the MDPs and post-MDP activities for other EDUs. Many of the parties readily acknowledge that a competitive electric generation market has not developed thus far in AEP's service territories and will not adequately develop by the time AEP's MDP expires in December 2005. With so few participants, so very little shopping having taken place in Columbus Southern's territory and no shopping at all having taken place in Ohio Power's territory, we do not want to simply allow market forces to be unfettered. We believe, in AEP's territory, a controlled transition is not only appropriate, but very much needed. We also believe that many, if not all parties, agree with this fundamental starting point.

The difference of opinion occurs with the manner in which to handle the near term. OCC, OMG, NEMA and LIA argue that Section 4928.14, Revised Code, provides the only mechanisms available to the Commission (adoption of a market-based standard service offer and a service developed through a CBP) and the proposed RSP is neither. Even with those two mechanisms identified in Section 4928.14, Revised Code, the parties disagree what should be done. However, AEP, staff, OEG and IEU-Ohio believe greater flexibility is available, namely, the Commission can adopt an RSP. We agree. AEP takes the position that a CBP is not practical and not worth the effort. Staff and IEU-Ohio agreed. We also agree and, as is within our authority, we conclude that a CBP is not warranted for AEP at the conclusion of its MDP. The record reflects that, in the past several years, only three competitive suppliers have been certified to provide competitive electric service in AEP's territory and only one is actually serving customers (Tr. I, 34, 127). Plus, there has been at most 3.4 percent shopping in Columbus Southern's service territory and zero percent shopping in Ohio Power's territory (Tr. II, 175; OCC Ex. 8; GMEC Ex. 5, at first set discovery requests 25 and 26 and third set discovery requests 1 and 2). This level of inactivity leads us to seriously doubt the efficacy of initiating a competitive bid. Instead, we conclude that an RSP (and in particular the one we adopt today) will accomplish, generally, the same as a CBP for customers and provide a reasonable means for customers to participate in that competitive environment as it continues to develop. As further explained in this decision, we agree to increase generation rates (which are avoidable to customers who choose another competitive generation supplier). These components of the RSP, along with continuation of the unaffected provisions of the ETP, we believe will prompt the competitive market and continue to provide customers a reasonable means for customer participation. Therefore, we conclude that, at this time, a CBP is not required for AEP between 2006 and 2008.

Many parties argue that AEP's proposed RSP is not a market-based standard service offer because it is not based upon the market. OMA and NEMA have argued that the RSP is not based upon a willing buyer and a willing seller. AEP proposes its RSP as a substitute for a market-based standard service offer (Plan at 3). Staff presented evidence that the RSP is a reasonable proxy of market-based rates based upon its evaluation (Tr. IV, 20-21, 26-27, 244). OCC's witness acknowledged that the Commission has the discretion to determine an appropriate proxy for a market-based standard service offer, given that both the retail electric choice market and the wholesale market have not sufficiently developed (Tr. III, 147). For the period involved (2006 through 2008), we conclude that the generation rates that we approve in this RSP today will constitute an appropriate market-based standard service offer, as required by Section 4928.14(A), Revised Code. We will evaluate any subsequent, additional generation rate adjustments (which are limited to only the enumerated categories). Additionally, we conclude that the RSP that we approve today complies with the requirements of Section 4928.14, Revised Code. None of the arguments raised to the contrary convinces us otherwise. Finally, we note that there is greater flexibility under Section 4928.14, Revised Code, than what some parties have advocated in this proceeding. The Ohio Supreme Court recently recognized, in *Constellation NewEnergy, Inc. v. Pub. Util. Comm.*, ____ Ohio St.3d ___, 2004-Ohio-6767 (December 17, 2004), that an RSP could satisfy Section 4928.14, Revised Code.

Next, we conclude that our decision today will fulfill our previously identified RSP goals. Throughout this decision, as we address the various components of the proposed RSP, we specifically explain how and why we believe that various approved components are acceptable, including how they meet or fulfill our intended goals.

B. Generation Rates and Charges (Provisions Two and Three of the RSP)

1. Three and Seven Percent Increases

AEP proposes in the RSP that, for all customer classes, the generation rates will increase each year (2006, 2007, and 2008) by three percent for Columbus Southern and by seven percent for Ohio Power. These increases will generate $151 million for Columbus Southern and $376 million for Ohio Power (AEP Ex. 3, at 10). AEP contends that the three and seven percent generation rate increases are reasonable to address the Commission's three objectives of a RSP. These generation rate increases are based upon the companies' judgment (AEP Ex. 2, at 12). Given that AEP has low generation rates currently, AEP contends that fixed increases will spur market competition and be preferable to customers, rather than imposition of full market-based rates (*Id.* at 13). AEP further notes that the generation rate increases complement the companies' substantial investments to comply with environmental requirements. AEP noted that it plans to spend $1.3 billion beyond normal capital expenditures after 2005 on generation-related environmental controls (AEP Ex. 2, at 14; AEP Ex. 3, at 11). Next, AEP points to other EDU generation rates and contends that its increased rates would still be below the current lowest average residential generation rates of those EDUs (AEP Ex. 5, at 13; Tr. III, 31).[8] When that comparison is made, AEP argues that its proposed generation rate increases are reasonable (AEP Ex. 5, 13; AEP Initial Br. 24, 67-68).

Staff supports the fixed generation rate increases as reasonable in magnitude and because they are completely avoidable if a competitor can beat the price and customers shop (Staff Ex. 2, at 8; Tr. IV, 152, 154-155, 163-164, 248-249; Staff Reply Br. 4). Staff evaluated this portion of the plan in the context of the current market, the expectation that generation rates will rise and the magnitude of the proposed numbers for company financial integrity (Tr. IV 156, 158; Staff Ex. 2, at 8). Moreover, staff noted that AEP's rates are low compared to the Ohio market and keeping them frozen would impede supplier entry in the territory (Tr. IV, 248).

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8 Staff notes that AEP is distinguishable from other EDUs in Ohio because it has lower cost generation supplies and has an infrastructure to allow it to move power within a seven-state region (Staff Initial Br. 4). Staff suggests that AEP's proposal here should be evaluated separately from the other RSPs (*Id.*).

OEG, Green Mountain, LIA, OCC, and IEU-Ohio disagree with the proposed fixed, generation rate increases. OEG and IEU-Ohio object to the three and seven percent generation rate increases on the ground that they will generate excessive earnings, while AEP has been already receiving very healthy returns (OEG Ex. 2, at 14-16; OEG Reply Br. 4, 6; IEU-Ohio Initial Br. 7). OEG contends that the fixed generation increases will engender 3.6 times more revenues than the companies' projected costs for the environmental expenditures identified (OEG Ex. 2, at 15). OEG and OCC are also skeptical that customers will really avoid the increased generation rates on the ground that the market is defective now and even AEP anticipates that it will remain defective for a period of time (OEG Reply Br. 22-23; OCC Reply Br. 20). Thus, in OEG's and OCC's view, customers will only have an option to shop in a defective market or take generation service from AEP at increasing rates (*Id.*). Moreover, OCC highlights that the identified projected costs for the environmental expenditures are not costs just for these companies; rather, they will be allocated throughout the entire AEP system, but AEP did not account for such allocation (Tr. I, 79; OCC Ex. 10, at 8; OCC Initial Br. 28). AEP and staff respond that, after the MDP, generation service is no longer subject to cost-based regulation and, thus, AEP's generation rates and charges need not be cost-based (AEP Initial Br. 31; Staff Initial Br. 4; Tr. IV, 154, 158, 165-166, 245). OEG counters by noting that AEP justified many aspects of the proposed RSP by relying solely on the cost of service for those items (e.g., additional generation-related expenses to be recovered through generation rate increases and deferrals) (OEG Reply Br. 17-18).

Green Mountain argues that the RSP's rates are below market (GMEC Initital Br. 8). Green Mountain further argues that AEP should be required to prove the cost basis of its generation rates (and distribution and transmission rates) since AEP has justified its RSP by pointing to various costs/expenses and Section 4905.33(B), Revised Code, prohibits service for less than actual cost for purposes of destroying competition (*Id.* at 18).

IEU-Ohio contends that justification for the fixed generation rate increases is weak because it is not clear that AEP will spend all estimated amounts on environmental compliance, the estimated expenditures only modestly affect production costs during the RSP period, and those expenditures will be allocated among the various operating companies as production costs (Tr. I, 58-60; IEU-Ohio Initial Br. 5-6). IEU-Ohio points out that the proposed fixed generation rate increases will allow AEP to collect $527 million more than current generation rates allow, in addition to the $702 million in transition costs allowed under the ETP decision (IEU-Ohio Initial Br. 3). IEU-Ohio points out that this RSP asks the Commission to approve generation rate increases on the basis that the current generation rates are below market, while in 1999, AEP claimed that the generation component was at above-market prices and, therefore, asked for regulatory transition costs (IEU-Ohio Initial Br. 17-18, 22; IEU-Ohio Reply Br. 7).

IEU-Ohio acknowledges that electric generation service (after the MDP) shall not be subject to traditional cost-of-service supervision or regulation, but it also believes that the Commission has a duty to ensure that the standard service offer prices are just and reasonable (IEU-Ohio Initial Br. 25-29; IEU-Ohio Reply Br. 3-5). In IEU-Ohio's view, the RSP's proposed generation rates are too high and not reasonable, particularly since AEP's financial condition has been very favorable over the last few years. Next, IEU-Ohio contends that these rate increases will simply fund investments and growth on earnings and are not necessary for financial stability (IEU-Ohio Initial Br. 30-31). IEU-Ohio also noted that, in Virginia, price caps have been extended and Ohio should realize that raising retail prices in Ohio (while other states extend rate caps) will not benefit Ohio as it strives to compete in the global economy (IEU-Ohio Reply Br. 8).

OCC argues that this portion of the RSP violates Section 4928.38, Revised Code, because it seeks recovery of additional generation-related costs not authorized in the ETP at the time when AEP is supposed to be on its own with respect to recovery of generation-related costs (OCC Motion to Dismiss 5). OCC further argues that these fixed generation rate increases are not cost-based or justified because a complete picture of current costs has not been made (some prior costs may no longer exist, while some new costs and benefits have developed) (Tr. I, 173-174, 222; OCC Initial Br. 28-31; OCC Reply Br. 16, 17). OCC supports OEG's estimated rates of return and argues that they demonstrate that the fixed generation rate increases alone will cause extremely high returns for AEP that should not be permitted (OCC Initial Br. 32, 39; OCC Reply Br. 16-17). In other words, OCC states that AEP should not be earning higher returns on equity than they could possibly be allowed in a regulatory environment when a developed competitive market is absent (*Id.* at 39).

LIA also disagrees with the generation rate increases in the RSP (LIA Initial Br. 16). On legal grounds, LIA argues that, since the RSP involves an increase in rates, AEP has violated Sections 4909.17 and 4909.19, Revised Code, by not following rate increase procedures (*Id.* at 9). Moreover, LIA contends that AEP's actions/inactions regarding RTO membership have caused a competitive market to not develop and, therefore, AEP does not have "clean hands" and should not be rewarded with excessive increases in rates (LIA Reply Br. 2). From a public policy perspective, LIA contends that the companies already have high profit margins and do not need rate increases, and yet do not propose any programs to mitigate the impact of the RSP on low-income customers (LIA Initial Br. 16, 20, 31; LIA Reply Br. 3-4, 6). LIA notes that AEP is the only Ohio utility to ever terminate funding for low-income energy efficiency programs (APAC Ex. 1, at 7; Tr. IV, 182; LIA Initial Br. 32). LIA further contends that the RSP will exacerbate the already high amounts of percentage of income payment plan (PIPP) arrearages for AEP customers (*Id.* at 26). If the Commission proceeds with an RSP, LIA and OCC argue the Commission must consider the impact of the RSP on the low-income consumers and vulnerable populations in order to promote rate stability and certainty (*Id.* at 20, 34; OCC Initial Br. 62). Specifically, LIA urges: (a) the Commission to allow PIPP customer pools to participate in CBPs during the RSP; (b) AEP to negotiate with the Ohio Department of Development, Commission staff, and low-income intervenors to develop "an approach to arrearages that reinforces good payment behavior by PIPP program participants and reduces the PIPP debt to a manageable level that can conceivably be repaid"; and (c) the Commission require funding by AEP of $1.5 million per year for a low-income energy efficiency program in AEP's service territory (APAC Ex. 1, at 8, 12; Tr. IV, 197, 201; LIA Initial Br. 29, 32; LIA Reply Br. 7-8). OCC supports these three recommendations (OCC Initial Br. 62).

Commission Discussion

Certainly, to some extent, the generation rate increases will provide additional funds to the companies and assist in their financial stability. As noted, AEP will be incurring large generation-related expenses above normal capital expenditure levels during the RSP period. However, we also believe that the RSP package as a whole supports our goals of helping to develop the competitive market and providing some rate stability. We reach this conclusion because we believe that the generation rate increases are a reasonable approximation of the future market conditions. With the RSP's structured, periodic generation rate increases, customers will not be subjected to significant swings in generation rates in an emerging competitive market for AEP. We believe this provision is not only very important to spurring a competitive market, but also to protecting customers from the risks and dangers associated with price volatility and a nascent competitive market.

We also accept our staff's conclusion that the percentage increases are reasonable in magnitude. Many of the parties object to this provision because they contend that AEP is already earning too much. However, these parties seem to forget that, with the expiration of the MDP, generation rates are subject to the market (not the Commission's traditional cost-of-service rate regulation) and that the plan was an option that AEP voluntarily proposed. Section 4928.05(A)(1), Revised Code. We make this observation to point out that, under the statutory scheme, company earnings levels would not come into play for establishing generation rates - market tolerances would otherwise dictate, just as AEP argued (AEP Reply Br. 26-27). We are strongly committed to encouraging the competitive market in AEP's service territories as it is the policy of this state, per Section 4928.02, Revised Code. Given that commitment, we do not feel that the earnings levels evidence or cost-based analyses and arguments presented by OEG, OCC, IEU-Ohio or LIA justify rejection of this provision. We believe that this provision will establish generation rates that are appropriate for the RSP period, spur the competitive market, and also protect customers from dramatic or volatile generation rate price changes. We do not agree that this provision violates any of the cited statutes.

While we have found the proposed generation rate increases to be reasonable, both in concept and in number, it is also appropriate to point out that these increases will be avoidable during the rate stabilization period. Customers who choose another competitive generation supplier can avoid AEP's increased generation rates (because those customers will pay, instead, the rates of their chosen supplier). We believe this is an important point to note.

We do realize that rate increases can be difficult for some customers to handle, as LIA has argued. We are not ignoring these concerns. In fact, we believe that the structured nature of the generation rate increases will be more helpful to the low-income customers in AEP's territory than would otherwise likely occur without the RSP. Ideally, we agree that rate increases are not preferred, but we are weighing and balancing several competing interests and we believe that the proposed generation rate increases will result in the most balanced and reasonable generation rates for all customers in AEP's service territories during the three years following the MDP. For these additional reasons, we accept this provision. Despite that conclusion, we agree that low-income customers, in particular, can be disproportionately affected by the RSP. To alleviate that concern, we conclude that low-income customers should receive some additional assistance. Therefore, we have provided for additional funding of low-income and economic development programs during the RSP period as set forth in Section VI.G of this decision.

2. Elimination of Five Percent Residential Discount

For all residential customers, AEP proposes an additional generation rate increase each year of 1.6 percent for Columbus Southern and 5.7 percent for Ohio Power, if the five percent generation discount terminates on June 30, 2004. This would end the five percent residential rate reduction 18 months earlier than what was agreed upon in the ETP stipulation (Tr. I, 28). If elimination of the five percent discount to residential customers is included, AEP calculates that the generation rate increases will be 8.5 percent for Columbus Southern residential customer and 13.2 percent for Ohio Power residential customers in 2006 (AEP Ex. 2, at 11). This would amount to roughly a $6 million increase for residential rates (Tr. I, 29). AEP supports this proposal by noting that Section 4928.40(C), Revised Code, allows the Commission to terminate the discount if it is "unduly discouraging market entry by [...] alternative suppliers." Despite the proposed June 30, 2004 date having passed, AEP has noted that the alternative is still viable, but the later termination of the discount (still prior to the end of the MDP) will result in reduced fixed increases for residential customers (AEP Initial Br. at footnote 11). AEP, staff and Green Mountain believe that the current generation rates, along with the existing temporary discount, unduly discourages market entry because of the small price differential between AEP's generation rates and others' generation supplies (AEP Ex. 2, at 12; Tr. IV, 23; GMEC Br. at 16-17). Staff and Green Mountain urge the Commission to eliminate the temporary discount (Staff Ex. 2, at 9; GMEC Initial Br. 17).

OCC opposes elimination of the five percent discount on the ground that the ETP stipulation requires the companies to retain the discount for residential customers through the MDP (OCC Initial Br. 32; OCC Reply Br. 17).[9] The ETP stipulation states that the companies will "not seek to reduce the [five percent] reduction in the generation component rate reduction for residential customers during the market development period" (OCC Ex. 1, at 6). OCC also contends that AEP has not demonstrated that the discount is unduly discouraging market entry, as required by Section 4928.40(C), Revised Code (OCC Ex. 10, at 5; OCC Reply Br. 18). In fact, AEP could not say that elimination of the discount would result in suppliers entering the residential market (AEP Ex. 2, at 12; Tr. I, 137-138). AEP contends that its RSP does not ask to remove the five percent discount during the MDP; it only noted that it was an option that the Commission could consider in the context of the RSP's proposed generation rate increases (AEP Initial Br. 27-28, 68, 78).

IEU-Ohio states that the Commission should consider elimination of AEP's five percent residential discount in a "stand-alone" proceeding that is "focused on the

9 OCC argues that the Commission lacks authority to approve any portion of the RSP that impacts any term in the ETP decision (OCC Motion to Dismiss 2; OCC Initial Br. 2-3). Staff disagrees with that argument because the Commission retains ongoing jurisdiction over its orders, including the authority to change or modify its earlier decisions as it deems necessary in the best interests of the utility and customers (Staff Initial Br. at footnote 1).

residential customer sector and the full range of conditions that are affecting market entry by alternate suppliers" (IEU-Ohio Initial Br. 41).

Commission Discussion

OCC correctly cites the ETP stipulation. We also believe that AEP's argument that its RSP does not ask to remove the five percent discount is an attempt at "hair-splitting". AEP's RSP proposed eliminating the five percent discount and it previously agreed that it would not make such a request during the MDP.

Notwithstanding the language in the ETP stipulation and our acceptance of that stipulation, we have the ability to evaluate the impact of the five percent residential discount under Section 4928.40(C), Revised Code. Section 4928.40(C), Revised Code, gives the Commission the flexibility to eliminate the five percent residential discount if it unduly discourages market entry in AEP's service territories. We believe that an early ending to the discount is not warranted and, rather, it is appropriate that the five percent residential discount in both companies' territories, end effective December 31, 2005. We further note that ending the five percent residential discount on December 31, 2005, is in keeping with SB3 (including Section 4928.40, Revised Code) and is consistent with the timing required of the residential discounts of four other EDUs. *Ohio Edison,* Case No. 03-2144-EL-ATA, *supra* at 24-25 and *In the Matter of the Application of The Cincinnati Gas & Electric Company to Modify its Nonresidential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish an Alternative Competitive-Bid Service Rate Option Subsequent to the Market Development Period,* Case No. 03-93-EL-ATA, Opinion and Order at 36-37 (September 29, 2004).

3. Additional Generation Rate Increases

AEP's RSP allows generation rates to further increase, after a Commission hearing, for: (a) increased expenditures incurred through an affiliate pooling arrangement for complying with changes in laws/rules/regulations related to environmental requirements, security, taxes, and new generation-related regulatory requirements imposed by statute/rule/ regulation/administrative order/court order; or (b) customer load switches that materially jeopardize either company's ability to recover the anticipated generation revenues. Total generation rate increases cannot be greater than seven percent for Columbus Southern and 11 percent for Ohio Power in any given year (if the five percent residential discount is not eliminated).[10] The additional generation adjustments are effectively capped at four percent. The RSP proposes a 90-day time frame, after which the proposed increase will become effective on an interim basis until the Commission's final order is implemented.

AEP points out that this aspect of the RSP only gives the company the flexibility to ask for additional, limited generation rate increases in the event of changes in the two enumerated categories; it does not pre-approve or guarantee rate increases (AEP Ex. 2, 16-

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[10] If the five percent residential discount would have been eliminated as of June 30, 2004, any additional generation rate increases would be at most four percent above the residential customers' fixed annual increase, which would be at most 5.6 percent for Columbus Southern residential customers and 9.7 percent for Ohio Power residential customers (AEP Ex. 2, at 18).

17; AEP Initial Br. 35). AEP characterizes this provision as a means to manage the risk it faces relative to the fixed generation rate increases (AEP Reply Br. 28). At this point in time, AEP does not expect to ask for additional rate increases (Tr. I, 198). Also, AEP mentions that any additional increases that might be authorized by the Commission could be avoided for customers who choose another competitive supplier (AEP Initial Br. 35).

Staff, Green Mountain and IEU-Ohio do not fully support or fully object to this provision. They believe that any request for additional generation rate increases should be evaluated by looking at the company's overall financial health (not just the events that triggered the proposed further increase) and not be limited to four percent (Staff Ex. 2, at 9-10; GMEC Reply Br. 12-13; IEU-Ohio Initial Br. 42; Tr. IV, 33, 153, 231, 245). Staff recognizes that the proposed additional generation increases would be sought for many of the same reasons that AEP had based its proposed three and seven percent increases and, thus, believes automatic additional increases should only be considered after looking at the whole company (Tr. IV, 153, 245-247). AEP responded by stating that a look at the overall financial health of the company is contrary to Section 4928.05(A)(1), Revised Code, because generation pricing will not be subject to cost-of-service ratemaking principles (AEP Initial Br. 38). Additionally, AEP predicts that holding generation rates down because of a strong "wires business" is likely to result in rate shock in 2009, which is what the Commission is trying to avoid today (*Id.*; Tr. I, 247).

OCC argues that the proposed four percent additional increase does not result from changes in market prices and, thus, is not market-based (OCC Ex. 10, at 9). Like staff, OCC characterizes this provision as improper single-issue ratemaking and also criticizes the ambiguity of the phrase "materially jeopardizes either or both companies' ability to recover the increased revenues" (*Id.*).

OEG worries that this portion of the RSP could permit recovery twice for the same expenses; essentially that the same costs used to justify the fixed increases arguably could justify the proposed additional increases (OEG Ex. 2, at 16-17). Plus, because the companies will continue to have very high earnings, OEG believes that the additional generation rate increases are not needed to maintain financial stability (OEG Initial Br. 8). AEP notes that this criticism is really a concern over the Commission's ability to judge any proposed additional generate rate increase and not a sufficient basis for rejecting this portion of the RSP (AEP Initial Br. 39).

<u>Commission Discussion</u>

We find this portion of the RSP to be acceptable. We agree with AEP that this portion of the RSP will allow AEP to seek additional generation rate increases; it does not pre-approve them (although it does limit any approved amount). We understand staff's and IEU-Ohio's preference that subsequent generation rate increases be viewed in the context of the company's overall financial health, but that position ignores the requirements of Section 4928.05(A)(1), Revised Code. Thus, we find this portion of the RSP to appropriately temper potentially large generation rate increases (by limiting the dollar amounts), while also recognizing AEP's interest in financial stability. This provision is a compromise position that takes into consideration the competing interests. We understand the criticism raised with the phrase "materially jeopardizes either or both companies' ability to recover the increased revenues." In the event that further increases are requested by AEP, we will evaluate this. Similarly, we understand OEG's concern that AEP could request further generation-related rate increases for items that it is already recovering. But, as AEP states, the concern does not justify rejecting the provision; it is really a question of whether the proposed further increase is properly evaluated. For these reasons, none of the comments raised in this proceeding convinces us that this portion of the RSP should be rejected.

C. Distribution Rates and Charges (Provision One of the RSP)

Under the RSP, AEP distribution rates and charges in effect on December 31, 2005, would remain in effect through 2008 (except for the universal service fund rider, energy efficiency fund rider, and certain cost-based charges such as right-of-way charges). These "frozen" distribution charges could be also adjusted in the event of an emergency, changes in transmission/distribution allocations under the FERC's seven-factor test, or if the companies experience increased distribution-related expenses due to: (a) changes in laws/rules/regulations related to environmental requirements; (b) security; (c) taxes; (d) O&M due to new requirements imposed by federal or state legislative or regulatory bodies after March 31, 2004; and (e) major storm damage service restoration. Furthermore, the "frozen" distribution rates will be adjusted, if the Commission approves, to recover certain deferred RTO administrative costs (deferred in 2004 and 2005) plus carrying costs and certain deferred carrying costs on certain environmental expenditures since 2002, plus carrying costs.

AEP points out that the RSP only freezes distribution rates for an additional one-year period for Ohio Power, because the ETP froze them previously (AEP Ex. 2, at 5). AEP acknowledges that, in addition to what is contained within the ETP, the RSP would add some additional categories for which the "frozen" distribution rates would/could be adjusted (*Id.*; Tr. I, 31-32). AEP contends that, at least with the proposed adjustments for security expenses and the specified O&M expenses, they are justified because of the unforeseen security issues that previously developed and the likelihood that O&M expenditures will be needed since the ETP was approved (AEP Ex. 2, at 6).

Staff, IEU-Ohio and OEG state that a distribution rate case should be conducted, instead of freezing distribution charges from 2006 to 2008 (Staff Ex. 2, at 7-8; Tr. IV, 230; IEU-Ohio Initial Br. 42; OEG Ex. 2, at 22-23). They reach this conclusion because these distribution rates were established in 1991 and 1994 rate cases (Staff Ex. 2, at 8). More specifically, OEG believes that AEP's returns on common equity have been very high over the last several years and the proposed RSP will only perpetuate them (OEG Ex. 2, at 11-14). AEP took issue with OEG's rate of return calculations, alleging a number of errors (AEP Initial Br. 31-35).

OCC also opposes this provision. OCC contends that the additional exceptions to the distribution rate freeze (security and O&M expenses) are unwarranted (OCC Ex. 10, at 6). In OCC's view, AEP accepted the risk that increasesd expenses for these two items would occur when it signed the ETP stipulation and AEP should not now be permitted to illegally attempt to modify the ETP or violate Sections 4909.18 and 4909.19, Revised Code

(OCC Ex. 10, at 6-7; OCC Motion to Dismiss at 9).[11] Moreover, OCC contends that these exceptions to the distribution rate freeze constitute single-issue ratemaking, which is not appropriate public policy because the exceptions do not recognize other cost-related changes (OCC Ex. 10, at 6-7; Tr. III, 187-188). In response, AEP states that OCC's position conflicts with its position that the Commission set a post-MDP generation rate at something other than market levels (AEP Initial Br. 14).

LIA disagrees with the distribution rate provision in the RSP because it will also allow rate increases (LIA Initial Br. 16).

Commission Discussion

We find that Provision One of the RSP is acceptable. The additional exceptions to the distribution rate freeze are, in the context of considering the RSP as a package, reasonable. We understand OCC's contention that the additional exceptions to the rate freeze can be considered single-issue ratemaking, but we also must point out that OCC previously agreed to other exceptions to the distribution rate freeze, which can also be considered single-issue ratemaking. The next question then is whether the additional exceptions are justified. We do accept AEP's contention that, in 1999 and 2000, security expenses and the specified O&M expenses were not fully foreseeable. In this respect, we believe that allowing for these additional exceptions to the distribution rate freeze during the RSP is acceptable. We view the extension of the distribution rate freeze as a positive aspect of the RSP, which meets our goal of fostering a competitive market and still balancing rate stability with financial certainty for AEP.

We appreciate the position taken by staff, IEU-Ohio and OEG about the need for a distribution rate case. They have correctly noted that a rate proceeding has not taken place for either company for a period of time. AEP believes that, after the RSP, it would be appropriate for the Commission to initiate rate proceedings (Tr. I, 102). AEP explained that a rate proceeding at this point would frustrate the Commission's goals of rate stability and financial stability over the next few years (*Id.*). We agree that embarking on a rate proceeding at this point could run counter to our ultimate goals. Therefore, we do not accept that position.

D. Deferral Requests (Provisions One, Five and Six of the RSP)

The companies propose to defer the costs of several items during the RSP (AEP Ex. 2, at 8-9; AEP Ex. 4, at 4-6, 10-12). These items are:

(a) RTO administrative charges (adjusted for net congestion costs) from the time of integration into PJM[12] through 2005, plus a carrying charge (based on the weighted average cost of capital).

(b) The 2004 and 2005 equity carrying charges on expenditures begun in 2002 through 2005 for expenditures located in Account 107, construction work in process (CWIP).

[11] OCC contends that, after the MDP, EDU distribution rates can only be adjusted through properly filed applications under Chapter 4909, Revised Code (OCC Motion to Dismiss 10).

[12] AEP integrated into PJM on October 1, 2004.

(c) The full carrying charges (based on the weighted average cost of capital) on expenditures begun in 2002 through 2005 for all functions in Accounts 101 (electric plant in service) and 106 (completed construction not classified), except line extension expenditures, which are already subject to carrying cost deferrals.

(d) Consumer education, customer choice implementation, and transition plan filings through 2005, plus a carrying charge.

(e) Consumer education, customer choice implementation, and transition plan filing costs incurred after 2005, and all RSP filing costs, plus a carrying charge.

Most of the expenditures in the second and third categories are associated with environmental control equipment (nitrogen oxide burners, flue gas desulphurization, and selective catalytic reduction) for generation facilities (Tr. II, 14-18; OCC Ex. 3). AEP estimated the total amounts of these proposed deferrals over the RSP as follows (AEP Ex. 4, at 3, 6-7; AEP Ex. 3, at 4-5, 7; AEP Ex. 2, at 8):

Proposed Deferral	Columbus Southern	Ohio Power
RTO Admin. Costs[13]	$11.9 million	$15.6 million
RTO Admin. Costs Carrying Costs	2.5 million	3.2 million[14]
CWIP Carrying Costs	1.0 million	9.0 million
In-Service Plant Carrying Costs	13.0 million	50.0 million
Addl. Carrying Costs for CWIP and		
In-Service Plant	2.0 million	9.0 million[15]
Pre-2006 Education, Choice		
Impl. and Transition Plan		
Filing Costs[16]	40.6 million	45.5 million
Post-2005 Education, Choice		
Impl., Transition Plan Filing		
and all RSP Filing Costs[17]	18.2 million	19.7 million
Total	$89.2 million	$152 million

13 These estimates do not include an adjustment for congestion costs, as those are unknown (AEP Ex. 3, at 3; AEP Ex. 2, at 8).

14 AEP's estimate of the RTO administrative costs totaled $14.4 million for Columbus Southern and $18.8 million for Ohio Power, while the revenues to be produced by this aspect of the RSP are estimated to be $48 million for Columbus Southern and $60 million for Ohio Power (AEP Ex. 3, at 7, 10). However, we note that AEP's brief reflects instead that the anticipated revenues to be produced by this aspect of the RSP will be $16.8 million for Columbus Southern and $20.7 million for Ohio Power (AEP Initial Br. Attachment A at 3 and Attachment B at 3).

15 AEP's estimates of the carrying costs of the CWIP and in-service plant totaled $16 million for Columbus Southern and $68 million for Ohio Power, while the revenues to be produced by this aspect of the RSP are estimated to be $23 million for Columbus Southern and $99 million for Ohio Power (AEP Ex. 3, at 7, 10).

16 These estimates were made by AEP in May 2000 (OCC Ex. 1, at 4). They do not include carrying charges. No updated estimates were presented as evidence in this proceeding.

17 The companies did not estimate RSP filing costs (AEP Ex. 3, at 5).

In AEP's view, these are new, significant costs that cannot be capitalized and were not built into current rates (AEP Ex. 4, at 7). It should be noted, however, that AEP would amortize these new deferrals over the three-year RSP and begin recovering those amounts as regulatory assets through distribution charges in 2006, except for the consumer education, customer choice implementation, transition plan filing costs incurred, and all RSP filing costs, plus a carrying charge (AEP Ex. 2, at 21; AEP Ex. 4, at 4).

1. Regional Transmission Organization Administrative Costs

Staff calculated an average of the RTO deferral rider to be .27 mills/kWh for both companies and found it to be a reasonable level for what it considers to be a new service (Tr. IV, 63-64, 67-68, 112, 253). OMG and NEMA do not fully object to this proposed deferral, but contend that recovery of it during the RSP will cause some shopping customers to be charged twice for those same costs (OMG/NEMA Initial Br. 9-11). OCC also agrees with this criticism, but still otherwise objects to the deferral, as detailed further below (OCC Initial Br. 8-9; OCC Reply Br. 8). More specifically, OMG and NEMA explain that any shopping customer will pay the pre-2006 RTO administrative charges to his/her generation supplier as part of the cost of receiving that generation supply and, then, also pay AEP when it assesses the deferral during the RSP. OMG and NEMA state that an easy solution is to require that AEP customers who shop after October 1, 2004, get a credit for PJM administrative charges until the end of the MDP, but impose the deferrals upon them during the RSP (OMG/NEMA Initial Br. 11-12). Green Mountain agrees (GMEC Reply Br. 9). AEP responds to this suggestion, stating that it is impossible to segregate how much each customer's bill will recover the deferral and, thus, the suggestion is not possible (AEP Reply Br. 19-20).

OCC objects to the RTO administrative cost deferral for several other reasons. OCC first contends that this proposed deferral should be rejected because it violates the intent of the distribution service rate cap (set forth in Section 4928.34(A)(6), Revised Code); it is simply an attempt to recover costs that were to be recovered by the capped distribution rates (OCC Ex. 10, at 7; OCC Initial Br. 5-6, 9; OCC Reply Br. 2-3; OCC Motion to Dismiss 7). OCC also considers this provision to violate the part of the ETP decision which freezes distribution rates beyond the MDP. OCC points out that a utility can recover transmission costs through an increase to the transmission component, which will correspondingly decrease the distribution component during the MDP (OCC Initial Br. at 6). AEP even acknowledged this possibility (Tr. I, 171). Second, OCC argues that AEP is proposing single-issue ratemaking contrary to Chapter 4909, Revised Code (OCC Initial Br. 7; OCC Reply Br. 12-13). OCC does not believe that the Commission should consider this single ($33.2 million) charge in isolation of overall transmission rates.

OCC next contends that the proposed deferral of the RTO administrative charges would improperly allow AEP to recover transmission-related expenses through nonbypassable distribution rates (OCC Reply Br. 7-8). AEP acknowledges that the RTO administrative charges are transmission-rated (AEP Ex. 2, at 7; AEP Ex. 4, at 16; Tr. I, 240). However, AEP contends that these costs benefit all customers (switching and non-switching customers) because all customers benefit with AEP's participation in an RTO. AEP explains that the only means to allocate cost recovery among all customers in a competitively neutral fashion is a nonbypassable distribution charge (AEP Ex. 2, at 7; AEP Ex. 4, at 18). AEP also explained that, without the requested authority or FERC authority, the RTO administrative charges would not be recovered (Tr. I, 237). Moreover, AEP stated that, while the RTO administrative costs could be recovered via a change in state transmission charges (and thereby reduce distribution rates), AEP would effectively not be able to recover those transmission expenses (Tr. I, 238). Finally, in OCC's view, it "strains credibility that the companies did not know there would be RTO administrative costs when they agreed to join an RTO in the ETP stipulation" (OCC Initial Br. 10). OCC also does not consider the RTO administrative costs to be a new service, as staff indicated, or rate stabilization charges. OCC believes these are MDP-incurred transmission charges proposed to be recovered through a distribution rider after the MDP (*Id.*).

LIA argues that a deferral of the pre-2006 RTO administrative costs is tantamount to an increase in the MDP-capped distribution rates (LIA Initial Br. 4, 6). LIA states that Section 4928.38, Revised Code, prohibits the creation of new deferrals associated with distribution service construction, and Section 4928.34(A)(6), Revised Code, and the ETP decision are also violated (*Id.* at 5, 7). In LIA's view, this deferral constitutes a "back door" attempt to raise distribution rates, regardless of when the deferral is collected (*Id.* at 6).

OEG contends that the RTO administrative cost deferral proposes to adjust frozen distribution rate under circumstances not permitted by the ETP decision (OEG Initial Br. 13). OEG also believes that the effect of the deferral request is to avoid a rebalancing of transmission and distribution rate levels, which is required by Section 4928.34(A)(1), Revised Code, to remain at the MDP levels (*Id.*). Next, OEG takes issue with the dollar amounts in this proposed deferral for two reasons. OEG points out that AEP does not plan to recognize, in the amount of RTO administrative deferrals, the benefit that AEP will receive from making additional off-system sales as a member of PJM (Tr. I, 173). Further, OEG highlights that these administrative costs will include costs related to the companies' efforts to participate in the MISO (Tr. I, 248; OEG Initial Br. 14).

IEU-Ohio states that these RTO administrative costs were considered when transition costs were developed in the ETP proceeding and the companies' current financial condition does not justify creation of new regulatory assets (IEU-Ohio Initial Br. at 44). For this reason, IEU-Ohio contends that the proposed deferral should be denied. IEU-Ohio also noted that, in July 2004, an AEP affiliate in Virginia agreed to forego recovery of RTO administrative costs, certain congestion costs, and ancillary service cost increases, except through a base rate case (IEU-Ohio Reply Br. 7-8, Attachment). That affiliate also agreed to not seek to defer such Virginia-specific costs. Furthermore, that affiliate agreed to not seek to recover development and implementation costs that were then being deferred, other than through a base rate case. IEU-Ohio makes the point that other treatment of RTO administrative costs has been agreeable to an AEP company.

Commission Discussion

The RTO administrative charges involved in this proposed deferral will be charges incurred from October 2004 through 2005. We do not believe that this proposed deferral is a rate increase. Accord, *Consumers' Counsel v. Pub. Util. Comm.* (1983), 6 Ohio St.3d 377. Recovery of the deferred RTO administrative charges would be based upon accruals during AEP's MDP. As a result, we will not approve the proposed deferral of 2004 and 2005 RTO administrative charges.

The Commission recognizes that AEP's expenditures for RTO membership during the MDP have been and will continue to be instrumental in enabling AEP to efficiently fulfill its provider of last resort (POLR) responsibilities during the rate stabilization period. AEP is required to provide that function after the MDP. Section 4928.14(A) and (B), Revised Code. The Commission has also recognized in other cases that the POLR responsibility of the EDU is one for which the EDU incurs necessary costs and which warrants compensation during rate stabilization periods. See, *Dayton, supra* at 28, and *Ohio Edison*, Case No. 03-2144-EL-ATA, *supra* at 23-24. The Supreme Court of Ohio recently upheld an earlier Commission conclusion that the existence of POLR costs makes it reasonable to apply a charge to customers during a RSP period. *Constellation, supra.* Our staff also made this argument in this proceeding (but in relation to the CWIP and in-service plant deferrals). We believe the proposed RTO administrative charge amounts for collection during the rate stabilization period constitute reasonable and not excessive compensation to AEP for part of the cost of fulfilling its POLR responsibilities and, accordingly, approve the collection of these amounts as part of a POLR charge. This POLR charge will be established as part of a separate unavoidable rider that is applicable to all distribution customers.

We reach this conclusion based upon the specific circumstances before us in this proceeding. Nothing in this decision is intended to be precedent-setting or to be construed as ruling upon the other RTO charge-related deferral requests that we have recently received from other EDUs. See, *In the Matter of the Application of The Dayton Power and Light Company for Authority to Modify its Accounting Procedures*, Case No. 04-1645-EL-AAM, and *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company to Modify their Accounting Procedures*, Case No. 04-1931-EL-AAM.

2. Carrying Costs of Construction Work in Progress and In-Service Plant Expenditures

Staff supports the CWIP and in-service plant deferrals as well (Staff Ex. 2, at 11). Staff considers such deferrals to be equivalent to POLR charges (Tr. IV, 108-109, 147, 148, 171). Staff reaches this conclusion because the RSP is providing an option to switch and avoid charges for AEP customers and creating a risk for AEP that customers will switch, for which it is reasonable, in staff's view, for AEP to collect POLR charges (Tr. IV, 149-150). AEP concurs that these costs function as POLR costs (AEP Initial Br. 47, 79; AEP Reply Br. 16). Moreover, staff noted that, when compared to similar charges proposed by other EDUs, staff felt that AEP's proposed levels were reasonable (*Id.*). Staff calculated the amounts per kWh to be .38 mills for Columbus Southern and 1.16 mills for Ohio Power, for an average of .84 mills (Tr. IV, 108-109). Staff also stated that allowing AEP to recover a part of what it would be able to obtain under traditional regulatory process when competition has not really arrived is reasonable (Staff Ex. 2, at 11). Staff further acknowledges that, if these costs are allowed as rate stabilization charges, it is fair for the charges to be bypassable (that is to say, a customer who chooses another supplier and is not returning would not be subject to the charge while purchasing another's generation) (Tr. IV, 254-255).

OCC objects to this portion of the RSP for a host of reasons. OCC argues that, if these generation-related deferrals are permitted for recovery after the MDP, then the rate freeze is meaningless (OCC Initial Br. at 14, 51; OCC Reply Br. 2-3). OCC believes that, after the MDP, new distribution deferrals are not permitted under Ohio law because distribution rates are subject to rate regulation under Chapter 4909, Revised Code (OCC Initial Br. 14-15, 52). Additionally, OCC contends that AEP assumed the risk of these expenditures when it agreed to freeze distribution rates in the ETP proceeding (*Id.* at 15, 17-19). OCC points to OEG's evidence that AEP does not need the deferrals to provide financial stability. OCC also claims that distribution rates should not be increased to recover generation costs, per the ETP decision and Sections 4928.15, 4928.17(A), 4928.34(A)(6) and 4928.38, Revised Code (*Id.* at 15-16; OCC Motion to Dismiss 8; OCC Reply Br. 10-11). Like the RTO administrative costs, OCC contends that the Commission should not approve these single-issue ratemaking deferrals without looking at the full picture and because shopping customers will then pay a portion of AEP's generation costs even though they will be taking generation service from a competitor (OCC Initial Br. 15, 22; OCC Reply Br. 12-13).

OEG and OCC argue that these deferrals constitute retroactive ratemaking (a rate increase during the MDP) because the deferral relates to amounts in existence prior to the date of the decision in this case (OEG Ex. 2, at 18-19; OCC Initial Br. 17-19). Also, OEG and LIA contend that these two deferrals take away one of the primary incentives of implementing electric choice in Ohio (a cap on distribution rates during the MDP) contrary to Section 4928.34(A)(6), Revised Code (OEG Initial Br. 9-11; LIA Initial Br. 4). Further, OEG, LIA and OCC believe these deferrals violate the ETP decision because they are generation-related expenses used to adjust distribution rates during the period allowed by the ETP decision for frozen distribution rates (LIA Initial Br. 5, 7; OEG Initial Br. 12-13; OCC Initial Br. 16). AEP disagrees, noting that the Commission has allowed deferrals for periods that precede the date of a decision (AEP Initial Br. 46). Also, AEP argues that accounting deferrals are not rate increases and, thus, cannot constitute retroactive ratemaking (*Id.*; AEP Initial Br. 70; AEP Reply Br. 17).

OEG also argues that these deferrals do not recover distribution-related costs and should not be deferred for recovery in distribution charges (OEG Ex. 2, at 20-22). AEP agrees that these deferrals are not recovering distribution costs and, thus, argues that the distribution rate freeze cannot preclude them (AEP Initial Br. 47). In AEP's and staff's view, recovery of these deferrals will function as POLR charges, not distribution service charges (*Id.*; AEP Reply Br. 16; Tr. IV, 108, 147).

Green Mountain has a different point of view. It argues that generation-related increases should not be as limited as set forth in the RSP (GMEC Initial Br. 15-16). Instead, Green Mountain contends that any generation-related costs that AEP seeks to recover should be included in generation rates. However, if the Commission accepts another recovery mechanism (such as the proposed deferrals), then the established recovery mechanism should be bypassable (*Id.*; GMEC Reply Br. 9).

IEU-Ohio states that these CWIP and in-service plant expenditures were considered when transition costs were developed in the ETP proceeding and the companies' current financial condition does not justify creation of new regulatory assets (IEU-Ohio Initial Br. at 44). For this reason, IEU-Ohio contends that these proposed deferrals should be denied.

<u>Commission Discussion</u>

Similar to our reasoning for the RTO administrative charges, we do not believe that this proposed deferral is a rate increase. However, recovery of the deferred CWIP and in-service plant carrying charges would be based upon accruals during AEP's MDP. The Commission recognizes that AEP's expenditures for CWIP and in-service plant during the MDP have been and will continue to be instrumental in enabling AEP to efficiently fulfill its POLR responsibilities during the rate stabilization period, which warrants compensation during rate stabilization period. Section 4928.14(A) and (B), Revised Code, requires AEP to provide that function after the MDP. We believe these carrying charge amounts proposed for collection during the rate stabilization period constitute a reasonable and not excessive compensation to AEP for part of the cost of fulfilling its POLR responsibilities and, accordingly, approve the collection of these amounts as part of a POLR charge. As noted earlier, this POLR charge will be established as part of a separate unavoidable rider that is applicable to all distribution customers.

3. Consumer Education, Customer Choice Implementation, Transition Plan Filing Costs, and all Rate Stabilization Plan Filing Costs

Staff supports this deferral provision (Staff Ex. 2, at 10). IEU-Ohio does not believe that the Commission needs to address most of this deferral because it was already addressed in the ETP decision (IEU-Ohio Initial Br. 43). Also, IEU-Ohio does not believe that the Commission should authorize increases for isolated categories of costs, even if expected (*Id.* at 44). OCC argues that, aside from the agreement in the ETP decision to allow some of these deferrals, the Commission should reject additional deferrals in this case (OCC Initial Br. at 52). OCC reaches this conclusion because new distribution deferrals and rate riders for single issues have no basis in Ohio law; the Commission can only adjust regulated distribution rates through a properly filed rate case.

<u>Commission Discussion</u>

We already allowed deferral for most of the costs in this category (in the ETP proceeding). This RSP provision would further defer those costs and also allow deferral of the RSP filing costs. In the context of considering the RSP package and our stated RSP goals, we are willing to accept this provision of AEP's plan.

E. Transmission Rates and Charges (Provision Four of the RSP)

This part of the proposed RSP states the AEP may adjust state transmission charges (attributable to the applicable company, affiliated company or RTO open access transmission tariff [OATT]) to reflect FERC-approved rates and charges during the RSP, whether imposed directly on the companies or through an approved RTO. These include RTO administrative changes imposed, amortization of RTO start-up costs, and/or surcharges for recovery of lost transmission revenues. Such rate changes would be effective 30 days after filing, unless delayed by the Commission (but no longer than a period of 60 days).

AEP characterizes this portion of the RSP as an affirmation of the companies' existing right to make a filing for recovery of FERC-approved costs (AEP Initial Br. 40, 60). AEP believes the proposed expedited review process of such applications is warranted because the Commission should look at new transmission charges and should allow the pass-through of FERC-approved transmission charges (Tr. I, 242-243). Furthermore, AEP believes these costs will be significant, new costs, which are not currently in rates (AEP Ex. 3, at 4; AEP Initial Br. 40). A preliminary estimate of at least some of the anticipated costs in this area is $10.4 million per year for Columbus Southern and $13.1 million per year Ohio Power (AEP Ex. 3, at 4).

Staff expressly supports this provision of the RSP (Staff Ex. 2, at 10). IEU-Ohio recommends that this provision be rejected because transmission costs were taken into consideration when the ETP decision was issued and there are indications that AEP's integration into PJM will create additional transmission revenues. Thus, IEU-Ohio believes that there is no need for this provision (IEU-Ohio Initial Br. 43). Similarly, OEG and OCC argue that this provision will allow AEP to be reimbursed for RTO expenses, but it does not take into account certain savings that will simultaneously be realized, e.g., off-system sales (OEG Reply Br. 19; OCC Reply Br. 13-14). OEG contends that the corresponding savings should be recognized so that the provision is truly a "pass through" (*Id.*). Also, OCC contends that there should be no authorization for additional transmission charges that have not been authorized by FERC or that AEP selects apart from charges in the PJM RTO OATT (OCC Initial Br. 46).

Commission Discussion

We find that this provision of AEP's RSP is reasonable, except as discussed below. In concept, any FERC-approved transmission rates and charges during the RSP should be passed through. We will look at them and ensure that "pass through" is appropriate. Despite IEU-Ohio's, OEG's and OCC's comments, we believe this aspect of Provision Four is appropriate. We do, however, have concerns with the Commission review process set forth in Provision Four. If viewed in isolation, we would not necessarily believe that the 30-day/60-day automatic process was problematic. However, we and our staff will be receiving similar types of applications from more than just AEP. For that reason, we believe that the time period proposed is not as workable as it should be. Therefore, we conclude that the applications to adjust state transmission charges (attributable to the applicable company, affiliate company or RTO OATT) to reflect FERC-approved rates and charges during the RSP (whether imposed directly on the companies or through an approved RTO) shall be automatically approved on the 61st day after filing, unless the Commission rejects, modifies or suspends the filing. We believe this approval process fairly and adequately balances: (1) the desire for a definitive conclusion from the Commission in a prompt manner, (2) the ability of other interested persons to participate, and (3) the concerns for adequate amounts of time to review the anticipated applications in the context of other Commission work.

F. Current Regulatory Asset Recovery (Provision Five of the RSP)

The RSP proposes that AEP continue to recover amortized generation-related transition regulatory assets under the approved ETP. Staff accepts this provision, describing this term as simply continuing practices established in the ETP decision (Staff Ex. 2, at 10). OCC supports this portion of the RSP because it continues one part of the ETP decision. However, OCC does argue that, if the Commission will not require AEP to keep the rest of the ETP bargain, the Commission should revisit this and other aspects of the ETP decision (OCC Ex. 10, at 4; OCC Initial Br. 47). To this argument, AEP contends that an examination of the regulatory assets recovery should not be a consequence of filing the RSP as requested (AEP Reply Br. 42). OCC notes that the bulk of the transition regulatory assets for Ohio Power (associated with mining operations) may no longer represent a liability to Ohio Power (Tr. II, 27, 36). IEU-Ohio is not opposed to this provision, if the Commission accepts its proposed RSP (IEU-Ohio Reply Br. 10, Footnote 11).

Commission Discussion

We also agree with Provision Five and find it appropriate to allow AEP to continue to recover amortized generation-related transition regulatory assets under the approved ETP. We note that no direct opposition to this portion of the RSP was raised by any of the parties.

G. Shopping Incentives and Credits (Provision Seven of the RSP)

AEP proposes in the RSP that Ohio Power will still not charge the regulatory asset charge rider, from January 1, 2006 to December 31, 2007, to the first 20 percent of the Ohio Power residential customer load that switches, as was agreed in the ETP stipulation.[18] Columbus Southern will, through the MDP and 2008, make available to the first 25 percent of the residential class load an incentive of 2.5 mills/kWh that the qualifying customers will receive as a credit. Any unused amount of the incentive money at December 31, 2005, will not be credited to regulatory asset charge recovery. Thus, as proposed under the RSP, Columbus Southern will receive as income any unused shopping incentive balance and not offset the incentive balance against the transition regulatory asset.

18 Although both the ETP stipulation and the RSP state that there will be no shopping incentive for Ohio Power customers, the provision to not charge certain shopping Ohio Power customers the regulatory asset charge rider was included in the RSP's Provision Seven under the heading "Shopping Incentives". Nothing in our decision should be construed as converting that term into a shopping incentive or characterizing it otherwise. We have simply chosen to discuss the entirety of Provision Seven at one time.

Columbus Southern's unused shopping incentive through January 2004 was roughly $12.9 million (Tr. II, 108; OCC Ex. 4). The RSP extends the Columbus Southern shopping incentive through 2008. As a trade off, AEP also proposes to alter the manner in which the unused portion of Columbus Southern's shopping incentive is handled (AEP Ex. 2, at 23-24; AEP Ex. 4, at 5; Tr. I, 33). To be clear, AEP's proposal to extend this shopping incentive is tied to the new proposed treatment of its unused balance (AEP Reply Br. 32). AEP argues that the extended shopping incentive, along with increased generation rates, should result in more shopping (AEP Initial Br. 48).

Staff believes that the unused Columbus Southern shopping incentive should be treated as a regulatory liability and flowed back to customers (Staff Ex. 2, at 12). IEU-Ohio concurs (IEU-Ohio Initial Br. 45). AEP believes that this position does not adequately acknowledge that the companies are proposing to extend the shopping incentive (AEP Initial Br. 49).

OCC believes Provision Seven of the plan violates the ETP decision by altering the treatment of the unused Columbus Southern shopping incentive (OCC Ex. 10, at 8; OCC Initial Br. 53). AEP points out that the effect of OCC's position is that no shopping incentive would be available to Columbus Southern residential customers during the RSP (AEP Initial Br. 49).

Green Mountain contends that the RSP's shopping incentive will be inadequate to spur shopping. AEP calculated that the average residential price to compare for the generation component (under the RSP and its shopping incentive terms) will be as follows (GMEC Ex. 5, at fourth set discovery request 1):

Company	2006	2007	2008
Columbus Southern			
With Three Percent Increase	4.26	4.38	4.51
With Termin. of Resid. Discount	4.20	4.27	4.33
Ohio Power			
With Seven Percent Increase	3.73	3.98	3.94
With Termin. of Resid. Discount	3.69	3.89	3.79

In Green Mountain's view, the residential incentive values may be at their highest during the RSP, but they will still not spur shopping (GMEC Initial Br. 10; GMEC Reply Br. 8). In addition to greater shopping incentives, Green Mountain also advocates for shopping credits (avoidable charges) set at market prices (GMEC Initial Br. 11). Green Mountain further advocates that the $10 switching fees be waived, market support generation be provided, a voluntary enrollment process be instituted, new partial payment priority changes be made, and reasonable/nondiscriminatory credit arrangements be created (*Id.* at 10-15, 19-20). AEP states in response to these additional requests that there is no evidence to support them and they should be rejected (AEP Reply Br. 40-14).

Commission Discussion

First, we accept again the term of this provision related to Ohio Power's residential customers who shop in 2006 and 2007. We continue to believe that this term will be beneficial to Ohio Power customers in the near future. No arguments were raised against this part of Provision Seven, except those raised by Green Mountain (in relation to the amount and impact), which we address further below.

The first criticism raised about Provision Seven of the RSP is that AEP proposes to not credit the unused Columbus Southern shopping incentive to regulatory asset charge recovery (and instead extends the incentive through 2008, with any remaining amounts becoming income to Columbus Southern). AEP correctly notes that, if the Commission does not accept this aspect of Provision Seven, there will be no shopping incentive for Columbus Southern's residential customers. Shopping credits and incentives were established to promote customer switching and effective competition. Sections 4928.37 and 4928.40, Revised Code. Accord, *Constellation, supra.* Shopping credits and incentives are not mandated by statute after the MDP. Certainly, however, the idea of having a Columbus Southern shopping incentive during the RSP is attractive, particularly since we are trying to spur further development of the competitive market in AEP's service territories. However, we must weigh that against AEP's clear statements that its proposed extension of the Columbus Southern shopping incentive is contingent upon any remaining amounts at the end of the RSP becoming income to Columbus Southern.

We do not agree that the unused amount of the Columbus Southern shopping incentive at the end of the RSP should become income to that company on the basis that it is a fair trade-off to offering to extend that incentive during the period, as AEP has argued. Under the ETP, Columbus Southern was not going to receive income if that shopping incentive was not completely used during the MDP. Instead, AEP previously agreed to flow those dollars back to customers (by making a reduction to the remaining regulatory asset amounts equivalent to the amount of the unused shopping incentive). Moreover, we do not believe that Columbus Southern should earn income when customers have not shopped sufficiently to utilize the same shopping incentive over an extended period. Furthermore, as explained below, we do not believe that the RSP must include a shopping incentive for Columbus Southern customers either. Therefore, the proposed Columbus Southern shopping incentive portion of Provision Seven of the RSP is rejected.

As previously noted, the ETP decision requires that the unused balance of the Columbus Southern shopping incentive at the end of the MDP be credited back to Columbus Southern customers (via an adjustment to the level of regulatory asset recovery). We agree that customers should benefit in the event that Columbus Southern customers do not shop sufficiently by the end of this year (which is the end of the MDP). We believe that most parties, if not all, would agree that sufficient shopping is very unlikely to occur by the end of the MDP and, thus, an unused dollar amount will exist. However, we conclude a redirected application of the unused shopping incentive monies is more appropriate, while yet still in line with the goal of benefiting customers. LIA and OCC have asked in this proceeding for specific dollars targeted to low-income customer issues because that segment of the customer base may be disproportionately affected by the RSP. As we noted in section VI.B.1 of this decision, we believe that it is appropriate to assist the AEP low-income customers. Therefore, we conclude that $14 million should be should be allotted by AEP for the benefit of the Columbus Southern and Ohio Power low-income customers, as well as for economic development during the RSP period. We will require AEP to work with our Service Monitoring and Enforcement Department staff to develop the details for the use of those sums. Our staff will consult with the Ohio Department of Development in relation to the use of that money in AEP's service territories.

Green Mountain has alleged that the shopping incentives (as identified for Columbus Southern customers above and a zero incentive for Ohio Power customers) will not be sufficient to spur shopping in either company's territory. As we have already noted, shopping incentives are not mandated after the MDP. In any event, the shopping incentives are only one manner of further developing the competitive market and we believe that, in the full context of the proposed RSP, our decision to require monetary assistance for low-income and economic development issues is an appropriate conclusion. With regard to Green Mountain's argument related to partial payment priority, the Commission is not willing to alter its established payment priority scheme just because AEP is seeking to establish a RSP. Green Mountain has also asked for several other specific alterations (establish other credits via avoidable charges, waiver of the $10 switching fees, provision of market support generation and institution of a voluntary enrollment process). We do not believe that these items are needed at this point. Accordingly, we will not adopt them.

H. Other Items (Provisions Eight through Eleven of the RSP)

1. Additional Future Proceedings

AEP recommends (in Provision Eight) that the Commission conduct a proceeding to determine the "manner in which electric generation service should be provided to the companies' customers" after the RSP and report the results to the legislature by December 31, 2005. AEP explains that this provision is intended to avoid facing the same situations at the end of the RSP as we face today (AEP Ex. 2, at 24-25). Staff and IEU-Ohio agree (Staff Ex. 2, at 13; IEU-Ohio Initial Br. 45). OMG and NEMA also appear to agree. Specifically, OMG and NEMA state that, if the Commission approves a RSP for AEP, it should establish a re-opener during 2007 in order to make adjustments to assist market development and to plan for the end of the rate stabilization period (to meet the statutory goals of market-base rates) (OMG/NEMA Initial Br. 12). OCC disagrees that the Commission should complete a report by 2005, arguing that any report completed by that date will not likely provide any valuable information for the post-RSP period (OCC Initial Br. 55-56).

Commission Discussion

This provision of the RSP is acceptable as a recommendation on steps the Commission should consider by the end of the RSP period. The Commission has a mandate to consider all possible options for implementation at the end of the rate stabilization period.

2. Functional Versus Structural Separation

In Provision Nine, the companies would continue functional separation (one corporate entity with separate groups to handle each function). AEP explained that it has not yet received authorization from the Securities and Exchange Commission to structurally separate, although AEP has made that request (AEP Ex. 2, at 25-26). At this point, AEP "does not contemplate structurally separating" the generation assets (*Id.*) because restructuring has slowed down. Staff concurs with this provision, particularly since structural separation could limit or preclude options in the future (Staff Ex. 2, at 13; Tr. IV, 250). IEU-Ohio does not oppose this provision (IEU-Ohio Initial Br. 45).

OCC, OMG, NEMA and Green Mountain state that AEP must structurally separate per Section 4928.17, Revised Code (OCC Initial Br. 56; OMG/NEMA Initial Br. 13-14; GMEC Initial Br. 21). PSEG states that it makes little sense for the Commission to approve the RSP based upon risks/volatility of the competitive market and not protect customers by requiring AEP to implement corporate separation (PSEG Br. 7-8). Green Mountain argues that to continue functional separation seeks something that AEP never lawfully had (because the ETP approved only structural separation) (GMEC Initial Br. 21). Green Mountain states that the Commission should not permit AEP to continue functional separation if the RSP is not implemented (*Id.*).

Commission Discussion

We are willing to accept this term of the RSP for several reasons. First and foremost, AEP has been unable to structurally separate, as it had planned, because it does not have the necessary federal authority to do so. We simply cannot force structural separation when other agencies also must give their approval and that approval has not been forthcoming. Second, we would be remiss if we did not recognize that many expectations surrounding a competitive electric market in Ohio and around the country have changed from 2000, which is when we approved AEP's plan in its ETP proceeding to structurally separate its generation functions from the remainder of its functions. Third, Sections 4928.17(C) and (D), Revised Code, allow the Commission to modify a previously approved corporate separation plan. OCC, OMG and NEMA seem to have overlooked that aspect of the corporate separation statute. More specifically, we conclude that good cause has been shown to allow AEP to operate on a functional separation basis for the RSP period and such functional separation can still provide compliance with the state's policies associated with competitive retail electric service, as enumerated in Section 4928.02, Revised Code.

3. Participation in Other CBPs

Provision 10 of the RSP allows the companies to submit bids in other EDU's CBPs. AEP argues that Section 4928.14(B), Revised Code, compels the Commission to grant this provision of the RSP and the Commission has acknowledged such previously (AEP Initial Br. 52). Staff agrees with this provision and IEU-Ohio believes current law already allows AEP to participate in the CBPs of other EDUs (Staff Ex. 2, 13; IEU-Ohio Initial Br. 46).

Green Mountain contends that AEP should not be permitted to participate in other CBPs until it has structurally separated (GMEC Initial Br. 21-22).

Commission Discussion

AEP correctly notes that we have refused to limit participation in CBPs to non-EDU affiliate participants because of the language in Section 4928.14(B), Revised Code. *In the Matter of the Commission's Promulgation of Rules for the Conduct of a Competitive Bidding Process for Electric Distribution Utilities Pursuant to Section 4928.14, Revised Code,* Case No. 01-2164-EL-ORD, Finding and Order at 9 (December 17, 2003). We find this provision of the RSP to be reasonable. Nothing that Green Mountain has argued on this provision convinces us that this aspect of the RSP should not be approved.

4. Minimum Stay Requirements

Also, the RSP addresses in Provision 11 the topic of minimum stay. It provides that, during the RSP, residential and small commercial customers that return to the standard service must remain through April 15 of the following year, if the customer took generation service from the company between May 16 and September 15. During the RSP, a 12-month minimum stay would be required for large commercial and industrial customers that return under the standard service tariff.

This RSP provision corresponds with AEP's current minimum stay tariff provisions, but those tariff provisions have not been in effect due to a Commission moratorium.[19] AEP believes that minimum stay requirements are needed to avoid seasonal impacts of switching when AEP's prices are essentially annual average rates (AEP Ex. 5, at 5). Staff finds AEP's approach to be reasonable, but also recommends that the alternative mentioned in those tariffs be more fully detailed (Staff Ex. 2, at 14).

OMG and NEMA argue that, before the minimum stay provisions are triggered, the Commission should require that shopping customers be able to return to the standard service offer three times (OMA/NEMA Initial Br. 15). They note that AEP agreed to such a term in its ETP and, since no real shopping has taken place, it makes sense to require this term during the RSP (*Id.*). AEP points out that the Commission did not accept this part of the ETP settlement and nothing was presented in this proceeding to warrant its acceptance now (AEP Reply Br. 39).

IEU-Ohio contends that this topic should be addressed by the Commission on a generic basis, not in this RSP proceeding (IEU-Ohio Initial Br. 46). OCC contends that AEP has not demonstrated a need for the minimum stay or any harm from the moratorium (any alleged harm will only occur if customers actually shop and then return to AEP) and, therefore, the moratorium should remain in place (OCC Initial Br.60).

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19 The Commission issued a moratorium on any minimum stay requirements for residential and small commercial customers on March 21, 2002, in *In the Matter of the Establishment of Electronic Data Exchange Standards and Uniform Business Practices for the Electric Utility Industry,* Case No. 00-813-EL-EDI. That moratorium has continued indefinitely. While another proposal is pending before the Commission on the matter, we have not issued a definitive ruling on the matter.

Commission Discussion

We are willing to accept this provision of the RSP. We realize that we still have not addressed the pending minimum stay proposal (which differs from AEP's minimum stay requirements) in the generic proceeding. For the short three-year period of the RSP, we are willing to allow AEP to implement these minimum stay requirements. It will allow us the opportunity to evaluate participation, gaming of enrollments, and the impact of our originally approved minimum stay requirements. We consider this approval to essentially test the debate that has been raised with us for quite a period of time.

VII. Conclusion

Based upon the foregoing, we conclude that the proposed RSP should be adopted (with the exception of the RSP's proposed elimination of the five percent residential discount in Provision Two, the proposed deferral of RTO administrative charges, the proposed deferral of CWIP and in-service plant carrying charges, the proposed review period associated with FERC-approved transmission rate changes, and the proposed treatment of the Columbus Southern shopping incentive) for the reasons set forth herein. We also conclude that OCC's motion to dismiss the application should be denied. Additionally, we conclude that, AEP shall allot $14 million for low-income customers and economic development, and work with our Service Monitoring and Enforcement Department staff to work out the details for those dollars. AEP is, furthermore, allowed to establish a POLR charge.

As we have already mentioned, we believe certain changes are warranted as the MDP ends for AEP. This decision will move AEP to market-based rates for the 2006-2008 period in an appropriate and balanced fashion and conforms with the state's electric policy (Section 4928.02, Revised Code) and this Commission's stated goals. Circumstances are not the same as when we issued our ETP decision and we recognize that fact and have reached conclusions today that we believe are most appropriate for the 2006-2008 period. To the extent any arguments were raised in this proceeding and they are not expressly addressed in this decision, they have been rejected.

As noted earlier in this Order, AEP will be held forth as the POLR to consumers who either fail to choose an alternative supplier or who choose to return to AEP's system after taking service from another energy company. Consistent with Ohio law, the POLR designation places expectations upon EDUs; the companies must have sufficient capacity to meet unanticipated demand. Additionally, the Commission is among many state agencies that have been charged by the Governor to enhance the business climate in Ohio as it competes on a regional, national, and global basis for economic development projects. One of the Commission's roles in this endeavor has been to focus on reliable energy. We believe that, consistent with Section 4928.02, Revised Code, Ohio consumers are entitled to a future secure in the knowledge that electricity will be available at competitive prices. We also feel strongly that electric generators of the future should be both environment-friendly and capable of taking advantage of Ohio's vast fuel resources. With the recognition that new technologies must be forthcoming to replace the utilities' aging generation fleet, we urge AEP to move forward with a plan to construct an integrated gasification combined-cycle (IGCC) facility in Ohio. AEP should engage the Ohio Power

Siting Board in pursuit of such a plant. We are encouraged by emerging information that suggests that the IGCC technology will be economically attractive. It is worth noting that the Commission is exploring regulatory mechanisms by which utilities, given their POLR responsibilities, might recover the costs of these new facilities.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

(1) On February 9, 2004, AEP filed an application with the Commission for approval of a rate stabilization plan for the period 2006 through 2008.

(2) Twenty-five entities filed motions to intervene in this proceeding. All those requests were granted.

(3) A technical conference was held on March 24, 2004. Objections to the application were filed on April 8, 2004.

(4) A local, public hearing in Canton, Ohio, was conducted on May 19, 2004. However, the Commission had not properly sent any of the publication notices to the newspapers in AEP's service territory. Therefore, the examiner scheduled another local hearing in Canton, Ohio, for July 7, 2004 and rescheduled the local hearing in Columbus, Ohio, for July 1, 2004. At the July 1 and 7, 2004 local hearings, three people provided testimony.

(5) On May 24, 2004, OCC filed a motion to dismiss the application on various legal grounds. By entry dated June 1, 2004, the examiner deferred a ruling on OCC's motion to dismiss, stating that all parties shall have the opportunity to argue the legality of AEP's proposal in post-hearing briefs.

(6) The evidentiary hearing began on June 8, 2004, and continued through June 14, 2004. AEP presented the testimony of five witnesses. The staff and OCC each presented the testimony of two witnesses. APAC, Lima/Allen Council on Community Affairs, and WSOS Community Action jointly sponsored the testimony of one witness and OEG presented the testimony of one witness.

(7) The parties filed post-hearing briefs on July 13 and 30, 2004.

(8) AEP's MDP will end on December 31, 2005.

(9) AEP's proposed elimination of the five percent residential discount in provision two is precluded by the ETP decision.

(10) OCC's motion to dismiss the application should be denied.

(11) We adopt all provisions of the proposed RSP with the exception of the:

(a) RSP's proposed elimination of the five percent residential discount in Provision Two,
(b) Proposed deferral of RTO administrative charges in Provisions One and Six,
(c) Proposed deferral of CWIP and in-service plant carrying charges in Provisions One and Six,
(d) Proposed review period associated with FERC-approved transmission rate changes in Provision Four, and
(e) Proposed treatment of the Columbus Southern shopping incentive in Provision Seven.

(12) Our adopted provisions of the proposed RSP, our decision to require AEP to allot $14 million for low-income customers and economic development, our decisions to require AEP to work with our Service Monitoring and Enforcement Department staff to work out the details for those dollars, and our decision to allow AEP to establish a POLR charge, taken together, appropriately balance three objectives: (a) rate certainty, (b) financial stability for AEP, and (c) the further development of the competitive electric market. Moreover, the combination of the approved components of the RSP, along with the additional conditions of our decision and continuation of the unaffected provisions of the ETP, will prompt the competitive market and continue to provide customers a reasonable means for customer participation in the electric competitive market.

<u>ORDER</u>

It is, therefore,

ORDERED, That OCC's motion to dismiss this application is denied. It is, further,

ORDERED, That AEP's application is approved, subject to the modifications set forth in this decision. It is, further,

ORDERED, That AEP work with our Service Monitoring and Enforcement staff to work out the details for the allotted low-income and economic development dollars. It is, further, ORDERED, That a copy of this opinion and order be served upon all 28 parties to this proceeding and any interested persons of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

GLP;geb

Entered in the Journal

JAN 2 6 2005

Reneé J. Jenkins
Secretary

Footnote

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Certified Territory of Monongahela Power Company.	))	Case No. 05-765-EL-UNC

ENTRY

The Commission finds:

(1) This Commission has encouraged Ohio's electric distribution utilities (EDUs) to file rate stabilization cases (RSP) for the time period following the end of the market development period for those companies. The Monongahela Power Company (Mon Power) has not chosen to pursue that option. Mon Power instead filed an application to initiate Case No. 04-1047-EL-ATA, proposing a fixed rate, market-based standard service offer (SSO). Under Mon Power's proposal, retail generation rates would be based on the results of a competitive bidding proposal (CBP) starting in January 2006.

(2) Although the Commission is considering Mon Power's CBP application, we have significant concerns about implementing that proposal. In particular, under the company's application, we believe Mon Power's retail customers may be facing potential rate shock and rate instability. Those are the same risks that the Commission sought to avoid in encouraging Ohio's EDUs to pursue an RSP. With the exception of Mon Power, Ohio's EDUs have proposed and obtained approval for an RSP.

(3) The Commission remains resolute that the RSP option is the best option for Ohio's electric customers and the Commission has found that the existing RSPs have produced both favorable and stabilized rates for consumers. Further, the CBP that was conducted for the First Energy territory, Case No. 04-1371-EL-ATA, demonstrated the value of the RSP. Given these concerns and the current market conditions, the Commission believes that it is appropriate to consider other options to protect Mon Power's customers and promote the public interest.

(4) The Commission has general supervision over public utilities under Section 4905.06, Revised Code. Under the Ohio Certified Electric Territories Act, Sections 4933.81, et seq., Revised Code, the Commission may transfer a portion of one EDU's territory to another EDU where it determines that the public interest would be promoted in doing so. Since Mon Power is not willing to propose an RSP, the Commission will consider whether another EDU could acquire Mon Power's service territory and serve Mon Power's customers through an RSP. A logical candidate for

doing so would be Columbus Southern Power (CSP), given its shared border with Mon Power.

(5) Based on advancing the public interest and promoting rate stabilization for Mon Power's existing customers, the Commission orders Mon Power and CSP to immediately pursue potential terms and conditions for transferring Mon Power's Ohio territory to CSP. Absent the filing of a proposed transaction to achieve this transfer, the companies shall file a report detailing the outcome of their discussions within 14 days of this order.

It is, therefore,

ORDERED, That Mon Power and CSP discuss potential terms and conditions of transferring Mon Power's Ohio territory to CSP. It is, further

ORDERED, That Mon Power and CSP jointly file a report detailing the outcome of their discussions within 14 days

ORDERED, That a copy of this entry be served on Mon Power, CSP and each party of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

SDL;geb

Entered in the Journal
JUN 14 2005

Reneé J. Jenkins
Secretary

Footnote

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

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

OPINION AND ORDER

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The Commission, considering the joint reports of Columbus Southern Power Company and Monongahela Power Company in response to the Commission's June 14, 2005 Entry, the evidence of record, the arguments of the parties, the applicable law, and being otherwise fully advised, hereby issues its Opinion and Order:

APPEARANCES:

Porter, Wright, Morris & Arthur, by Daniel R. Conway and Andrew C. Emerson, 41 South High Street, 30th Floor, Columbus, Ohio 43215, and Kathryn L. Patton, Deputy General Counsel, 800 Cabin Hill Road, Greensburg, Pennsylvania 15601, on behalf of the Monongahela Power Company.

Marvin I. Resnik and Sandra Williams, American Electric Power Service Corporation, 1 Riverside Plaza, Columbus, Ohio, 43215-2373, on behalf of Columbus Southern Power Company.

Jim Petro, Attorney General of the state of Ohio, Duane W. Luckey, Senior Deputy Attorney General, Public Utilities Section, by Thomas W. McNamee, 180 East Broad Street, 9th Floor, Columbus, Ohio 43215-3793, on behalf of the staff of the Public Utilities Commission of Ohio.

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, by Ann M. Hotz and Jeffrey Small, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio, 43215-3485, on behalf of the residential customers of the Ohio jurisdictional electric distribution utilities.

McNees, Wallace & Nurick, LLC, by Samuel C. Randazzo and Daniel J. Neilsen, Fifth Third Center, 21 East State Street, Suite 1700, Columbus, Ohio 43215-4228, on behalf of the Industrial Energy Users-Ohio.

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

David C. Rinebolt, Executive Director and Counsel, 231 West Lima Street, Findlay, Ohio, 45839-1793, on behalf of Ohio Partners for Affordable Energy.

OPINION:

I. History of this Proceeding:

By its Entry issued on June 14, 2005, the Commission ordered Columbus Southern Power Company (CSP) and Monongahela Power Company (Mon Power) to engage in discussions regarding the acquisition by CSP of Mon Power's Ohio certified service territory. Joint reports were filed by Mon Power and CSP (the Companies) on June 28, July 15, and August 3, 2005, concerning discussions regarding CSP's acquisition of Mon Power's Ohio certified service territory. The Companies filed an additional joint report on August 9, 2005 (Joint Report) advising the Commission that the Companies successfully completed their negotiations and have entered into an Asset Purchase Agreement, which was included as an exhibit to that Joint Report. The terms of the Asset Purchase Agreement will be discussed more fully below.

On August 18, 2005, Industrial Energy Users – Ohio (IEU-Ohio) filed a motion to intervene in this proceeding and a memorandum in support. The memorandum in support of IEU-Ohio's motion to intervene included a request that the Commission conduct a hearing regarding the terms of the proposed transfer, in accordance with Section 4905.48, Revised Code, which addresses transactions between public utilities.

On August 22, 2005, an attorney examiner entry established the case schedule for filing interventions and prefiled testimony, conducting discovery, and set the hearing date for October 11, 2005 at 10:00 a.m., in Hearing Room 11-F at the offices of the Commission, 180 East Broad Street, Columbus, Ohio. Also by this entry, the title of this case was changed to the above case title, and a notice of the October 11, 2005 evidentiary hearing was to be published one time in a newspaper of general circulation in each county in both Mon Power's service area and CSP's service area at least 30 days prior to the hearing.

On September 7, 2005, Ohio Partners for Affordable Energy (OPAE) filed a motion to intervene and memorandum in support. Also on September 7, 2005, Michael Smalz of the Ohio State Legal Service Association, Columbus, Ohio, filed a motion for the admission of David C. Rinebolt, to appear *pro hac vice* on behalf of OPAE before the Commission in this proceeding, with a memorandum in support.

On September 9, 2005, the Ohio Energy Group (OEG) filed a motion to intervene and memorandum in support. On September 15, 2005, the Office of the Ohio Consumers' Counsel (OCC) filed a motion to intervene and memorandum in support.

By attorney examiner entry issued September 29, 2005, IEU-Ohio's, OPAE's, OEG's, and OCC's motions to intervene in this proceeding were granted. The motion to admit David C. Rinebolt, *pro hac vice,* to represent OPAE was also granted by this entry. Further by this entry, OCC's motion for a local public hearing in Marietta, Ohio was denied; however, the Commission would take testimony from any members of the public present on October 11, 2005 at 10:00 a.m., in Hearing Room 11-F, preceding the evidentiary hearing. Last, the attorney examiner entry stated that IEU-Ohio's request for the Commission to conduct a hearing regarding the terms of the proposed transfer, in accordance with Section 4905.48, Revised Code, was moot, because the case schedule for this proceeding includes an evidentiary hearing.

On September 30, 2005, the Ohio Hospital Association (OHA) filed a motion to intervene and a memorandum in support.

On October 11, 2005, two members of the public, Paul Mommessin (Krayton Polymers) and Bob Flygar (Eramet), presented sworn testimony preceding the evidentiary hearing, in accordance with the September 29, 2005 attorney examiner entry. The public testimony was mainly directed at the economic impact ("rate shock") of the proposed transfer. The witnesses also requested that the Commission consider phasing in the rates, under CSP's RSP, to help the Mon Power customers absorb the impact of transfer.

The evidentiary hearing commenced on October 11, 2005, following the public testimony noted above. The pending motion of OHA to intervene in this proceeding was granted at the hearing. Twelve witnesses presented testimony: George B. Blankenship, Robert B. Reeping, Raymond E. Valdes, Peter Toomey, and Mark A. Mader, on behalf of Mon Power; J. Craig Baker, Selwyn J. Dias, David M. Roush, and Leonard V. Assante, on behalf of CSP; and J. Edward Hess, Robert B. Fortney, and Richard C. Cahaan, on behalf of Commission Staff (Staff). On October 12, 2005, OCC filed rebuttal testimony in this proceeding. The hearing reconvened on October 12, 2005, to hear the direct and rebuttal testimony of OCC's witness, Randell J. Corbin.

Post-hearing briefs were filed on October 21, 2005, and reply briefs were filed on October 28, 2005. Letters from consumers and other interested groups, expressing concerns about the "rate shock" associated with the proposed transfer, have been filed in the docket of this case.

II. August 9, 2005 Joint Report

The Companies' August 9, 2005 Joint Report proposes, under the terms of the Asset Purchase Agreement (APA), that CSP will purchase, with certain exceptions, the assets located in Ohio that are used by Mon Power in its Ohio transmission and distribution business, including the rights to serve Mon Power's existing certified service territory in Ohio (Joint Report at 2).[1] The purchase price for the identified assets will be the net book value of the acquired assets, plus $10 million (the purchase price will be subject to a post-closing true-up). (*Id.* at 3.)

1 The APA is identified as Exhibit 1 to the August 9, 2005 Joint Report. The assets located in Ohio and used by Mon Power in its Ohio transmission and distribution business are described in Section 2.1 of the APA and the related schedules to Section 2.1.

As to the rates to be charged to acquired Mon Power customers, CSP proposes that the customers in Mon Power's present Ohio certified service territory be charged rates established in CSP's Rate Stabilization Plan (RSP), under Case No. 04-169-EL-UNC, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post Market Development Period Rate Stabilization Plan*, filed February 9, 2004 and approved January 26, 2005 (*id.* at 6). CSP proposes that the one exception to this general rate proposition is that Mon Power's large commercial and industrial (C&I) customers will be assessed a nonbypassable surcharge on a per kWh basis set at a level to produce $10 million over an approximately five-year period (*id.*).

In addition, CSP proposes that it be permitted to recover the difference between its power acquisition costs and the revenues produced under CSP's rates for the rate stabilization period January 1, 2006 through December 31, 2008 (*id.* at 7; CSP Ex. 1, at 7-8). The Joint Report states that Mon Power has agreed to sell CSP 100 percent of its power requirements to serve the new load associated with the former Mon Power customers from January 1, 2006 through May 31, 2007, at $45 per MWh (*id.*; CSP Ex. 1 at 6; Mon Power Ex. 5, at 9-10). For the remainder of the rate stabilization period, CSP proposes to conduct a Request for Proposals (RFP) for the same customer load for the period from June 1, 2007 through December 31, 2008 (*id.* at 7-8; CSP Ex. 1, at 6-7). CSP states that, as a result of the Commission's order for CSP to extend service at CSP's rates to Mon Power's Ohio service territory, the difference, or revenue differential, between the revenues collected under CSP's base generation rates (without any existing or new generation surcharges) and CSP's power purchase costs, under the power sales agreement (PSA)[2] with Mon Power and the subsequent RFP bid(s) for the above three-year period will trigger the "4%" provision of its Rate Stabilization Plan (*id.* at 8; CSP Ex. 1, at 7-10).[3] The difference for the first year is expected to be approximately $17 to $19 million (*id.*; CSP Ex. 3, at 8-9 and DMR Ex. 3).[4] CSP seeks approval, as part of this proceeding, to collect this amount from all of CSP's current and new customers at a generation surcharge level based upon expected load in 2006 (*id.*; CSP Ex. 1, at 9-10; CSP Ex. 3 at DMR Ex. 5 "Power Acquisition Rider").[5]

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2 The Power Sales Agreement is included as Exhibit G to the APA. The testimony of Mon Power witness Mader refers to the power sales agreement as a "power purchase agreement (PPA)." (Mon Power Ex. 5, at 9-10).

3 The "4%" provision refers to Section 3 of CSP's Rate Stabilization Plan (RSP) application, filed February 9, 2004, under Case No. 04-169-EL-UNC, and approved by the Commission on January 26, 2005.

4 DMR Ex. 3 (of CSP Ex. 3) is titled "Power Acquisition Cost Difference."

5 DMR Ex. 5 (of CSP Ex. 3) is a proposed "Power Acquisition Rider" for Columbus Southern Power Company P.U.C.O No. 6, which is the new tariff approved in CSP's RSP case, effective January 1, 2006. The text of the proposed rider states: "Effective January 1, 2006, all customers subject to the provisions of this Rider, including any bills rendered under special contract, shall be adjusted by the Power Acquisition Rider of 0.07945¢ per KWH."

III. Determination of Whether the Transfer is in the Public Interest

The Companies filed their August 9, 2005 Joint Report pursuant the Commission's June 14, 2005 Entry, and Sections 4905.48 and 4933.85, Revised Code. These sections state:

§ 4905.48. Transactions between public utilities

With the consent and approval of the public utilities commission:

(A) ....

(B) Any public utility may purchase or lease the property, plant, or business of any other such public utility.

(C) Any such public utility may sell or lease its property or business to any other such public utility.

(D) ....

To obtain the consent and approval of the commission for such authority, a petition, joint or otherwise, signed and verified by the president and the secretary of the respective companies, clearly setting forth the object and purposes desired, and stating whether or not it is for the purchase, sale, lease, or making of contracts, or for any other purpose provided in this section, and also the terms and conditions of the same, shall be filed with the commission. If the commission deems it necessary, it shall, upon the filing of such petition, fix a time and place for a hearing.

If, after such hearing or in case no hearing is required, the commission is satisfied that the prayer of such petition should be granted and the public will thereby be furnished adequate service for a reasonable and just rate, rental, toll, or charge, it shall make such order as it deems proper and the circumstances require, and thereupon the things provided for in such order may be done.

§ 4933.85 Transfer of rights

The rights and authority granted under sections 4933.81 to 4933.84 of the Revised Code may be assigned or transferred only with the approval of the public utilities commission and approval shall be granted if the commission finds that the assignment or transfer is not contrary to the public interest. Upon the merger or consolidation of electric suppliers, the surviving or new electric supplier shall, without further action, succeed to all rights and authority previously granted under sections 4933.81 to 4933.84 of the Revised Code to the merged or consolidated electric suppliers.

As set forth above, the Commission's responsibility, pursuant to Sections 4905.48 and 4933.85, Revised Code, is to determine whether the transfer of Mon Power's facilities and service territory to CSP is not contrary to the public interest and will furnish adequate service for a reasonable and just rate. Various parties have presented arguments for and against whether certain of the terms and conditions of the Companies' proposal set forth in the August 9, 2005 Joint Report meet the statutory criteria for granting the transfer. However, except for possibly OEG, the intervening parties do not categorically oppose the transfer of Mon Power's service territory to CSP. Mon Power and CSP have presented a number of witnesses to support the position that their proposal meets the statutory criteria to grant their requested transfer. Staff and other parties have proposed alternatives or modifications to the Companies' proposal. In this section of the order, the Commission will address whether, in general, the Companies' proposal will be in the public interest. In the following section, the Commission will address in particular the issues raised by the parties to the terms and conditions of the transfer and the establishment of rates.

The Companies argue that by taking service under CSP's tariffs pursuant to CSP's Commission-approved RSP, Mon Power's customers will not be subject to the volatility and the much larger rate increases they are projected to face from the procurement of power through Mon Power's competitive bid process (CBP) (CSP Ex. 2, at 3). They contend that the rates that result from the proposed transaction are significantly lower than the projected Mon Power rates that would result if the transaction was not completed and a CBP is used to procure the necessary generation (Mon Power Ex. 1, at 5-6). Based on wholesale power cost projections for 2006-2008 provided by Mon Power witness Reeping, Mon Power witness Valdes calculated corresponding rates, by customer class, for each year of the 2006-2008 period. Mon Power witness Blankenship provided as part of his testimony a side-by-side comparison of the rates for each year of the 3-year period, which is set forth below.

Customer Class	2006		2007		2008	
	MP Rate	CSP Rate	MP Rate	CSP Rate	MP Rate	CSP Rate
Residential	$0.12141/kWh	$0.0834/kWh	$0.11480/kWh	$0.0846/kWh	$0.11112/kWh	$0.0856/kWh
Commercial	$0.10454/kWh	$0.0712/kWh	$0.09824/kWh	$0.0726/kWh	$0.09520/kWh	$0.0740/kWh
Industrial	$0.07649/kWh	$0.0447/kWh	$0.07116/kWh	$0.0457/kWh	$0.06816/kWh	$0.0467/kWh

(Mon Power Ex. 1, at 6; Mon Power Ex. 2, at 4-5; Mon Power Ex. 3, at 4-5.)

In addition to the testimony of Mon Power's witnesses, CSP witness Roush estimated the impact on customers moving from Mon Power to CSP. He testified that the estimated rate increase, without the transfer, under Mon Power's projected rates in 2006 by customer class as follows: Residential 79%; Commercial 71%; and Industrial 137% (CSP

Ex. 3, at 4). If the transfer is approved as they propose, Mr. Roush estimated the 2006 rate increase impact to be: Residential 23%; Commercial 17%; and Industrial 38% (*id.*, at 3). The Companies argue that these figures provide compelling evidence as to why this transaction is in the public interest and will lead to adequate service for a reasonable and just rate.

The Companies also argue that the uncertainty surrounding the future impact on rates by the litigation currently being pursued by Mon Power regarding its right to recover its wholesale power costs from Mon Power's large C&I customers for 2004 and 2005 will be eliminated.[6] Mon Power witness Valdes calculated the under-recovery of wholesale power costs incurred by Mon Power from 2004 through 2005 to be approximately $46.8 million, which the Companies argue could potentially be ordered by a court to be recovered from Mon Power's rate payers (Mon Power Ex. 3, at 6). As part of the proposed transaction, Mon Power has agreed to dismiss its pending litigation with the Commission related to these claims. The Companies also note that service will continue to be provided by CSP using largely the same employees, equipment, and for a limited time from the same service center used by Mon Power (CSP Ex. 2, at 3). Further, Mon Power agrees to provide CSP with any assistance it may need during the initial two-year period as CSP gains experience with the new territory and its customers. Lastly, the Companies contend that, because CSP is a wholly owned affiliate of American Electric Power Company, Inc. (AEP), CSP has access to all of AEP's resources and its overall financial strength and stability.

The Staff, with the changes it proposes, supports the proposed transfer transaction. Staff witness Hess believes that the proposal mitigates the rate shock of shifting Mon Power's customers to market-based rates after December 31, 2005, and that the proposal is a reasonable compromise to the federal and state litigation (Staff Ex. 1, at 5). Staff witness Cahaan also takes the position that the benefits of providing a rate stabilization plan to the southeastern part of the state will provide benefits to the rest of the CSP service territory due to the strong economic ties between these two service territories (Staff Ex. 3, at 4). Staff argues that, in general, prosperity in one area affects surrounding territories in the state. However, Staff argues that distribution rate cases should be undertaken for CSP, as well as Ohio Power Company (Ohio Power), inasmuch as it has been many years since their last rate cases and the transfer of Mon Power's assets could have an impact on distribution rates.

OCC argues that Ohio law does not permit the Commission to automatically increase the rates of customers of an acquired utility to those of the rates of the customers of the acquiring utility. It argues that the Commission must follow the procedures for

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6 See *Monongahela Power Co. v. Alan R. Schriber, et al.*, 322 F. Supp. 2d 902, United States District Court for the Southern District of Ohio Eastern Division, before Judge Edmund A. Sargus, Jr., and *Monongahela Power Co. v. Pub. Util. Comm'n*, Case No. 05-392 in the Supreme Court of Ohio.

fixation of rates set forth in Section 4909.15, Revised Code. If the Commission does not agree, OCC proposes that the Commission phase-in the rates to be charged Mon Power customers to minimize rate shock. OCC witness Corbin believes that the increase in rates for Mon Power residential customers would be more than the 23 percent estimated by Mr. Roush. He contends that, by using Mon Power's actual average monthly usage to Mr. Roush estimates, the average residential customers will experience a 34 percent increase or approximately $20 more a month, without including the addition of a 4 percent generation increase under CSP's RSP (OCC Ex. 2, at 4). OCC also argues that CSP's calculated residential customer increase does not take into account the 5 percent discount in Mon Power generation rates provide by electric restructuring under Senate Bill 3. Under a policy of gradualism, OCC recommends that the rate increase to Mon Power residential customers be limited to 1/3 the increase proposed by the Companies and the remainder recovered in increases the following two years of the RSP (*id.*, at 7 and 8). OCC also does not support the undertaking of distribution rate cases for CSP or Ohio Power, arguing that it is unreasonable and unlawful. OCC argues that the subject of a distribution rate case was raised in both CSP's ETP and RSP and through those proceedings the Commission approved, as part of an overall plan, CSP and Ohio Power distribution rate freezes through the end of 2008.

OPAE also argues that Mon Power customers should be charged under existing Mon Power rates if the transfer is approved. It also supports OCC's phase-in plan as an alternative and believes more energy efficiency assistance to low-income customers should be made available if rates are to increase. OEG takes the position that CSP customers receive no benefit from CSP acquiring Mon Power's service territory and in fact end up paying more from an increase in the RSP generation charge. IEU-Ohio also has concerns with CSP's power purchases from Mon Power as part of the APA.

Having reviewed the arguments and recommendations set forth above, the Commission finds that the transfer transaction, as modified as set forth below, does meet the requirements of Sections 4905.48 and 4933.85, Revised Code, and is not contrary to the public interest and will result in the public being furnished adequate service for a reasonable and just rate. The evidence shows that the Mon Power customers being acquired by CSP will be far better off under the rates established under the Companies' proposal than by being served at a CBP provided by Mon Power. Further, this proposal will end any further litigation by Mon Power in state and federal courts, provides stable rates for Mon Power customers for three years under CSP's RSP, and provides electric service from a utility with financial strength and stability.

We disagree with OCC's argument that the Commission can only change the rates charged to Mon Power customers pursuant to Section 4909.15, Revised Code. Although the Commission may have authorized mergers and granted utilities' requests that they continue to apply the individual base rates of each company until the merged company's next base rate case, such as the merger of West Ohio Gas Company and East Ohio Gas Company,[7] we believe that, in transfer proceedings such as this under Sections 4905.48 and 4933.85, Revised Code, the acquiring utility is permitted to charge its approved rates to the acquired customers. This is not a case of a utility increasing its base rates, but rather a case of a utility charging its rates pursuant to an approved RSP. Clearly, Section 4909.15, Revised Code, does not apply. We are also puzzled why OCC would make such an argument, which would most likely leave Mon Power customers subject to charges under a CBP starting in 2006. The evidence in this proceeding substantiates that such charges would be much higher than CSP's RSP rates.

With regard to OCC's proposal for a phase-in plan to address its and OPAE's concern over rate shock, we believe that with the transfers of Mon Power's customers to CSP and the charging of CSP's RSP rates, the Commission is ameliorating rate shock as much as reasonably possible. Although we recognize that the CSP rates are higher than Mon Power's current rates, whether you use CSP's or OCC's estimated increases, it does not seem unreasonable to ask Mon Power customers to pay the same rates that CSP customers are charged, particularly when looking at the alternative. We also note that Mon Power's rates have been the lowest in the state and its customers benefited from those rates for many years. The Commission also finds that there are sufficient low-income customer energy efficiency programs available through the utilities and state and federal programs to address OPAE's concerns.

As for Staff's request to initiate distribution base rate proceedings, we find such a request to be contrary to the RSP distribution rate freeze provisions. We noted in our RSP Opinion and Order of January 26, 2005 that we were approving the RSP as a package and that embarking on a rate proceeding at that point could run counter to our ultimate goals of rate stability and financial certainty for AEP (RSP Opinion and Order at 23). The Commission does not find that initiating distribution rate base proceedings at this time is warranted. We will, however, be looking at having CSP and Ohio Power file such rate cases at the end of the RSP.

Lastly, the Commission finds that all Mon Power and CSP customers will benefit from this transfer as argued by the Companies and Staff. Although we acknowledge that Mon Power customers are the primary beneficiaries of the transfer, economic benefits will inure to all citizens and businesses in both regions by helping to sustain the economic development in southeastern Ohio.

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7 See *In the Matter of the Application of the East Ohio Gas Company and West Ohio Gas Company for Authority to Merge*, Case No. 96-991-GA-UNC et al., Finding and Order December 19, 1996.

IV. Terms and Conditions of the Proposal:

A. Transfer of Assets

As discussed above, the Companies' August 9, 2005 Joint Report proposes, under the terms of the APA, that CSP will purchase the assets located in Ohio that are used by Mon Power in its Ohio transmission and distribution business, including the rights to serve Mon Power's existing certified service territory in Ohio (with the exception of certain excluded assets that are identified in Section 2.2 of the APA). (APA at 1.) The purchase price for the identified assets will be the Net Book Value of the acquired assets, as of the effective date of the transfer of Mon Power's Ohio certified service territory, less Mon Power's share of property taxes, prorated to Mon Power under the provisions of Section 7.7(h)(i) of the APA (*id.*, Ex. A, at 7).[8] The Net Book Value of the assets as of March 31, 2005, is included in APA as Schedule 5.5 (*id.*, Ex. A, at 7). The purchase price for the identified Ohio assets will be subject to a post-closing true-up, under Section 3.2 of the APA (*id.*, Ex. A, at 7). The Companies anticipate that the total purchase price for Mon Power's net assets associated with its Ohio service territory will be approximately $45 million (CSP Ex. 1, at 5)[9]

As part of the transfer of assets, CSP will be acquiring certain regulatory assets and regulatory liabilities presently on Mon Power's accounting books associated with Mon Power's Ohio service territory (CSP Ex. 4, at 11.) CSP witness Baker's testimony indicates that CSP will acquire approximately $3.7 million of regulatory assets currently recorded on the books of Mon Power (CSP Ex. 1, at 4). CSP witness Dias' testimony asserts that acquiring the regulatory assets which are an integral part of the (Mon Power) balance sheet is a reasonable expectation in such a (transfer) transaction (CSP Ex. 2, at 8). CSP proposes to recover these acquired regulatory assets and refund these acquired regulatory liabilities in its next distribution rate case filing (CSP Ex. 4, at 11). The regulatory assets and regulatory liabilities to be acquired are related to the following items:

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8 The total purchase price, under the APA, also includes the $10 million Litigation Termination Surcharge, which is discussed above in a separate section.

9 The approximate $45 million total purchase price for net assets does not include the $10 million Litigation Termination Surcharge.

Description		Regulatory Assets	Regulatory Liabilities
Deferred Taxes - Current	(FAS 109)	$171,000	$(51,000)
Deferred Taxes	(FAS 109)	$2,912,000	
Total Deferred Taxes	(FAS 109)	$3,083,000	$(51,000)
Net Deferred Taxes	(FAS 109)	$3,032,000	
Ohio kWh Taxes		645,000	-
Ohio Consumer Education Costs		176,000	(176,000)
Line Extension Costs		78,000	-
Cost of Removal		-	1,000
	Total	$3,982,000	$(226,000)
Net Regulatory Assets		$3,756,000	

(CSP Ex. 4, at 12; Mon Power Ex. 4 at 5; Joint Report at 8-9 and APA at Schedule 5.5-1.)

CSP notes that the above amounts are as of March 31, 2005 and are subject to revision through a true-up process to reflect activity through the closing of the transfer transaction (CSP Ex. 4, at 12). CSP is requesting approval to record these acquired regulatory assets and regulatory liabilities on its regulated accounting books at the same values as on Mon Power's accounting books (*id.*) CSP is also requesting approval to recover the acquired regulatory assets from and refund the acquired regulatory liabilities to all CSP's electric distribution customers beginning with its next distribution rate case (after the RSP period) (*id.*).

IEU-Ohio asserts that the Companies' proposal requires an examination of what "net book value" means (IEU-Ohio Initial Br. at 11). IEU-Ohio contends that the meaning advanced by Mon Power and CSP is in error (*id.*). IEU-Ohio questions the $3,031,609 of assets that have been identified as "FAS 109-related"[10] regulatory assets (*id.*). IEU-Ohio submits that this is the most significant portion of the total regulatory assets ($3,756,000) that the Companies propose to be transferred from Mon Power's books to CSP's books (*id.*). IEU-Ohio argues that the FAS 109-related regulatory assets allocated to Ohio, by Mon Power, improperly include generation-related regulatory assets; therefore, the FAS 109-related regulatory assets currently recorded on Mon Power's books are incorrect and

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10 "FAS-109" refers to Statement No. 109, issued by the Financial Accounting Standards Board (FASB), in February 1992, to address accounting for income taxes. The FASB develops broad accounting concepts as well as standards for financial reporting. It is not a government agency with regulatory authority. See http://www.fasb.org.

inflated. IEU-Ohio bases its contention on the specific calculation used by Mon Power to allocate this regulatory asset to Mon Power Ohio's books (*id.* at 11-12). Further, IEU-Ohio contends that there was no regulatory order providing for the recording of the FAS 109-related regulatory assets in Account 182.3.[11] (*Id.;* Tr. I, 96-97 & 137.) IEU-Ohio asserts that the Commission should direct that a detailed audit of Mon Power's books should be conducted to ensure that any costs that migrate from Mon Power's books and records to CSP's book and records are the result of proper accounting practices and are appropriately allocable or assignable to the Ohio service territory of Mon Power (*id.*).

Mon Power witness Toomey indicated in his direct testimony that Mon Power's regulatory asset and regulatory liability accounts were established "as a result of the proper application of ratemaking methodology for the inclusion of tax expense in cost recovery; there was no specific regulatory order." (Mon Power Ex. 4, at 6.) On cross-examination, Mr. Toomey again testified that there was not a specific regulatory order approved for these accounts, and stated his belief that FAS 109 provided the authority for Mon Power's recording of its regulatory assets (Mon Power Ex. 4, at 6; see also Tr. at 95-97). Mr. Toomey also asserted that Mon Power's method of accounting for its income taxes and its deferred income taxes is in accordance with the Federal Energy Regulatory Commission (FERC) prescribed Uniform System of Accounts (USOA) (Tr. I, at 93-97).

CSP, in its Reply Brief, asserts that the Commission did authorize the creation of FAS-109 regulatory assets and liabilities in Mon Power's rate proceeding, Case No. 94-1918-EL-AIR (*id.* at 12). CSP further asserts that even if there were not a specific Commission order, there are other bases for concluding that the regulatory asset was properly created (*id.*). Mon Power, in its Reply Brief, asserts that the bulk of the net regulatory assets and liabilities are deferred taxes that result from differences in timing between when the tax costs are incurred and when revenue is collected from customers through rates to recover those costs (*id.* at 2). Mon Power further asserts that its regulatory assets and liabilities were established in accordance with the FERC Uniform System of Accounts, 18 C.F.R. Part 101, and the Statement of Financial Accounting Standard (FAS) 109 (*id.* at 3). Mon Power argues that the net book value of the FAS 109-related regulatory assets represents the cost of taxes incurred by Mon Power and not yet recovered through customer rates (*id.*). This is a cost that Mon Power believes it is entitled to recover from its customers (*id.*). Mon Power contends that, by purchasing this asset from Mon Power, CSP will act as a conduit for the collection of the revenues that will recover that cost (*id.;* Mon Power Ex. 4, at 6). Staff believes that a distribution rate case is the better place to work out the treatment of all of CSP's assets and costs (Staff Reply Br. at 7). If the Commission does not order a distribution rate case, however, Staff agrees that an audit should be performed as IEU-Ohio suggests (Staff Reply Br. at 7).

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11 See IEU-Ohio Ex. 1, 18 C.F.R. § 182.3 "Other Regulatory Assets," which states in pertinent part: "A. This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from ratemaking action of regulatory agencies."

Having reviewed the arguments and recommendations set forth above, the Commission finds that the proposed asset transfer from Mon Power to CSP should be approved subject to our findings below. The evidence presented by the Companies sufficiently supports the transfer of the transmission and distribution assets requested by the Companies. However, with regard to the regulatory assets, mainly associated with deferred taxes, the Commission believes that an audit should be performed before those regulatory assets are transferred over to CSP's books as suggested by IEU-Ohio and Staff. The Commission finds that the testimony and arguments presented by the Companies show that the regulatory assets in question were properly booked by Mon Power. However, the Commission questions the allocation methodology used in transferring a portion of the regulatory assets to CSP in connection with this transfer. From the record, it is not clear that the portion of the regulatory assets being transferred are associated with transmission and distribution assets only. After trying to discredit IEU-Ohio's argument, Mon Power notes in its reply brief that "IEU-Ohio's criticism is really that Mon Power should have removed the generation-related FAS 109 regulatory assets from the total company FAS 109 amount before performing the allocation instead of removing the generation-related FAS 109 regulatory assets as part of the allocation." The Commission believes that that is exactly the point. We do not believe that the Companies' methodology actually does properly remove any generation-related assets. Accordingly, we will direct the Companies to perform an audit to ensure that the regulatory assets being transferred relate to transmission and distribution assets only. The Commission believes that this audit can be completed during the 60-day post-closing true-up period provision under Section 3.2 of the APA. The Commission also believes this is a better alternative for CSP than to find that an asset did not receive proper accounting treatment during a later distribution rate case.

B. <u>Recovery of Generation Costs Under the 4 Percent RSP Rider</u>

As noted above, CSP proposes that it be permitted to recover the difference between its power acquisition costs and the revenues produced under CSP's rates for the rate stabilization period January 1, 2006 through December 31, 2008 (Joint Report at 7; CSP Ex. 1, at 7-8). The power sales agreement (PSA)[12] provides for Mon Power to sell CSP 100 percent of its power requirements to serve the new load associated with the former Mon Power customers from January 1, 2006 through May 31, 2007, at $45 per MWh (*id.*; CSP Ex. 1, at 6). For the remainder of the rate stabilization period, CSP proposes to conduct an RFP for the same customer load for the period from June 1, 2007 through December 31, 2008 (*id.* at 7-8; CSP Ex. 1, at 6-7). CSP asserts that, as a result of the Commission's order for CSP to extend service at CSP's rates to Mon Power's Ohio service territory, the difference, or revenue differential, between the revenues collected under CSP's base generation rates (without any existing or new generation surcharges) and CSP's power purchase costs

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12 The PSA is included as Exhibit G to the APA. The testimony of Mon Power witness Mader refers to the power sales agreement as a "power purchase agreement (PPA)." (Mon Power Ex. 5, at 9-10).

(under the purchase power agreement with Mon Power) will trigger the "4%" provision of its RSP (*id.* at 8; CSP Ex. 1, at 7-9; CSP Ex. 3, at 8-9 and DMR Ex. 3; CSP Ex. 4, at 10).[13] The difference for the first year is expected to be approximately $17 to $19 million (Joint Report at 8; CSP Ex. 3, at 8-9 and DMR Ex. 3).[14] CSP seeks approval, as part of this proceeding, to collect this amount from all of CSP's current and new customers at a generation surcharge level based upon expected load in 2006 (*id.*; CSP Ex. 1, at 9-10; CSP Ex. 3 at DMR Ex. 5).[15]

For years 2007 and 2008, (also as a result of the Commission's order for CSP to extend service at CSP's rates to Mon Power's Ohio service territory) CSP anticipates that there will be a revenue differential between the revenues collected under CSP's base generation rates and the power purchase costs from the RFP process (*id.*; CSP Ex. 3 at 8-9). CSP asserts that it will also be entitled to recover the revenue differential under the 4 percent provision applicable to each of those years (*id.*; CSP Ex. 1, at 7-10).

CSP witness Baker testified that CSP does not have adequate generation capacity to serve both its current load and the Mon Power load. (Tr. I, 130.) Baker's direct testimony asserts that CSP's willingness to participate in this transfer transaction is conditioned on CSP's ability to collect the additional power supply costs associated with providing electric distribution service to the approximately 29,000 customers and combined load of approximately 300 MW that would be acquired through this transfer (CSP Ex. 1, at 7-8). Baker's direct testimony indicates that, although the Joint Report contemplated power acquisition surcharge adjustments at the end of calendar years 2006 and 2007, during which Mon Power's customers would be served under CSP's filed tariff, CSP now proposes that, for ease of administration and for customer understanding, to initially "true-up" the Power Acquisition Rider prior to the end of the seventeen-month period of the PSA (May 31, 2007), and to reflect the true-up in the Power Acquisition Rider applied during the second portion of the three-year period (June 1, 2007 through December 31, 2008) (*id.*, at 7.) Baker's testimony also proposes a second true-up that would occur at the end of the RSP (December 31, 2008) (*id.*). Any over- or under-collection at December 31, 2008, would be subsequently refunded or collected through CSP's distribution tariffs (*id.*, at 7-8). Baker's testimony asserts that application of a "true-up" procedure equally minimizes customer risk of over-recovery by CSP and CSP's risk of its own under-recovery (*id.*, at 8). CSP witness Roush testified that, based on his calculations, a residential customer using 1,000 kWh of electricity per month would see a monthly rate increase of $0.79 as a result of the Power Acquisition Rider (CSP Ex. 3, at 9).

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13 The "4%" provision refers to Section 3 of CSP's Rate Stabilization Plan application, filed February 9, 2004, under Case No. 04-169-EL-UNC, and approved by the Commission on January 26, 2005.

14 DMR Ex. 3 (of CSP Ex. 3) is titled "Power Acquisition Cost Difference."

15 See n. 5 above for additional information concerning DMR Ex. 5 (of CSP Ex. 3) and the proposed Power Acquisition Rider.

The testimony of Staff witness Cahaan asserts that because CSP is assuming this obligation in response to a request by the Commission as a matter of public policy, such cost recovery falls within the scope of the 4 percent regulatory cost recovery provisions of CSP's RSP, and which should be recovered, as proposed, from all CSP customers (Staff Ex. 3, at 2-4). The testimony of Staff witness Fortney recommends that the language in this rider be modified to indicate that it is a "temporary" charge that will be applied only until the amount authorized by the Commission is collected (Staff Ex. 2, at 4; reference to CSP Ex. 3, at DMR Ex. 5 "Power Acquisition Rider").

OEG asserts that there are no benefits to existing CSP customers from the terms of the proposed transfer. Further, even with the "true-ups," the second power acquisition time period involves CSP's purchase of power at market rates to serve the former Mon Power customer load; OEG opines that this will result in a substantial increase in the Power Acquisition Rider (OEG Br. at 3-4).

IEU-Ohio opposes the Power Acquisition Rider proposed by CSP to recover the difference between the costs CSP will incur to purchase power to serve the former Mon Power customers and the revenues collected from those customers under CSP's generation rates. IEU-Ohio contends that CSP will be charging a market-based price on January 1, 2006 (IEU-Ohio Initial Br. at 13-15). IEU-Ohio further asserts that the cost recovery to be provided by the Power Acquisition Rider is not authorized under the RSP provision for additional generation increases, and, in any event, should not be permitted without a hearing concerning CSP's need for the recovery (*id.* at 15-18). IEU-Ohio argues that AEP has provided neither any information on CSP's costs nor any information for the Commission to make a determination of how much, if any, CSP should be permitted to increase its currently approved SSO rates through the 4 percent discretionary increase portion of its RSP plan (*id.* at 17, citing Tr. I, 121).

Having reviewed the arguments and recommendations set forth above, the Commission finds that this order, approving the transfer of Mon Power's Ohio certified territory to CSP, is the type of administrative order contemplated under CSP's RSP that would result in consideration of an additional generation rate increase. The evidence shows that CSP does not have the generation capacity to serve both its current customers and the former Mon Power customers. The evidence also reflects that CSP's current generation rates will not provide sufficient revenue to cover the PSA rate of $45/MWh. Further, the proposed Power Acquisition Rider provides a mechanism for the generation surcharge to be adjusted twice during the three-year period from 2006 through 2008. The Commission finds, therefore, that CSP's Power Acquisition Rider is a reasonable mechanism to recover the incremental fuel costs of providing service to the former Mon Power customers and should be approved. The Commission also finds that CSP's proposed tariff language for the Power Acquisition Rider should be modified to indicate that it is a "temporary" charge that will be applied only until the amount authorized by the Commission in this proceeding is collected.

The Commission notes, however, that CSP's RSP contains the provision that the additional generation adjustments are effectively capped at 4 percent.[16] Accordingly, the calculation of the Power Acquisition Rider must not exceed the 4 percent limit.

C. Surcharge on Mon Power's Large Commercial and Industrial Customers

The APA provides for CSP to pay Mon Power $10 million over and above the book value of the assets being transferred. The Companies state that the $10 million represents a portion of the purchase price of Mon Power's property under the APA attributable to Mon Power's agreement to terminate all litigation, including appellate proceedings, concerning Mon Power's attempts to recover its wholesale power costs for default generation services provided to its large commercial and industrial (C&I) customers by charging them Market-Based Standard Service Offer rates or a Purchased Power Recovery Surcharge beginning January 1, 2004 (Joint Report at 6; Mon Power Ex. 5, at 8). Mon Power argues that the $10 million represents a fraction of the total $46.8 million amount that was not collected from large C&I customers because of Commission's ruling that the Market Development Period for these customer could not end until December 31, 2005. Mon Power witness testified that the $10 million represents a portion of the total valuation of the transaction to transfer its Ohio service territory and cannot be viewed in isolation. It was part of a negotiation that included the sale of property at net book value and a power purchase agreement of approximately 2.7 million MWhs at $45/MWh (Mon Power Ex. 5, at 8).

As part of the rate design proposed by CSP to take over Mon Power's service territory in Ohio, CSP proposes to recover the $10 million from acquired Mon Power large C&I customers over an approximately five-year period through a separate nonbypassable per kWh rider. The surcharge is to remain in effect until the $10 million is recovered, including a carrying charge on the unrecovered balance of the $10 million at the weighted average cost of capital computed in a manner consistent with the method used by CSP in its RSP. The Companies state that they will provide the Staff with an accounting of the revenues collected under the surcharge to demonstrate that there is not an over-recovery.

Staff proposes that, to the extent the Commission is concerned about the economic impact of allocating the $10 million to the Mon Power's large C&I customers, it could spread the cost over all of the current Mon Power customers, or over the entire CSP territory, to reduce the impact. Staff witness Hess testified that such a spreading of the

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16 See Case No. 04-169-EL-UNC, *In the Matter of the Application of Columbus Southern Power and Ohio Power Company for Approval of a Post-Market Development Period Rate Stabilization Plan*, January 26, 2005 Opinion and Order, at 20.

cost would lessen the severity of the economic impact on Mon Power's C&I customers and recover the cost from a larger customer base in recognition of the benefit to all customers from economic development. He believes that this situation is similar to the justification of spreading "delta revenue" arising out of the Commission's approval of economic development contracts prior to electric restructuring. Mr. Hess testified that, assuming the rate of return purposed by the Companies and a five-year amortization, the rate to allocate these costs to all Mon Power large C&I customers, to all Mon Power customers, and to all Mon Power and CSP customers would be as follows:

0.21567 cents/kWh – Mon Power large C&I customer
0.15787 cents/kWh - All Mon Power customers
0.01274 cents/kWh – All CSP and Mon Power customers

(Staff Ex. 1, at 6).

IEU-Ohio and OEG argue that the surcharge should not be approved. IEU-Ohio asserts that, if the surcharge represents Mon Power's losses from providing power to C&I customers during 2004 and 2005, Mon Power is essentially being paid $10 million for the same claims of confiscation that it has maintained unsuccessfully in state and federal courts. IEU-Ohio argues that Mon Power is attempting to recover past purchased power cost that the Commission denied and that the matter is *res judicata*. OEG agrees with IEU-Ohio and also points out that CSP customers receive no benefit from the payment of the $10 million to Mon Power, and under no circumstances should CSP customers be required to pay the surcharge.

OCC takes no position regarding whether other customer classes should be charged the surcharge; however, it argues that the surcharge recovers costs that cannot be reasonably assigned to residential customers on a cost causation basis. OCC witness Corbin testified that the litigation that brought about the $10 million surcharge did not involve residential customers and, therefore, they should not be responsible to pay any part of the surcharge (OCC Ex. 3, at 4). OPAE also agrees that the surcharge should not be charged to residential or CSP customers. OPAE also argues that even charging Mon Power's large C&I customers constitutes retroactive ratemaking if based on uncollected fuel costs from 2004 and 2005 and should also not be permitted as a premium to the purchase price.

The Commission finds that a surcharge to recover the $10 million agreed to by the Companies as part of a negotiated purchase price to transfer Mon Power's certified territory in Ohio to CSP is not unreasonable. The Commission finds Mon Power was not required to transfer its assets at book value to CSP, as opposed to fair market value. We recognize that for CSP to acquire Mon Power's Ohio assets at book value it has agreed to compensate Mon Power for ending its litigation with the Commission to recover costs borne by Mon Power to supply power to large C&I customers during the years 2004 and 2005 at rates establish under the Mon Power's Electric Transition Plan (ETP) approved by the Commission in Case No. 00-02-EL-ETP. In light of this recognition, we find that a surcharge to recover the $10 million over approximately five years is reasonable. We do not find the $10 million to be a premium over market or retroactive ratemaking, but part of the total cost for the transfer of facilities and customer base. CSP's recovery of this portion of the purchase price is not *res judicata* or a collateral attack on prior Commission orders.

The testimony of Staff witness Fortney recommends that the proposed language in this rider be modified to indicated that it is a "temporary" charge that will be applied only until the amount authorized by the Commission is collected (Staff Ex. 2, at 4; reference to CSP Ex. 3, at DMR Ex. 4, "Monongahela Power Litigation Termination Rider"). The Commission finds that the Staff recommendation is well-taken. Accordingly, the Commission also finds that CSP's proposed tariff language for the Monongahela Power Litigation Termination Rider should be modified to indicate that it is a "temporary" charge that will be applied only until the amount authorized by the Commission in this proceeding is collected.

The remaining question is the customer base over which this surcharge should apply. Having considered the positions put forth by the various parties to this case, we conclude that the surcharge should be spread over all Mon Power and CSP customer classes. The Commission recognizes that, through unanticipated events, Mon Power incurred costs to supply generation service to its large C&I customers that were not recovered through frozen rates and finds that the $10 million payment by CSP is not unreasonable as part of the purchased price of the transfer. However, we cannot agree that the recovery of this amount should come from just Mon Power's large C&I customers. To limit the surcharge to just Mon Power's large C&I customers, as proposed by the Companies, would presume that Mon Power's large C&I customers have been charged rates lower than they should have been for 2004 and 2005. The Commission in arguments before the United States Southern Ohio District Court and at the Supreme Court of Ohio has steadfastly argued against that view. See *Monongahela Power Co. v. Alan R. Schriber, et al.*, 322 F. Supp. 2d 902; 2004 U.S. Dist. LEXIS 11739 (S.D. Ohio, May 19, 2004 Opinion and Order); and *Monongahela Power Co. v. Pub. Util. Comm'n.*, 104 Ohio St. 3d 571 (2004). Consequently, this portion of the purchase price should be spread over all Mon Power and CSP customers, just as the other costs of the transfer will eventually be paid by all customers. Further, as pointed out by Staff witness Hess, to spread this surcharge over a larger customer base greatly decreases the impact of the surcharge and reduces the rate stock on the businesses in southeastern Ohio helping to sustain economic development in the region and throughout the state.

D. Carrying Charges

As part of this transfer transaction, CSP proposes a carrying charge on the $10 million surcharge as well as on certain accounting deferrals for the incremental operating and capital costs of executing this transfer (CSP Ex. 4, at 13-14; CSP Ex. 2, at 6 and 7). The proposed carrying charges result from a weighted cost of capital which used a 12.46 percent return on equity (ROE). This ROE was established in CSP's last base rate case, Case No. 91-418-EL-AIR (Opinion and Order issued on May 12, 1992) (Staff Ex. 3, at 5). Staff witness Cahaan testified that he believes it is not reasonable to use the ROE established in 1992, inasmuch as interest rates have fallen since that time. Staff recommends a ROE of 10.5 percent, recognizing a balance of fallen interest rates and an increased perception of risk in the electric industry due to electric restructuring (*id.*, at 7). Using this ROE would result in a carrying charge rate of 11.78 percent (Tr. I, 207).

CSP on brief argues that the use of the ROE from its last rate case is supported by the Uniform System of Accounts which has been adopted by the Federal Energy Regulatory Commission (FERC) when computing the Allowance for Funds Used During Construction (AFUDC). CSP witness Assante testified that AFUDC is similar to the weight average cost of capital for purposes of computing the present carrying charges and, therefore, it is appropriate to use the ROE from the last rate case (CSP Ex. 4, at 14).

IEU-Ohio argues that the carrying charge rate should not exceed 11.78 percent inasmuch as CSP has failed to offer any evidence that its proposed ROE is reasonable. OCC argues that Staff's proposed rate is too high under the current market conditions of relatively low costs of borrowing. OCC proposes that the carrying charge be based on AEP's cost of long-term debt.

For purposes of this transaction, the Commission finds that using more current data to arrive at a ROE, as Staff has done, is more appropriate. The financial picture has changed greatly since 1992, particularly when looking at interest rates. As Staff witness Cahaan has noted, an examination of U. S. Treasury bond interest indicates that rates have dropped by approximately 3.5 to 4 percentage points since 1992 (Staff Ex. 3, at 6). We also find that it is reasonable to use a weighted cost of capital instead of just the cost of long-term debt. Accordingly, we find it proper to modify CSP's calculation of the carrying charge rate to reflect a ROE of 10.5 percent and an overall carrying charge of 11.78 percent.

E. USF Rider Adjustments

Testimony by Staff witness Robert Fortney recommends that the Universal Service Fund Rider (USF Rider), which funds the electric Percentage Income Payment Plan (PIPP), be set at a "blended rate" that combines the Mon Power and CSP rates, if the transfer is approved (Staff Ex. 2, at 5; Tr. I, 199-200). CSP supports Staff's recommendation for blending the two companies' USF rider rates (CSP Ex. 3, at 9). CSP asserts that all of its customers should have the same USF rider rate, which should result from blending the CSP and Mon Power data *(id.)*. CSP further supports a Commission order regarding its USF rider in this case (CSP Ex. 3; CSP Reply Br. at 15.)

OPAE objects to the blended USF rate for two reasons. First, former Mon Power customers on PIPP will be paying higher CSP rates, rather than the current Mon Power rates; therefore, the costs for electricity (consumed by CSP's PIPP customers) that CSP's USF rider has to reimburse will be higher (OPAE Br. at 6). OPAE opines that blending the rate will result in a shortfall in collections (*id.*). Second, OPAE asserts that the cost implications of the customer transfer and its impact on the USF rider calculation should be determined in the Ohio Department of Development (ODOD) case to establish the USF Riders for 2006 (*id.*).

ODOD filed an application on October 28, 2005, under Case No. 05-717-EL-UNC (05-717), to establish the USF Riders for 2006. A review of ODOD's application in 05-717 indicates that ODOD has proposed an alternate blended USF rate for CSP in 2006, if the Mon Power certified territory transfer is approved (ODOD Application at 11, and Ex. L). The Commission finds it appropriate that the cost implications of the Mon Power customer transfer to CSP and any corresponding impact on the CSP's USF rider calculation be addressed in 05-717.

V. Miscellaneous

A. Pending Proceedings

As part of the Companies' proposed transfer, they are requesting that the Commission dismiss Case No. 04-1482-EL-CSS. This complaint case, brought by IEU-Ohio against Mon Power on September 27, 2004, alleges that Mon Power and its affiliates have been in violation of the Ohio Revised Code and its ETP to the detriment of Mon Power's customers. Mon Power filed a motion to dismiss the complaint on November 8, 2004, asserting that the issues raised by the complaint were the same issues that IEU-Ohio was arguing in the Mon Power confiscatory case initiated by the Commission in Case No. 04-880-EL-UNC (04-880).

IEU-Ohio argues that there is no basis for dismissing its complaint. IEU-Ohio asserts that Mon Power had made misrepresentations regarding its ability to provide generation services to C&I customers during the ETP Market Development Period (MDP). However, IEU-Ohio is willing to withdraw its complaint if IEU-Ohio's proposed changes to the transfer transaction are approved.

The Commission finds that it is appropriate to dismiss IEU-Ohio's complaint case. We believe that the issues of the complaint, regarding harm to C&I customers by charging market based rates for 2004 and 2005, were adequately addressed and/or mooted by our decisions in Case No. 03-1104-EL-ATA (03-1104), in which Mon Power's attempt to end its MDP for large C&I customers at the end 2003 was denied, and in 04-880, in which the Commission found that Mon Power's rates for C&I customers during the MDP were not confiscatory. With or without the approval of transfer transaction, IEU-Ohio's complaint should be dismissed.

The Commission also finds that Mon Power's *Application for a Pass-through and Surcharge for Wholesale Power Supply*, Case No. 03-2567-EL-ATA (03-2567) filed on December 31, 2003, and its Application for Certain Findings under the Public Utility Holding Company Act of 1935 (PUHCA), Case No. 03-993-EL-UNC (03-993) filed on April 15, 2003, should also be dismissed. In the 03-2567 filing, Mon Power requested approval to apply a retail surcharge on C&I customers to recover the difference in price between it power purchases for those customers and the ETP established generation rate. In the 03-993 filing, Mon Power requested the Commission make certain findings required by the PUHCA so that it could transfer certain generation facilities. The Commission finds that the 03-2567 application is contrary to the Commission's Finding and Order and Entry on Rehearing issued in 03-1104, as well as subsumed by our Opinion and Order in 04-880. We also find that both these cases are now moot by our approval of the transfer transaction. Consequently, we will dismiss these cases and close these dockets.

The Commission also finds that with the approval of the transfer transaction, Mon Power's *Application for Approval of a Standard Service Offer and Competitive Bidding Process*, Case No 04-1047-EL-ATA (04-1047), should also be dismissed. Mon Power filed that application to establish fixed-rate market-based standard service offer using a competitive bidding process that would take effect at the beginning of 2006. With the initiation of the current proceeding, the Commission by entry issued on June 21, 2005, continued the 04-1047 proceeding until a determination was made in this proceeding. With the approval of the transfer of Mon Power's service territory to CSP, there is no further need for Mon Power's application. Accordingly, Mon Power's application should be dismissed as well.

B. Waiver Requests

CSP has requested six temporary waivers of Commission rules as part of the proposed transfer of Mon Power's Ohio certified territory to CSP (Joint Report at 9; CSP Ex. 2, at 8-13; CSP Initial Br. at 16-18). Mon Power witness Valdes testified as to the need for the waiver requests identified in Section 12(F) of the Joint Report (*id.* at 9; Mon Power Ex. 3, at 3, 7-8). Staff supports the Companies' waiver requests (Staff Ex. 2, at 2). No parties opposed the waiver requests.

1. Disconnection Rules: 4901:1-10-15 and 4901:1-18-05, O.A.C.

Mon Power witness Valdes' testimony indicates that after the transfer of Mon Power's Ohio customers to CSP, Mon Power will still have accounts receivable for services provided prior to the transfer of those customers to CSP (*id.*, at 3, 7-8). Under the terms of the APA, Mon Power is entitled to receive the revenues from those receivables (*id.*, at 7). Mon Power asserts that once the transfer has occurred, however, it will no longer be the electric distribution utility for the customers who purchased the services related to those receivables and, thus, it will no longer be in a position to disconnect service in the event of non-payment (*id.*). CSP has agreed to assist Mon Power's collection of those receivables by disconnecting service for non-payment, at Mon Power's request (*id.*). Mon Power and CSP agree that it is appropriate to request a waiver from the Commission's rules to the extent that the rules allow EDUs to disconnect customers for non-payment only when the disconnecting EDU provided the services in question (*id.*; CSP Ex. 2, at 9-10). The Companies assert that a waiver request, if necessary, is appropriate because it would allow disconnection only in the non-payment circumstances already permitted by the disconnection rules and, therefore, is consistent with the intent of those rules (Mon Power Ex. 3, at 7-8; CSP Ex. 2, at 9-10). Mon Power witness Valdes' testimony indicates that the waivers should include the provisions in Chapter 4901:1-18, O.A.C., which apply to disconnection of service to residential customers, and Rules 4901:1-10-15 through 17, O.A.C., which apply to the disconnection of nonresidential customers (Mon Power Ex. 3, at 8).

The specific rules that apply to disconnection of service are Rule 4901:1-18-05, O.A.C., for residential customers, and Rule 4901:1-10-15, O.A.C., for nonresidential customers. The Commission finds that it is reasonable for Mon Power to be authorized to collect its accounts receivable, and, if necessary, for CSP to disconnect the customer's service for non-payment. The Commission, therefore, finds that CSP's request for waiver of Rules 4901:1-18-05 and 4901:1-10-15, O.A.C., should be granted for a period of twelve months. The Commission, however, does not waive any of the disconnection notice requirements under Rules 4901:1-10-16 and 4901:1-10-17, O.A.C. Last, the Commission directs the Companies' to develop a process for Mon Power to promptly notify CSP of payments made by its former customers to avoid disconnection by CSP.

2. Twelve-month Consumption History: Rule 4901:1-10-22, O.A.C.

Rule 4901:1-10-22, O.A.C., requires that bills rendered by EDUs show the customer's historical consumption during each of the prior twelve months. CSP requests a waiver of this provision of Rule 4901:1-10-22(B)(22), O.A.C. (CSP Ex. 2, at 10; CSP Initial Br. at 17.) CSP asserts that in order to minimize the cost and time constraints to effectuate the transfer transaction, CSP's system integration plan for its existing computer customer information system does not include the transfer of Mon Power's customer information related to consumption history (CSP Ex. 2, at 10; CSP Initial Br. at 17). CSP asserts that, beginning with the first billing cycle during which CSP renders bills to Mon Power's transferred customers, CSP will begin building the consumption history for those customers (*id.*).

The Commission finds that CSP's request for a temporary waiver of Rule 4901:1-10-22(B)(22), O.A.C., is reasonable and should be granted for twelve months, beginning with January 2006. The Commission further finds that Mon Power should provide the twelve-month historical consumption information (for service rendered through December 31, 2005) to CSP for CSP's use in providing customer service, such as establishing a budget plan. Last, the Commission directs that Mon Power include a notice with its final Ohio customer bills (for service rendered through December 31, 2005) that advises customers to keep that bill for their own record of historical consumption.

3. Long-Term Forecast Report: Rule 4901:5-3-01, O.A.C.

Rule 4901:5-3-01, O.A.C, and Section 4935.04, Revised Code, require EDUs to file annually with the Commission a "forms only" Long-Term Forecast Report (LTFR). The rules further require that a "complete" LTFR be filed and a public hearing be held every five years and whenever any of the annual "forms only" LTFR reports contain a substantial change from the preceding year's report. CSP states that it is due to file a "forms only" report on April 15, 2006, and that it has historically filed a single LFTR along with the Ohio Power Company (CSP Ex. 2, at 11). In the event the Mon Power transaction would trigger a "substantial change," as defined in division (D)(3)(c) of Section 4935.04, Revised Code (and Rule 4901:5-1-1(L), O.A.C.), CSP requests a waiver from the requirements that a "complete" LTFR be filed and that a public hearing be held (CSP Ex. 2, at 11; CSP Initial Br. at 17).

The Commission notes that CSP's latest "complete" LTFR was filed under Case No. 02-0502-EL-FOR. Therefore, it is appropriate, under the Commission's rules, for CSP to file a "forms only" LTFR in April 2006. The Commission finds that CSP's request for a waiver of the requirements that a "complete" LTFR be filed and that a public hearing be held, in the event of a "substantial change" due to the Mon Power transfer, is reasonable and should be granted.

4. Identification of Meters: Rule 4901:1-10-05, O.A.C.

Paragraph (G) of Rule 4901:1-10-05, O.A.C., requires EDUs to identify their customers' meters by placing the Company's name and the meter number in a conspicuous position on the meter. CSP witness Dias indicates that, generally, meters have a tag or label affixed to the nameplate or under the cover of the meters, identifying the company that owns them (CSP Ex. 2, at 11; CSP Initial Br. at 17). CSP asserts that it intends to place an AEP sticker over these existing Mon Power tags or stickers to identify the meters as belonging to CSP. CSP requests a temporary waiver of four months to allow CSP time to be able to affix an AEP sticker on the covers of the former Mon Power meters being used to bill the Mon Power customers transferred to CSP (CSP Ex. 2 at 11; CSP Initial Br. at 17-18).

The Commission finds that CSP's request for a waiver of Rule 4901:1-10-05(G), O.A.C., for four months is reasonable and should be granted, effective January 1, 2006.

5. Days Between Billing Cycles: CSP Tariff PUCO No. 5, Terms and Conditions of Service

CSP submits that the Terms and Conditions of Service in CSP's tariff, P.U.C.O. No. 5, define the word "month" as "the time elapsed between two successive meter readings for the summer period of not less than 28 days nor more than 33 days apart and for the winter period of not less than 28 days nor more than 35 days apart." (CSP Ex. 2, at 11-12; CSP Initial Br. at 17.) At the time of the transfer of Mon Power's Ohio customers, CSP intends to incorporate Mon Power's customers into its billing system once they are new customers (CSP Ex. 2, at 12). To accommodate this unique situation, CSP is not planning on reading the meters of any of the transferred customers whose meter reading dates occur during the initial ten cycles following the transfer (*id.*). CSP notes that for some of these customers, this process will result in the time elapsed between their first two meter readings being as short as 16 days or as long as 48 days apart (allowing for weekends and holidays). (*Id.*) Due to the unusual circumstances of the transfer, CSP requests a temporary waiver during the first billing period of the transition to define the word "month" as "the time elapsed between two successive meter readings for the period of not less than 16 days nor more than 48 days apart." (*Id.*)

The Commission notes that, while CSP's waiver request identified the tariff as P.U.C.O. No. 5, the specific CSP tariff approved to take effect on January 1, 2006, is CSP tariff P.U.C.O. No. 6.[17] The Commission finds that CSP's request for a temporary waiver of the definition of "month" as used in the company's tariff, P.U.C.O No. 6, is reasonable and should be granted. Accordingly, CSP's billing cycles for the months of January and February 2006 should be based on successive meter readings of not less than 16 days or more than 48 days apart. If CSP determines that it needs additional time under this waiver request, it should request that time by filing a letter in this docket.

[17] The Commission approved CSP tariff P.U.C.O. No. 6 in CSP's RSP case, Case No. 04-169-EL-UNC.

6. Monthly Billing Demand: CSP Tariff PUCO No. 5

CSP submits that its tariffs require that monthly readings used to bill demand customers be based on the single highest 30-minute integrated kilowatt peak registered during the month (CSP Ex. 2, at 12). CSP further submits that Mon Power's tariffs require using the single highest 15-minute integrated peak for billing demand and, consequently, their meters register kilowatt demands at 15-minute intervals (*id.*). CSP asserts that to bill the Mon Power customers being transferred to CSP, all of Mon Power's Ohio demand meters will have to be replaced or reprogrammed, which work is estimated to take approximately twelve months (*id.*). CSP requests that, until the meters are reprogrammed or replaced, the Commission grant a temporary waiver that would allow CSP to continue to bill demand usage for these transferred customers under CSP existing tariffs, but based on the customer's highest 15-minute kilowatt peak (*id.*, at 12-13; CSP Initial Br. at 18).

The Commission finds that CSP's waiver request to bill Mon Power's "demand" customers under CSP's existing tariff, but based on the customer's highest 15-minute peak, until the demand meters can be reprogrammed or replaced, is reasonable and should be granted for twelve months, beginning January 2006. The Commission notes that this waiver request is granted for CSP tariff P.U.C.O. No. 6, which is effective January 1, 2006.

C. Other Transition Concerns

1. Notification Letters

Staff witness Fortney testified that the above waiver requests appear to be reasonable and staff recommends that they be granted (Staff Ex. 2, at 2). Yet, staff further recommends that CSP work with the staff of the Service Monitoring and Enforcement Department to develop "notification" letters to the Mon Power customers who will be switched to CSP (*id.*). The Commission finds that Staff's recommendation regarding customer notification letters is reasonable and should be implemented. Accordingly, the Commission directs CSP to work with the staff, as noted above, to develop notification letters to the Mon Power customers who will be transferred to CSP.

2. Budget Customers

The Commission notes that neither company offered testimony regarding the transition of Mon Power's Ohio budget customers to CSP. Accordingly, the Commission directs the companies to establish a process under which Mon Power's current budget customers are identified, and to contact the identified customers concerning their desire to move to a budget plan under CSP's 2006 rates. In light of the fact that CSP's 2006 rates will be higher than those experienced by Mon Power customers to date, the Commission further directs CSP to inform all of the transferred customers of CSP's budget payment plan, and to use the customer's most recent twelve-month consumption in determining the budget payment.

3. PIPP Customers

The Commission also notes that neither company offered testimony regarding the transition of Mon Power's Ohio PIPP customers to CSP PIPP customers under CSP's 2006 rates. (The only concern raised by other parties related to potential impact on the USF rider, as discussed above.) Accordingly, the Commission directs the companies to establish a process under which Mon Power's Ohio PIPP customers are identified, and transitioned to CSP's PIPP plan.

4. Emergency Plan under Rule 4901:1-10-08, O.A.C.

The Commission notes that neither company offered testimony regarding the transition of the pertinent customer information from Mon Power's emergency plan that is required under Rule 4901:1-10-08, O.A.C. Accordingly, the Commission directs Mon Power to share with CSP the sections of its Rule 4901:1-10-08, O.A.C., emergency plan that will be necessary for CSP to continue providing service in the territory, including the critical customer list used for restoration of service.

5. 2005 Service Reports

The Commission reminds Mon Power that it is still responsible for the generation of certain reports required by the administrative code in relation to performance during the 2005 calendar year. Specifically, the reports that are required by Rules 4901:1-10-10, 4901:1-10-11, 4901:1-10-26, and 4901:1-10-27, O.A.C. The Commission requires the sections of these reports that deal with performance and condition of the system over the past year. The sections of those reports that deal with future commitments and action plans may be omitted.

D. Effective Date

One of the conditions for the proposed transfer is that the Commission's order should be issued in time to permit the transfer of the service territory no earlier than December 31, 2005, and to eliminate the need for Mon Power to complete a competitive bidding process (in order to acquire a wholesale power supply) for a market-based standard service offer beginning January 1, 2006. (Joint Report at 9; Mon Power Initial Br. at 23.)

No parties raised an objection to the proposed transfer date of December 31, 2005 (which is also the end date of the frozen rates under Mon Power's MDP). Based on the need for Mon Power's customers to have post-MDP rates in place on January 1, 2006, the Commission finds that it is appropriate to order that Mon Power's voluntary transfer of its Ohio certified territory to Columbus Southern Power Company be effective December 31, 2005. Further, Columbus Southern Power Company, in accordance with Section 4933.85, Revised Code, and the changes described in this Order to amend the Joint Report, shall assume the right and obligation to provide electric service to consumers within Mon Power's former certified service territory, effective January 1, 2006. As recommended by Staff, however, CSP's rates for the acquired Mon Power customers will be effective on a service rendered basis on or after January 1, 2006, as opposed to the Companies' request for rates effective with the first bill these customers receive after the transfer becomes effective.

E. Cancellation of Mon Power's Tariffs and Related Agreements

Mon Power requests that, simultaneous with the sale of its Ohio utility property and the transfer of its certified territory to CSP, the Commission cancel its existing P.U.C.O. tariffs. In addition, Mon Power requests that the Commission confirm in any order implementing this transfer transaction that all electric service agreements or other tariff-based agreements that Mon Power entered into pursuant to its P.U.C.O tariffs and that incorporate provisions of those tariffs as essential terms of the electric service agreements are terminated at the time those related tariffs are cancelled. (Joint Report at 10; Mon Power Initial Br. at 23.)

With the approval of the transfer of Mon Power's service territory to CSP, there is no further need for Mon Power's P.U.C.O. tariffs after December 31, 2005. Accordingly, Mon Power tariffs P.U.C.O. No. 1 (Certified Supplier Tariff)[18] and P.U.C.O. No. 3 (Electric Service)[19] should be cancelled, effective January 1, 2006, and Mon Power's tariff docket 89-6005-EL-TRF should be closed effective January 1, 2006. Further, any electric service agreements or other tariff-based agreements that Mon Power entered into under its P.U.C.O. tariffs and that incorporate provisions of those tariffs as essential elements of the electric service should be terminated, effective January 1, 2006.

F. Rehearing Applications

The Commission is issuing this Opinion and Order in an expedited manner in an attempt to provide rate certainty to CSP and all customers it will serve beginning 2006. The Commission recognizes the importance of having Standard Service Offer rates, required by Section 4928.14, Revised Code, for Mon Power customers in effect beginning

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18 The latest revisions to P.U.C.O. Tariff No. 1 were effective on August 18, 2003, and filed in compliance with Case No. 03-1242-EL-ATA.

19 The latest revisions to P.U.C.O. Tariff No. 3 were effective on August 23, 2004, and filed in compliance with the July 20, 2004 Order issued under Case No. 04-482-EL-ATA.

January 1, 2006. This order accomplishes that requirement by having Mon Power customers served under CSP's RSP beginning in 2006. In order to provide as much certainty as possible, it is the Commission's intent to rule on any applications for rehearing that may be filed by the end of this year. To meet this time frame, the Commission encourages any party, who plans to file for rehearing, to do so as soon as possible. Further, we will direct such party to serve its application on all other parties to this proceeding by e-mail by 3:00 p.m., on the day the application is filed with the Commission. Any memorandum contra shall be filed no later than 5 days after the filing of an application for rehearing.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) By its Entry issued on June 14, 2005, the Commission ordered Columbus Southern Power Company and Monongahela Power Company to engage in discussions regarding the acquisition by CSP of Mon Power's Ohio certified service territory. In its June 14, 2005 Entry, the Commission directed that Mon Power and CSP were to report to the Commission on the progress of those discussions within 14 days of the date of its entry.

(2) Joint reports were filed by Mon Power and CSP on June 28, July 15, and August 3, 2005, concerning discussions regarding CSP's acquisition of Mon Power's Ohio certified service territory. The Companies filed an additional joint report on August 9, 2005, advising the Commission that the Companies successfully completed their negotiations and have entered into an Asset Purchase Agreement, which was included in its report as an exhibit.

(3) The Commission has jurisdiction over this matter pursuant Sections 4905.48 and 4933.85, Revised Code. The Commission's responsibility, pursuant to Sections 4905.48 and 4933.85, Revised Code, is to determine whether the transfer of Mon Power's facilities and service territory to CSP is not contrary to the public interest and will furnish adequate service for a reasonable and just rate.

(4) The transfer transaction, as modified, meets the requirements of Sections 4905.48 and 4933.85, Revised Code, and is not contrary the public interest and will furnish adequate service for a reasonable and just rate.

(5) Inasmuch as this is not a case of a utility increasing its base rates, but rather a case of a utility charging its rates pursuant to an approved RSP, Section 4909.15, Revised Code, does not apply.

(6) The transfer of Mon Power's customers to CSP and the charging of CSP's RSP rates ameliorates rate shock as much as reasonably possible.

(7) Staff's request to initiate distribution base rate proceedings is contrary to the RSP distribution rate freeze provisions.

(8) A surcharge to recover the $10 million agreed to by the Companies as part of a negotiated purchase price to transfer Mon Power's certified territory in Ohio to CSP is not unreasonable.

(9) CSP's calculation of the carrying charge rate should be modified to reflect a ROE of 10.5 percent and an overall carrying charge of 11.78 percent.

(10) CSP will purchase the assets used in Mon Power's Ohio transmission and distribution business, including the rights to serve Mon Power's existing Ohio certified territory (with the exception of certain excluded assets that are identified in Section 2.2 of the APA).

(11) The purchase price for the identified Ohio assets will be subject to a post-closing true-up, under Section 3.2 of the APA.

(12) As part of the transfer of assets, CSP will be acquiring certain regulatory assets and regulatory liabilities presently on Mon Power's books associated with Mon Power's Ohio service territory.

(13) The companies anticipate that the total purchase price for Mon Power's net assets associated with its Ohio service territory will be approximately $45 million.

(14) The regulatory assets acquired by CSP will be approximately $3.7 million (of the total purchase price for Mon Power's net assets above).

(15) The evidence presented by the companies sufficiently supports the transfer of the transmission and distribution assets requested by the companies.

(16) The evidence reflects that Mon Power's regulatory assets were properly booked by Mon Power.

(17) The Commission questions the allocation methodology used in transferring a portion of the regulatory assets to CSP in connection with this transfer, because it is not clear from the record that these regulatory assets are only associated with transmission and distribution assets.

(18) With regard to the regulatory assets, mainly associated with deferred taxes, the Commission believes that an audit should be performed before those regulatory assets are transferred over to CSP's books to ensure the regulatory assets are related to transmission and distribution only.

(19) The evidence reflects that CSP's request for temporary waivers of rules 4901:1-18-05, 4901:1-10-15, 4901:1-10-22, 4901:5-3-01, and 4901:1-10-05, O.A.C., is reasonable.

(20) The evidence reflects that CSP's request for temporary waivers of its tariff term "days between billing cycles" and its tariff definition of "month" is reasonable.

(21) Based on the need for Mon Power's customers to have post-MDP rates in place on January 1, 2006, it is appropriate to order that Mon Power's voluntary transfer of its Ohio certified territory to CSP be effective December 31, 2005.

(22) It is appropriate, in light of the transfer, for CSP to assume the right and obligation to provide electric service to consumers within Mon Power's former certified territory on January 1, 2006.

(23) The evidence reflects that with the approval of the transfer of Mon Power's service territory to CSP, there is no further need for Mon Power's P.U.C.O. tariffs, after December 31, 2005.

(24) This order, approving the transfer of Mon Power's Ohio certified territory to CSP, is the type of administrative order contemplated under CSP's RSP that would result in consideration of an additional generation rate increase.

(25) The evidence shows that CSP does not have the generation capacity to serve both its current customers and the former customers.

(26) The evidence also reflects that CSP's current generation rates will not provide sufficient revenue to cover the PSA rate of $45/MWh.

(27) CSP's Power Acquisition Rider is a reasonable mechanism to recover the incremental fuel costs of providing service to the former Mon Power customers.

ORDER:

It is, therefore,

ORDERED, That Monongahela Power Company's voluntary transfer of its Ohio certified territory to Columbus Southern Power Company is approved, effective December 31, 2005. It is, further,

ORDERED, That Columbus Southern Power Company, in accordance with Section 4933.85, Revised Code, and the changes described in this Opinion and Order to amend the Joint Report, shall assume the right and obligation to provide electric service to consumers within Mon Power's former certified service territory, effective January 1, 2006. It is, further,

ORDERED, That Mon Power tariffs P.U.C.O. No. 1 (Certified Supplier Tariff) and P.U.C.O. No. 3 (Electric Service) should be cancelled, effective January 1, 2006, and Mon Power's tariff docket 89-6005-EL-TRF should be closed effective January 1, 2006. It is, further,

ORDERED, That Monongahela Power Company's electric service agreements, or other tariff-based agreements, that it entered into under its existing Ohio tariffs and that incorporate provisions of those tariffs as essential terms of the electric service agreements are terminated effective, January 1, 2006, with the cancellation of Monongahela Power Company's tariffs (P.U.C.O. No. 1 and No. 3) on that date. It is, further, ORDERED, That CSP file revised tariffs for Commission approval that reflects the terms and conditions of this Opinion and Order within 30 days of this Opinion and Order. It is, further,

ORDERED, That CSP's proposed accounting deferrals be approved consistent with this Opinion and Order. It is, further,

ORDERED, That CSP's Power Acquisition Rider, to recover the incremental fuel costs of providing service to the former Mon Power customers, is approved, effective January 1, 2006. It is, further,

ORDERED, That CSP's six requests for temporary waivers are granted consistent with this Opinion and Order, effective January 1, 2006. It is, further,

ORDERED, That the companies perform an audit to ensure that the regulatory assets being transferred to CSP are related to transmission and distribution assets only. It is, further,

ORDERED, That CSP submit, within 30 days after the transfer of the service territory, two copies of a revised certified service territory boundary map to our Docketing Division to be placed in the Commission's map files. It is, further,

ORDERED, That Case Nos. 04-1047-EL-ATA, 04-1482-EL-CSS, 03-993-EL-UNC, and 03-2567-EL-ATA are dismissed and closed of record. It is, further,

ORDERED, That any party who files an application for rehearing serve its application for rehearing on all other parties to this proceeding by e-mail by 3:00 p.m., on the day the application is filed with the Commission. Any memorandum contra shall be filed no later than 5 days after the filing of an application for rehearing. It is, further, ORDERED, That a copy of this entry be served upon Mon Power, CSP, and all interested parties of record in this proceeding and all parties of record in Case No. 04-169-EL-UNC, and that a copy of this entry be docketed in the above case dockets that are being closed of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

RRG/JKS:ct

Entered in the Journal

NOV 09 2005

Reneé J. Jenkins
Secretary

Abbreviations & Acronyms

AEP	American Electric Power Company, Inc.
AFUDC	Allowance for funds used during construction
APA	Asset purchase agreement
C&I customers	Large commercial, industrial, and street lighting customers
CPB	Competitive bidding process under Section 4928.14, Revised Code
CSP	Columbus Southern Power Company
EDU	Electric distribution utility
ETP	Electric transition plan
FAS	Financial Accounting Standards
FASB	Financial Accounting Standards Board
FAS 109	Financial Accounting Standards Board – Statement No. 109 "Accounting for Income Taxes" (Issued 2/92)
FERC	Federal Energy Regulatory Commission
IEU-Ohio	Industrial Energy Users of Ohio
Joint Report	The August 9, 2005 Joint Report filed by CSP and Mon Power
kWh	Kilowatt-hour
LTFR	Long-term forecast report
MBSSO	Market-based standard service offer
MDP	Market development period
MW	Megawatt – one million watts
MWh	Megawatt-hour – One thousand kilo-watt hours or one million watt-hours
Mon Power	Monongahela Power Company
OCC	Office of the Ohio Consumers' Counsel

ODOD	Ohio Department of Development
OEG	Ohio Energy Group
OHA	Ohio Hospital Association
OPAE	Ohio Partners for Affordable Energy
PIPP	Percentage of income payment plan
PPA	Power purchase agreement (another term for a power sales agreement)
PSA	Power sales agreement
PUHCA	Public Utility Holding Company Act of 1935
RFP	Request for proposal
RSP	Rate stabilization plan
ROE	Return on equity
USF	Universal Service Fund
Staff	The Commission's Staff

S.B. 3 Amended Substitute Senate Bill 3 of the 123rd General Assembly that enacted the Ohio electric restructuring legislation, or the "Ohio Restructuring Act."

T&D	Transmission and distribution
"the Companies"	Columbus Southern Power and Monongahela Power
USOA	Uniform System of Accounts

Footnote

7

CASE NUMBER:	09-0119-EL-AEC
CASE DESCRIPTION:	ORMET PRIMARY ALUMINUM CORPORATION
DOCUMENT SIGNED ON:	5/25/2012
DATE OF SERVICE:	______________________________

04/06/2012 Notice of withdrawal of counsel and substitution of counsel, Mark Yurick from the law firm of Taft Stettinius & Hollister LLP, formerly Chester, Wilcox & Saxbe, LLP filed by M. Yurick.

12/22/2011 Supreme Court Document The following decision, announcement or notice of action by the Supreme Court of Ohio with respect to this case is provided solely for the information and convenience of the reader, and should not be construed as a part of the record of this case before the Public Utilities Commission of Ohio, and may be subject to formal revision before it is published in the Ohio Official Reports. The Court's opinions from 1992 to the present are available online from the Reporter of Decisions at http://www.sconet.state.oh.us/ROD/ - Slip Opinion (Mar. 22, 2011) [Cite as In re Application of Ormet Primary Aluminum Corp., 129 Ohio St.3d 9, 2011-Ohio-2377.] electronically filed by Kimberly L Keeton on behalf of Public Utilities Commission of Ohio

10/03/2011 Revised Schedule "A" for 2012, filed by E. Hand on behalf of Ormet Primary Aluminum Corporation.

09/30/2011 Revised Schedule "A" for 2012, filed by E. Hand on behalf of Ormet Primary Aluminum Corporation. (FAX)

01/26/2011 Withdrawal of Matthew S. White from proceedings filed by J. Bentine on behalf of the Chester, Willcox and Saxbe Law Firm.

11/16/2010 Notice of withdrawal of counsel, Joseph M. Clark in these proceedings filed by McNees Wallace & Nurick LLC by J. Oliker.

10/06/2010 Notice of withdrawal of counsel, L. McAlister, filed on behalf of McNees Wallace & Nurick LLC by J. Clark.

09/30/2010 Revised Schedule "B" for 2011, filed by E. Hand on behalf of Ormet Primary Aluminum Corporation.

09/29/2010 Revised schedule "B" filed by E. Hand on behalf of Ormet Primary Aluminum Corporation. (FAX)

12/24/2009 Reply of Ormet Primary Aluminum Corporation to comments of Ohio Consumers' Counsel filed by E. Hand.

12/23/2009 Reply of Ormet Primary Aluminum Corporation to comments of Ohio Consumers' Counsel, filed by E. Hand. (Fax)

12/17/2009 Correspondence letter addressing concerns related to the revised and executed Power Agreement, dated September 19, 2009, between Ormet Primary Aluminum Corporation and Ohio Power Company and Columbus Southern Power Company filed by G. Poulos on behalf of the Office of the Ohio Consumers' Counsel.

12/14/2009 Service Notice

12/14/2009 Supreme Court Transmittal papers for SC # 09-2060.

11/12/2009 Notice of appeal of Columbus Southern Power Company and Ohio Power Company filed by S. Nourse. (S.C. # 09-2060)

10/30/2009 Letter questioning the PUCO's authority to help corporations like Ormet, filed by F Arnett, consumer.

10/01/2009 Revised Schedule A for 2010 filed by E. Hand on behalf of Ormet Primary Aluminum Corporation, Columbus Southern Power Company and Ohio Power Company (collectively "AEP Ohio")

09/30/2009 Revised Schedule A for 2010 filed by E. Hand on behalf of Ormet Primary Aluminum Corporation, Columbus Southern Power Company and Ohio Power Company (collectively "AEP Ohio"). (FAX)

09/18/2009 Revised and executed power agreement between Ormet Primary Aluminum Corporation ("Ormet") and Ohio Power Company and Columbus Southern Power Company (collectively "AEP Ohio") filed by E. Hand. on behalf of "Ormet".

09/15/2009 Service Notice

09/15/2009 Entry on rehearing denying the application for rehearing filed by IEU-Ohio and granting the applications for rehearing filed by OCC, OEG and AEP-Ohio.

09/09/2009 Service Notice.

09/09/2009 Entry ordering that the application for rehearing filed by Industry Energy Users-Ohio, the Office of the Ohio Consumers' Counsel and the Ohio Energy Group and AEP-Ohio be granted.

08/24/2009 Memorandum contra Columbus Southern Power Company's and Ohio Power Company's application for rehearing filed by L. McAlister on behalf of Industrial Energy Users-Ohio.

08/24/2009 Columbus Southern Power Company's and Ohio Power Company's memorandum contra application for rehearing filed jointly by Ohio Consumers' Counsel and Ohio Energy Group by S. Nourse.

08/24/2009 Memorandum contra to the applications for rehearing of AEP Ohio and IEU filed by D. Barnowski on behalf of Ormet Primary Aluminum Corporation.

08/24/2009 Memorandum contra AEP-Ohio's application for rehearing by the Office of the Ohio Consumers' Counsel and the Ohio Energy Group filed by G. Poulos on behalf of the Office of the Ohio Consumers' Counsel and M. Kurtz on behalf of The Ohio Energy Group.

08/14/2009 Application for rehearing and memorandum in support of Industrial Energy Users-Ohio filed by L. McAlister.

08/14/2009 Application for rehearing and memorandum in support filed by G. Poulos on behalf of OCC and by M. Kurtz on behalf of The Ohio Energy Group.

08/14/2009 Application for rehearing and memorandum in support filed by S. Nourse on behalf of Columbus Southern Power Company and Ohio Power Company.

07/23/2009 Letter opposing the possibility that the community may subsidize the purchase of power for Ormet Corporation in Hannibal, Ohio, filed by S. Wolboldt, consumer.

07/15/2009 Service Notice.

07/15/2009 Opinion and order stating that the amended application for a unique arrangement filed by Ormet be approved as modified by the Commission; that Ormet and AEP-Ohio file an executed power agreement in this docket that conforms to the modifications ordered by the Commission; that the approved unique arrangement shall be effective for services rendered following the filing in this docket of an executed power agreement; that AEP-Ohio be authorized to defer delta revenues for the remainder of the calendar year 2009 and for calendar years 2010 and 2011, to the extent set forth in this opinion and order.

07/01/2009 Post hearing brief by the Office of the Ohio Consumers' Counsel by G. Poulos and the Ohio Energy Group by M. Kurtz.

07/01/2009 Post hearing brief of Industrial Energy Users-Ohio by L. McAlister.

07/01/2009 Post hearing brief of the Kroger Company by M. White.

07/01/2009 Columbus Southern Power Company's and Ohio Power Company's post hearing brief filed by S. Nourse.

07/01/2009 Brief filed by PUCO Staff.

07/01/2009 Transcript, Vol. 4, for hearing held on Wednesday, June 17, 2009 before Rebecca Hussey and Gregory Price, Attorney Examiners, electronically filed by Mrs. Jennifer Duffer on behalf of Armstrong & Okey, Inc. and Anderson, Rosemary Foster Mrs.

07/01/2009 Post hearing brief of Ormet Primary Aluminum Corporation filed by E. Hand.

06/26/2009 Exhibits for transcript electronically filed on 6/26/09 for hearing held on June 11, 2009 before R. Hussey and G. Price, Attorney Examiners.

06/26/2009 Confidential document target for transcript filed by Armstrong and Okey on behalf of Ormet Aluminum Corporation, Ohio Power Company and Columbus Southern Power Company. (39 pages)

06/25/2009 Transcript for Ohio Power hearing held 6/11/09, Vol. 3, electronically filed by Mrs. Jennifer Duffer on behalf of Armstrong & Okey, Inc. and Anderson, Rosemary Foster Mrs.

06/15/2009 Rebuttal testimony of Robert B. Fortney, Rates and Tariffs Division, PUCO.

06/03/2009 Service Notice

06/03/2009 Errata for motion for protective order filed by D. Barnowski on behalf of Ormet Primary Aluminum Corporation. (original)

06/03/2009 Entry ordered that the evidentiary hearing in this proceeding resume on June 11, 2009, at 10:00 a.m., at the offices of the Commission, Hearing Room 11-C, 180 E. Broad Street Columbus, Ohio 43215. (GAP)

06/02/2009 Errata for motion for protective order filed by D. Barnowski on behalf Ormet Primary Aluminum Corporation.

06/01/2009 Supplemental direct testimony of James Burns Riley on behalf of Ormet Primary Aluminum Corporation filed by E. Hand. (reacted version)

06/01/2009 Motion for protective order and memorandum in support filed by E. Hand on behalf of Ormet Primary Aluminum Corporation.

06/01/2009 Confidential document: Testimony-James Burns Riley filed b E. Hand on behalf of Ormet Primary Aluminum Corp. (12 pgs)

06/01/2009 Letter thanking the Commission for granting a continuance of the hearing in this proceeding on May 1, 2009, filed by E. Hand on behalf of Ormet Primary Aluminum Corporation.

05/18/2009 Exhibits for transcript electronically filed on May 18, 2009 for hearing held May 1, 2009 before Attorney Examiner G. Price.

05/18/2009 Letter providing a status report concerning anticipated timing for the filing of further Ormet direct testimony supporting Ormet's requested 2009 rate under the proposed Unique Arrangement filed on behalf of Ormet Primary Aluminum Corporation by D. Bonner.

05/18/2009 Transcript- Volume II for hearing held May 1, 2009 before Attorney Examiner G. Price electronically filed by Mrs. Jennifer Duffer on behalf of Armstrong & Okey, Inc. and Jones, Maria DiPaolo Mrs.

05/15/2009 Status Report concerning anticipated timing for the filing of further Ormet direct testimony supporting Ormets requested 2009 rate under the proposed unique arrangement filed on behalf of Ormet Primary Aluminum Corporation by D. Bonner. (FAX)

05/14/2009 Transcript for hearing held 4/30/2009 before Attomey Examiner G. Price electronically filed by Mrs. Jennifer Duffer on behalf of Armstrong & Okey, Inc. and Jones, Maria DiPaolo.

05/14/2009 Exhibits for transcript electronically filed on 5/14/09 for hearing held on 4/30/09 before Attorney Examiner G. Price.

05/06/2009 Notice to take deposition upon oral examination and request for production of documents filed by M. Grady on behalf of OCC.

04/30/2009 Motion of Ormet Primary Aluminum Corporation to commence hearing scheduled for April 30, 2009, at 9:00 a.m. filed by D. Bonner. (original)

04/29/2009 Prepared testimony of Robert B. Fortney filed by PUCO Staff.

04/29/2009 Motion for admission pro hac vice of Daniel D. Barnowski filed by S. Richardson.

04/29/2009 Objections of Ohio Energy Group filed by M. Kurtz.

04/28/2009 Objection of Ohio Energy Group filed by M. Kurtz. (FAX)

04/28/2009 Comments of The Kroger Company filed by J. Bentine.

04/28/2009 Motion to intervene and memorandum in support filed by J. Clark on behalf of Industrial Energy Users-Ohio.

04/28/2009 Comments filed by G. Poulos on behalf of OCC.

04/27/2009 Motion of Ormet Primary Aluminum Corporation to commence hearing at 9:00 a.m. on April 30, 2009 filed by D. Bonner. (FAX)

04/27/2009 Direct testimony of Amr A. Ibrahim filed by G. Poulos on behalf of OCC.

04/24/2009 Entry ordering the motion filed by OCC and OEG be granted; intervenor testimony in this proceeding must be filed no later than 12:00 p.m., on April 27, 2009. (GP)

04/24/2009 Motion and memorandum in support for extension of time to establish a staggered schedule for the filing of direct testimony and request for an expedited ruling filed by G. Poulos on behalf of The Office of the Ohio Consumers' Counsel and M. Kurtz on behalf of The Ohio Energy Group.

04/24/2009 Motion for subpoena duces tecum and memorandum in support filed by G. Poulos on behalf of the Office of the Ohio Consumers' Counsel.

04/24/2009 Service notice.

04/24/2009 Motion for subpoena duces tecum and memorandum in support filed by G. Poulos on behalf of the Ohio Consumers' Counsel.

04/23/2009 Notice to take depositions upon oral examination and request for production of documents filed by G. Poulos on behalf of the Office of the Ohio Consumers' Counsel.

04/23/2009 Direct testimony of Michael F. Tanchuk, filed by E. Hand on behalf of Ormet Primary Aluminum Corporation.

04/17/2009 Service notice.

04/17/2009 Entry ordering the motions to intervene of AEP, Ohio Energy Group, The Kroger Company, Industrial Energy Users-Ohio, and the OCC are granted; motions for admission pro hac vice to permit Douglas Bonner, Clinton Vince, William Booth and Emma Hand to practice before the Commission are granted; interested intervenors shall file a motion to intervene and set forth comments and objections by April 28, 2009; that a hearing be held April 30, 2009, at 10:00 a.m., at the offices of the Commission, 180 E. Broad Street, Columbus, Ohio 43215-3793. (RG)

04/10/2009 Amended application of Ormet Primary Aluminum Corporation for approval of a unique arrangement with Ohio Power Company and Columbus Southern Power Company filed by E. Hand.

04/07/2009 Motion for admission pro hac vice of Douglas G. Bonner filed by S. Richardson on behalf of Ormet Primary Aluminum Corporation.

03/23/2009 Memorandum contra filed on behalf of Ormet Primary Aluminum Corporation by E. Hand.

03/20/2009 Memorandum contra filed on behalf of Ormet Primary Aluminum Corporation by E. Hand. (FAX)

03/20/2009 Memorandum contra Ohio Consumers' Counsel's motion to shorten discovery response time filed on behalf of Columbus Southern Power Company and Ohio Power Company by M. Resnik.

03/19/2009 Memorandum contra filed on behalf of Ormet Primary Aluminum Corporation by E. Hand. (Original)

03/18/2009 Memorandum contra filed on behalf of Ormet Primary Aluminum Corporation by E. Hand. (FAX)

03/13/2009 Motion to intervene and motion to shorten the discovery response time, request for expedited ruling on motion to shorten the discovery response time and memorandum in support, filed by G. Poulos on behalf of OCC.

03/13/2009 Motion for intervention and memorandum in support filed by M. White on behalf of The Kroger Co.

03/09/2009 Comments filed on behalf of Industrial Energy Users-Ohio by L. McAlister.

03/04/2009 Motion to intervene and memorandum in support filed on behalf of Ohio Energy Group by M. Kurtz.

03/03/2009 Motion to intervene and memorandum in support filed on behalf of Ohio Energy Group by M. Kurtz. (FAX)

02/27/2009 Motion of Columbus Southern Power Company and Ohio Power Company to intervene filed by S. Nourse.

02/17/2009 Motion for admission pro hac vice of Clinton A. Vince, William D. Booth and Emma F. Hand filed by S. Richardson on behalf of Ormond Primary Aluminum Corporation.

02/17/2009 In the matter of the application of Ormet Primary Aluminum Corporation for approval of a unique arrangement with Ohio Power Company and Columbus Southern Power Company.

CASE NUMBER:	09-0516-EL-AEC
CASE DESCRIPTION:	ERAMET MARIETTA INC AND COLUMBUS SOUTHERN POWER COMPANY
DOCUMENT SIGNED ON:	5/25/2012
DATE OF SERVICE:	______________________

12/22/2011 Supreme Court Document The following decision, announcement or notice of action by the Supreme Court of Ohio with respect to this case is provided solely for the information and convenience of the reader, and should not be construed as a part of the record of this case before the Public Utilities Commission of Ohio, and may be subject to formal revision before it is published in the Ohio Official Reports. The Court's opinions from 1992 to the present are available online from the Reporter of Decisions at http://www.sconet.state.oh.us/ROD/ - Slip Opinion (Mar. 22, 2011) [Cite as In re Application of Ormet Primary Aluminum Corp., 129 Ohio St.3d 9, 2011-Ohio-2377.] electronically filed by Kimberly L Keeton on behalf of Public Utilities Commission of Ohio

03/04/2011 Service Notice

03/03/2011 Entry ordering that the motion for protective order filed by Eramet be denied, in accordance with Finding (16); that on March 10, 2011, the reasonable arrangement reports be released to OCC, in accordance with finding (17). (HPG)

11/16/2010 Notice of withdrawal of counsel, Joseph M. Clark in these proceedings filed by McNees Wallace & Nurick LLC by J. Oliker.

10/08/2010 Notice of the withdrawal of Lisa G. McAlister and the substitution of Samuel C. Randazzo as counsel for Eramet Marietta, Inc. filed by S. Randazzo.

10/06/2010 Notice of withdrawal of counsel, L. McAlister, filed on behalf of McNees Wallace & Nurick LLC by J. Clark.

09/09/2010 Notice of withdrawal of counsel for Eramet Marietta, Inc. filed by L. McAlister.

08/13/2010 Reply to OCC's memorandum contra motion for protective order filed by L McAlister on behalf of Eramet Marietta Inc.

08/09/2010 Memorandum contra Eramet Marietta, Inc.'s motion for protective order by the Ohio Consumers' Counsel filed by M. Grady.

07/22/2010 Motion of Eramet Marietta Inc. for protective order and memorandum in support filed by L. McAlister.

05/26/2010 Service Notice

05/26/2010 Supreme Court Transmittal papers for SC# 10-723.

04/26/2010 Notice of appeal of the Columbus Southern Power Company filed by S.. Nourse. (Supreme Court #10-0723)

03/24/2010 Service Notice

03/24/2010 Entry ordering that the application for rehearing filed by Eramet be granted, that the application for rehearing filed by CSP be denied, and that the application for rehearing filed by OCC and OEG be granted, in part, and denied, in part.

02/12/2010 Letter stating that Eramet Marietta, Inc. has complied with the Commission's direction to the best of their ability and requests the Commission approve their application to commit their capabilities to Columbus Southern Power filed by L. McAlister on behalf of Eramet Marietta, Inc.

12/11/2009 Service Notice.

12/11/2009 Entry on rehearing ordering that the applications for rehearing filed by Columbus Southern Power Company, Ohio Consumers' Counsel, the Ohio Energy Group, and Eramet be granted.

11/25/2009 Columbus Southern Power Company's memorandum contra application for rehearing filed jointly by Ohio Consumers' Counsel and Ohio Energy Group filed by M. Resnik.

11/25/2009 Columbus Southern Power Company's memorandum contra application for rehearing filed by Eramet Marietta, Inc. by S. Nourse.

11/23/2009 Memorandum contra Columbus Southern Power Company's application for rehearing by the Office of the Ohio Consumers' Counsel and the Ohio Energy Group filed by M. Grady on behalf of the Office of the Ohio Consumers' Counsel and D. Boehm on behalf of The Ohio Energy Group.

11/23/2009 Memorandum contra application for rehearing of Columbus Southern Power Company, the Ohio Consumers' Counsel, and the Ohio Energy Group filed by L. McAlister on behalf of Eramet Marietta, Inc.

11/16/2009 Application for rehearing by the Office of the Ohio Consumers' Counsel by M. Grady and the Ohio Energy Group by D. Boehm.

11/16/2009 Application for rehearing and memorandum in support of Eramet Marietta, Inc. filed by L. McAlister.

11/13/2009 Application for rehearing filed on behalf of Columbus Southern Power Company by M. Resnik.

10/28/2009 Final executed contract for services rendered on and after October 28, 2009 filed by L. McAlister on behalf of Eramet Marietta, Inc.

10/15/2009 Service notice.

10/15/2009 Opinion and order ordering the joint stipulation and recommendation be approved as modified by the Commission.

09/08/2009 Columbus Southern Power Company's reply brief filed by M. Resnik.

09/08/2009 Reply brief of the Staff submitted on behalf of the Staff of The Public Utilities Commission of Ohio.

09/08/2009 Reply brief by the Office of the Ohio Consumers' Counsel and The Ohio Energy Group filed by M. Grady on behalf of the Office of the Ohio Consumers' Counsel and D. Boehm on behalf of The Ohio Energy Group.

09/08/2009 Reply brief of Eramet Marietta, Inc. filed by L. McAlister.

08/28/2009 Transcript for hearing held on August 14, 2009 before Attorney Examiners G. Price and R. Hussey in Columbus, OH - Eramet Volume IV electronically filed by Mrs. Jennifer Duffer on behalf of Armstrong & Okey, Inc. and Jones, Maria DiPaolo Mrs.

08/24/2009 Motion for protective order and memorandum in support of Eramet Marietta, Inc. filed by L. McAlister.

08/24/2009 Post-hearing brief of Eramet Marietta, Inc., redacted version, filed by L. McAlister.

08/24/2009 Post-hearing brief by the Office of the Ohio Consumers' Counsel and the Ohio Energy Group filed by M. Grady on behalf of the Office of the Ohio Consumers' Counsel and D. Boehm on behalf of the Ohio Energy Group.

08/24/2009 Post-hearing brief filed by M. Resnik on behalf of Columbus Southern Power Company.

08/24/2009 Initial brief on behalf of the Staff of The Public Utilities Commission of Ohio filed by T. McNamee.

08/24/2009 Composite index for transcript for hearings held on August 4, 5 and 10, 2009 before Attorney Examiner's G. Price and R. Hussey in Columbus, Ohio filed by Armstrong & Okey, Inc.

08/24/2009 Confidential document: Excerpt from transcript filed by Armstrong & Okey, Inc. on behalf of Eramet Marietta, Inc and Columbus Southern Power Company. (10 PAGES)

08/24/2009 OCC Exhibits 1 and 2 of transcript electronically filed on August 24, 2009. (Part 1 of 2)

08/24/2009 OCC Exhibits 1 and 2 of transcript electronically filed on August 24, 2009. (Part 2 of 2)

08/24/2009 Composite Index for transcript for hearings held on August 4, 5, & 10, 2009 before Attorney Examiners G. Price and R. Hussey in Columbus, OH electronically filed by Mrs. Jennifer Duffer on behalf of Armstrong & Okey, Inc. and Jones, Maria DiPaolo Mrs.

08/24/2009 Transcript for hearing held on August 10, 2009 before Attorney Examiner's G. Price and R. Hussey in Columbus, OH - Volume III electronically filed by Mrs. Jennifer Duffer on behalf of Armstrong & Okey, Inc. and Jones, Maria DiPaolo Mrs.

08/24/2009 Confidential document: Post-hearing brief of Eramet Marietta, Inc. filed by L. McAlister on behalf of Eramet Marietta, Inc. (24 PAGES)

08/19/2009 Confidential document: OCC exhibits 6, 7, 8, 9-A and Joint Stipulation filed by Maria DiPaolo-Jones on behalf of Armstrong & Okey. (56 PAGES)

08/19/2009 Transcript, Volume II, for hearing held August 5, 2009 before AE's G. Price and R. Hussey, electronically filed by Mrs. Jennifer Duffer on behalf of Armstrong & Okey, Inc. and Jones, Maria DiPaolo Mrs.

08/18/2009 Confidential document: OCC Exhibits 4 and 5 of transcript for hearing held 8/4/2009 filed by Maria DiPaols Jones , Armstrong & Okey. (116 PAGES)

08/18/2009 Transcript, Volume 1, for hearing held August 4, 2009 before AE's G. Price and R. Hussey, electronically filed by Mrs. Jennifer Duffer on behalf of Armstrong & Okey, Inc. and Jones, Maria DiPaolo Mrs.

08/14/2009 Correspondence stating to look favorably upon Eramet's application and act quickly to secure reasonable power rates for the company filed by D. Caldwell. (FAX)

08/12/2009 Rebuttal testimony of AMR A. Ibrahim filed by M Grady on behalf of OCC.

08/11/2009 Correspondence approving the proposal of Eramet Marietta, Inc. filed by K. Brown.

08/11/2009 Correspondence asking to take under consideration the impact and ramification of the increase in power rates of Ohio River Valley filed by S. Cook, president on behalf of Washington County Commissioners.

08/07/2009 Motion in Limine and memorandum in support of Eramet Marietta, Inc. filed by L. McAlister.

08/06/2009 Supplemental prepared testimony of Robert B. Fortney filed by T. McNamee on behalf of the Public Utilities Commission of Ohio.

08/05/2009 Joint stipulation and recommendation filed by L. McAlister on behalf of the Ohio Energy Group and T. McNamee on behalf the staff of the Public Utilities Commission.

08/05/2009 Correspondence letter concerning the current electricity rate plan for AEP, filed by M. Jacoby, consumer.

08/04/2009 Correspondence regarding an attachment that was inadvertently omitted from the direct testimony of John A. Willoughby filed by L. McAlister on behalf of Eramet Marietta Inc.

08/03/2009 Correspondence in support of proposal filed by K. Brown, consumer.

08/03/2009 Correspondence letter regarding rate arrangement filed by M. Jacoby on behalf of the Southeastern Ohio Port Authority.

07/31/2009 Direct testimony and exhibits of J. Craig Baker on behalf of American Electric Power Service Corporation filed by M. Resnik.

07/31/2009 Prepared testimony of Robert B. Fortney on behalf of the Public Utilities Commission of Ohio filed by T. McNamee.

07/31/2009 Direct testimony and exhibits of Amr A. Ibrahim on behalf of the Office of the Ohio Consumers' Counsel filed by M. Grady.

07/29/2009 Motion for protective order and memorandum in support of Eramet Marietta, Inc. filed by L. McAlister.

07/29/2009 Redacted direct testimony of Robert L. Flygar filed by L. McAlister on behalf of Eramet Marietta, Inc.

07/29/2009 Confidential document target for Direct testimony of Robert Flygar and Frank Bjorklund filed on behalf of Eramet Marietta, Inc. by L. McAlister.

07/29/2009 Direct testimony of John A. Willoughby filed on behalf of Eramet Marietta, Inc. filed by L. McAlister.

07/29/2009 Redacted direct testimony of Frank Bjorklund filed on behalf of Eramet Marietta, Inc.filed by L. McAlister.

07/24/2009 Notice to take depositions upon oral examination and request for production of documents, filed by G. Poulos on behalf of the Office of the Ohio Consumers' Counsel.

07/24/2009 Notice to take depositions upon oral examination and request for production of documents, filed by G. Poulos on behalf of the Office of the Ohio Consumers' Counsel.

07/24/2009 Notice of the addition of counsel by the Office of the Ohio Consumers' Counsel, filed by M. Grady.

07/23/2009 Service Notice.

07/23/2009 Entry ordering that the revised procedural schedule set forth in finding (3) be adopted; that the motion for admission pro hac vice of Gregory Timmons be granted. (RH)

07/22/2009 Motion to modify the procedural schedule and for an expedited ruling and memorandum in support filed by L. McAlister on behalf of Eramet Marietta, Inc.

07/20/2009 Motion for admission pro hac vice of Gregory Timmons, memorandum in support filed by L. McAlister on behalf of Eramet Marietta, Inc.

07/16/2009 Entry granting the motions to intervene by CSP, OEG, and OCC; it is further ordered that this matter be set for a prehearing conference on July 31, 2009 at 10 a.m. at the office of the Commission, and that the hearing should commence on August 6, 2009 at 10 a.m. at the offices of the Commission, 180 East Broad Street, 11th floor, hearing room 11-F, Columbus, OH 43215. (RH)

07/16/2009 Service Notice.

07/15/2009 Letter stating that OEG adopts its memorandum in support of its motion to intervene as its comments and objections in this case filed by D. Boehm on behalf of the Ohio Energy Group.

07/13/2009 Letter stating that OEG adopts its memorandum in support of its motion to intervene as its comments and objections in this case filed by D. Boehm on behalf of the Ohio Energy Group. (Fax)

07/09/2009 Comments of the Ohio Consumers' Counsel filed by G. Poulos.

07/02/2009 Service Notice

07/02/2009 Entry ordering that OCC's motion to shorten the discovery response time is denied, as set forth in finding (4); that discovery and replies of parties shall be served by hand delivery, email, or telefax, in accordance with finding (5); and that That any other interested party wishing to intervene in this matter shall file a motion to intervene and set forth any comments and objections to the application by July 9,2009, as detailed in paragraph (6).

07/01/2009	Memorandum contra Ohio Consumers' Counsel's motion to shorten discovery response time filed on behalf of Columbus Southern Power filed by S. Nourse.
07/01/2009	Motion to intervene and comments filed on behalf of Columbus Southern Power Company filed by S. Nourse.
06/30/2009	Motion to intervene and memorandum in support filed by D. Boehm on behalf of The Ohio Energy Group.
06/29/2009	Memorandum contra OCC's motion to shorten the discovery response time of Eramet Marietta Inc. filed by T. Froehle.
06/26/2009	Motion to intervene, motion to shorten the discovery response time, and request for expedited ruling on motion to shorten the discovery response time, memorandum in support filed by G. Poulos on behalf of Ohio Consumers' Counsel.
06/19/2009	In the matter of the application for establishment of a reasonable arrangement between Eramet Marietta Inc. and Columbus Southern Power Company.

Footnotes

8 & 11

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals.	)	Case No. 10-2376-EL-UNC
In the Matter of the Application of Columbus Southern Power Company 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 Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.	)	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Amend their Emergency Curtailment Service Riders.	)	Case No. 10-343-EL-ATA Case No. 10-344-EL-ATA
In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company.	)	Case No. 10-2929-EL-UNC
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Mechanisms to Recover Deferred Fuel Costs Ordered Under Section 4928.144, Revised Code.	)	Case No. 11-4920-EL-RDR Case No. 11-4921-EL-RDR

ENTRY

The Commission finds:

(1) On January 27, 2011, in Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM and 11-350-EL-AAM, 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 (ESP 2).

(2) On September 7, 2011, a Stipulation and Recommendation (Stipulation) was filed for the purpose of resolving all the issues raised in the ESP 2 cases and several other AEP-Ohio cases pending before the Commission, Case No. 10-2376-EL-UNC, *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals* (Merger Case); Case No. 10-343-EL-ATA, *In the Matter of the Application of Columbus Southern Power Company to Amend its Emergency Curtailment Service Riders* and Case No. 10-344-EL-ATA, *In the Matter of the Application of Ohio Power Company to Amend its Emergency Curtailment Service Riders* (jointly Curtailment Cases); Case No. 10-2929-EL-UNC, *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company* (Capacity Charges Case); and Case No. 11-4920-EL-RDR, *In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144, Revised Code*, and Case No. 11-4921-EL-RDR, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144, Revised Code* (jointly Deferred Fuel Cost Cases).

(3) On December 14, 2011, the Commission issued its Opinion and Order in the consolidated cases, finding that the Stipulation, as modified, be adopted and approved.

(4) However, on February 23, 2012, the Commission issued its Entry on Rehearing determining that the Stipulation, as a package, did not benefit ratepayers and the public interest and, thus, did not satisfy the three-part test for the consideration of stipulations. The Commission directed AEP-Ohio to file new proposed tariffs to continue the provisions, terms, and conditions of its previous electric security plan no later than February 28, 2012.

(5) On February 28, 2012, AEP-Ohio submitted its proposed compliance tariffs containing the provisions, terms, and conditions of its previous electric security plan, as approved in Case No. 08-917-EL-SSO (ESP 1) et al. *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.* AEP-Ohio further explains that the implementation of the phase-in recovery rider (PIRR), as approved in ESP 1, was recalculated on its January and February collections and carrying costs for those two months based on the long term debt rate. Therefore, AEP-Ohio states that the new PIRR rates are designed to collect the revised balance over the remaining 82 months of the amortization period.

(6) On March 2, 2012, Industrial Energy Users-Ohio (IEU-Ohio) filed objections to AEP-Ohio's compliance tariffs. In its objections, IEU-Ohio asserts that AEP-Ohio's compliance tariffs contain a blended fuel adjustment clause (FAC) transmission cost recovery rider (TCRR) for both Ohio Power Company and Columbus Southern Power Company instead of individual provisions, improperly included the PIRR in its compliance tariffs, and failed to file an appropriate application of its capacity charges. IEU-Ohio also maintains that AEP-Ohio incorrectly omitted key terms and conditions of service.

(7) On March 5, 2012, Ormet filed an objection to AEP-Ohio's compliance tariffs. Ormet contends that the inclusion of the PIRR in the compliance tariffs is improper and unauthorized.

(8) On March 5, 2012, AEP-Ohio filed a Notice of Intent that it intends to submit a modified ESP pursuant to Section 4928.143, Revised Code, by March 30, 2012.

(9) On March 6, 2012, the Ohio Consumers' Counsel and the Appalachian Peace and Justice Network (collectively OCC/APJN) filed a motion to reject portions of AEP-Ohio's compliance filing that implement the PIRR. In the alternative, OCC/APJN request that the Commission issue an order to stay the collection of the PIRR rates or order the PIRR rates be collected subject to refund.

(10) Also on March 6, 2012, FirstEnergy Solutions (FES) filed objections to AEP-Ohio's proposed tariffs. FES opines that no recovery mechanism for the PIRR has been authorized, and AEP-Ohio failed to include a TCRR rate for its IRP-D customers.

(11) AEP-Ohio filed revised tariffs on March 6, 2012, that reinserted terms and conditions that were omitted from the proposed tariffs filed on February 28, 2012. Also on March 6, 2012, AEP-Ohio filed a reply to objections filed by IEU-Ohio, Ormet, and OCC/APJN. AEP-Ohio asserts that the Commission already merged the FAC in a separate docket in Case No. 11-5906-EL-FAC (11-5906), and it would be impractical and unnecessary to revise not only the FAC provisions, but also the TCRR implementation. AEP-Ohio argues the inclusion of the PIRR was appropriate, and the capacity charges are appropriate as they do not relate to the implementation of the prior retail rate plan. Further, AEP-Ohio urges the Commission to reject OCC's requests to stay the prior rate plan or make the rates subject to refund.

(12) The Commission finds that, with the exception of the tariffs for the PIRR, FAC, and TCRR, the tariffs filed by AEP-Ohio are consistent with its February 23, 2012, Entry on Rehearing, do not appear to be unjust or unreasonable, and should be approved, effective March 9, 2012.

(13) Regarding the FAC and TCRR, the Commission finds that, pursuant to AEP-Ohio's application in the Merger Case, the approval of the merger will not affect CSP and OP's rates. Specifically, the application provides that CSP and OP shall continue service to customers within the pre-merger certified territories in accordance with their respective rates and terms and conditions in effect until such time as the Commission approves new rates and terms and conditions. While AEP-Ohio is correct that its FAC rates were approved in 11-5906, the rates were approved in light of the Commission's approval of the Stipulation in the ESP 2 proceedings, which was subsequently disapproved on February 23, 2012. Accordingly, OP shall file final unblended TCRR and FAC rates to be effective March 7, 2012, subject to subsequent Commission review. Further, FES correctly points out that AEP-Ohio failed

to include a TCRR rate for its IRP-D customers. Therefore, we direct AEP-Ohio to amend Original Sheet No. 475-1 to make it consistent with ESP 1's terms and conditions.

(14) With respect to the PIRR, AEP-Ohio is directed to file, in final form, new tariffs removing the PIRR at this time. The Commission will address AEP-Ohio's application to establish the PIRR by subsequent entry in the Deferred Fuel Cost Cases.

(15) Further, as AEP-Ohio filed corrections to its compliance filing on March 6, 2012, we do not need to address IEU-Ohio's objection that AEP-Ohio incorrectly omitted key terms and conditions of service.

(16) In addition, as the captioned cases were consolidated by the Stipulation which the Commission disapproved, all future filings should be made in the appropriate case docket, as the consolidated case matters will no longer be docketed in all of the above-captioned cases.

(17) Finally, the Commission notes that, on March 5, 2012, AEP-Ohio filed its notice of intent to file a modified ESP application. The Commission expects that such modified ESP application will include a thorough discussion of: any plans of AEP-Ohio to divest its generation assets, including provisions to ensure that adequate capacity will be available on an on-going basis to Ohio customers, notwithstanding any potential plant retirements; provisions to address rate design concerns for small commercial customers and residential customers in the former CSP service territory using more than 800 kWh in winter months; provisions regarding plans to take advantage of a territory-wide deployment of emerging metering technology to provide ample choices regarding pricing, information, and electric energy services for customers in a competitive market, including provisions that AEP-Ohio does not foreclose the possibility of working collaboratively with other utilities, retail energy suppliers, and interested stakeholders to explore cost saving and market development opportunities; provisions to take advantage of the deployment of emerging distribution system technologies in all locations where they can cost-effectively improve the efficiency of the distribution system or enhance reliability consistent with the value customers place on

service reliability; provisions for reasonable support for the development of technologies that could provide significant economic benefits; provisions ensuring that AEP-Ohio has the ability to meet Ohio's renewable energy standards over the long-term; provisions that any proposed retail stability charge be applied to all customers within AEP-Ohio service territory; provisions addressing the prompt modification or termination of the AEP Interconnection Agreement to reflect State law and policies; or provisions that provide for market-based pricing for standard service offer customers in a manner more expeditious than proposed within AEP-Ohio's Notice of Intent. The Commission further expects that AEP-Ohio will look to recent Commission precedent for guidance in formulating its modified ESP in considering how to best ensure its customers have market-based standard service offer pricing in an efficient and expeditious manner. (See *In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code,* Case No. 11-3549-EL-SSO; *In the Matter of Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code,* Case No. 10-388-EL-SSO.)

It is, therefore,

ORDERED, That, with the exception of the tariffs for the PIRR, TCRR, and FAC, the tariffs filed on February 28, 2012, by AEP-Ohio be approved, effective for bills rendered on or after March 9, 2012. It is, further,

ORDERED, That OP file unblended TCRR and FAC rates to be effective March 9, 2012, subject to Commission review. It is, further,

ORDERED, That OP file tariffs including a TCRR rate for IRP-D customers, consistent with ESP 1's terms and conditions. It is, further,

ORDERED, That AEP-Ohio file new tariffs removing the PIRR at this time. The Commission will address AEP-Ohio's applications in the Deferred Fuel Cost Cases. It is, further, ORDERED, That the Companies file in final form four complete copies of tariffs. One copy shall be filed with this case docket, one shall be filed with each company's TRF docket, and the remaining two copies shall be designated for distribution to the Rates and Tariffs Division of the Commission's Utilities Department. The Companies shall also update their respective tariffs previously filed electronically with the Commission's Docketing Division. It is, further,

ORDERED, That the Companies shall notify their customers of the changes to the tariff via bill message or bill insert within 30 days of the effective date. A copy of this notice shall be submitted to the Commission's Service Monitoring and Enforcement Department prior to its distribution to customers. It is, further,

ORDERED, That a copy of this entry be served on all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Paul A. Centolella

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

JJT/sc

Entered in the Journal

MAR 0 7 2012

Barcy F. McNeal

Barcy F. McNeal
Secretary

Footnote

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AEP
AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

March 23. 2012

The Honorable Greta See
Attorney Examiner
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, Ohio 43215

Re: *Ohio Power Company*, Case No. 10-2929-EL-UNC

Steven T. Nourse
Senior Counsel –
Regulatory Services
(614) 716-1608 (P)
(614) 716-2014 (F)
stnourse@aep.com

Dear Ms. See:

On March 14, 2012, you issued a scheduling entry that, among other things, afforded Ohio Power Company (dba AEP Ohio) an opportunity to update or revise the testimony that was filed on August 31, 2011 in this proceeding. Today, AEP Ohio is filing the enclosed testimony to be sponsored by the following witnesses during the upcoming evidentiary hearing:

Richard E. Munczinksi, AEP
Frank C. Graves, The Brattle Group
Kelly D. Pearce, PhD, AEP
Dana E. Horton, AEP
William A. Allen, AEP

With the exception of Mr. Allen, the four remaining witnesses had previously filed testimony on August 31, 2011 and are now submitting an updated/revised version of their Direct Testimony. For those four witnesses, a redlined version of testimony is also being submitted solely for the convenience of the parties so that they can see the specific changes made from the August 31, 2011 versions (regarding the exhibits of Dr. Pearce, only a portion of KDP-7 changed). During the April 17, 2012 hearing, AEP Ohio will sponsor and introduce for admission into the evidentiary record the clean, updated version of each piece of testimony that is being filed today. Please note that the testimony of William A. Klun that was filed on August 31, 2011 is no longer being sponsored and should be considered withdrawn.

Thank you for your attention to this matter.

Respectfully Submitted,

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

REDLINED DIRECT TESTIMONY OF
RICHARD E. MUNCZINSKI
KELLY D. PEARCE
FRANK C. GRAVES
DANA E. HORTON
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: March 23, 2012

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

DIRECT TESTIMONY OF
RICHARD E. MUNCZINSKI
ON BEHALF OF
~~COLUMBUS SOUTHERN POWER COMPANY~~
~~AND~~
OHIO POWER COMPANY

Filed: ~~August 31, 2011~~March 23, 2012

INDEX TO DIRECT TESTIMONY OF
RICHARD E. MUNCZINSKI

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
RICHARD E. MUNCZINSKI
ON BEHALF OF
~~COLUMBUS SOUTHERN POWER~~
~~AND~~
OHIO POWER COMPANY

PERSONAL DATA

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Richard E. Munczinski and my business address is One Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the American Electric Power Service Corporation (AEPSC), a unit of American Electric Power (AEP). My title is Senior Vice President – Regulatory Services, over regulatory activities across AEP's operating companies, including ~~Columbus Southern Power Company (CSP) and~~ Ohio Power Company (OPCo), hereby ~~collectively~~ referred to as AEP Ohio or the Compani~~es~~y.

Q. WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT -REGULATORY SERVICES?

A. I am directly responsible for overseeing AEP's regulatory activities before eleven state regulatory commissions and the Federal Energy Regulatory Commission (FERC). Additionally, I am AEP's Chief Reliability Compliance Officer. In this role, I oversee the development and implementation of strategic policy within AEP to ensure compliance with North American Reliability Corporation (NERC) reliability standards for the AEP system, as well as AEP's participation in regional transmission organization (RTOs).

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I earned a bachelor of engineering degree in electrical engineering and a master's degree in management science from Stevens Institute of Technology in Hoboken, New Jersey. I am a member of the Institute of Electrical and Electronics Engineers.

Prior to joining AEP, I was an electrical engineer for Ebasco Services Inc., New York. I joined AEP in 1978 in the Project Engineering department and transferred to Corporate Planning and Budgeting in 1982. I became Director of Rate Case Management in 1992 and Vice President of Regulatory Services in 1996 leading the regulatory approval process for the merger with Central and South West Corporation (CSW). I was named Senior Vice President - Corporate Planning and Budgeting in 1998 and Senior Vice President - Shared Services in 2008. I have served in my current role as Senior Vice President-Regulatory Services of AEP since January 2010.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE A REGULATORY AGENCY?

A. I have testified or submitted testimony before the regulatory commissions in the states of Ohio, Virginia, West Virginia, Michigan, Arkansas, Indiana, Kentucky, Louisiana, Oklahoma, Texas and before the Federal Energy Regulatory Commission (FERC).

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am AEP Ohio's overall policy witness supporting AEP Ohio's position that ~~CSP and OPCo~~it should be allowed to collect its~~their~~ capacity costs from Competitive Retail Electric Service (CRES) providers. AEP Ohio maintains that its position is consistent with the terms and conditions in the existing PJM Interconnection, LLC (PJM) Reliability Assurance Agreement (RAA), as further discussed by Company witness Horton. I have also been advised by counsel that, under the terms of the RAA, the wholesale capacity rate to be charged by ~~CSP and OPCo~~the Company to CRES providers should be decided not by the Commission, but rather in a case that is currently pending rehearing at FERC. Nonetheless, as directed by the Public Utilities Commission of Ohio's (Commission) ~~August 11~~March 7, 201~~1~~2 Entry, the Compan~~ies~~y's testimony and exhibits, as updated from the filing made on August 31, 2011, will provide the Commission with the necessary evidence regarding the appropriate capacity cost and a fair compensation mechanism pertaining to capacity charges to be paid by CRES providers for use of AEP Ohio's capacity. Additionally, I will explain why it is important that neither shareholders nor non-shopping customers should subsidize CRES providers in their use of AEP Ohio capacity. My testimony is supported by other witnesses testifying on behalf of AEP Ohio in these proceedings and takes into account AEP

Ohio's comments and reply comments previously filed in this proceeding, Case No. 10-2929-EL-UNC (Capacity Charges) case.

WITNESSES AND SPONSORED TESTIMONY

Q. HOW IS THE COMPAN~~IES~~Y'S CAPACITY CHARGES CASE FILING ORGANIZED?

A. AEP Ohio has five witnesses supporting various key issues for the Capacity Charges case. The following table summarizes and serves to introduce the witnesses, the general subject area each is sponsoring, and a brief description of the respective testimony.

Table 1: Witnesses in the Capacity Charges Case

Witness	Subject Area	General Description of Testimony
Richard E. Munczinski (AEP)	Policy Witness	• Background of Case • AEP Ohio's position
~~William A. Klun (MJ Beck Consulting)~~William A. Allen (AEP)	~~Independent Generation Finance Witness~~Financial Analysis	• Quantify Financial Harm Associated with RPM-priced capacity • Current Shopping Levels~~Shortfalls of RPM relative to financing generation~~
Frank C. Graves (The Brattle Group)	Independent RPM Capacity Market Witness	• Cost difference between PJM RPM price and AEP's embedded costs • Economic issues in CRES capacity pricing
Dana E. Horton (AEP)	PJM Capacity Market Witness	• PJM's FRR and RPM capacity options • FRR rules and procedures • RPM auction process
Kelly D. Pearce (AEP)	Cost of Capacity Witness	• AEP Ohio's cost of capacity • Formula rate description • Energy credit • CRES self-supply option

BACKGROUND OF THE CASE

Q. PLEASE DESCRIBE THE HISTORY OF THE CAPACITY CHARGES CASE WITH RESPECT TO AEP OHIO.

A. On November 1, 2010, AEP Ohio filed an application with the Federal Energy Regulatory Commission (FERC) in FERC Docket No. ER11-1995-000. On November 24, 2010, at the direction of FERC, AEP Ohio refiled its application in FERC Docket No. ER11-2183-000. As a Fixed Resource Requirement (FRR) entity, AEP Ohio's application proposed to implement an existing clause within the PJM RAA to change the basis of compensation for use of its capacity by CRES providers to an AEP Ohio cost-based method.

Prior to 2007, and during the PJM Reliability Pricing Model (RPM) auction development phase, AEP, as well as other parties, expressed concern over the long-term negative impacts of the RPM capacity market on vertically integrated utilities and their customers. Thus, as discussed in the testimony of Company witness Horton, Section D.8 of Schedule 8.1 (Schedule D) of the PJM RAA, or the FRR provision, was drafted to ensure that FRR entities could request a cost-based method of recovering their capacity costs. Under FRR, there are essentially three alternatives for pricing capacity provided to CRES providers: 1) a properly designed retail state compensation mechanism and in the absence of such a mechanism, 2) rates based on the PJM RPM capacity auction price, and 3) a method based on the FRR entity's costs (a formula cost-based method) or such other cost basis shown to be just and reasonable.

AEP Ohio has self-supplied its capacity as a FRR entity since the RPM inception in June 2007, thus opting out of the PJM RPM auction market for purposes of meeting its load obligations each year through planning year 2014/2015. Since the RPM auction inception, AEP Ohio has been compensated at the adjusted PJM RPM auction price for supplying capacity associated with load lost to CRES providers who choose not to self-supply their own capacity. The CRES providers who choose not to self-supply merely act as a middle-man on capacity flowing from AEP Ohio. While the RPM auction prices have fluctuated significantly, the auction price for the next several years have dropped to levels that would prevent AEP Ohio from receiving anything remotely approaching full compensation from CRES providers for AEP Ohio capacity costs.

In its November 2010 FERC application, AEP Ohio proposed cost-based formula tariffs that were based on the Compani~~i~~es' 2009 FERC Form 1 filings.[1] AEP Ohio made this application to remedy the situation where CRES providers were receiving a subsidy for their use of the Compan~~ies~~y's capacity due to the use of RPM auction prices. Additionally, AEP Ohio filed this 2009 information in Ohio in this Capacity Charges case. Company witness Pearce provides an update to these rates based on 2010 information and provides the evidence of the proper level of compensation to be recovered from CRES providers who utilize AEP Ohio's capacity.

In response to AEP Ohio's November 2010 application to the FERC, the Commission represented to FERC that as of December 8, 2010 it was "adopt[ing] as the state compensation mechanism for the Companies the current capacity

[1] At the time of this filing, the merger of Ohio Power Company's predecessor companies, Columbus Southern Power Company and Ohio Power Company, had not been finalized. Hence, for 2009 and 2010, formula calculations were done for each company in recognition of their status as separate legal entities. The merger was effective as of December 31, 2011.

charges established by the three-year capacity auction conducted by PJM," which is the PJM RPM auction price.

On January 20, 2011, FERC issued an Order rejecting the AEP Ohio rate proposal, not on the merits, but due to the Commission's December 8, 2010 order stating that it was adopting an interim state compensation mechanism. AEP Ohio's application for rehearing of FERC's January 20, 2011 Order remains pending before FERC. AEP Ohio also filed a complaint case, FERC Docket No. EL11-32-000, to seek modifications to Schedule D of the RAA designed to clarify the original intent as understood by AEP Ohio. The purpose of that filing was to confirm that any state compensation mechanism must compensate FRR entities for capacity costs through charges included in retail rates and to preserve the FRR entities' right to submit filings under Section 205 of the Federal Power Act to establish just and reasonable FRR charges. Otherwise, utilities may be forced to accept rates at below cost levels.

Q. DID AEP OHIO RENEW ITS FRR ELECTION FOR THE 2015/2016 PLANNING YEAR?

A. No. AEP Ohio did not pursue an FRR election for the 2015/2016 Planning Year. On March 7, 2012 AEP Ohio advised PJM that it would become an RPM entity for purposes of capacity pricing for the 2015/2016 Planning Year. To be clear, this decision means that the load of AEP Ohio will be in the RPM market starting in mid-2015 and does not mean that all of the generation assets currently owned by AEP Ohio will enter the RPM capacity market at that time. There is an upcoming PJM process related to designation of particular units and that has not presently been completed.

Q. WHAT IS THE SIGNIFICANCE OF AEP OHIO BECOMING AN RPM ENTITY IN THE PJM CAPACITY MARKET?

A. AEP Ohio status as an RPM entity starting on June 1, 2015 means that the pricing issues in this case become transitional in nature and only need to address the period from June 1, 2012 through May 31, 2015.

AEP OHIO'S POSITION

Q. PLEASE BRIEFLY SUMMARIZE AEP OHIO'S POSITION IN THIS CAPACITY CHARGES CASE.

A. AEP Ohio's position in the pending FERC proceeding and in this Ohio Capacity Charges proceeding, which is set forth in detail in the Compani~~es~~y's January 7, 2011 Application for Rehearing in this docket, is that the current capacity pricing mechanism undercompensates AEP Ohio for the capacity it provides to CRES providers. The impact on AEP Ohio's ability to be compensated for its costs has become significant due to the trend in RPM auction prices, as well the growth in shopping by AEP Ohio customers whose CRES providers take advantage of the capacity supplied by AEP Ohio as opposed to supplying their own capacity. These concerns prompted the November 2010 FERC filing. On advice of counsel, it is my understanding that CSP and OPCo have the right under the RAA to request that FERC establish the wholesale rate that the companies may charge for capacity to CRES providers, which right they exercised in the November 2010 FERC filing, as amplified by the FERC complaint. However, given the FERC's order on the Compan~~ies~~y's November 2010 filing and the Commission's entry in this case, AEP Ohio will present evidence as to the proper level of compensation to be recovered from CRES providers who utilize AEP Ohio's capacity.

Q. WHAT ARE THE CONSEQUENCES OF ALIGNING A STATE COMPENSATION MECHANISM WITH THE PJM RPM PRICE?

A. Aligning the state compensation mechanism to the PJM RPM wholesale price means that Ohio capacity is solely influenced by the administrative PJM and RPM's auction process and its participants who may not have Ohio's best interests in mind. To the extent that the Commission's December 8, 2010 Entry eliminated other options for capacity compensation, it would, in my view, undermine the ability to provide just and reasonable compensation to AEP Ohio and the ability to provide customers with reliable and adequate service. During the development phase of the RPM, the FERC addressed these concerns by establishing alternative, non-RPM auction based methods for establishing capacity prices for FRR entities.

Additionally, the RPM clearing price is a one-year price projected three years in advance. As shown in the historical auction clearing prices presented in Exhibit KDP-7 in the testimony of Company witness Pearce, these prices can fluctuate dramatically from year to year. This provides little or no incentive to invest in Ohio asset generation.

Q. WHY IS IT APPROPRIATE TO TIE CAPACITY PRICES CHARGED TO CRES PROVIDERS TO AEP OHIO'S COST OF CAPACITY?

A. There are several reasons why CRES providers that are passing through AEP Ohio's capacity should pay for use of that capacity based on AEP Ohio's costs. First, it is important that neither shareholders nor non-shopping customers subsidize CRES providers for use of AEP Ohio's capacity. Reliance on AEP Ohio to supply capacity to CRES providers while not requiring those providers to pay the cost of that capacity is inequitable. Second, cost-based compensation represents a long-term view of affordable and reliable capacity for Ohio customers in contrast to the short-term RPM-based pricing. Finally, because AEP Ohio is an FRR entity, its capacity is dedicated to its Ohio customers. This includes those customers who choose to shop and are served by CRES providers who opt to utilize AEP Ohio's capacity. Accordingly, such capacity dedication comes hand in hand with rates that are based on AEP Ohio's costs and not on the RPM market.

Q. HOW DOES AEP OHIO RECOVER ITS CAPACITY COSTS FROM RETAIL CUSTOMERS THAT TAKE GENERATION SERVICE FROM AEP OHIO?

A. As described and submitted in AEP Ohio's Initial Comments filed in this proceeding, AEP Ohio, as a Load Serving Entity (LSE) in PJM, does not participate in the PJM RPM auction market for the purposes of meeting AEP Ohio's load obligation. The cost of AEP Ohio's capacity resources that are used by the CRES providers who fail to secure their own resources are recovered from non-shopping retail customers through state jurisdiction, Commission-approved generation rates. Such rates for January 2012 through May 2014 are the subject of the Company's current 2012-2014 ESP case and are intended to cover AEP Ohio's cost of generation, including the cost of capacity. However, CRES providers who serve shopping customers, and who choose not to self-supply capacity, are currently required to pay only the PJM RPM-based auction price. Thus, while these CRES providers are using AEP Ohio's capacity resources, they avoid paying the embedded generation capacity costs that are on the books of AEP Ohio. Accordingly, AEP Ohio is forced to absorb the cost of an unreasonable and ultimately unsustainable subsidy to CRES providers in Ohio. The bottom line is CRES providers should provide fair compensation to AEP Ohio for its capacity just as non-shopping customers do.

While the Commission opined in the December 8th Order that AEP Ohio has other mechanisms for the recovery of capacity costs from retail customers, this is not true. Shopping customers do not pay AEP Ohio for capacity costs, they pay the capacity charged by CRES providers. Non-shopping customers only pay SSO generation rates. AEP Ohio is not receiving compensation for CRES-related capacity costs through any of its retail rate mechanisms. The Commission's interim compensation mechanism, based on the RPM-based pricing, does not provide adequate compensation for its costs of providing capacity to CRES providers.

Q. WHAT IS THE APPROPRIATE LEVEL OF COMPENSATION THAT AEP OHIO SHOULD RECEIVE FROM CRES PROVIDERS FOR USE OF AEP OHIO'S CAPACITY?

A. AEP Ohio should be allowed just and reasonable compensation from CRES providers based on AEP Ohio's embedded cost of capacity that will allow for continued investment in Ohio generation resources. Such charges will not create a subsidy, as is currently occurring. Such charges will facilitate long-term resource adequacy and reliability.

Q. WHY DID AEP OHIO DECIDE TO REQUEST A CHANGE IN FRR COMPENSATION METHODS?

A. As other AEP Ohio witnesses support, adjusted RPM-based capacity rates tend to fluctuate over time while embedded cost-based rates are relatively stable. At this particular time in the market cycle, adjusted RPM-based capacity rates are below AEP Ohio's embedded costs. As reflected in Exhibit KDP-7 in the testimony of Company witness Pearce, the adjusted RPM-based rates not only fluctuate year to year, but are well below the cost of a new combined cycle unit (Gross CONE). Therefore, AEP Ohio determined that it was time to utilize the cost-based method with the full understanding that it would require FERC approval of the proposed rates. Based on 2010 FERC Form 1 data, as calculated by Company witness Pearce, capacity rates are $327.59/MW-day for Columbus Southern Power ~~SP~~(CSP) and $379.23/MW-day for OPCo or $355.72/MW-day on a combined basis for AEP Ohio.

Q. WHAT ARE THE IMPACTS TO AEP OHIO IF THE RATES BASED ON EXISTING RPM AUCTION PRICES REMAIN THE ONLY APPROVED COST COMPENSATION MECHANISM?

A. ~~At 100% shopping, the impacts to AEP Ohio could exceed $485M for 2011, $771M for 2012, and $971M for 2013. At 50% shopping the impacts to AEP Ohio could exceed $242M for 2011, $386M for 2012, and $486M for 2013. These financial impacts will obviously impact the long-term generation capacity investment within the state.~~ AEP Ohio would experience serious financial harm, the details of which are separately discussed by AEP Ohio witness Allen in his testimony.

Q. WHAT ARE THE LONG-TERM GENERATION CAPACITY SUPPLY CONCERNS ASSOCIATED WITH THE CURRENT RPM-BASED CAPACITY PRICING MECHANISM?

A. During the development phase of the RPM model, the Ohio Commission had concerns with protecting a state's generation resource adequacy. As stated in the Commission's comments in FERC Docket No. EL05-148-000:

> "...PJM's rules do not recognize the need to recover reasonable investment costs nor the timely repayment of debt—bedrock principles required for financing an industry as capital intensive as the electricity industry." (p.14).

The Commission goes on to state:

> "Generator owners cannot long survive on recovery of the short run marginal cost of energy alone, but must consistently recover some of their long run marginal costs as well." (p.14).

The Ohio Commission's previous state policy recognized an obligation to ensure adequate supply of generation resources for the customers of Ohio and, as a result, they approved AEP Ohio's standard service offer pricing in the 2009-2011 ESP case. Additionally, the state compensation mechanism alternative was drafted into the PJM RAA to address these generation supply concerns as discussed by Company witness Horton.

While AEP Ohio believes the November 2010 FERC application for the cost-based method will address long-term supply concerns, if the Commission seeks to establish a properly designed non-interim state compensation mechanism, then the rate must ensure reasonable compensation for costs incurred by suppliers that build or have built generation. A just and reasonable state compensation mechanism should provide for the compensation of embedded costs of generation, but also provide incentives for investment in generation. A state compensation mechanism that is based on short-term RPM auction prices would amount to an abdication of the authority to ensure long-term generation adequacy and reliability within the state.

Q. HOW CAN THE COMMISSION ADDRESS THESE CONCERNS AND PROMOTE INVESTMENT IN THE STATE OF OHIO?

A. By allowing AEP Ohio to be appropriately compensated for its costs associated with capacity, the Commission will provide the investment community with more certainty, eliminate some regulatory risk, and ensure sustained investment within the state of Ohio. Without the Commission's support of an appropriate and reasonable cost compensation mechanism, it would be imprudent and irresponsible for AEP Ohio to invest long-term capital in an unclear, unstable cost recovery environment. If left unaddressed or as reflected in the Commission's December 2010 order regarding an interim state compensation mechanism, this uncertainty, coupled with increasing environmental mandates puts Ohio customers at risk for long-term in-state generation capacity deficiencies.

Q. MANY OHIO CRES PROVIDERS HAVE EXPRESSED CONCERN WITH ALLOWING THE COMPANY TO RECOVER ITS CAPACITY COSTS AND HOW THAT MIGHT IMPACT COMPETITION WITHIN THE STATE OF OHIO. HOW DO YOU RESPOND?

A. Implementing a just and reasonable mechanism to allow AEP Ohio to recover its capacity costs from CRES providers actually provides for a more equal and fair competitive market in Ohio for generation services. If CRES providers choose not to self-supply, the Compan~~ies~~y must provide the capacity resources to the CRES provider. Commission support of recovery of capacity costs through appropriate wholesale charges to CRES providers will mitigate the anticompetitive subsidy that currently flows to CRES providers which use AEP Ohio's capacity. I am advised by counsel that the subsidy undermines the explicit state policy referenced in Ohio Revised Code §4928.02 (H) and allows for CRES providers to pay a much lower rate than AEP Ohio non-shopping customers who use the same capacity resources.

CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. AEP Ohio maintains that the Commission, as well as the FERC, must honor the long recognized distinction between its authority to regulate retail electric rates and the FERC's authority over wholesale electric rates, whether the rates relate to sale of energy or the sale of capacity. AEP Ohio has consistently maintained the legal position (through counsel) that the RAA, even with implicit FERC approval, cannot alter the bright-line between retail rate regulation and wholesale rate regulation. A properly designed state compensation mechanism to compensate a FRR entity for its capacity obligations must, at a minimum, allow the FRR entity to recover its costs of providing capacity to support shopping. Otherwise, the state compensation mechanism will not appropriately compensate the FRR entity for capacity.

Second, AEP Ohio disagrees that the Commission's interim compensation mechanism, based on the RPM auction-based pricing, provides adequate compensation for its costs of providing capacity to CRES providers. Moreover, AEP Ohio is not receiving compensation for those capacity costs through any of its retail rates charged to shopping or non-shopping customers.

Third, as demonstrated by Company witnesses Allen's and Pearce's testimon~~y~~ies, AEP Ohio is not receiving adequate compensation for performing its FRR capacity obligations, and the gap between its costs and the compensation for those costs is increasing at an alarming rate. ~~T~~The failure to recover just and adequate compensation for its FRR capacity obligations is threatening AEP Ohio's financial stability and is a significant disincentive for generation investment within the state of Ohio.

Furthermore, in this proceeding there is the additional issue of what is in the best interests of Ohio and the retail customers of Ohio. The Commission should not be looking to use the short-term market auction prices at the expense of longer-term stability, reliability and investment in generation. That is a "penny-wise, pound-foolish" approach that could be disastrous in the long run. The Commission also should not allow a subsidy to CRES providers by permitting artificially low capacity rates to prevail. Non-shopping customers pay capacity charges that recover embedded costs. CRES providers, who choose not to self-supply, should also pay capacity charges that recover embedded costs.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILTIES COMMISSION OF OHIO

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

DIRECT TESTIMONY OF
FRANK C. GRAVES
ON BEHALF OF
~~COLUMBUS SOUTHERN POWER COMPANY~~
~~AND~~
OHIO POWER COMPANY

Filed: ~~August 31, 2011~~
March 23, 2012

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
FRANK C. GRAVES
ON BEHALF OF
~~COLUMBUS SOUTHERN POWER COMPANY~~
~~AND~~
OHIO POWER COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND TITLE.

A. My name is Frank C. Graves. I am a Principal at *The Brattle Group*, where I am also co-leader of the Utility Practice Area. My firm is located at 44 Brattle Street, Cambridge, MA, 02138.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will explain why it is appropriate for ~~Columbus Southern Power Company (CSP) and~~ Ohio Power Company (OPCo) (also referred to as "AEP Ohio") to be able to charge Competitive Retail Electric Service (CRES) providers within its franchise service territories an amount for capacity that reflects the embedded (fully allocated accounting) cost of the assets AEP Ohio must hold under its Fixed Resource Requirements (FRR) obligations as a member of PJM, rather than using the capacity price set in PJM's Reliability Pricing Model (RPM) auctions.

Q. ARE YOU REVIEWING OR ASSESSING THE SPECIFIC PARAMETERS OF AEP OHIO'S EMBEDDED COST CALCULATIONS AND THEIR FAITHFULNESS TO THE TRUE COST OF SERVICE?

A. No. I am not commenting on the accuracy of AEP Ohio's calculations or formulas for specifying the embedded capacity cost, nor on whether those costs are fully reflected in their proposed rates. Rather, I am commenting on the policy question of whether ~~(assuming such calculations are accurate) the~~ it would be just and reasonable for -AEP Ohio ~~proposal is just and reasonable~~ to use embedded cost pricing for capacity, especially in light of whether it could have an undue, adverse impact on retail power marketing or wholesale generation competition.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND RELEVANT EXPERTISE?

A. I have an M.S. in Management from the MIT Sloan School of Management with a concentration in finance, and a B.A. in Mathematics from Indiana University. I have been consulting to the electric industry for over 30 years on matters related to long term resource planning, pricing, prudence, risk management, fuel and power procurement, environmental compliance, market forecasting and performance, regulatory policy impacts, and other long term influences on utility assets, costs, and obligations.

I have appeared numerous times as an expert witness before state and federal courts and regulatory bodies, including the Federal Energy Regulatory Commission (FERC), and utility commissions (or administrative law judges for them) in Ohio, Illinois, Pennsylvania, Wisconsin, Kentucky, Michigan, Massachusetts, Vermont, New York, Virginia, Texas, California, New Mexico, and Utah to explain tradeoffs and likely costs and benefits of utility activities and decisions. I have also been a witness in state and federal courts regarding contract disputes between energy companies.

In regard to the topics at issue in this proceeding, I have been very active in consulting on the design of terms and conditions, supply procurement mechanisms, and pricing and valuation of Default, or Standard Service Offer, in states with retail access, as well as in how those service designs interact with market performance and the viability of the incumbent utility and retail electric providers. A detailed description of my expertise is attached as Appendix A to this testimony.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND OPINIONS.

A. The unique circumstances in PJM of AEP Ohio as an FRR entity obligated to supply all the capacity needs of any/all load in its franchise territory make it inappropriate to require usinge a PJM RPM-based price as the tariffed rate for transferring AEP Ohio's capacity to CRES providers. The current RPM price is much lower than AEP Ohio's embedded costs, so it would not be compensatory for AEP Ohio. This difference will increase in the next two years, as RPM prices for 2012/2013 and 2013/2014 are even lower than at present. RPM prices are short term (one-year) rates that do not reflect the costs of serving the long term, more binding and broader reliability obligations that AEP Ohio faces (as an FRR utility) but that a CRES provider does not.

In addition to current RPM prices being below AEP Ohio's embedded cost, PJM market energy prices also are quite low right now, largely due to the recession and the dramatic emergence of inexpensive shale gas. This combination of low capacity and energy prices is making CRES providers more active than in the recent past, facilitating their marketing but also making it essential that the price they face for capacity from AEP Ohio be fair and compensatory. Requiring ~~Using~~ an RPM-based price (without other cost recovery mechanisms) -would introduce uneconomic bypass opportunities for the CRES providers, at the expense of AEP Ohio customers and shareholders. While such bypass would undoubtedly increase the prevalence of retail providers in AEP Ohio's service territory, it would not be fostering efficient competition.

CONTEXT FOR THE DISPUTE

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR UNDERSTANDING OF THE BACKGROUND FOR THIS DISPUTE.

A. The disputed issue in this case which I am addressing is whether AEP Ohio's charge for releasing capacity to CRES providers that provide retail electric supply services in AEP Ohio's territories should be based on AEP Ohio's own embedded costs of service for the underlying generation assets it is required to hold as an FRR provider, or should be based on the one-year market value of capacity as it has arisen in PJM's Reliability Pricing Model (RPM) for three-year forward planning reserve obligations. AEP has proposed a compromise position but reserves its ~~rights~~right to an ~~the former.~~ embedded cost basis (with formula rates). Some intervenors ~~while commenters (and the interim policy of the PUCO)~~ tend to prefer the PJM RPM auction price basis.

The cost difference between the two viewpoints is material. For the PJM Planning Year beginning June 1, 2011, the RPM auction price of capacity in the AEP region (unconstrained PJM) is $116.16/MW-day, but when this is scaled up for PJM reserve margins and capacity loss factors, it is $145.79 in AEP Ohio's service territories. In contrast, the correspondingly adjusted embedded cost of service for AEP Ohio's generation plant is $355.72/MW-day. If this is reduced for the ~~recent past~~ energy operating margins that would have been available last summer to AEP Ohio in PJM's wholesale markets, the net cost becomes $338.14/MW-day. Those energy margins would likely be smaller now, due to falling PJM prices. By comparison, the "Net CONE" value for the PJM estimated "net cost of new entry" was $171.40/MW-day for this time frame when the RPM price was struck[1]. Net CONE is the carrying cost for a new gas combustion turbine peaker, reduced by the energy margins such a unit would have earned on average in the prior three years at actual PJM spot prices.

These discrepancies between AEP Ohio's embedded cost, and Net CONE and RPM prices will become larger in the next two years, because RPM prices (including scaling factors) will be $20.01/MW-day and $33.71/MW-day for 2012/13 and 2013/2014 respectively while Net CONE values for these same planning years are $276.09/MW-day and $317.95/MW-day respectively (see direct testimony of Company witness Pearce at exhibit KDP-7).

Q. WHY IS THE PJM RPM PRICE SO MUCH LOWER THAN AEP OHIO'S EMBEDDED COSTS?

A. There are several reasons. First, AEP Ohio's cost reflects the average capital and fixed costs of its fleet of generation, which includes approximately 13,000 MW of plants of a variety of ages and technologies, but is largely comprised of baseload

[1] See testimony of Company witness Pearce for details on these cost calculations.

coal plants. The PJM price reflects (in part) the net cost of a gas peaker, which is a less capital-intensive type of generation than most of AEP Ohio's fleet. Second, the PJM RPM price moves up or down relative to a peaker's cost depending on how much capacity is available in the PJM market, what bid prices are offered by generators and other resources, and the location of the demand curve. That is, it reflects the marginal value of capacity as it was expected/set three years ago, when the PJM auction for 2011/12 capacity obligations was conducted in 2008. To the extent there was excess supply offered in that auction compared to PJM's target reserve margins, resulting capacity prices will be low, often much below Net CONE. For 2011/12, the auction cleared at slightly over an 18% reserve margin. The available capacity through 2014/15 also exceeds planning reserve targets, contributing to low RPM prices. For the past several years, RPM prices have been below Net CONE largely because the kinds of capacity that have been attracted to participating in RPM auctions have been mostly plant life extensions and capacity upgrades, demand-response resources, and expanded transmission capacity -- all of which tend to cost less per MW than a new plant (and especially, less than a baseload coal plant). Further, load growth (hence need for capacity) was reduced due to the economic downturn.

The kinds of incremental capacity resources that RPM has attracted are sufficient for maintaining reliability over the next few years (which is precisely what PJM intended), but they are not necessarily the same kinds of resources that would be preferred for long term resource planning that is focused on minimizing lifecycle costs of power, risks, and addressing other kinds of social policy considerations. AEP Ohio's resources were chosen in the latter context, hence are much different in character and carrying costs.

Retail providers would understandably like to have AEP Ohio provide capacity at as low a cost as possible, so some ~~they~~ have ~~are~~ advocated that~~ing~~ the PJM RPM price basis be required. However, as explained below, this would not be compensatory for AEP Ohio, which has a longer, more binding reliability obligation as a FRR utility than the CRES providers incur as short term Load Serving Entities (LSE). Requiring the application of ~~Thus, applying~~ the RPM-based price would introduce an uneconomic bypass opportunity for CRES providers, at the expense of AEP Ohio customers and shareholders. While such bypass would undoubtedly increase the prevalence of retail providers in AEP Ohio's service territory in the short run, it would not be fostering efficient or durable competition. It is more likely that if market prices increase materially, CRES providers will turn their former AEP Ohio customers back to AEP Ohio as the default service provider.

Q. WHY DOES AEP OHIO NEED TO RECOVER ITS EMBEDDED CAPACITY COSTS FROM CRES PROVIDERS WHILE OTHER OHIO UTILITIES DO NOT?

A. ~~In PJM, only~~ Upon joining PJM, AEP ~~and Duke have e~~elected to be an FRR supplier~~s~~ of capacity to its~~their~~ service territory. ~~territories (and Duke will not start serving in this role until January 2012).~~. This means AEP Ohio is not a participant in PJM's RPM auctions or capacity procurement (except insofar as it has capacity not needed for its native load -- and its auction participation is limited to 1300 MW). However, ~~but~~ it still is obligated to PJM to provide long term capacity (5-year minimum commitment, initially) for all the load in its distribution franchise territories, regardless of whether those customers are new or old, or whether their energy supply comes from AEP Ohio or a third-party CRES provider. Concomitantly, CRES providers in AEP Ohio's territory must have previously notified PJM and AEP of their intentions to become FRR entities themselves for their expected retail loads and have obtained the needed capacity in prior bilateral procurements, or else they must buy capacity from AEP Ohio at the rates which are in dispute today.

Q. IF RETAIL SUPPLIERS WHO WISH TO BE SELLING ELECTRICITY IN AEP OHIO'S TERRITORY ALREADY COULD HAVE HAD ACCESS TO ALTERNATIVE CAPACITY IN PJM FOR 2011 AND BEYOND, WHY WOULD THEY NOT HAVE OBTAINED IT?

A. Apparently many did not choose to procure such capacity and import it into AEP Ohio's territory. This is understandable, for two reasons. First, they may have had few or no committed retail customers three years in advance; a shorter contracting horizon is more typical for retail electric services. Second, they may have been uncertain about the energy prices that would prevail in 2012~~1~~ (which are the larger part of their overall cost of generation they could offer to retail customers), so they did not foresee the opportunity to sell retail services that has arisen with the recent decline in energy costs. However, short term market circumstances are now favorable, and as a result, they would now like to procure their capacity under current RPM prices.

ECONOMIC ISSUES IN CRES CAPACITY PRICING

Q. ABOVE, YOU SHOWED WHAT CRES PROVIDER'S COSTS WILL BE IF THE CAPACITY PORTION OF THE CRES PROVIDER'S BILL IS BASED ON RPM PRICES RATHER THAN AEP'S COSTS. WHY ISN'T THIS A DESIRABLE RESULT? IF THE CRES PROVIDER PASSED ON THAT REDUCTION AND ITS SERVICES WOULD BE CHEAPER, SHOULDN'T CUSTOMERS HAVE ACCESS TO THAT SERVICE?

A. First, it is not assured that CRES providers would pass on the lower costs to customers, rather than keep most of the savings for themselves. But even if they did, this is not a desirable result from an overall economic viewpoint (even though it might seem like one to the customers of CRES providers), because customer switching (under RPM-based pricing) would not be occurring due to an actual economic advantage (or societal efficiency gain) in the supply of electric power service by those CRES providers (in lieu of AEP Ohio). Rather, it would simply involve the resale of AEP Ohio's capacity at a discount, subsidizing CRES providers at the expense of AEP Ohio, which would be taking a loss on the resale of their existing capacity (potentially reallocating those shortfalls to non-shopping AEP Ohio customers). In essence, it would be an uneconomic bypass, not efficiency gains from true competition. For instance, being able to sell retail services based on RPM capacity costs will not induce CRES providers to take ~~appropriate~~ responsibility for their own capacity development/procurement in the future. To the contrary, it would encourage them to avoid such commitments, and it would give them the incentive and opportunity to become active sellers in years when RPM prices turn out to be below AEP Ohio's embedded costs, and not when the reverse occurs.

Q. WHY WOULD EXTENDING CAPACITY TO CRES PROVIDERS AT RPM-BASED PRICES CREATE A FINANCIAL LOSS FOR AEP?

Absent the recovery mechanism AEP Ohio has proposed, it only collects its cost of capacity from retail customers to the extent they are non-shopping customers. If customers switch to a CRES provider, AEP Ohio is still liable for their capacity needs. Embedded in AEP Ohio's retail rates are the same costs it is requesting FERC to approve for its capacity resale to CRES providers (except insofar as a cost-indexed formula is used for the CRES rate).

Q. IF CUSTOMERS WERE TO SWITCH TO A CRES PROVIDER THAT COULD USE AEP CAPACITY AT RPM-BASED PRICES, WOULD AEP SIMPLY INCUR A LOSS EQUAL TO THE DIFFERENCE BETWEEN ITS EMBEDDED CAPACITY COSTS AND THE RPM-BASED PRICE, OR WOULD THERE BE OFFSETTING SAVINGS OR MARKET OPPORTUNITIES TO MITIGATE THE LOSS?

A. If customers leave for a CRES provider, AEP Ohio would be relieved of its obligation to provide the energy supply component of electricity service to those customers. This means it could resell the energy that would have otherwise been needed at the PJM LMP price for locally produced power. After subtracting out the average production costs, AEP Ohio would have net operating margins which partially offset its need to recover the full embedded cost of the released capacity.

Of course, the prices and quantities of these wholesale market energy revenues are highly uncertain and circumstantial.

Q. IF THE COMMISSION DOES INCLUDE ENERGY CREDITS, SHOULD IT CONSIDER PUTTING A LIMIT OR FLOOR ON THE OFFSETTING ENERGY CREDITS IN THE CALCULATION OF ITS NET CAPACITY CHARGE?

A. Yes, I also understand that AEP Ohio is recommending limitations on any such energy credit mechanism, as discussed by Company witness Pearce. The concern is that energy operating margins could become occasionally so high that if fully deducted, the net capacity costs would become negative. In that situation, AEP would be paying the CRES to take its capacity, thereby effectively giving all of the value of offsystem wholesale margins to the CRES providers. This would create a perverse situation in which the CRES provider could enjoy wholesale energy savings benefits from netback capacity prices, even though it was not participating in wholesale markets at all, and even though it did not provide any of the initial capital investment or managerial acumen to build, maintain, or market that generation whose energy happened to become deep in the money.

Q. SHOULD THE COMMISSION BE CONCERNED THAT THERE LIKELY WOULD BE LESS CRES PROVIDER ACTIVITY IN THE AEP OHIO SERVICE TERRITORY UNDER AEP OHIO'S PROPOSAL THAN WITH RPM-BASED PRICES FOR CAPACITY?

A. No, the focus should be on fairness and on genuine competition, not just entry by CRES providers. It is very likely that there would be less near-term CRES activity under AEP Ohio's proposal, but this is not a basis for concluding there would be adverse impacts on bonafide retail competition from approving the cost-based rates AEP Ohio has requested. The chance that there may be less CRES activity under AEP Ohio's proposal than under RPM pricing is not the appropriate focus. If AEP Ohio were to charge~~d~~ nothing at all for its capacity to CRES providers, that would encourage even more CRES entrants to the regional market. But that establishes a market of free riders, not one of more capable suppliers having truly lower costs or superior service. The AEP Ohio embedded rates are currently higher than the RPM-based prices, hence undoubtedly less advantageous to CRES providers than RPM-based charges, but that is not the same as saying there would be harm to competition from charging the AEP Ohio formula rates. AEP Ohio should not be put in a position where it has to subsidize its competitors in order to "foster competition." Such competition would be ~~entirely~~ artificial and only sustainable to the continuing extent of the subsidy. Bonafide competitors should have to take over the service obligation to their customers on comparable terms to the way AEP provides that service today, i.e., with a long term commitment for their capacity adequacy.

Simply fostering retail competition for its own sake, especially if success is measured in terms of how many customers have switched away from a utility default provider, is not an appropriate or informative metric of economic benefit or efficiency. Increasing customer switching to CRES providers could be achieved in numerous ways that have no social economic benefit whatsoever, except to the retail providers themselves. For instance, a huge surcharge could be added to the default service charge in order to make it easier for CRES providers to beat the default price. This would attract CRES entrants, but again not because they have a true lower cost of providing the service. Rather, it would be because of a wealth transfer or subsidy involved to improve their position relative to other participants.

Q. WOULD THERE BE ADVERSE, UNECONOMIC CONSEQUENCES FROM IMPLEMENTING RPM-BASED CAPACITY PRICING?

A. Yes, I think that is likely, unless there is an agreement on other financial stabilization measures. Reliability in a power pool is inherently a public good, which tends to invite "free-riders". That is, if one party provides capacity resources needed for reliability to its customers but cannot restrict those reliability benefits to just its own customers (e.g., due to Kirchoff's Laws of electricity flow on an interconnected network), then other suppliers and customers automatically benefit. This tends to create an incentive to let others solve the capacity development problem/obligation. Precisely for that reason, PJM (and other reliability monitoring agencies) imposes a pro rata requirement on all LSEs to supply or obtain capacity on equivalent terms, to the same extent, or else they cannot gain the benefits of pool membership. The CRES proposal effectively asks that they be allowed to be partial LSEs, not providing capacity over the same horizon as AEP Ohio or even other retail service providers (e.g. in default service auctions). They essentially ~~simply~~ want to rent the capacity that others are paying for on a shorter term basis, at currently low RPM rates.

If CRES providers gained access to AEP Ohio's capacity at RPM-based rates, they would have little or no incentive to contract forward for FRR capacity in the future, in a manner that would actually signal their need and willingness to pay for it to potential developers. To the contrary, they would be being rewarded and encouraged to wait. Similarly, AEP Ohio would now be bearing a disincentive to develop future capacity, because it would know that there are future "free-riders" waiting and expecting to pay less than cost for it.

Q. DO YOU BELIEVE THE RPM-BASED PRICING ADVOCATED BY CRES PROVIDERS IS OPPORTUNISTIC AND WOULD NOT BE SOUGHT UNDER DIFFERENT MARKET CIRCUMSTANCES?

A. Yes, I do. If AEP Ohio's embedded rate was below the RPM-based rate, as could happen in a tight market, it is very hard to imagine that CRES providers would be insisting on paying the RPM-based rate rather than having access to the then-low AEP Ohio embedded rate. They appear to be ~~re clearly~~ seeking a "lower of cost or market" rate under circumstances where the market price happens to be the lower of the two.

Q. IS THERE A NEED FOR CAPACITY EXPANSION IN THE AEP REGION OF PJM AT THIS TIME, AND DOES THIS AFFECT WHETHER IT IS MORE APPROPRIATE TO USE RPM PRICES THAN AEP OHIO'S EMBEDDED COSTS?

A. Right now, and perhaps even for the next several years, there is no apparent need for new capacity in and around AEP or much of PJM, at least in regard to maintaining adequate reliability; regional reserve margins are generally above planning targets. There may be other reasonable motives and opportunities for expanding or changing the capacity mix in PJM, but those considerations are not reflected in, nor fostered by, the RPM price so far, and they will not be differentially satisfied by CRES providers facing RPM prices rather than embedded costs. However, it is possible that pending EPA regulations may induce coal plant retirements that create a new, longer term and larger need for capacity expansion than the RPM market yet reflects~~ or can respond to~~.

Q. WHAT ABOUT THE EFFICIENCY OF PRICES SEEN BY GENERATION CUSTOMERS?

A. Customers of AEP Ohio are currently not seeing the short run prices of capacity in their retail service. Instead, they are seeing average costs, as is appropriate to AEP Ohio's full cost recovery. However, the underlying resources were chosen in a process that considered the best available long-term solutions at the time they were built, and in fact the overall effect of those choices is that AEP Ohio generation has been mostly comparable to or cheaper than the PJM market for the past several years. This is not efficient, but it is attractive to customers and at the same time fair to AEP's investors, who are enjoying reliable cost recovery for having put those resources in place. RPM-based capacity prices would provide a more efficient short term signal, but they would not necessarily induce long term efficient choices by customers, if customers were able to use switching simply to enjoy the "lower of cost or market" alternative (and dodge responsibility for long term development costs). Other adjustments would be needed to offset this impact.

~~**Q. THE EFFICIENCY OF THE PRICE FACING SHOPPING CUSTOMERS DOES SEEM TO DEPEND ON WHETHER RPM OR EMBEDDED COSTS ARE USED, CORRECT?**~~

~~A. Yes, that is correct, but only partially so, as the overall efficiency also depends on how customers are charged for the costs of the risks to AEP Ohio for customers' ability to shop and return to default service. That is, shopping customers would see the most efficient price, in principle, if it was a combination of the PJM RPM-based price for capacity plus market energy costs (LMPs plus adders for losses, transmission congestion, and other services as needed for load following and risk management). However, they would be gaining access to that exercise that choice opportunistically — the "lower of cost or market" choice described previously. Recognizing this, AEP Ohio has designed an option-based POLR surcharge to compensate it for the cost of the risk to AEP Ohio for customer's ability to shop and return to default service that assumes the capacity costs to CRES providers will be the proposed embedded cost rate. These POLR rights would be much more costly if the switching options had been priced based on the RPM-based capacity prices.~~[3]

Q. DOES THE USE OF FORMULA RATES FOR SETTING THE EMBEDDED COST OF AEP OHIO'S CAPACITY TO CRES PROVIDERS CREATE ANY UNDUE TRANSFER OF RISKS OR INCENTIVES THAT COULD DISTORT WHOLESALE GENERATION MARKETS?

[3] ~~It is important to appreciate that this POLR option charge in no way covers the capacity costs of supporting retail customers. It is solely related to the cost of risk that is intrinsic to customers enjoying the right to opportunistically choose the lower cost of two alternatives.~~

A. I believe the question of whether a formula rate is appropriate for AEP Ohio's situation is a separate question from whether CRES providers should have access to AEP Ohio's capacity at embedded costs. I have not reviewed the terms of the proposed formula in detail, though I am aware of its general nature. It is correct to observe that merchant generation companies (who do not have a franchise load under embedded rates for selling their output) do not have a comparable mechanism for recovering their costs of generation capital and operating costs, or any changes to those costs that may arise from shifting regulations or market conditions. This provides a certain degree of financial advantage to AEP Ohio's generation, and embedded pricing to CRES providers continues that advantage.

However, it is also true that the unregulated generation companies enjoy some advantages and flexibilities in power supply and pricing that AEP Ohio's generation does not. In particular, merchant generators do not have an obligation to serve beyond the extent to which they voluntarily enter ~~contract~~ forward sales contracts. If market conditions become unattractive (e.g, if fuel costs rise, or environmental compliance upgrades are too costly to complete and remain profitable in the wholesale markets), they can retire units and not replace them. That is, they do not need to build unless or until market prices are attractive. And under some~~those~~ circumstances (of unexpectedly high demand or low supply), the market price of power may ~~also~~ rise ~~as much or~~ more than the operating costs on their existing infra-marginal units, allowing them to harvest large profits. This is a risky situation (not assured of occurring), but they do have the possibility of large upside gains in tight markets that AEP Ohio does not enjoy under its cost of service arrangements – and such gains might be substantial for a company like AEP Ohio with many baseload units having low operating costs. Overall, this does mean there are differences in risks, incentives and opportunities facing AEP Ohio compared to merchant generators, but those differences arise because the AEP Ohio generation faces different obligations and constraints as well.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I conclude that the proposed use of embedded costs for AEP Ohio's CRES capacity rate is just and reasonable, and that its approval would have no adverse impacts on efficient retail competition. In contrast, requiring the ~~proposed~~ RPM-based rate without other financial compensation adjustments would simply entail AEP Ohio being forced to subsidize its own bypass.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

DIRECT TESTIMONY OF
KELLY D. PEARCE
ON BEHALF OF
~~COLUMBUS SOUTHERN POWER COMPANY~~
~~AND~~
OHIO POWER COMPANY

Filed: March 23, 2012~~August 31, 2011~~

INDEX TO DIRECT TESTIMONY OF
KELLY D. PEARCE

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
KELLY D. PEARCE
ON BEHALF OF
~~COLUMBUS SOUTHERN POWER COMPANY~~
~~AND~~
OHIO POWER COMPANY

PERSONAL BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelly D. Pearce. My business address is 155 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by American Electric Power Service Corporation (AEPSC) as Director-Contracts and Analysis.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Mechanical Engineering from Oklahoma State University in 1984. I received Master of Science and Doctor of Philosophy degrees in Nuclear Engineering from the University of Michigan in 1986 and 1991 respectively. I received a Master of Science in Industrial Administration degree from Carnegie Mellon University in 1994.

From 1986 to 1988 I worked for a subsidiary of Olen Corporation. From 1991 to 1996 I worked for the United States Department of Energy within the Office of Fossil Energy. My responsibilities included serving as a Contracting Officer's

Representative in the oversight and administration of government-funded research of advanced generation and environmental remediation technologies and projects. I also supported strategic studies for deployment and commercialization of these technologies as well as administration and support of Government research and development solicitations. I was promoted twice during this time.

In 1996 I joined AEPSC as a Rate Consultant I. In 2001, I was promoted to Senior Regulatory Consultant. My responsibilities included preparation of class cost-of-service studies and rate design for AEP operating companies and the preparation of special contracts and regulated pricing for retail customers. In 2003 I transferred to Commercial Operations as Manager of Cost Recovery Analysis. In 2007 I was promoted to Director of Commercial Analysis. During this period, I was responsible for analyzing the financial impacts of Commercial Operations-related activities. I also supported settlement of AEP's generation pooling agreements among the operating companies.

In 2010 I transferred to Regulatory Services in my current position of Director-Contracts and Analysis. My group is responsible for performing financial analyses concerning AEP's generation resources and load obligations, various settlement support for AEP's power pools and regulatory support in areas that relate to commercial operations. In addition, my group is responsible for AEP's formula rate contracts.

I am a registered Professional Engineer in Ohio and West Virginia.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I submitted testimony and testified before the Public Utilities Commission of Ohio (Commission) on behalf of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo) in Case No. 11-346-EL-SSO, et al, i.e., the Stipulation.

In addition, I submitted testimony to the Virginia State Corporation Commission (VASCC) in Case Numbers PUE-2001-00011 and PUE-2011-00034 and submitted testimony and testified before the VASCC in Case No. PUE-2001-00306. I also submitted testimony and testified before the Indiana Utility Regulatory Commission in Cause No. 43992. My testimony in these proceedings was on behalf of operating companies that are affiliates of ~~Columbus Southern Power Company (CSP)~~ and ~~Ohio Power Company (OPCo), hereby collectively referred to as AEP Ohio or the Companies~~. For clarity, it should be noted that due to the CSP and OPCo merger, the merged entity, OPCo, will subsequently be referred to as AEP Ohio.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to first discuss the market structure and capacity obligations that require the use of ~~CSP's and OPCo'~~AEP Ohio's generation capacity and the costs associated with this capacity used to support generation service to switching customers. I will then introduce, describe and support the formula rates proposed by AEP Ohio~~CSP and OPCo~~. Theise rates, if adopted, would be utilized to compensate AEP Ohio for capacity that is used by Competitive Retail Electric Service (CRES) providers to serve the former AEP Ohio generation customers in cases where the CRES providers choose not to provide their own capacity. In addition, I will explain some of the specific shortcomings of the use of the PJM Interconnection, L.L.C (PJM) Reliability Pricing Model (RPM) capacity clearing prices as a pricing mechanism for this capacity.

As will be shown in my testimony, the current calculations are based upon 2010 Federal Energy Regulatory Commission (FERC) Form 1 (FF1) information. Since CSP and OPCo were separate entities during that period, the calculations are performed separately for the two, pre-merger companies and then combined to determine a merged AEP Ohio capacity rate. Consequently, within my testimony CSP and OPCo will subsequently refer to the separate, pre-merger entities and for clarity, I will refer to the merged entity as AEP Ohio or the Company.

EXHIBITS

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes, I am sponsoring seven Exhibits identified as follows:

Exhibit KDP-1: Formula Template for CSP,

Exhibit KDP-2: Formula Template for OPCo,

Exhibit KDP-3: Formula Template for CSP populated with 2010 data,

Exhibit KDP-4: Formula Template for OPCo populated with 2010 data,

Exhibit KDP-5: Energy credit for CSP and OPCo,

Exhibit KDP-6: Merged CSP and OPCO Capacity Value

Exhibit KDP-7: PJM Capacity Values

Q. WERE THESE EXHIBITS PREPARED UNDER YOUR SUPERVISION AND DIRECTION?

A. Yes.

APPLICABLE MARKET AND CAPACITY OBLIGATION

Q. WHAT IS THE RATIONALE FOR THE FORMULA RATES PROPOSED?

A. As explained by AEP Ohio witnesses Munczinski and Horton, ~~CSP and OPCo~~ AEP Ohio elected to utilize the Fixed Resource Requirement (FRR) option to provide or "self-supply" capacity to meet their load serving entity (LSE) obligations rather than acquire this capacity through the PJM RPM market. Since ~~the Companies are~~ AEP Ohio is self-supplying its ~~their~~ own generation resources to satisfy these load obligations, the costs to provide this capacity is the actual embedded capacity cost of AEP Ohio's ~~CSP's and OPCo's~~ generation.

Q. UNDER THE FRR OPTION HOW LONG IS THE COMMITMENT TO PROVIDE CAPACITY TO CRES PROVIDERS?

A. In accordance with PJM rules AEP Ohio must make this commitment three years in advance. The Company is ~~ies are~~ then fully committed and locked-in to providing the capacity resources needed for all of the loads that are contained in thei~~r~~ forecasted load requirement, plus the additional capacity necessary to satisfy the required Installed Reserve Margin (IRM).

Q. HOW DOES RETAIL CHOICE IMPACT THIS PROCESS?

A. At the time the Company ~~ies~~ completed its portion of the AEP ~~their~~ PJM FRR capacity plan, it~~they must~~ included all of its forecasted retail loads within the AEP Zone, which was ~~are~~ then used to determine the capacity obligation. Subsequently, if CRES providers sign up any of this AEP Ohio ~~ese~~ load~~s~~, the CRES providers are required and obligated to reimburse the Company~~ies~~ for their capacity costs that have already been committed to serve this load during the PJM Planning Year (PY) that is for the 12-month period from June to May.

Q. IS THERE ANY EXCEPTION THAT ALLOWS AEP OHIO TO REDUCE ITS CAPACITY OBLIGATION TO ACCOUNT FOR LOADS SERVED BY CRES PROVIDERS?

A. Yes, there is one exception. If a CRES provider had notifie~~s~~d AEP Ohio prior to the submittal of its capacity plan for a future planning year, which occurs three years before delivery~~,~~ that the CRES provider will supply its own generation capacity for that year, then AEP Ohio would have ~~may~~ reduced its own capacity resources by an equivalent amount for that year. The CRES provider could have ~~may~~ elected this option for load it ha~~s~~d already signed up for the applicable planning year and/or for load it anticipate~~s~~d serving or hope~~s~~d to sign up in the three years prior to the applicable planning year.

Q. SO IF CRES PROVIDERS D~~O~~ID NOT AVAIL THEMSELVES OF THIS OPTION, HOW IS THE CAPACITY OBLIGATION OF THESE CUSTOMERS MET?

A. It is unchanged. ~~If~~ Since CRES providers cho~~o~~se not to self-supply, then AEP Ohio~~CSP and OPCo~~ was *required* to ~~must~~ commit the capacity necessary to serve all customer ~~load~~loads, *including loads already committed to a CRES provider for the future period.* In short, in that situation, shopping customers' capacity obligations continue to be met by the capacity resources of AEP Ohio.

Q. HOW IS AEP OHIO IMPACTED BY THIS RESULT?

A. AEP Ohio continues to maintain and provide the capacity resources for shopping customers, but no longer receive these customers' generation revenues.

Q. IS THERE ANY COMPENSATION MADE TO AEP OHIO FOR THIS CAPACITY COMMITMENT?

A. Yes. Under the Commission's current interim compensation mechanism, CRES providers reimburse AEP Ohio a capacity payment that is based on the RPM clearing price.

Q. DO THESE PAYMENTS PROVIDE AN APPROPRIATE LEVEL OF COMPENSATION?

A. No, they do not provide an appropriate level of compensation. CRES providers have chosen to use the capacity of AEP Ohio, as opposed to self supplying capacity, and as such should fairly compensate the Company~~ies~~ for the cost of that capacity. The formula rate that I describe below provides fair and appropriate compensation for use of the Company's~~ies'~~ capacity.

FORMULA RATE DESCRIPTION

Q. PLEASE GENERALLY DESCRIBE THE DEVELOPMENT OF THE FRR-BASED REIMBURSEMENT RATES PROPOSED BY AEP OHIO~~CSP AND OPCO~~.

A. ~~CSP and OPCo~~ AEP Ohio utilized a formula rate approach for this capacity that is based upon the average cost of serving AEP Ohio's ~~CSP's and OPCo's~~ LSE obligation load, both the load served directly by ~~CSP and OPCo~~ AEP Ohio or by a CRES provider, on a ~~$~~dollar per ~~/~~MegaWatt-day basis. By CRES providers paying a rate that is based upon average costs, they are neither subsidizing nor being subsidized by AEP Ohio~~CSP and OPCo~~.

Q. PLEASE PROVIDE AN EXAMPLE OF THE SUBSIDIZATION THAT CAN OCCUR.

A. Under FRR, the Compan~~ies are~~y is providing its~~their~~ own generation resources to provide the capacity obligation. The costs associated with these assets tend to be fairly constant or "fixed" over the near term. If switched load is still served using these assets, but the CRES providers are allowed to pay a rate that is above or below those costs, then the CRES providers are inappropriately subsidizing or being subsidized by AEP Ohio.

Q. WHAT ARE SOME OF THE ADVANTAGES OF THE FORMULA RATE APPROACH?

A. Formula rates are currently utilized in many states by AEP for other wholesale sales. As previously stated, the formula rates use an average allocation of cost between the parties based on common cost allocation mechanisms.

Second, the formula rate approach provides a high degree of transparency. The bulk of the input information can be tied back to the ~~Federal Energy Regulatory Commission (FERC) Form 1 (~~FF1~~)~~ annual reports of the Company~~companies~~ and the various work papers are readily available to the affected parties upon request for rate verification. What is ~~are~~ approved as the rate~~s are~~ is the formulas itself~~themselves~~. Following approval, the rate~~s are~~ is simply updated using the next year's accounting information. As a result, updating the rate becomes a straightforward, fairly mechanical process and the updates are readily available for regulatory review.

Under the Company's~~ies~~ proposal, rates will be known prior to the beginning of a given PJM PY.

Q. WHAT IS THE SOURCE OF THE RATE TEMPLATE THAT IS PROPOSED IN THIS PROCEEDING?

A. The formula rate template selected for this rate development is modeled after the template recently approved by FERC to derive the capacity charges applied to wholesale sales made by Southwestern Electric Power Company (SWEPCo), an AEP Ohio-affiliated operating company, to the Cities of Minden, Louisiana and Prescott, Arkansas. These cities are full requirements customers taking both capacity and energy from SWEPCO under long term agreements. This formula rate was the subject of a lengthy negotiation between the seller and purchasers and FERC Staff. In addition, it adopts various modifications originating from FERC Staff. As such, this template represents a fair and reasonable formula for calculation of capacity costs. The capacity portion of this formula rate template was used to develop the proposed AEP Ohio ~~CSP and OPCo~~ capacity rates.

Q. HOW ARE THE RATES UPDATED?

A. Under AEP Ohio's proposal, the Company~~ies~~ will utilize a given year's FF1 annual report shortly after it is available to update the capacity rates that will be available for the subsequent PJM PY. For example, once the 2011 FF1 becomes available, currently required by FERC no later than April 18, 2012, AEP Ohio will update the capacity rates and have it ~~them~~ available no later than May 31, 2012. This is ~~ese are~~ the rates that will be in effect for the PJM PY 2012/2013 that runs from June 1, 2012 through May 31, 2013. The same process will be used for each subsequent year as long as such rates are in effect, currently anticipated to end after the PJM PY 2014/2015.

CAPACITY RATE

Q. PLEASE DESCRIBE THE CAPACITY PORTION OF THE RATE IN DETAIL.

A. The blank or unpopulated formula rate templates ~~for the Companies~~ are provided in Exhibits KDP-1 and KDP-2 for CSP and OPCo, respectively. These Exhibits utilize common cost allocation principles in that they are used to compute an average per unit cost that includes the cost of capital on assets and actual expenses incurred. The final daily charge calculation that would be used to compute the individual CRES providers' bills based on their applicable MW capacity is shown on page 1 of each of these Exhibits. This is the same calculation performed today by AEP to bill CRES providers for load they are currently serving. The cost based capacity rate calculation, before application of the loss factor, is shown on page 2 of these Exhibits. As seen throughout these Exhibits, the specific references for the inputs are clearly shown. The FF1 annual reports are utilized heavily throughout these templates for source data. In certain instances, additional detail is obtained from the Companies' books and records (CBR), such as the income statements.

Q. ARE THERE ANY ITEMS IN PARTICULAR TO NOTE?

A. Yes. As shown on page 6, line 4 of Exhibits KDP-1 and KDP-2, the annual production costs are reduced by the amount of revenues that are collected from other wholesale entities related to capacity transactions. These revenues include capacity transactions with affiliates and non-affiliates alike. As a result, CRES providers will get the benefit of these transactions and are not paying for any capacity cost that is associated with transactions to other wholesale entities, including affiliates and PJM RPM market participants.

Also, as shown on page 5, line 8 of these Exhibits, only 50% of the non-pollution control construction work in progress (CWIP) is included, which, as previously explained, is a result of the templates used to develop these rates.

Q. ARE THERE ANY DIFFERENCES RELATIVE TO THE FERC-APPROVED TEMPLATES FOR MINDEN AND PRESCOTT?

A. Yes. The Company has made three significant modifications to the templates relative to the capacity portion of the rates approved at FERC:

- the peaks used to determine the capacity rates,
- the Return on Equity (ROE), and
- the elimination of a post-period reconciliation and the resulting use of end-of-year account balances rather than annual average amounts.

Q. PLEASE DESCRIBE THE FIRST CAPACITY MODIFICATION.

A. As noted on page 2 of Exhibits KDP-1 and KDP-2, the denominator is based on the average CSP and OPCo peak demands that are coincident with the PJM five highest daily summer peak demands. This is appropriate in order to be consistent with the demands used to charge CRES providers today through the PJM settlement process.

Q. PLEASE DESCRIBE THE SECOND CAPACITY MODIFICATION.

A. The ROE approved in the original template was 11.10%. The ROE has been modified to a fixed 11.15% to be consistent with the ROE proposed in CSP's and OPCo's ~~pending~~ distribution proceedings, Case Numbers 11-0351-EL-AIR and 11-